A NOTE ON THE ECONOMIC PRINCIPLES OF ELECTRICITY PRICING

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IN THIS note we attempt to explore the economic principles of electricity pricing. While we shall make some references to theoretically ideal pricing principles, we shall for the most part be concerned with practical rules which can be expected to come reasonably close to the theoretically ideal solutions.

We proceed on the assumption that the rate of return to be earned by capital invested in electricity undertakings is given. This rate of return will presumably be the appropriate "shadow rate of interest" for the economy in which the electricity undertakings are located. Under some circumstances this shadow rate of interest may not be a unique number but may vary among investments in accordance with their riskiness; in such a case the rate to be applied to electricity undertakings is that corresponding to the estimated degree of riskiness of these investments.

One principle which is of primordial importance in the theory of electricity pricing is that the rate structure should foster the full utilization of available capacity. This principle should not be interpreted to mean that full utilization should be sought at all costs, however. The way in which it works can best be illustrated by an example of a single thermal station working in isolation. If under an initially prevailing rate structure the plant is used to full capacity only 50 per cent of the time, it is worth while to reduce the charges for electricity during those periods in which the capacity is not fully used. In some cases a small reduction in the charge will induce additional demand for electricity in these off-peak hours to the point where full capacity utilization is achieved. But most commonly there will be some periods during which even very substantial reduction of tariffs will be insufficient to induce full capacity utilization. For such periods the minimum admissible tariff is one which covers the marginal costs of generating and distributing the electricity. These include principally the costs of the coal or other fuel necessary to generate electricity during these off-peak hours plus a charge to cover the losses of electricity in transmission and distribution.

The practical rule of electricity pricing which we would advocate to cover this case would be that the marginal cost of producing and delivering electricity should be the price during off-peak hours, while during peak hours the tariff should include, in addition to the marginal cost, a charge for the fixed costs of the plant. The appropriate charge could be obtained by dividing the annual fixed costs associated with the plant by the number of kw hours of peak-time electricity generated during the year. If running costs were 4 np. per kwh this would be the charge during off-peak hours. If the annual fixed costs associated with the plant were Rs. 8,000, and the number of kwh generated during peak times was 100,000 in a year, the extra charge for peak-time use of electricity would be 8 np. per kwh, and the total charge for peak-time use would be 12 np. per kwh.

The reader may already suspect the ways in which this rule might lead to trouble. There may have been 100,000 hours of peak-time use of electricity during a prior period in which all kwh were priced at an average cost of, say, 8 np. But when the charge for these particular hours is raised to 12 np. per kwh it may be that the system is no longer used to capacity during all of the previous peak-time hours. The theoretical solution which is indicated here is a tariff which varies according to the time of day, and perhaps also according to the season of the year, in such a way as to induce the maximal utilization of existing capacity, subject to the constraint that the charge should never be lower than 4 np. per kwh. Such a tariff structure could theoretically be obtained for any existing system, and it would be independent of the shadow rate of interest. A tariff which varied in such a way as to ration the available capacity among existing users when their demand exceeded capacity and which offered electricity at marginal cost when demand failed to reach capacity would be ideal from the allocative point of view. If the amounts collected in excess of marginal cost during the times when electricity was being rationed by way of the tariff fell short of an acceptable rate of return on investment, there would be no reason to expand capacity. When, however, these receipts rose above the shadow rate of return on capital, this would be a signal that further investment in capacity was economically desirable.

From the above example it is easy to see that the theoretical solution could not be put into practice in its full detail. However, the essence of this solution–a distinction between peak-time use of electricity (which is charged with the fixed costs of the system) and off-peak use

of electricity (which is charged only with the marginal costs of generation and distribution)—is preserved in the practical rule which we suggest. This rule, perhaps with minor variations, would be applicable for any system, however large, which is exclusively thermal.

