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Principles of Modern Electricity Pricing

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Abstract—This paper presents a framework for electric power pricing, reviews the basic theory of marginal cost pricing applicable to the power sector, and summarizes recent developments. The adaptation of the theory for practical application in relation to the objectives of power pricing policy results in a two stage procedure for tariff setting. First, the detailed structure of the strict long-run marginal costs (LRMC) of supply which meet the economic efficiency criterion are computed. Second, the strict LRMC is adjusted to arrive at an appropriate realistic tariff schedule which satisfies other constraints, including economic second best and social lifeline rate considerations, financial needs, simplicity of metering and billing, etc. The results obtained through past applications of modern pricing structures internationally are reviewed, and the U.S. situation is discussed with respect to the Public Utility Regulatory Policies Act (PURPA) of 1978.

I. Introduction and Overview

Modern societies have become increasingly dependent on various types of energy sources, among which electric power has occupied a dominant position. Traditionally, electric power pricing policy in most countries has been determined mainly on the basis of financial or accounting criteria, e.g., raising sufficient sales revenues to meet operating expenses and debt service requirements while providing a reasonable contribution towards the capital required for future power system expansion.

However, in recent times several new factors have arisen, including the rapid growth of demand, the increase in fuel oil prices and prices of fossil fuel and nuclear plant, the dwindling availability of cheaply exploitable hydroelectric resources, and the expansion of power systems into areas of lower consumer density at relatively high unit costs. These developments have led to increasing emphasis being laid on the use of economic principles in order to produce and consume electric power efficiently, while conserving scarce resources, and meeting various national objectives. In particular, a great deal of attention has been paid to the use of marginal cost pricing policies in the electric power sector. We note that price is an effective "soft" technique of demand management especially in the long run. The effects of pricing policy are also greatly enhanced by coordinating it properly with other "soft" demand management tools such as financial/tax incentives, and "hard" demand management techniques including load control, etc., that are more useful in the short run.

The objectives of power tariff policy in the national context, and a pricing framework based on long-run marginal costs (LRMC) which meets these requirements, are summarized in this section. In Section II, the economic principles underlying the LRMC approach are described, and in Section III, a framework for calculating strict LRMC is presented. The process of adjusting LRMC to devise a practical tariff structure which meets other national constraints is discussed in Section IV. Section V contains a review of recent results of modern pricing structures in several countries and a discussion of the implications of the Public Utilities Regulatory Policies Act (PURPA) of 1978 in the U.S., and this is followed by a technical appendix.

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A. Requirements of a Power Tariff

The modern approach to power pricing recognizes the existence of several objectives or criteria, not all of which are mutually consistent. First, national economic resources must be allocated efficiently, not only among different sectors of the economy, but within the electric power sector. This implies that cost-reflecting prices must be used to indicate to the electricity consumers the true economic costs of supplying their specific needs, so that supply and demand can be matched efficiently.

Second, certain principles relating to fairness and equity must be satisfied, including: a) the fair allocation of costs among consumers according to the burdens they impose on the system; b) the assurance of a reasonable degree of price stability and avoidance of large price fluctuations from year to year; and c) the provision of a minimum level of service to persons who may not be able to afford the full cost.

Third, the power prices should raise sufficient revenues to meet the financial requirements of the utility, as described earlier. Fourth, the power tariff structure must be simple enough to facilitate the metering and billing of customers. Fifth, and finally, other economic and political requirements must also be considered. These might include, for example, subsidized electricity supply to certain sectors in order to enhance growth or to certain geographic areas for regional development.

Since the above criteria are often in conflict with one another, it is necessary to accept certain tradeoffs between them. The LRMC approach to price setting described below has both the analytical rigor and inherent flexibility to provide a tariff structure that is responsive to these basic objectives.

B. LRMC-Based Tariffs

A tariff based on LRMC is consistent with the first objective, that is, the efficient allocation of resources. The traditional accounting approach is concerned with the recovery of historical or sunk costs, while in the LRMC calculation the important consideration is the amount of future resources used or saved by consumer decisions. Since electricity prices are the amounts paid for increments of consumption, in general they should reflect the incremental cost incurred. Supply costs increase if existing consumers increase their demand or if new consumers are connected to the system. Therefore, prices that act as a signal to consumers should be related to the economic value of future resources required to meet consumption

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changes. The accounting approach that uses historical assets and embedded costs implies that future economic resources will be as cheap or as expensive as in the past. This could lead to overinvestment and waste, or underinvestment and the additional costs of unnecessary scarcity.

To promote better utilization of capacity, and to avoid unnecessary investments to meet peak demands, which tend to grow very rapidly, the LRMC approach permits the structuring of prices so that they vary according to the marginal costs of serving demands: a) by different consumer categories; b) in different seasons; c) at different hours of the day; d) by different voltage levels; e) in different geographical areas; and so on.

In particular, with an appropriate choice of the peak period, structuring the LRMC-based tariffs by time of day generally leads to the conclusion that peak consumers should pay both capacity and energy costs, whereas offpeak consumers should pay only the energy costs. Similarly, analysis of LRMC by voltage level usually indicates that the lower the service voltage, the greater the costs consumers impose on the system.

The structuring of LRMC-based tariffs also meets subcategories a) and b) of the second, or fairness, objective mentioned earlier. The economic resource costs of future consumption are allocated as far as possible among the customers according to the incremental costs they impose on the power system. In the traditional approach, fairness was often defined rather narrowly and led to the allocation of arbitrary accounting costs to various rating periods and consumers thus violating the economic efficiency criterion. Because the LRMC method deals with future costs over a long period—for example, at least 5 to 10 years—the resulting prices in constant terms tend to be quite stable over time. This smoothing out of costs over a long period is especially important given capital indivisibilities or "lumpiness" of power system investments.

Using economic opportunity costs (or shadow prices—especially for capital, labor, and fuel) instead of purely financial costs, and taking externalities into consideration whenever possible also link the LRMC method and efficient resource allocation.

The development of LRMC-based tariff structures which also meet the other objectives of pricing policy mentioned earlier, are discussed next.

C. Practical Tariff Setting

The first stage of the LRMC approach is the calculation of pure or strict LRMC that reflect the economic efficiency criterion. If price was set strictly equal to LRMC, consumers could indicate their willingness to pay for more consumption, thus signaling the justification of further investment to expand capacity.

In the second stage of tariff setting, ways are sought in which the strict LRMC may be adjusted to meet the other objectives, among which the financial requirement is most important. If prices were set equal to strict LRMC, it is likely that there will be a financial surplus. This is because marginal costs tend to be higher than average costs when the unit costs of supply are increasing. In principle, financial surpluses of the utility may be taxed away by the state, but in practice the use of power pricing as a tool for raising central government revenues is usually politically unpopular and rarely applied. Such surplus revenues can also be utilized in a way that is consistent with the other objectives. For example, the connection charges can be subsidized without violating the LRMC price, or low-income consumers could be provided with a subsidized block of electricity to meet their basic requirement, thus satisfying sociopolitical objectives. Conversely, if marginal costs are below average costs—typically as a result of economies of scale—then pricing at the strict LRMC will lead to a financial deficit. This will have to be made up, for example, by higher lump sum connection charges, flat rate charges, or even government subsidies.

Another reason for deviating from the strict LRMC arises because of second-best considerations. When prices elsewhere in the economy do not reflect marginal costs, especially for electric power substitutes and complements, then departures from the strict marginal cost pricing rule for electricity services would be justified. For example, in rural areas, inexpensive alternative energy may be available in the form of subsidized kerosene and/or gas. In this case, pricing electricity below the LRMC may be justified, to prevent excessive use of the alternative forms of energy. Similarly, if incentives are provided to import private generators and their fuel is also subsidized, then charging the full marginal cost to industrial consumers may encourage them to purchase their own or captive power plant. This is economically less efficient from a national perspectives. Since the computation of strict LRMC is based on the power utilities' least cost expansion program, LRMC may also need to be modified by short-term considerations if previously unforeseen events make the long-run system plan suboptimal in the short run. Typical examples include a sudden reduction in demand growth and a large excess of installed capacity that may justify somewhat reduced capacity charges, or a rapid increase in fuel prices, which could warrant a short-term fuel surcharge.

As discussed earlier, the LRMC approach permits a high degree of tariff structuring. However, data constraints and the objective of simplifying metering and billing procedures usually requires that there should be a practical limit to differentiation of tariffs by: a) major customer categories—residential, industrial, commercial, special, rural, and so on; b) voltage levels (high, medium, and low); c) time of day (peak, offpeak); and d) geographic region. Finally, various other constraints also may be incorporated into the LRMC based tariffs, such as the political requirement of having a uniform national tariff, subsidizing rural electrification, and so on. In each case, however, such deviations from LRMC will impose an efficiency cost on the economy.

D. Summary

In the first stage of calculating LRMC, the economic (first best) efficiency objectives of tariff setting are satisfied, because the method of calculation is based on future economic resource costs rather than sunk costs, and also incorporates economic considerations such as shadow prices and externalities. The structuring of marginal costs permits an efficient and fair allocation of the tariff burden on consumers. In the second stage of developing an LRMC-based tariff, deviations from strict LRMC are considered to meet important financial, social, economic (second best), and political criteria. This second step of adjusting strict LRMC is generally as important as the first stage calculation.