We now consider the case of a system in which thermal and hydro capacity are combined. We assume first a situation in which the hydro capacity is of the run-of-the-stream type. It is the nature of run-of-the-stream projects that both the capacity output of the hydro undertaking and the timing of that capacity output are determined. In some cases the mechanical generating capacity will be sufficiently great to utilise to the full the seasonal maximum flow of water in the stream. In this case the flow of water is the thing which fundamentally determines the capacity output of the hydro part of the system. In other cases, the generating capacity may not be sufficient to utilize the maximum flow of water. Here, there are likely to be times during the year when capacity output of the hydro operation is determined by the flow of water in the stream and other times when this capacity is determined by the amount of generating equipment installed. For our present purpose, however, this distinction is not important. The important thing is that in any given run-of-the-stream hydro undertaking both the total annual maximum output and its timing are determined. Under such circumstances, and given the fact that the running costs of such a project are virtually negligible it is pointless to allow any potential output to go to waste. Therefore, it is evident that the full capacity of a run-of-the-stream hydro project should be brought into plat before any connected thermal capacity is called upon to produce electricity. The run-of-the-stream hydro undertaking should serve as the base load of the system.

The principle of rate making in this case is essentially the same as that discussed above for the purely thermal system. The peak load of the system will be borne by thermal capacity and the charge per kwh during the peak period should cover both the fixed and running costs of thermal electricity. If thermal electricity is required to supplement hydro electricity during any of the off-peak hours of the system the appropriate charge for these hours will be the marginal costs of producing thermal electricity. In the remaining off-peak hours, if any, when no thermal electricity is used, and the output of the run-of-the-stream hydro undertaking is below its full potential, the appropriate charge would be the running cost of producing and delivering the hydro power — a charge which would generally be very low indeed.

When thermal capacity is combined with hydro capacity of the storage type the roles of hydro and thermal production are the reverse of those indicated for the preceding case. A hydro-storage undertaking differs markedly from the run-of-the-stream operation in that the timing of the production of hydro power now becomes subject to control of electricity authorities. Broadly speaking, the total electricity output which a hydro-storage project can produce during the dry season is determined by the amount of water which it can store. But the flow of water through the generators can be cut off at any time the authorities desire, permitting the use of this hydro capacity for accommodating the more extreme variations in the level of total demand of the system. If, as in India, the rainy season is short and the dry season long, one can without great error distribute the total annual cost of the hydro-storage operation equally over all the kwh produced during the year. The cost per kwh thus obtained may be considered as the marginal per kwh produced by a hydro-storage project. But as we shall see this cost is not likely to be relevant for the purpose of rate making.

The best way to understand the principle of rate making when a hydro-storage project is combined with thermal facilities is to visualize a graph in which the total demand for the system's electricity is plotted for the different hours in the year. There may be a few hours in the year when the system is called upon to deliver 200,000 kw, more hours when the system is called upon to deliver at least 160,000 kw, still more hours when at least 140,000 kw are demanded, etc. The rule in this case is to use the hydro-storage capacity to accommodate the peak demand of the system. One way in which it might work out would be that hydro capacity would be called into play only when the demand for electricity in the entire system exceeded 140,000 kw, and only to fill the amount by which system demand exceeded 140,000 kw. The way in which the critical level of demand is determined, at which hydro capacity should come into play, is as follows. If using hydro capacity to meet demand in excess of 140,000 kw would lead to the exhaustion of the water supply significantly before the end of the dry season, then 140,000 kw is too low a critical level. If, on the other hand, the use of a critical level of 140,000 kw would leave significant quantities of water in storage at the end of the dry season, then this critical level is too high. The critical level should be set in such a way that under normal circumstances the rule of using hydro capacity only to meet demand in

excess of the critical level can be expected to lead to a situation in which the amount of water stored in the dam is just exhausted at the end of the dry season.

We now turn to the actual process of rate making in this case: Obviously, with hydro capacity serving to meet peak-time demand, the rate charged for truly off-peak use of electricity should be the marginal cost of producing and distributing thermal power. This rate will come into play at those times when the system has some unused thermal capacity. But what is specially interesting about this case is the fact that thermal costs also determine the peak-time charge for electricity, even though the brunt of the peak load is borne by hydro power. The way in which this apparently anomalous result emerges is as follows. Any significant increment in peak-time demand will require the raising of the critical level on which hydro capacity is brought into play. For example, a substantial increase in peak-time demand might require the raising of the critical level from 140,000 kw to 160,000 kw. Now the full capacity of the dam would be utilized in providing for electricity about the 160,000 kw. point, and if previously the available thermal capacity was only 140,000 kw the increase in peak-time demand will require the expansion of capacity by 20,000 kw. Both the fixed and the variable costs of this expansion in capacity should be borne by those who demand electricity at peak time. Thus the appropriate charge for peak-time use of electricity will be determined by the cost of expanding thermal capacity.