The LRMC approach provides an explicit framework for analyzing system costs and setting tariffs. If departures from the strict LRMC are required for noneconomic reasons, then the economic efficiency cost of these deviations may be estimated roughly by comparing the impact of the modified tariff relative to (benchmark) strict LRMC. Since the cost structure may be studied in considerable detail during the LRMC calculations, this analysis also helps to pinpoint weaknesses and inefficiencies in the various parts of the power system—for example, overinvestment, unbalanced investment, or excessive losses at the generation, transmission, and distribution levels, in different geographic areas, and so on. This aspect is particularly useful in improving system expansion planning.

Finally, any LRMC-based tariff is a compromise between many different objectives. Therefore, there is no "ideal" tariff. By using the LRMC approach, it is possible to revise and improve the tariff on a consistent and ongoing basis, and thereby approach the optimum price over a period of several years, without subjecting long-standing consumers to "unfair" shocks, in the form of large abrupt price changes.

II. Economics of Marginal Cost Pricing

Marginal cost pricing theory dates back to the pathbreaking efforts of Dupuit [11] and Hotelling [17], [47], [48]. The development of the theory, especially for application in the electric power sector, received a strong impetus from the 1950's [2], [3], [51], [54], [57]. Recent work has led to developments in peak load pricing, incorporation of the effects of uncertainty and the costs of power shortages, etc. [7], [20], [26], [49], [53], [55]. This section briefly reviews the basic principles of marginal cost pricing and some recent developments.

A. Basic Marginal Cost Theory

The rationale for setting price equal to marginal cost may be clarified using Fig. 1. Let $EFGD_0$ be the demand curve (which determines the kilowatt-hours of electricity demanded per year, at any given average price level), while AGS is the supply curve (represented by the marginal cost (MC) of supplying additional units of output).

At the price p, and demand Q, the total benefit of consumption is represented by the consumers willingness to pay, i.e., the area under the demand curve $OEFJ$, and the cost of supply is the area under supply curve $OAHJ$. Therefore, the net benefit, or total benefit minus supply costs, is given by the area $AEFH$. Clearly, the maximum net benefit AEG is achieved when price is set equal to marginal cost at the optimum market clearing point G, i.e., (p_0, Q_0). In mathematical terms, the net benefit (NB) is given by

$$NB = \int_0^Q p(Q)\, dQ - \int_0^Q MC(Q)\, dQ$$

where $p(Q)$ and $MC(Q)$ are the equations of the demand and supply curves, respectively. Maximizing NB yields:

$$d(NB)/dQ = p(Q) - MC(Q) = 0$$

which is the point of intersection of the demand and marginal cost curves (p_0, Q_0). Next, we add to this static analysis, the dynamic effect of growth of demand from year 0 to year 1, which leads to an outward shift in the demand curve from D_0 to D_1. Assuming that the correct market clearing price p_0 exists in year 0, excess demand GK will occur in year 1. Ideally, the supply should be increased to Q_1 and the new optimal market clearing price established at p_1. But data concerning the demand curve D_1 may be incomplete, making it difficult to locate the point L.

Fortunately, system data permit the marginal cost curve to be determined more accurately. Therefore, as a first step, the supply may be increased to an intermediate level Q', at the price p'. Observation of the excess demand MN indicates that both the supply and the marginal cost price should be further increased. Conversely, if we overshoot L and end up in a situation of excess supply, then it may be necessary to wait until the growth of demand catches up with the over capacity. In this iterative manner, it is possible to move along the marginal cost curve towards the optimal market clearing point. Note that, as we approach the optimum, it is also shifting with demand growth, and therefore we may never hit this moving target. However, the basic rule of setting price equal to the marginal cost and expanding supply until the market clears, is still valid.

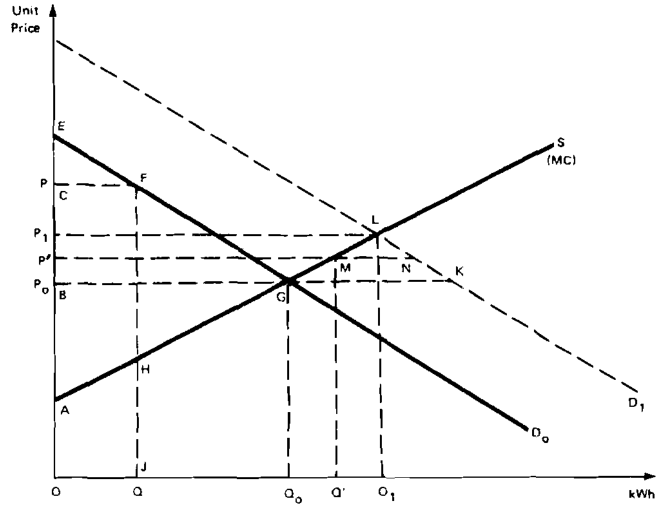

Fig. 1. Supply and demand diagram for electricity consumption.

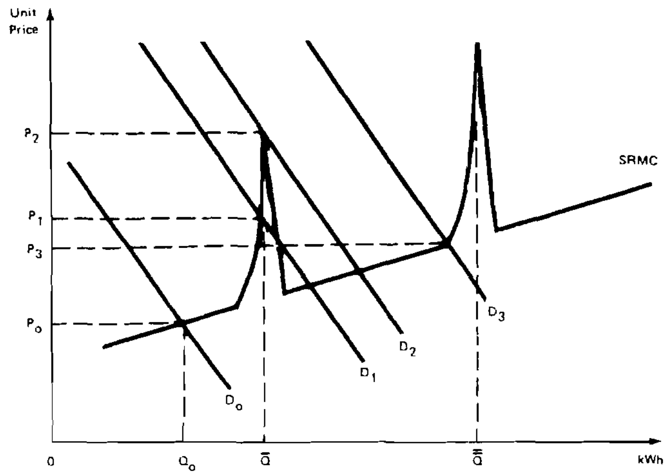

Fig. 2. The effect of capital indivisibilities on price.

B. Capital Indivisibilities and Peak Load Pricing

Owing to economies of scale, capacity additions to power systems (especially generation) tend to be large and long-lived, resulting in lumpy investments. Suppose that in year 0, the maximum supply capacity is $\overline{Q}$, as shown in Fig. 2, while the optimal price and output combination (p_0, Q_0) prevails, corresponding to the demand curve D_0 and the short-run marginal cost (SRMC) curve (e.g., fuel, operating, and maintenance costs). As demand grows from D_0 to D_1 over time, with capacity fixed, the price must be increased to p_1 to clear the

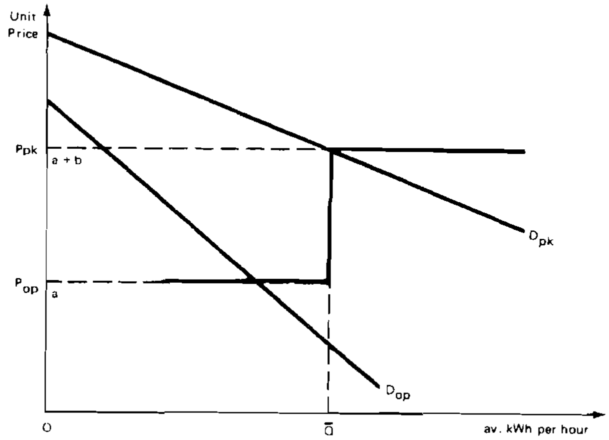

Fig. 3. Basic peak load pricing model.

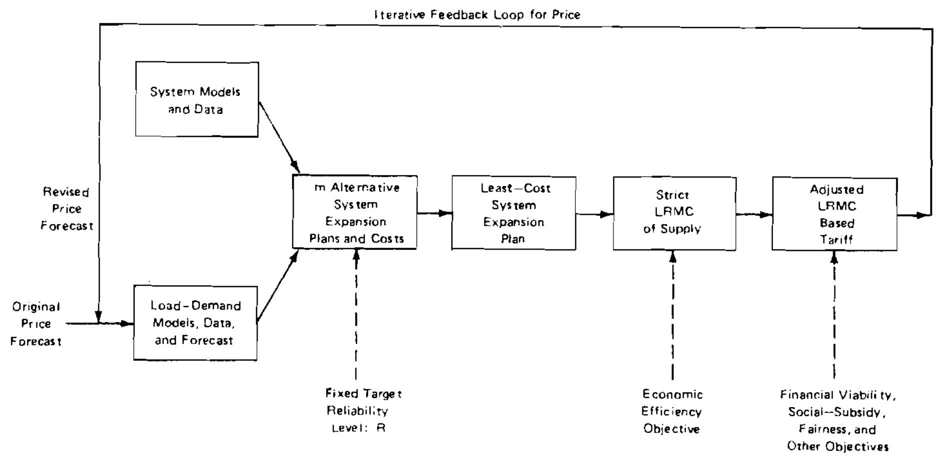

Fig. 4. The use of price feedback in estimating LRMC based tariffs.

market. When the demand curve has shifted to D_2 and the price is p_2, new plant is added on. Once the capacity increases to $\bar{\bar{Q}}$, p_3 becomes the optimal price corresponding to demand D_3 and the SRMC line. Generally, the resulting large price fluctuations over time will be unacceptable to consumers. This practical problem may be avoided by adopting an LRMC approach, and peak load pricing.

The basic static peak load pricing model shown in Fig. 3 has two demand curves; for example, D_{pk} could represent the peak demand during the x daylight and evening hours of the day when electric loads are light. For simplicity, a single type of plant is assumed with the SMC of fuel, operating, and maintenance costs given by the constant a, and the LRMC of adding to capacity (e.g., investment costs suitably annuitized and distributed over the lifetime output of the plant) given by the constant b. The diagram indicates that the pressure on capacity arises due to peak demand D_{pk}, while the off-peak demand D_{op} does not infringe on the capacity $\bar{Q}$. The optimal pricing rule now has two parts corresponding to two distinct rating periods (i.e., differentiated by the time of day); (i) peak period price of $p_{pk} = a + b$; and (ii) off-peak period price of $p_{op} = a$. The logic of this simple result is that peak period users, who are the cause of capacity additions, should bear full responsibility for the capacity costs as well as fuel, operating and maintenance costs, while off-peak consumers only pay the latter costs (see also Appendix).

C. *Extensions of Simple Models*

The simplified models presented so far must be extended to analyze the economics of real-world power systems. First, the usual procedure adopted in marginal cost pricing studies may require some iteration as shown in Fig. 4. Typically, a deterministic long-range demand forecast is made assuming some given future evolution of prices. Then, using power system models and data, several plans are proposed to meet this demand at some fixed target reliability level (see below). The cheapest or least cost system expansion plan is chosen from these alternatives. Finally strict LRMC is computed on the basis of this least cost plan and an adjusted LRMC tariff structure is prepared. If the new tariff that is to be imposed on consumers is significantly different from the original assumption regarding the evolution of prices, however, then this first-round tariff structure must be fed back into the model to revise the demand forecast and repeat the LRMC calculation.

In theory, this iterative procedure could be repeated until future demand, prices, and LRMC-based tariff estimates become mutually self-consistent. In practice, uncertainties in price elasticities of demand and other data may dictate a more pragmatic approach in which the LRMC results would be used after only one iteration to devise new power tariffs and to implement them. The demand behavior is then observed over some time period; the LRMC is re-estimated and tariffs are revised to move closer to the optimum, which may itself have shifted, as described previously. An extreme form of price feedback could result in a shift of the peak outside the original peak period, especially if the latter was too narrowly defined. That is, peak load pricing may shift the demand peak, from one pricing period to another. If sufficient data on the price elasticity of demand were available, theory indicates that each potential or secondary peak should be priced to keep its magnitude just below the available capacity level. Since the necessary information would rarely be available in practice, a combination of techniques including use of a sufficiently wide peak period, redefining the peak period to include both the actual and potential peaks, direct switching of certain consumer loads, and so on, may be used to avoid the shifting peak problem.

Second, the interrelated issues of supply and demand uncertainty, reserve margins, and costs of shortages raise certain problems. Since the least cost system expansion plan to meet the demand forecast is generally determined assuming some (arbitrary) target level of system reliability (e.g., loss-of-load probability (LOLP), reserve margin, etc.), the marginal costs depend on the target reliability level [26]. However, economic theory suggests that reliability should also be treated as a variable to be optimized, and both price and capacity (or equivalently, reliability) levels should be optimized simultaneously. The optimal price is the marginal cost price, while the optimal reliability level is achieved when the marginal cost of capacity additions are equal to the expected value of economic cost savings to consumers due to electricity supply shortages averted by those capacity increments. These considerations lead to a more generalized approach to system expansion planning [25].

Consider a simple expression for the net benefits NB of electricity consumption, which is to be maximized:

$$NB(D,R) = TB(D) - SC(D,R) - OC(D,R)$$

where TB is total benefits of consumption if there were no outages; SC is supply costs (i.e., system costs); OC is outage costs (i.e., costs to consumers of supply shortages); D is demand; and R is reliability.

In the traditional approach to system planning both D and R are exogenously fixed, and therefore NB is maximized, when SC is minimized, i.e., least cost system expansion planning. However, if R is treated as a variable:

$$\frac{d(NB)}{dR} = -\frac{\partial}{\partial R}(SC + OC) + \frac{\partial}{\partial D}(TB - SC - OC) \cdot \frac{\partial D}{\partial R} = 0$$

is the necessary first-order maximization condition. Assuming $\partial D/\partial R = 0$, yields: $\partial(SC)/\partial R = -\partial(OC)/\partial R$.

Therefore, as described earlier, reliability should be increased by adding to capacity until the above condition is satisfied. An alternative way of expressing this result is that since TB is independent of R, NB is maximized when total costs: $TC = (SC + OC)$ are minimized. The above criterion effectively subsumes the traditional system planning rule of minimizing only system costs, but it raises new problems stemming from the need to accurately estimate outage costs [27], [29].

Third, consider again the choice between SRMC and LRMC for pricing. The SRMC may be defined as the cost of meeting additional electricity consumption, (including the costs of shortages) with capacity fixed. The LRMC is the cost of providing an increase in consumption (sustained indefinitely into the future) in a situation where optimal capacity adjustments are possible. When the system is optimally planned and operated (i.e., capacity and reliability are optimal), SRMC and LRMC coincide. However, if the system plan is temporarily suboptimal, significant deviations between SRMC and LRMC will have to be carefully resolved. For example, in the post 1973 period many utilities are replacing oil fired plant with coal fired units to realize fuel cost savings. This may result in significant excess capacity, and low marginal capacity costs in the short run, thus justifying a reduction in demand charges below the LRMC level. However, as peak demand grows and the system approaches optimality again, the capacity charges should rise smoothly towards LRMC. This transition could become undesirably abrupt if the initial reduction in demand charges was too large and demand growth was overstimulated.

Finally, if there are substantial outage costs outside the peak period, then the optimal marginal capacity costs may be allocated among the different rating periods in proportion to the corresponding marginal outage costs. It has been suggested that capacity costs should be allocated to different rating periods in inverse proportion to LOLP, but this would be only an approximation because aggregate reliability indices such as LOLP are poor proxies for *prorating* outage costs.

D. Shadow Pricing

In the idealized world of perfect competition the interaction of many small profit maximizing producers and welfare maximizing consumers gives rise to market prices that reflect the true economic costs, and scarce resources are efficiently allocated [23]. However, conditions are likely to be far from ideal in the real world. Distortions due to monopoly practices, external economies, and diseconomies (which are not internalized in the private market), interventions in the market process through taxes, import duties and subsidies, etc., all result in market (or financial) prices for goods and services, which may diverge substantially from their shadow prices or true economic opportunity costs. For example, in a country where subsidized diesel fuel is available for electricity generation, the appropriate shadow price would be the import price rather than the artificially low market price. Moreover, if there are large numbers of poor consumers, pricing based only on strict efficiency criteria may be socially and politically unacceptable. Such considerations necessitate the use of appropriate shadow prices (instead of market prices) of inputs to the electricity sector, to determine the optimal investment program as well as LRMC [30], [31].

III. Calculating Strict LRMC

Strict LRMC may be defined practically as the incremental cost of optimum adjustments in the system expansion plan and system operations attributable to a small increment of demand which is sustained into the future. The term long-run incremental cost may also be used interchangeably with LRMC, because the changes refer to small but finite variations. LRMC must be structured within a disaggregated framework, based chiefly on technical grounds. This structuring may include: differentiation of marginal costs by time of day, voltage level, geographic area, season of the year, and so on. The degree of structuring and sophistication of the LRMC calculation depends on data constraints and the usefulness of the results, given the practical problems of computing and applying a complex tariff; e.g., in theory, the LRMC of each individual consumer at each moment of time, may be estimated. The basic

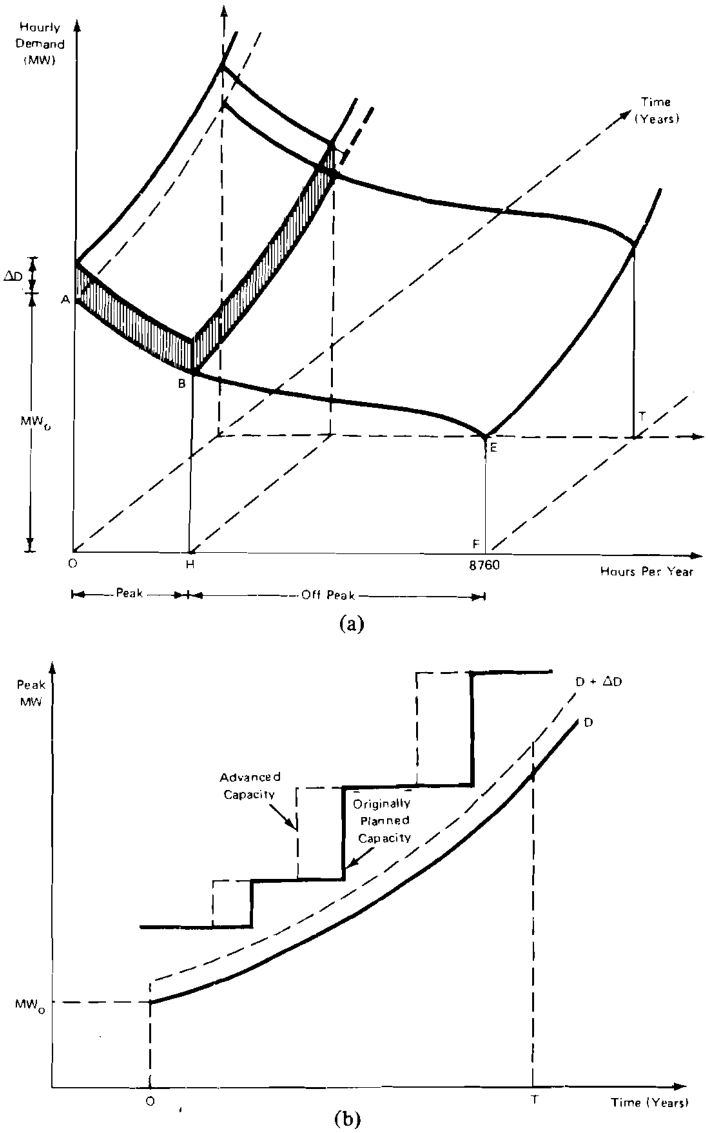

Fig. 5. (a) Typical annual LDC. (b) Forecast of peak power demand.

concepts for calculating strict LRMC are summarized below, while details of theory and illustrative case studies may be found in [31] and [55].