The existence of storage hydro capacity capable of being used for peaking purposes is likely to lower the peak-time charge for electricity and to broaden the period to a greater number of hours. When a system is purely thermal it may have to meet peak demand in, say, four hours of the day, and these peak demands may be very substantially higher than the average volume of electricity demanded during the rest of the day. If hydro capacity is available it may be able to accommodate not only this very concentrated demand, but also something in addition. The critical level may be below the point associated with a four-hour daily peak. Hydro capacity may, for example, be able to meet the excess demand over a level which is typically achieved in 10 or 12 hours of the day. If this is the case then an increase in peak demand will call for an increase in thermal capacity which can be expected to be utilized for 10 or 12 hours in the day. The rate for peak-time use of electricity would accordingly be the rate determined by spreading the fixed annual costs of thermal capacity over 10 or 12 hours of the day rather than, say, four hours a day; and the peak-time rate will accordingly be lower than it would have been in a purely thermal system with comparable demand conditions.

One may enquire whether the above rule of rate making would still apply if the rate determined for peak time on the basis indicated was lower than the cost per kwh obtained by dividing the total annual costs of the hydro project by the number of kwh which it generated. That is to say, does the rule still apply if it calls for a rate which would yield an accounting loss to the hydro operation? The answer, we believe, is that the rule should apply even in this case. Incremental peak-time demand can in fact be made at the costs which are indicated by the rule. Moreover, in a situation of growing demand the observation of the rule is likely to lead to progressively greater accounting profits for the hydro operation. When at a given state of development the storage capacity of the dam is very large relative to total demand and to associated thermal capacity, it may work out that the peak of the thermal part of the system is 18 or 20 hours a day. But as demand grows it is not likely that the storage capacity of the dam will grow along with it. The result is that thermal capacity will have to expand to meet the increased demand. As this occurs, the capacity of the hydro project will become a progressively small fraction of the total capacity of the system. The critical level will rise, the peak of the system will become progressively smaller, and the peak-time charge for electricity will become progressively higher. Since for accounting purposes the electricity produced by the hydro capacity should be valued at the peak-time charge, it is clear that the total value of the hydro project's output will rise progressively, and its profitability should also rise.

We turn now to a discussion of the principles of rate making in projects which are purely hydro. In a storage project there is the presumption, already indicated, that the total annual output of electricity is given, and that its timing is subject to a considerable degree of control. As long as this is the case there is no point in attempting to distinguish between peak and off-peak use of electricity. The rule for rate making in this case is to charge an equal amount for each kwh. This amount should in principle be governed by the demand conditions. That is, the available amount of electricity should be rationed among demanders by adjusting the price of electricity. If the available amount of electricity is very large it may for a time fetch a price which is too low to cover the annual fixed costs of the project including the shadow return on invested capital. But as demand grows the price which this electricity will fetch is likely to rise. The movement of this price will give the appropriate signal as to when new capacity should be added to the system.

In the case of a run-of-the-stream hydro project, operating in isolation, the principle of rate making is to ration the available amount of electricity, varying the rate per kwh both by time of day and by season. As this principle is difficult to apply in practice, we suggest the following rule which approximates its effects. The rule should be to charge a higher, possibly much higher, rate during peak periods. This peak-time rate should in every case be sufficiently high to maintain demand within the limits of capacity. In some cases this rule might lead to some difficulties, such as a very narrow peak arising when the charge is sufficiently high to contain demand at the time when electricity is most wanted. It may be that at this maximum peak-time price there is a peak of only one or two hours in the day, but if, for the remaining hours, only running costs are charged, then the demand in some of these other hours will exceed the system's capacity. Under these circumstances, the appropriate action is to institute two levels of peak-time tariff — one for the very high peak of one or two hours, and the second, a lower tariff for these intermediate hours for which demand is below capacity when electricity is charged at the high peak rate, and above capacity when electricity is charged at running cost.