A. Cost Categories and Rating Periods

The three broad categories of marginal costs are: capacity costs, energy costs and consumer costs. Marginal capacity costs are basically the investment costs of generation, transmission and distribution facilities associated with supplying additional kilowatts. Marginal energy costs are the fuel and operating costs of providing additional kilowatt-hours. Marginal customer costs are the incremental costs directly attributable to consumers including costs of hook-up, metering, and billing. Relevant operation and maintenance costs (O&M), as well as administrative and general costs (A&G) must also be allocated to these basic cost categories. Furthermore, where appropriate, these elements of LRMC must be structured by time of use, voltage level, and so on.

The first step in structuring is the selection of appropriate rating periods. The system load duration curves and generation schedules, should be examined to determine periods during which demand presses on capacity and supply costs are highest. These cyclical critical periods may be due to daily demand variations (e.g., evening lighting load), or seasonal variations in both demand (e.g., summer airconditioning peak load), and supply (e.g., dry season for hydro systems). To illustrate the principles of structuring and calculating strict LRMC, we begin with an all thermal system that does not exhibit marked seasonability of demand, choosing only two rating periods by time of day, i.e., peak and off-peak. Seasonal variations in LRMC and the analysis of hydroelectric systems are discussed later.

B. Marginal Capacity Costs

Consider in Fig. 5(a), the typical system annual load duration curve (LDC) *ABEF* for the starting year 0, divided into two rating periods: peak and off-peak. As demand grows over time, the LDC increases in magnitude, and the resultant forecast of peak demand is given by the curve *D* in Fig. 5(b), starting from the initial value *MW*. The LRMC of capacity may be determined by asking the following question: what is the change in system capacity costs ΔC associated with a sustained increment ΔD in the long run peak demand (as shown by the shaded area of Fig. 5(a) and the broken line $D + \Delta D$ in Fig. 5(b)). Consequently, the LRMC of generation would be $(\Delta C/\Delta D)$, where the increment of demand ΔD is marginal *both* in time, and in terms of MW. In theory, ΔD can be either positive or negative, and generally the ratio $(\Delta C/\Delta D)$ will vary with the sign as well as the magnitude of ΔD. If many such values of $(\Delta C/\Delta D)$ are computed, it is possible to average them to obtain LRMC.

In an optimally planned system, the new incremental load would normally be met by advancing future plant or inserting new units such as gas turbines or peaking hydro plant (see Fig. 5(b)). Using a computerized generation planning model, it is easy to determine the change in capacity costs ΔC by simulating the expansion path and system operation, with and without the demand increment ΔD. If a more sophisticated tariff structure having many rating periods is used, then the LRMC in any rating period may be estimated by running the computerized system expansion model with a sustained load increment added to the LDC during that particular period. This method that simulates the optimal system planning process is based on the dynamic LRMC concept.

When constraints due to time, data and facilities preclude this ideal approach, more approximate methods may be used. Several practical methods of estimating LRMC are analyzed in [35] and [36]. Simple considerations based on a more static interpretation of LRMC often yield very good results. Suppose that gas turbines are used for peaking; then the required LRMC of generating capacity ($\text{LRMC}_{\text{Gen. Cap.}}$) may be approximated by the cost per kW installed, annuitized over the expected lifetime. This figure must be adjusted for the reserve margin ($RM\%$) and losses due to station use ($L_{su}\%$). Thus a typical expression would be:

$$\text{LRMC}_{\text{Gen. Cap.}} = (\text{Annuitized Cost per kW}) \cdot (1 + RM\%)/(1 - L_{su}\%).$$

In our basic model, all capacity costs are to be charged to peak period consumers. Therefore, if the capacity costs of base load generating units are included in the calculations, it is very important to net out potential fuel savings due to displacement of less efficient plant by these new base load units (see Appendix for details). Even intuitively, it would not be sensible to incorrectly charge peak consumers the high-capacity costs of expensive base load units (e.g., nuclear), thus encouraging them, for example to install their own captive gas turbine plant.

Next, the LRMC of transmission and distribution (T&D) are calculated. Generally, all T&D investment costs (except customer costs—discussed later) are allocated to incremental capacity, because the designs of these facilities are determined principally by the peak kilowatt that they carry rather than the kWh. However, particularly at the distribution level, the size of a given feeder may depend on local peak demand which may not occur within the system peak period and this could complicate the problem of allocating distribution capacity costs among the various rating periods [3]. The concept of structuring by voltage level may be introduced at this stage. Consider three supply voltage categories: high, medium, and low (HV, MV, LV). Since consumers at each voltage level are charged only upstream costs, capacity costs at each voltage level must be identified.

The simplest approach is to use the average incremental cost (AIC) method to estimate the LRMC of T&D. Suppose that in year i, ΔMW_i, and I_i are the increase in demand served (relative to the previous year), and the investment cost respectively. Then, the AIC of capacity is given by:

$$\text{AIC} = \frac{\left[\dfrac{\sum_{i=0}^{T} I_i}{(1+r)^i}\right]}{\left[\dfrac{\sum_{i=L}^{T+L} \Delta MW_i}{(1+r)^i}\right]}$$

where r is the discount rate (e.g., the opportunity cost of capital), T is the planning horizon (e.g., 10 years), and L is the average time delay between the investment and commissioning dates for new facilities. We note that in the AIC method the actual additional increments of demand are considered as they occur, rather than the hypothetical fixed demand increment ΔD used (more rigorously) in calculating generation LRMC. However, because there is no problem of plant mix with T&D investments, AIC and the hypothetical increment method will yield similar results, while AIC is also usually much easier to calculate using readily available planning data. An alternative method of determining marginal T&D costs at several different voltage levels would be to use historical data to fit regression equations such as:

$$(\text{Transmission Costs}) = a + b \cdot (\text{Peak Demand}).$$

However there is no guarantee that such past relationships would hold true in the future, as the system expands.

Assume that the AIC of EHV and HV transmission has been computed and annuitized over the lifetime of the plant (e.g., 30 years) to yield the marginal costs $\Delta \text{LRMC}_{\text{HV}}$. Then, the total LRMC of capacity during the peak period, at the HV level would be:

$$\text{LRMC}_{\text{HV Cap.}} = \text{LRMC}_{\text{Gen. Cap.}}/(1 - L_{\text{HV}}\%) + \Delta \text{LRMC}_{\text{HV}}$$

where $L_{\text{HV}}\%$ is the percentage of incoming peak power that is lost in EHV and HV network. This procedure may be repeated at the MV and LV levels. The LRMC of T&D calculated in this way is based on actual growth of future demand, and averaged over many consumers. However, facilities associated with given generating sites or loads should be specifically allocated to these uses rather than averaged out, e.g., transmission spur line, exceptionally low or high distribution costs for one or more given customers.

C. Marginal Energy Costs and Treatment of Losses

The system lamda concept is useful in calculating marginal energy costs. The LRMC of peak period energy will be the running costs of the machines to be used last in the merit order, to meet the incremental peak kilowatt-hour represented by ΔD. In our model, this would be the fuel and operating costs of gas turbines, adjusted by the appropriate peak loss factors at each voltage level. Similarly, the LRMC of off-peak energy would usually be the running costs of the least efficient base load or cycling plant used during this period. Exceptions occur when the marginal plant used during a rating period was not necessarily the least efficient machine that could have been used. For example, less efficient plants which have long start-up times and are required in the next rating period, may be operated earlier in the loading order than more efficient plant. This would correspond to minimization of operating costs over several rating periods rather than on an hourly basis. Again since the heat rate of the plants could vary with output level, the simple linear relationship usually assumed between generation costs and kilowatt-hours may need to be replaced by a more realistic nonlinear model [36]. We note that the loss factors for adjusting off-peak costs will be smaller than the peak period loss factors when current flows are greatest [6].

The treatment of losses raises several important issues. While total normal technical losses (including station use) vary from system to system, if these are significantly greater than about 15 percent of gross generation, then loss reduction should have a high priority. When engineering losses in excess of acceptable levels are routinely passed onto the customer, this may act as a disincentive to improvements in technical or administrative efficiency. Losses due to theft and unpaid bills are also often loaded onto paying customers. Here again, the issue is whether these nontechnical losses could be reduced by appropriate measures, or if incremental consumption always has an unavoidable component of such losses associated with it. Theft in U.S. systems has been estimated to average about 2 percent of gross generation, but norms in developing countries may have to be set somewhat higher [10], [31]. The LRMC analysis at the generation, transmission and distribution levels helps to establish whether these incremental costs are excessive because of overinvestment, high losses, or both.

D. Consumer Costs

It has proved difficult to allocate part of the distribution system investment costs to customer costs, on the basis of a skeleton system required to serve a hypothetical minimum load. Similarly regression analysis of past data to fit equations such as:

$$(\text{Distribution Costs}) = a + b \cdot (\text{Peak Demand}) + c \cdot (\text{Number of Customers})$$

has not been too successful because peak demand and the number of customers are usually highly correlated. Therefore, general distribution network costs may be considered as capacity costs, while customer costs are defined as those which can be readily allocated to users. Initial customer costs consist of nonrecurrent expenses attributable to items such as service drop lines, meters and labor for installation. These costs may be charged to the customer as a lump sum or distributed payments over several years.

Recurrent customer costs that occur due to meter reading, billing, administrative and other expenses, could be imposed as a recurring flat charge, in addition to kilowatt and kilowatt-hour charges. In general, the allocation of incremental (nonfuel) operation, maintenance and administrative costs among the categories: capacity, energy and customer costs, varies from system to system and requires specific analysis. However, these costs are usually small and their allocation will not greatly affect the results.

E. Analysis of Hydroelectric Generation [31], [55]

Next, we briefly mention several specific issues which arise in the analysis of hydro systems, and when seasonal variations in LRMC are important. Generally, in an all hydro system the LRMC of generating capacity would be based on the cost of increasing peaking capability (i.e., additional turbines, penstocks, expansion of powerhouse etc.), while incremental energy costs would be the costs of expanding reservoir storage. When there is significant spilling of water (e.g., during the wet season), incremental energy costs would be very small (e.g., O&M costs only), and at times when demand does not press on capacity, incremental capacity costs may be ignored. However, if the system is likely to be energy constrained and all incremental capacity is needed primarily to generate more energy because the energy shortage precedes the capacity constraint for many years in the future, then the distinction between peak and off-peak costs, and between capacity and energy costs, tends to blur. In an extreme case, because hydro energy consumed during any period (except when spilling) usually leads to an equivalent drawdown of the reservoirs, it may be sufficient only to levy a simple kilowatt-hour charge at all times, e.g., by applying the AIC method to total incremental system costs.

In a mixed hydro-thermal system, an important general guideline is that if the hydro is used to displace thermal plant, during a rating period then the running cost of the latter is the relevant incremental energy costs. If pumped storage is involved, the marginal energy costs or value of water used would be the cost of pumping net of appropriate losses. Also, if the pattern of operation is likely to change rapidly in the future (e.g., shift from gas turbines to peaking hydro as the marginal peaking plant, or vice versa), then the value of the LRMC would have to be calculated as a weighted average, with the weights depending on the share of future generation by the different types of plant used.

IV. Adjusting Strict LRMC

Once strict LRMC has been calculated, the first stage of tariff setting is complete. In the second stage, the actual tariff structure which meets economic second best, social, financial, political and other constraints must be derived by modifying strict LRMC, and this topic is dealt with below. This process of adjusting LRMC will, in general, result in deviations in both the magnitude and structure of strict LRMC. Changes in tariff structure at this stage will be based mainly on sociopolitical factors, e.g., differentiation by type of consumer (residential, commercial, industrial and so on), or by income level (low-, middle-, and high-income residential). Practical considerations such as the difficulties of metering and billing will also affect the final tariff structure.

The constraints which necessitate deviations in the final tariffs relative to strict LRMC fall into two categories [30]. The first group consists of distortions which may be analyzed basically within an economic framework, i.e., second best considerations and subsidized (or lifeline) tariffs for low income consumers. In these cases, it is possible to quantify the extent of the deviation from strict LRMC by using an appropriate pricing model and explicit system of shadow prices instead of market prices. Strict (shadow-priced) LRMC also deviates from the market-priced LRMC, and this is done to correct for distortions in the economy. Therefore, the constraints which force further departures from strict LRMC (in the second stage of the tariff setting procedure) may also be considered consequently as distortions which impose their own shadow values on the calculation. The second group includes all other considerations such as financial viability, sociopolitical constraints and problems of metering and billing where strict economic analysis is difficult to apply. These two groups of constraints may be interrelated, e.g., subsidized tariffs can simultaneously have economic welfare, financial and sociopolitical implications.

A. Second-Best Considerations

Where prices elsewhere in the economy, especially of substitutes and complements for electric power, do not reflect marginal costs, a "second best" departure from a strict marginal cost pricing policy for electricity services may be required. More generally, price distortions affecting inputs into the production of electric power and outputs of other sectors which are electricity intensive (e.g., aluminum) should also be considered. The former type of distortion may be dealt with by direct shadow pricing of inputs as discussed earlier, but the latter case (although quite rare) requires more detailed analysis of the market for the output. As an example of price distortion for an energy substitute, consider the subsidies for imported generators and/or diesel fuel, which exist in some countries. This may make it advantageous for users to set up their own captive plant, even though to the economy as a whole this is not the least cost way of meeting the demand. The appropriate solution in this case might be for the government to revoke such subsidies or restrict imports of private generating plant. However, if transportation policy dictates the need to maintain subsidies for diesel fuel, or if strong pressure groups make such changes politically unfeasible, the low cost of (subsidized) private generation may require the setting of an optimal grid supplied electricity price which is below strict LRMC. The extent of the deviation from strict LRMC is determined by the magnitude of the subsidy and degree of substitutability of the alternative energy source [28], [31].

A related question concerns the availability of subsidized kerosene which in many countries is aimed mainly at providing basic energy requirements for low income consumers at prices they can afford. The subsidy may also prevent low income households especially in developing countries from shifting to use of noncommercial fuels, e.g., wood, the overuse of which leads to deforestation and associated environmental consequences, or animal dung, which has a high opportunity cost as a fertilizer. However, undesirable leakages may occur if the cheap "poor mans" fuel is mixed with more expensive gasoline or diesel and used by relatively wealthy automobile owners or industrialists. If we assume the kerosene subsidy as given, then once again the price of electricity must be reduced proportionately.

B. Subsidized or Lifeline Rates

In addition to the second best economic arguments (e.g., associated with subsidized kerosene), sociopolitical or equity arguments are often advanced in favor of "lifeline" rates for electric power, especially where the costs of electricity consumption are high in comparison to the relevant income levels. While the ability of electric power utilities to act as discriminating monopolists permits such tariff structuring, the appropriateness of the "lifeline" rate policy and the size of the rate blocks requires detailed analysis.

The concept of a subsidized "social" block, or "lifeline" rate, for low income consumers has another important economic rationale, based on the income redistribution argument. We clarify this point with the aid of Fig. 6 which shows the

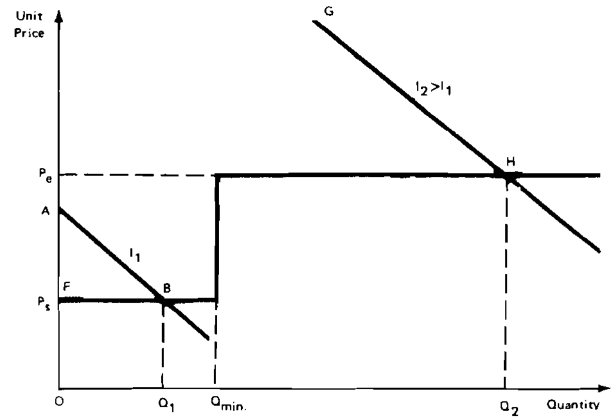

Fig. 6. Welfare economic basis for the social and lifeline rate.

respective demand curves AB and GH of low (I_1) and average (I_2) income domestic users, the social tariff P_s over the minimum consumption block 0 to $Q_{\min}$, and marginal cost based price level P_e. If the actual tariff $P = P_e$, then the average household will be consuming at the "optimal" level Q_2, but the poor household will not be able to afford the service.

If increased benefits accruing to the poor have a high social weight or value, the consumer surplus portion ABF should be multiplied by the appropriate social weight (greater than unity). Then, although in nominal market prices the point A lies below P_e, the weighted distance OA could be greater than the marginal cost of supply. The adoption of the increasing block tariff shown in Fig. 6, consisting of the lifeline rate P_s, followed by the full tariff P_e, helps to capture this "weighted" consumer surplus of the poor user, but does not affect the optimum consumption pattern of the average consumer, if we ignore the income effect due to reduced expenditure of the average consumer for the first block of consumption, i.e., up to $Q_{\min}$. In practice, the magnitude $Q_{\min}$ should be based on acceptable criteria for identifying "low income" groups, and reasonable estimates of their minimum consumption levels (e.g., sufficient to supply basic requirements for lighting, heating, appliances). In the U.S. where the average household consumes over 700 kWh/month, the minimum consumption level may typically be of the order of 100 to 200 kWh/month, while in the developing countries where average electricity use is much lower, $Q_{\min}$ is usually around 500 kWh/month. For the price P_s, one simple welfare model yields:

$$P_s = \text{strict LRMC} \times (\text{poor persons income} \div \text{critical income})$$

where the critical income is like a nationally established poverty line [30]. The utility's revenue constraints and the ability to pay of the poor consumer would also be considered in determining P_s and $Q_{\min}$ [13]. This approach may be reinforced by an appropriate connections policy (e.g., subsidized house connections, etc.). In the U.S., the rights of poor and disadvantaged customers are recognized in the Public Utilities Regulatory Policies Act (PURPA) of 1978, with respect to lifeline rates (Section 114), and protection against unfair termination of service (Section 115 (g)) [45].