II

The discussion of the preceding section was based on the assumption that any *additional* marginal capacity to be acquired by a system would be thermal. This assumption is justified by the special characteristics of hydro production. The number of potential hydro-electric sites in an area is always limited, and as demand grows, their capacity is likely to be exceeded. If, for a time, new hydro-power can be obtained more cheaply than additional thermal power, then naturally additional capacity should be hydro, and the principles of pricing should be those outlined for the purely hydro case. But we believe that this situation is not very likely to be important in most areas of India. The continued rapid growth of demand for electricity will surely press on the limits of available hydro sites. Moreover, the continued formation and widening of grid networks will tend to produce systems containing both hydro and thermal plants, and thes systems will surely require expanding amounts of thermal capacity to meet expanding demand. Thus the cases discussed in the preceding section are likely to be the most relevant ones for future decision-making in India. However, in order not to ignore alternative possibilities completely, we here list the ways in which marginal expansion by way of hydro rather than thermal capacity could take place, and we comment briefly on the rate policy and/or investment policy appropriate in each contingency.

(a) *Provision of additional storage capacity in a purely hydro project*: New capacity should surely be added, if it is possible to add it, when the output of the new facilities can be expected to yield a sufficient return to justify the added investment. The effort should be made to charge the same basic rate for the full output of the enterprise; in general this will entail a lower rate than the one which would have rationed output prior to the expansion of capacity. On occasion it may be true that the flat rate per kwh which would ration the new output yields a return on the prospective new capacity too low to justify the investment, and yet the investment may in fact be justified. This result can occur because it may be possible to establish a set of tariffs which discriminate among classes of users, among times of day, and/or among seasons of the year, and which would yield sufficient revenue to justify the additional investment. The highest rate charged under this discriminating pattern should, however, be no higher than the basic rate which would have rationed the output of the old capacity among consumers. When computing the return attributable to the new investment in such a case, the total income accruing to new and old capacity should be divided between them in proportion to their contributions to output.

(b) *Provision of additional storage capacity in a thermal or hydro-thermal project*: Adding to storage capacity will lower the critical level at which hydro generation comes into play. It will accordingly broaden the peak of the thermal part of the system, and lower the peak-time charge. If at the lower charge for peak-time electricity, an acceptable return for the new investment is obtained, the investment is justified.

(c) *Provision of additional run-of-the-stream base-load capacity*: Normally this should have no influence on rates, as the tariffs should be determined by the costs of providing peak-time electricity. As long as thermal capacity is necessary for peak use both before and after the addition of the new base-load capacity, there should be no change in peak-time rates. And off-peak rates should change only in the case where the additional base-load capacity causes the displacement of thermal capacity from off-peak hours. To determine whether investment on additional hydro base—load capacity is worth while, the prospective output of the new capacity can for all practical purposes be valued at the rates prevailing before the addition to capacity. Where the additional capacity is built to take advantage of seasonal high flows of water, only output over and above the pre-existing capacity should, of course, be attributed to it.

(d) *Provision of additional generating facilities on a hydro-storage project* typically has two effects. First, it increases the output obtainable from the project in the rainy season. This is analogous to run-of-the-stream output, and should be treated as base-load output of the system. Second, the additional generating facilities, while not adding to the storage capacity of the dam, do increase the flexibility of use of that capacity, by augmenting the maximum instantaneous output which it is possible to generate. While a theoretical case could be made for the charging of a special peak-within-a-peak rate for electricity generated at times when the hydro generating capacity was fully utilized, we do not consider this to be a practical policy. We prefer to look upon the benefits of additional hydro generating capacity in a given storage project as consisting of

(1) the value of the extra base-load electricity generated during the wet season because of this added capacity, and

(2) the extra revenue which can be obtained from stored water during the dry season because of the extra generating capacity. Paradoxically, the increased generating capacity has the function of *raising* the appropriate peak-time charge for electricity. It does this by increasing the flexibility of use of hydro capacity and meeting peak demands of short duration which might otherwise have to be left unsatisfied. As a result of this flexibility, the "critical level" of thermal output is slightly raised, and the thermal peak slightly narrowed, with the consequence of a slight rise in the appropriate peak-time rate applicable to all the electricity produced by the storage project.