C. Financial Viability

The financial constraints most often encountered relate to the revenue requirements of the sector, and are often embodied in criteria such as some target financial rate of return on assets, or an acceptable rate of contribution towards the future investment program. In principle, for state-owned power utilities, the most efficient solution would be to set price equal to marginal cost and rely on government subsidies (or taxes) to meet the utilities financial needs. In practice, some measure of financial autonomy and self-sufficiency is an important goal for the sector. Because of the premium that is placed on public funds, a marginal cost pricing policy which results in failure to achieve minimum financial targets for continued operation of the power sector, would rarely be acceptable. The converse and more typical case, where marginal cost pricing would result in financial surpluses well in excess of traditional revenue targets, often leads to consumer resistance. Therefore in either case, changes in revenues have to be achieved by adjusting the strict marginal cost based tariffs.

A widely used criterion of financial viability is the utility's potential to earn an acceptable rate of return on assets, for example, the net operating income after taxes given as a fraction of net fixed assets in operation plus, in some cases, adequate working capital. In the case of private utilities--for example, in the U.S.--the regulatory authorities have traditionally imposed a fair rate of return as an upper limit on earnings (and therefore, on average price per unit sold) [14]. Where utilities are government owned, as in most developing countries, the target rate of return is usually considered a minimum requirement to help resist sociopolitical pressures that tend to keep prices too low. If the asset base is defined in revalued terms, then this requirement is more consistent with the forward-looking approach of LRMC. Another future oriented financial criterion that is especially useful when the system expands rapidly, requires the utility to make a reasonable contribution to its future investment program from its own revenues. This self-financing ratio is often expressed by the amount of internally generated funds available after operating expenses and debt service, as a fraction of capital expenditures.

The application of the financial criteria often raises serious conceptual and practical problems. Thus, if a rate of return test is to be used, then the question of asset revaluation arises. The use of historical costs for working assets, typically original cost less depreciation, would tend to understate their value when capital costs are rising rapidly. If assets are to be revalued, the costs of either a) exactly reproducing the power system at today's prices; or b) replacing it with an equivalent system, also at today's prices, might be used after netting out depreciation to allow for the loss of value corresponding to the economic and functional obsolescence of existing equipment. Significant difficulties of interpretation clearly will occur in the practical application of either approach.

Whichever criterion or combination of criteria is used, it is important that the initial tariffs based on strict LRMC be included in the utility's financial forecast. Then these first round tariffs may be adjusted through an iterative process until the chosen parameters of financial viability fall within the acceptable range. Although this process is usually quite ad hoc, some practical guidelines may be effectively used for reconciling strict LRMC and the revenue requirement. The relative adjustments to strict LRMC between major consumer categories like residential and industrial, as well as among the different rating periods (like peak and off-peak) within a given consumer category, will determine the share of the revenue burden to be borne by each user group in a given rating period [37].

The simplest practical method of adjustment, which also appears to be the most equitable, is to retain the relative structure of LRMC and vary the average rate level by equiproportional changes. In general this procedure will not be economically efficient.

The application of the Baumol–Bradford inverse elasticity rule whereby the greatest (least) divergence from strict LRMC occurs for the consumer group and rating period where the price elasticity is lowest (highest), is the most satisfactory adjustment procedure from the viewpoint of economic efficiency (1). In the case of two goods, the following expression applies:

$$(1 - \mathrm{LRMC}_1/p_1)/(1 - \mathrm{LRMC}_2/p_2) = (1/e_1 + 1/e_{12})/(1/e_2 + 1/e_{21}).$$

LRMC_i and p_i are the strict LRMC and price, respectively, of good i; while

$$e_i = (\partial Q_i/\partial p_i)/(Q_i/p_i)$$

and

$$e_{ij} = (\partial Q_i/\partial p_j)/(Q_i/p_j)$$

are the own and cross price elasticities, respectively, of demand (Q) with respect to price (p). The two goods 1 and 2 may be interpreted as either the electricity consumption of two different consumer groups in the same rating period or the consumption of the same consumer group in two distinct rating periods. In practice, a larger number of consumer types and rating periods must be considered and application of the rule will be limited by lack of data on price elasticities and the need to use subjective estimates [19]. This technique may appear to penalize some customers more than others, thus violating the fairness objective.

Adjustments involving lump-sum payments/rebates or changes in customer and connection charges are also consistent with economic efficiency provided consumers electricity usage is relatively unaffected by these procedures, i.e., consumption depends mainly on the variable charges. The magnitude of the adjustments that can be made may be insufficient however. Another related approach for reducing revenues is to charge strict LRMC only for marginal consumption and reduce the price for an initial block of electricity use. These subsidies on customer charges or on the initial consumption block can also be tailored to satisfy the lifeline rate requirement for poor consumers, but such measures tend to complicate the price structure.

In practice, an eclectic approach involving a combination of all these methods is most likely to be successful.

D. Other Considerations

There are several additional economic, political, and social considerations that may be adequate justification for departing from a strictly marginal-cost-based tariff policy. The decision to electrify a remote rural area, which may also entail subsidized tariffs because the beneficiaries are not able to pay the full price based on high unit costs, could be made on completely noneconomic grounds, e.g., for general sociopolitical reasons such as maintaining a viable regional industrial or agricultural base, stemming rural to urban migration, or alleviating local political discontent. However, the full economic benefits of such a course of action may be much greater than the apparent efficiency costs which arise from any divergence between actual price and strict LRMC. This possibility is likely to be much more significant in a developing country than in a developed one, not only because of the high cost of power relative to incomes in the former, but also because the available administrative or fiscal machinery to redistribute incomes or achieve regional or industrial development objectives by other means is frequently ineffective.

For the same reason, it is particularly difficult to reform pricing policy where low incomes and a tradition of subsidized power combine to create extreme sociopolitical difficulties in raising prices to anywhere near marginal costs. In practice, price changes have to be gradual, in view of the costs which may be imposed on those who have already incurred expenditures on electrical equipment and made other decisions, while expecting little or no changes in traditional power pricing policies. The efficiency costs of "gradualism" can be seen as an implicit shadow value placed upon the social benefits that result from this policy. Another macroeconomic type argument that electricity price increases may be inflationary is rarely valid because the costs of electricity use are usually a small proportion of household expenses and of industrial production costs. The overstimulation of demand and lack of funds to expand supply, resulting from low electricity prices are potentially much more serious long-run problems that cannot be ignored.

E. Metering and Billing and Customer Comprehension

Owing to both the practical difficulties and the economics of metering and billing, the tariff structure may have to be simplified. Another crucial factor is that the tariff structure must be comprehensible to the average customer. Otherwise, individuals will not be able to adjust their consumption according to the price signal. Therefore, the number of customer categories, rating periods, consumption blocks, voltage levels, and so on will have to be limited.

The degree of sophistication of metering (e.g., by time of day) depends on the practical problems of installation and maintenance, the net benefit of metering (based on a cost benefit analysis that compares the lower supply costs of reduced consumption with the cost of metering plus the decrease in net consumption benefits) [31]. Thus for very poor consumers receiving a subsidized rate, a simple current limiting device may suffice, because the cost of even simple kilowatt-hour metering may exceed its net benefit. In general, various forms of peak load pricing (i.e., maximum demand or time-of-day metering) would be more applicable to large MV and HV industrial and commercial consumers. For practical details of metering see [32].

Most LV consumption, especially for households, is metered only on a kilowatt-hour basis, with the price per kilowatt-hour based on a combined energy and "rolled in" capacity charge (e.g., using appropriate coincidence and load factors). More sophisticated meters, such as time-of-day meters which incorporate synchronous clocks, may be affected by power outages. At the other end of the scale, current limiting devices are easier to tamper with.

Recently, the concept of homeostatic utility control has been proposed in the U.S., using advanced solid-state technology (including use of microprocessors) to implement sophisticated metering, automatic meter reading, load management techniques and pricing structures [41]. In contrast, some developing countries may lack technically skilled labor for installation and maintenance of sophisticated meters, or even reliable meter readers. Therefore, choice of appropriate metering is usually very country specific, and is likely to involve many practical considerations.

V. Practical Implementation and Results of Modern Pricing Structures

In this section we briefly review the types of tariff structures used to implement the LRMC approach, and the most recent empirical evidence regarding the effectiveness of such modern pricing structures. Finally, the U.S. situation and the implications of the PURPA of 1978 are discussed.

A. Types of Tariff Structures

Over the last 50 years price structures have become increasingly complex as both the techniques for analyzing the structure of supply costs and the metering hardware available to apply these tariffs have become progressively more sophisticated. Since the quantity, quality and price of electricity supplied to each consumer can be, if necessary, individually controlled or at least monitored, a high degree of discrimination and structuring is possible with electricity prices. In theory, a separate tariff could be devised for each customer. In practice, however, as discussed in the previous section, the complexity of the tariff would be limited by the metering capabilities, the problems of billing, and the ability of electricity users to comprehend and react to the price signals provided by the power utility.

The structuring of LRMC with respect to voltage level, geographic area, and customer type have been discussed earlier. This section focuses on how tariffs may be devised and implemented, that vary in relation to the following principal aspects: (a) energy or kilowatt-hour consumption; (b) power demand based on kilowatt or kilovolt-ampere consumption; and (c) fixed charges, including both nonrecurrent and recurrent charges. Structuring of aspects (a) and (b) by time of use and usage level will also be reviewed, as well as interruptible rates, the use of tariff adjustment clauses to correct for power factor, fuel surcharges, and so on. These basic building blocks may be combined in various ways to yield literally hundreds of tariff structures differing in their finer details.

The most common form of tariff is the energy charge based on the customer's kilowatt-hour consumption over a given period of time, typically one month. Kilowatt-hour meters that record consumption continuously over shorter periods—for example, 15-min intervals or during two different periods of the day—may be used to implement electricity prices that vary by time of use (TOU). During the peak period, typically, the capacity charge is converted into an equivalent kilowatt-hour charge and added to the energy charge.

Unit charges may also be varied according to the number of kilowatt-hours consumed, yielding two basic types of block tariff structures. Block structures may also be used with kilowatt or capacity charges but this is not a common practice. In the increasing or inverted block tariff, the kilowatt price increases as consumption rises. Incorporation of the increasing block structure in applying the LRMC-based methodology has already been discussed, particularly in the section on social or subsidized prices.

The decreasing block tariff, in which the initial slab of consumption has the highest price followed by successively cheaper blocks has been widely used especially for households and small consumers with only kilowatt-hour metering, where more complex metering would be economically justified (see the section on metering and billing). The rationale for this policy included arguments that: (a) the utility could recover some of the fixed customer costs through the high priced initial block even though kilowatt-hour consumption was low; (b) the first block corresponded to the high cost of supplying the customers peak period load, whereas additional consumption was mainly caused by off-peak appliance use that could be supplied at relatively low cost; (c) the utility should encourage increased consumption to realize economies of scale in production; (d) price discrimination could be used to extract the maximum revenue from smaller users who had low price elasticities of demand while also encouraging consumption of larger users who were more sensitive to high prices; and (e) if temporary excess capacity existed–for example, when a new hydrosite was developed–the new energy could be supplied "costlessly" and, therefore, higher consumption should be encouraged to collect the maximum potential revenues.

All of these arguments ignore the fact that if any slab of the decreasing block tariff is significantly below LRMC, it signals the consumer that electricity is much cheaper than it really is, thus encouraging wasteful consumption. First, if customer costs must be recovered then single or recurring fixed charges should be used. Second, unless there is clear evidence that customers with greater consumption have higher user load factors and consume relatively more off-peak energy at the margin, any additional kilowatt-hours consumed by all consumers will be equally costly to supply. Therefore, there would be little basis for price discrimination according to consumption level. Third, even if economies of scale exist at the aggregate level of the utility, they do not apply in the case of the variable costs to individual customers. In fact, few utilities currently exhibit any economies of scale, and real unit costs of supply in the long run are rising. Fourth, it cannot be generally assumed that the consumption of larger users would be more sensitive to price. Fifth, using up any short-run excess capacity is not costless in the long run, because if demand growth is unduly stimulated, future investments must be advanced. Finally, the decreasing block rate is highly regressive and "unfair," because it penalizes poorer consumers who generally use less electricity but must pay higher prices per unit purchased (see also, earlier discussion of lifeline tariffs).

As explained earlier, the purpose of structuring tariffs by TOU, voltage level, geographic area, and so on, is to convey the LRMC of supply to consumers as accurately as possible. Although peak load or TOU tariffs may also be determined on the basis of accounting costs, the allocation of system capacity costs to different pricing periods in this case is usually quite arbitrary. For example, one method attempts to identify peaking, intermediate and base load generation plant and then allocates the costs of these units to the peak, shoulder and off-peak periods. Another procedure uses the probability of contribution to the peak based on the number of hours in each rating period in which demand exceeds some arbitrary threshold level, divided by the total number of such hours in the year, as the allocation criterion [38]. None of these methods satisfy the economic efficiency objective, and therefore, references to peak load and TOU rates in the subsequent discussions imply that these are based on LRMC.

TOU metering (when this is justified) is the best way to apply an LRMC-based pricing structure. The Hopkinson or two-part tariff with separate energy and peak demand charges is used widely, but if the consumer's maximum kilowatt or kilovolt-ampere demand is not measured at the time of the system peak, then he or she could be unfairly penalized. If only kilowatt-hour metering is available, the capacity charge may be levied on the customer's connected kilovolt-amperes; for example, with a current limiting breaker or fuse to limit the maximum load. But this is even more questionable, since it requires that the relationship between the consumer's peak demand and connected kilovolt-amperes be accurately known. Interruptible tariffs are an extreme form of peak load pricing in which the customer agrees to be disconnected or shed at short notice when there is a power shortage. These prices have to be low because there is no burden on system capacity. Sometimes the interruptible customer is offered the option of remaining on the system at a time of shortage provided he pays a much higher price. In either case, when demand presses on supply the interruptible tariff increases rapidly either to a high value or to infinity–if the customer is automatically shed.

Fixed charges are most often related to consumer costs as described earlier. A lump-sum payment may be levied to cover the initial cost of providing the service connection, or the repayment period may be spread over several years to provide relief to customers. Recurrent fixed costs are charged to meet the costs of meter reading, billing, and other repetitive expenses. In some cases, the charge based on a consumer's connected kilovolt-amperes is also called a "fixed" charge, but this is really a proxy for the capacity or kilowatt cost, which is a variable charge.

In general, the conversion of strict LRMC into applicable kilowatt, kilovolt-ampere, or equivalent kilowatt-hour charges during different pricing periods requires the knowledge of other customer characteristics such as the load factor, diversity or coincidence factor, ratio of connected kilovolt-amperes to maximum demand, and so on [31].

Tariffs contain power factor (PF) penalty surcharges in excess of the regular price to encourage consumers whose PF drops below some acceptable limit to install capacitative correction. Fuel surcharge or fuel adjustment clauses are also becoming increasingly common. This permits the utility to quickly pass on to the consumer any unforeseen increases in fuel costs, especially of liquid fuels. Ideally, any changes in relative input prices would require reestimation of strict LRMC followed by changes in the tariff structure, but the legislative procedure to achieve the latter may take a long time. A convenient short-run fuel adjustment clause can, meanwhile, provide much needed financial relief [16].

B. Recent Empirical Evidence

Peak load pricing or TOU tariffs have been applied in varying degrees for many years in Europe, and more recently in some developing countries [24], [31]. In general, high- and medium-voltage industrial and commercial customers have been faced with separate capacity and energy changes, varying by time-of-day or season. Greater deviations are allowed for low-voltage consumers, because of lifeline rate considerations (as discussed earlier), or simplicity of metering (e.g., demand charge based on maximum load limited by breaker or fuse, demand charge rolled-in to energy charge using a typical user's load factor, etc.). Recurrent flat rate charges are also used to recover fixed costs. We note that the conditions imposed on

TABLE I
SOME TYPICAL EXAMPLES OF PEAK LOAD TARIFFS[a]

Country	HV and MV Consumers			LV (Domestic) Consumers		Percentage Hydro b/
	Demand Charge ($/kW/month)	Energy Charge (c/kWh)	Fixed Charge ($/month)	Energy Charge (c/kWh)	Fixed Charge ($/month)	
A. Europe England (Northwestern Area Electricity Board - 1980)	>650 V April-Oct.: 0.0 Nov.-March: 6.33	0700-2400 daily 5.91 2400-0700 daily 2.78	1.0 per kVA	I. Two part 8.48 II. White Meter 0900-2200: 9.37 2200-0900: 4.0	2.82 3.75	1 to 2
France (Electricité de France -1980) f/	5-30 kV 3.21	Nov.-Feb. c/ 0700-0900 and 1700-1900: 10.36 Oct.-March 0600-2200: 6.08 d/ 2200-0600 and Sunday: 3.06 April-Sept. 0600-2200: 3.87 c/ 2200-0600 and Sunday: 2.42	- - -	Breaker Size 3 kW 6.45 6 kW 6.45 9 kW 6.45 12 kW 6.45 15 kW 6.45 18 kW 6.45	 3.90 6.14 10.27 14.37 18.49 22.61	38 to 40
Norway (Water Resources and Electricity Board-1975)	Oct.-April Contract 1.65 All year Contract 1.89	 0.86 Oct.-April: 0.86 May-Sept.: 0.44	-	0.85 (regular rate) 3.34 (in excess of subscribed level)	2.78 per Subscribed kW	99
Sweden (State Power Board-1980)	70 & 130 kV 0.27 (Contractual) 2.71 (Peak Load)	May-Aug: 1.35 Sept-April: 1.56	38-75	0600-2200: 4.37 2200-0600: 2.21	3.88 plus 2.24 to 0.59 per amp. of fuse rating (from 16 to 200A)	58 to 60
B. Developing Countries Indonesia (Perusahaan Umum Listrik Negara -1980)	12&20kV, 200-5000 kVA 2.56 e/	1800-2200: 4.64 2200-1800: 3.20	-	0-200VA: - 201-500VA: 4.64 501-2200VA: 6.24 2201-6600VA: 7.20 > 6600VA: 9.20	18.5 e/ 4.48 e/ 4.48 e/ 4.48 e/ 4.48 e/	24
Kenya (Kenya Power Company-1980)	11&33kV, > 100 MWh per month 6.74 e/	0800-2200 Mon.-Frid: 3.75 All other times: 2.25	53.93	< 30kWh: 3.30 > 30kWh: 7.49	2.25	75
Pakistan (Water and Power Development Authority-1980)	66 & 132 kV 7.11	2.64	-	< 40kWh: 3.15 41-200kWh: 4.57 > 200kWh: 7.61	-	80 to 82

a/ To facilitate comparison, all prices have been converted into constant mid 1980 US$, using: (a) exchange rates prevailing in the year that the tariffs were applicable; and where necessary, (b) the U.S. implicit deflator of GNP up to 1980.

b/ Energy generated from hydroelectric sources in 1978-79, as a percentage of total generation.

c/ excluding Sunday.

d/ excluding Sunday and Nov.-Feb.: 0700-0900 & 1700-1900.

e/ per connected kVA.

f/ includes 17.6% valued added tax.

interruptible loads are an extreme form of peak load pricing, where the price charged to these customers during periods of capacity shortage is either very high (if the consumer has the option to continue receiving power at an increased price) or infinite (if the load is automatically shed). Some typical power tariffs recently applied in several countries are summarized in Table I.