III

The distinction made in the previous sections between peak-time and off-peak rates for electricity requires, for its proper implementation, that the electricity undertakings be able to measure not only the total amount of electricity used by a consumer but also the amounts used at peak and off-peak times. Meters are available to do this job, but they are too expensive for use in the case of small consumers. They can, however, easily be used for large industrial consumers, and we shall assume that this group's consumption of power is so metered.

In this section we inquire into the possibilities of adopting "second best" methods which would approximate the effects of a time-tariff for the several classes of small consumers (domestic, small industrial, commercial). What makes such approximate methods possible is the fact that the electricity consumption of each type of user tends to be concentrated on a relatively well-defined period of the day. Thus, while some domestic consumption of electricity takes place in day time and late-night hours, the overwhelming bulk of this class's consumption occurs between nightfall and, say, 10 p.m. On the other hand, small industrial consumption is concentrated in the day-time hours, having its peak between around 9 a. m. and around 5 p. m. Commercial consumption tends to have its peak between nightfall and, say, 8 p.m, the precise timing depending on the store hours which are customarily observed.

In the case of purely hydro-storage system or of a thermal-cum-hydro-storage system, one need not worry seriously about the distinction between peak and off-peak hours. In the pure hydro-storage system, all kwh generated should in any case be charged at the same basic rate. In the thermal-cum-hydro-storage system, the thermal peak is likely to be quite broad—in the order of 10 to 14 hours a day, aggregating perhaps to 4000 or 5000 hours a year. With such a broad peak, some 80 or 90 per cent of the total thermal output of the system is likely to be at peak time. The ideal solution would be to charge a basic rate of roughly 4 np. per kwh in off-peak times (this is a rough estimate of the average running cost of thermal electricity in India), and a basic rate of around 11 np. per kwh in peak hours. (This is obtained by spreading the estimated annual fixed costs (Rs. 280) of thermal-capacity over 4000 peak-time hours, and adding the resulting charge to the 4 np. running cost per kwh.) But since for small consumers there is no way of distinguishing peak from off-peak consumption, the best practical solution is simply to charge the basic rate of 11 np. for all kwh they consume. The resulting "overcharge" for

electricity taken in off-peak hours will apply only to a small fraction of the total electricity taken by these groups.[1]

In the case of a purely thermal system, or of a system where run-of-the stream hydro capacity serves as base load with thermal capacity meeting peak-time demand, the situation is a bit more complicated. Here the appropriate rate policy depends on the pattern of demand for the total output of the system. The relevant alternative patterns are three, which differ according to the timing of the system peak. There may be a "lighting" peak, between the hours of, say 6 p.m. and 10 p. m.; a "day time" peak, between the hours of, say, 9 a. m. and 5 p.m.; or what we shall call a "plateau" peak, extending all the way from, say, 9 a. m. to 9 or 10 p. m.

The "plateau" peak has identical consequences for rate making as the extended thermal peak which emerges when thermal and hydro-storage capacities are joined in a single grid. For large industrial users, peak-time charges in the order of 11 np. per kwh are indicated, and off-peak charges in the neighbourhood of 4 np. per kwh. For other users, a basic charge of around 11 np. per kwh is indicated for all the electricity they consume.

The "lighting" peak occurs when the demands of domestic and commercial consumers, together with public lighting requirements, more than offset the normal night-time dip of industrial consumption. The peak is narrow, perhaps some 4 hours a day, or around 1500 hours a year, and thermal capacity must be built and maintained to meet this peak demand. It is only natural that the peak-time charge required to make this investment pay off should be high. Spreading Rs. 280 of annual fixed charge per kw of capacity over 1500 hours of peak-time use gives a fixed charge per kwh of roughly 19 np., to which must be added running cost of around 4 np., per kwh. The total basic charge for peak-time electricity is thus around 23 np., per kwh and that for off-peak use is around 4 np. per kwh. Large industrial users should in these circumstances pay the higher rate for peak-time use and the lower rate for use at other times. Domestic and commercial users should pay the 23 np. basic rate for all the electricity they consume, as the great bulk of their consumption takes place during the lighting peak. Public lighting authorities, whose use of electricity extends well beyond the lighting peak, could easily like large industrial

1 An overcharge for off-peak use is inevitable in this case, and there is no point in reducing the peak-time charge below the appropriate level in an effort to sweeten the pill.

consumers, be charged on a time-tariff basis. Even without special metering it is possible to estimate with great precision the time pattern of electricity use by these public authorties.

Special difficulties arise, in the case of lighting peak, mainly with respect to small industrial consumers. The bulk of their consumption is presumably outside the hours of the lighting peak, so that one may argue for charging them a basic rate as low as 4 np. per kwh. On the other hand, charging this rate for all their consumption might cause them to increase their electricity use not only in off-peak hours, when the system has idle capacity to serve them, but also in peak hours. The electricity authorities can safeguard themselves against this possibility by charging this group the basic rates corresponding to a "plateau" peak (estimated at around 11 np. per kwh). Since the consumption per hour of this group is certainly less in the "lighting-peak" hours than in day time, charging them on a basis which would be appropriate if their consumption were the same in these two periods will yield more than sufficient revenue to cover the fixed charges associated with whatever capacity their peak-time demand requires. Thus, depending on the judgment of the electricity authorities as to how much electricity small industrial consumers are likely to demand during the lighting peak, the appropriate basic charge for these users should be somewhere between 4 np. and 11 np. per kwh.

The "day-time" peak occurs when the concentration of industrial demand in day-shift work outweighs the impact of lighting demand in the early evening. Day-time peaks are typically of the order of 8 hours' duration, so that (making allowances for Sundays etc.) peak-time demand would amount to some 2500 hours per day. The annual fixed charge of Rs. 280 spread over 2500 hours, yields a fixed charge per kwh of around 11 np., which, together with running costs of 4 np., implies a basic peak-time rate of around 15 np. This is the appropriate basic rate for small industrial consumers in the case of a day-time peak. For the commercial and residential consumers the situation would be analogous to that of small industrial consumers when the system has a lighting peak. The appropriate basic rate here would lie between 4 and 11 np. per kwh, the choice within this range depending on the extent of commercial and residential demand which the electricity authorities estimate will occur during the day-time peak.

IV

In this section we attempt to draw the main implications for rate policy which emerge from this analysis. The first and probably most important of these implications is the dominant role which thermal costs are likely to have for rate-setting. In grids containing both hydro and thermal capacity, the relevant marginal costs of additions to capacity will almost certainly be thermal costs. Thus only in grids containing essentially no thermal capacity, which are unlikely to be important as demand and grid-formation expand, will one have to look to other than thermal costs in order to find the appropriate levels of tariffs.

The dominance of thermal costs is a particularly convenient fact if one wants to estimate rough "norms" for electricity rates for a country in which, as in India, a great number of systems or grids exists. This is because the costs of thermal capacity do not exhibit nearly such wide geographical variations as the costs of hydro capacity. Variations in capital costs per kw of thermal capacity stem mainly from differences in the sizes of generating plants. Given that India has by now entered a stage in which most additional thermal plants are in the order of 100 kw or more of capacity, the capital costs per kw of such additions are not likely to be very different as one moves from site to site. For expansions of thermal capacity in the next decade, Rs. 700 per kw can be regarded as a low capital cost, and Rs. 1,000 per kw can be regarded as a high capital cost, at least so long as the present foreign exchange rate prevails. To this must be added a capital cost of transmission and distribution facilities of some Rs. 500 per kw of installed capacity, and a capitalized charge for interest accumulated during the gestation period (here estimated at 15 per cent of the total invested capital). The plausible range for total capital-at-charge at the beginning of operation of newly added facilities is thus from Rs. 1,380 to Rs. 1,725 per kw of new capacity. At a charge of 12 per cent for interest-cum-depreciation, the annual fixed charge directly associated with the added capacity would be between, say, Rs.140 and Rs. 175 per kw. To this must be added an annual charge of Rs. 100 to Rs. 150 per kw for the maintenance of the capacity in operating conditions, and for associated administrative expenses. Total annual fixed charges per kw of capacity are therefore likely to range between Rs. 240 and 325. Running costs per kwh of electricity produced are unlikely to be lower than 3 np., and unlikely (even in regions remote to the sources of coal) to be higher than 5 np.

(4)

The accompanying tables 1 and 2 give the range within which electricity rates might be expected to lie, if they are to be set on the economic principles outlined in this paper. Table 1 gives minimum levels for rates obtained by using an annual fixed charge of Rs. 240 and a running cost of 3 np. per kwh. Table 2 gives maximum levels obtained by using an annual fixed charge of Rs. 325 and running cost of 5 np. per kwh. In Table 3 the midpoints of the ranges demarcated by the entries in tables 1 and 2 are presented, to indicate plausible average rates for the different types of systems and categories of consumers. For convenience of reference, the ranges emerging from tables 1 and 2 are denoted in parentheses following each figure in Table 3.

TABLE 1

PLAUSIBLE MINIMUM BASIC ELECTRICITY RATES (in np/kwh) CLASSIFIED BY TYPE OF SYSTEM AND CONSUMER CATEGORY

Category of consumer / *Type of system*	*Large industrial*	*Small industrial*	*Commercial & residential*
Thermal-cum-hydro-storage			
(a) 12 hour thermal peak (4000 hrs/yr)	8* / 3†	8	8
(b) 9 hour thermal peak (3000 hrs/yr)	11* / 3†	11	11
Purely Thermal or Thermal-cum-base-load-hydro			
(a) plateau peak (4000 hrs/yr)	8* / 3†	8	8
(b) lighting peak (1500 hrs/yr)	19* / 3†	3-8	19
(c) day time peak (2500 hrs/yr)	13* / 3†	13	3-8

* during system peak † during off-peak periods

TABLE 2

PLAUSIBLE MAXIMUM BASIC ELECTRICITY RATES (in np/kwh) CLASSIFIED BY TYPE OF SYSTEM AND CONSUMER CATEGORY

Category of consumer / *Type of system*	*Large industrial*	*Small industrial*	*Commercial & residential*
Thermal-cum-hydro-storage			
(a) 12 hour thermal peak (4000 hrs/yr)	13* / 5†	13	13
(b) 9 hour thermal peak (3000 hrs/yr)	16* / 5†	16	16
Purely Thermal or Thermal-cum-base-load-hydro			
(a) plateau peak (4000 hrs/yr)	13* / 5†	13	13
(b) lighting peak (1500 hrs/yr)	27* / 5†	5-13	27
(c) day time peak (2500 hrs/yr)	18* / 5†	18	5-13

* during system peak † during off-peak periods

TABLE 3

PLAUSIBLE AVERAGE BASIC ELECTRICITY RATES (in np/kwh) CLASSIFIED BY TYPE OF SYSTEM AND CONSUMER CATEGORY

Category of consumer / *Type of System*	*Large industrial*	*Small industrial*	*Commercial & residential*
Thermal-cum-hydro-storage			
(a) 12 hour thermal peak (4000 hrs/yr)	10.5 (±2.5)* / 4.0 (±1.0)†	10.5 (±2.5)	10.5 (±2.5)
(b) 9 hour thermal peak (3000 hrs/yr)	13.5 (±2.5)* / 4.0 (±1.0)†	13.5 (±2.5)	13.5 (±2.5)
Purely Thermal or Thermal-cum-base-load-hydro			
(a) plateau peak (4000 hrs/yr)	10.5 (±2.5)* / 4.0 (±1.0)†	10.5 (±2.5)	10.5 (±2.5)
(b) lighting peak (1500 hrs/yr)	23.0 (±4.0)* / 4.0 (±1.0)†	4.0 (±1.0) — 10.5 (±2.5)	23.0 (±4.0)
(c) day time peak (2500 hrs/yr)	15.5 (±2.5)* / 4.5 (±1.0)†	15.5 (±2.5)	4.0 (±1.0)— 10.5 (2.5)

* during system peak † during off-peak periods

In order for the reader to interpret the electricity rates given in tables 1 to 3, we must clarify what we mean by "basic" rates. These rates might best be considered as f.o.b. wholesale prices of electricity. They apply to high-voltage electricity, measured at the generating station. Two adjustments must be made to these rates in order to estimate the retail prices they imply. In the first place, and most important, there is the adjustment for losses in transmission and in transformation to low voltage. These losses are virtually non-existent for high-voltage (large industrial) consumers, but they are quite important for low-voltage (residential, commercial, and small industrial) consumers. Something like a quarter of the power generated is lost in the processes of transformation to and transmission at low voltage. Thus if the basic (wholsale) rate were 15 np. per kwh, the retail rate for low-voltage consumers would have to be around 20 np. per kwh simply to take account of transformation and transmission losses. In general, to adjust for this factor, the rates in the tables would have to be increased by about a third for the low-voltage consumer categories.

The second, and less important, adjustment would add a charge for connecting, metering, billing, and otherwise servicing the individual consumer. This charge would appropriately be independent of the volume of consumption, and would best be set as a fixed monthly charge for cosumers in each category. But if for practical reasons it were deemed advisable to incorporate an allowance for "consumer costs" in the rates per kwh paid by the different classes of consumers, a modest adjustment in addition to that for transmission and transformation would have to be made in the basic rates.

One of the striking features of the rate patterns presented in the tables is that they contain no rate below 3 np. per kwh. Yet it is well known that many industrial undertakings in India do obtain electricity at lower rates than this. We shall not here inquire into the individual cases in which lower rates are charged, but shall simply indicate the sorts of situation in which lower rates might be justified. The first is the purely hydro project, which for some reason cannot be effectively integrated into a larger grid so as to complement thermal capacity. The second is the thermal-cum-hydro-base-load system, in which the hydro-base-load capacity is large relative to thermal capacity. Under such circumstances, it may be unnecessary to use thermal capacity at all during the off-peak hours, thus justifying a lower charge for off-peak use of electricity than that indicated by the marginal costs

of producing thermal power. These two types of situations must now prevail in some parts of India; accordingly blanket objections to rates below around 3 np. per kwh are not justified. But such situations are likely to become less and less prevalent in the future, as demand grows and as grid-formation proceeds. Thus in long-term planning, in decision making about industrial locations, etc., the general principle should be to consider the expected marginal costs of thermal power as the minimum admissible price of power. Moreover, this minimum should be taken as applying only during the off-peak hours of the system.

The final implication which we wish to draw from our analysis concerns the common practice of charging two-part tariffs for industrial use of electricity. A two-part tariff consists of a fixed monthly charge based on the consumer's level of maximum demand, plus a flat rate per kwh consumed. The theory behind the two-part tariff is that the consumer should be made to pay for the fixed charges associated with the capacity which his maximum demand requires, and that once these charges are paid, he should be free to consume all the electricity he wants at its marginal cost of production and delivery. The difficulties with this approach are both theoretical and practical. On the theoretical side, charging all consumers fixed charges to cover the capacity costs associated with their maximum demands will generally lead to more being collected on this account than is necessary to cover the fixed charges of the system. The reason for this is that the maximum demands of individual consumers are not simultaneous, so that the same capacity can help to meet more than one consumer's maximum demand. When one contemplates reducing the fixed charges to take account of this objection, the practical difficulties emerge. A consumer whose maximum demand comes at a time when the system is at its peak should really be required to pay for the full cost of the capacity necessary to meet his maximum demand, while a consumer whose maximum demand occurs at an off-peak time should not. No simple two-part tariff will make this vital distinction. If the fixed charge is made somewhat lower than the charge associated with the consumer's maximum demand, the same problem crops up in setting the appropriate rate per kwh consumed. A rate higher than the marginal cost of producing and delivering electricity is too high for the periods when the system has unused capacity; a rate equal to marginal cost is too low for the periods when the system is at its peak.

The way out of these dilemmas is to abandon the two-part tariff in favour of a time-tariff at least for those (large industrial) consumers, for whom a time-tariff can be economically and effectively administered. The time-tariff recognizes that it is possible to supply additional off-peak power at marginal cost, while provision of additional peak-time power requires the expansion of capacity. The principle that the fixed costs of capacity should be borne by peak-time demand is fundamental; any rate-making rule which attempts to by-pass this principle is bound to have less than optimal results. Our analysis thus strongly favours as rapid a transition as possible to a rate structure which distinguishes sharply between peak and off-peak use of power by large industrial consumers.