The HV and MV tariff structures in european countries where there is substantial thermal generation (England and France), reflect the importance of both seasonal and time-of-day demand peaks, and the variations in energy costs of the least efficient or marginal plants operated during the various rating periods. In the scandinavian countries where hydroelectric generation is dominant, seasonal variations in the availability of water (e.g., the additional costs of storage in the winter months) tend to dictate the structure of prices. The HV and MV tariffs adopted in the developing countries are quite recent and somewhat simpler because of the need to introduce these new pricing structures gradually, the shortage of appropriate metering, and so on. The LV domestic tariff in all countries are also relatively uncomplicated particularly due to use of less complex metering; for example, the demand charges (if any) are levied on the basis of subscribed kilovolt-ampere or maximum size of fuse or breaker. Off-peak nighttime discounts are offered in some thermal generation dominated systems. The generally low level of domestic tariffs, especially of lifeline rates, reflect the importance of socio-political considerations.

Where these modern pricing structures have been in existence long enough to show results, their impact has been favorable. Industrial and commercial customers in europe have responded to peak load prices in many ways, including: (a) changing their pattern of production by increasing activity during off-peak periods and vice versa; (b) using waste heat or combustible residual materials to generate their own energy during peak periods; (c) storing heat and energy for use during peak periods; and so on. The dominant response has been to shift load from the peak to the off-peak period rather than cutback their total electricity consumption. For example, peak loads of a wide range of european industries have been reduced by amounts ranging from 30 to 90 percent, while the group load factor of 70 percent of industrial load in U.K. increased from 45 to 70 percent from 1961 to 1975 [4], [43], [44]. In the case of LV residential consumers, the price signals are not so clearly conveyed due to lack of complex metering. Therefore, these tariffs have been effectively supplemented in several european countries, by a coordinated package of other domestic load management techniques, including storage (space and water) heating during off-peak hours and central control of specific domestic loads (e.g., ripple control) [4], [24]. Some problems have been encountered in Europe, especially France, due to shifting of the peak.

C. PURPA and Peak Load Pricing in the U.S.

U.S. regulatory bodies and utilities have generally hesitated for a long time to change from conventional accounting or embedded cost approaches to rate making, and adopt more modern techniques based on LRMC. This was mainly due to the steady decline in historical electricity prices, resulting from technological improvements and economies of scale; for example, the average price paid by U.S. domestic consumers fell from 6¢/kWh to almost 2¢/kWh between 1930 and 1970, while mean annual consumption increased from about 500 to 7050 kWh per household during the same period. However, the recent worldwide increases in rates of inflation and energy costs have reversed the trend, with the average revenues received from households rising almost 100% to a little over 4¢/kWh between 1970 and 1978, while mean consumption also continued to increase to about 8850 kWh. These developments have stimulated interest in marginal cost pricing. Thus for example, in 1974 the National Association of Regulatory Utility Commissioners (NARUC) requested that a study of load management and rate design be carried out, the first phase if which was completed in 1977 while further work is ongoing [32]-[34]. Meanwhile, the National Energy Act (NEA) passed by Congress in October 1978 which includes the PURPA has been a major step forward in helping to rationalize electricity tariffs in the U.S. [45]. In Section 111(d), PURPA establishes federal standards for power pricing (applicable to utilities with retail sales exceeding 500 GWh in a baseline year after January 1, 1976), and the individual state regulatory authorities have to determine by November 1981 whether or not they wish to apply the standards (Section 111(a)). Although a few state regulatory bodies (e.g., California, Michigan, New York, and Wisconsin) have been applying TOU rates for several years, at least to some large consumers (including embedded/accounting cost based TOU rates in Michigan), the majority are still uncommitted in this regard.

While compliance with PURPA is not mandatory (see Section 111(a)), the detailed description of these standards in Section 115, relating especially to Cost of Service, Time-of-Day Rates, and Load Management Techniques, may be interpreted in the spirit of the LRMC approach described earlier, in terms of structuring tariffs, and using marginal costs based on long-run considerations. For example, Section 115(a) describes the methods to be used for determining cost of service:

> "Such methods shall to the maximum extent practicable
>
> 1) permit identification of differences in cost incurrence for each such class of electric consumers, attributable to *daily* and *seasonal time of use* of services; and
> 2) permit identification of differences in cost incurrence attributable to differences in *customer, demand, and energy components of cost*.
>
> In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if
>
> 1) *additional capacity* is added to meet peak demand relative to base demand; and
> 2) *additional kilowatt-hours* of electric energy are delivered to electric consumers" (author's italic for emphasis).

The Federal Energy Regulatory Commission (FERC) has followed up quickly to implement Section 133 of PURPA which sets out the requirements for "Gathering Information on Costs of Service." While this is only the first step required to calculate the costs of service, after which there yet remains the long drawn-out process of devising and implementing a new tariff, it is nevertheless an essential prerequisite for all that is to follow. FERC has clearly ruled against several utilities which challenged the appropriateness of the marginal cost approach, and has already required 190 utilities to comply with the data gathering and reporting requirements of Section 133, by November 1980 [12].

The european experience and preliminary results from ongoing rate studies in the U.S. indicate that the benefits of implementing TOU tariffs (based on LRMC) for large HV and MV consumers could be substantial [18], [46]. Thus, Mitchell *et al.* [24], have roughly estimated that potential long-term savings in both investment and operating costs for the whole U.S. would be about $1.3 to 3.5 billion per year, corresponding to the postponement or avoidance of constructing about 28 GW of capacity. Some specific results of TOU pricing experiments in the U.S. are summarized below but should be interpreted cautiously. First, changes in load shape due to TOU rates are difficult to analyze because demand in a given rating period will be affected not only by the price in that period but by the price changes in other periods. Second, short- and long-run responses may be quite different and cannot be easily separated out. Finally, the effects of many other factors such as climate and user tastes also complicate the analysis.

More specific results indicate that 515 large industrial and commercial users in 5 service areas of California, Michigan, New York, and Wisconsin with minimum demands ranging from 300 kW to 5000 kW responded to TOU prices as follows [39]. About 20 percent of the customers surveyed reduced their peak demand. Over one third of these switched their load to the off-peak period, mainly by shifting equipment use, while the rest reduced their peak demand without shifting to off-peak use, by more efficient operation of air conditioning, ventilation and lighting. 55 percent of users reported no change in peak demand; on average 82 percent of these did not respond to TOU tariffs because their production process was inflexible or the change was not cost effective, while only 18 percent made no effort to change. Finally, 25 percent of the large users increased peak demand because of stepped up production. About 90 percent of all users surveyed indicated that they understood the TOU rates well, and nearly two thirds had made impact studies of the new price structures.

Studies involving TOU metering for residential consumers are now being carried out in several states. Some broad but tentative conclusions have already been reported for Arizona, Connecticut, Ohio, North Carolina, Rhode Island, and Wisconsin, including: reduced kilowatt demand during the peak hour, reduced kilowatt-hour consumption for the entire peak period, more favorable diversity factor for TOU customers, reduction in intermediate period (or shoulder) demand, and no evidence of needle peaking outside the peak period [21], [22]. Another set of results from Wisconsin indicates that an eight to one ratio in the peak to off-peak price would reduce the average peak to off-peak energy consumption during the Summer by 24 percent, with the degree of response being positively related to the number of large household appliances owned [5]. While all of these studies report on short-run results, additional long-run consumer responses may be anticipated due to the increasing ability of households to change their patterns of appliance ownership and usage over time.

However, application of TOU prices to LV residential and commercial customers requires more study, to determine whether the significant costs of additional metering is outweighed by the net savings due to improved patterns of consumption [31]. For example, a recent British study indicates that on the basis of such a cost-benefit analysis of metering, TOU prices for domestic consumers would not be justified [9]. More generally, load management techniques such as control of domestic water and space storage heating and cooling have been very effective in Europe and show promise in the U.S. [8], [15], [40]. Available load control technologies include radio and ripple control, power line carrier, telephone line, time switches, interlocks, and load limiters, etc. However, the usefulness of these methods in the U.S. has to be verified further in the light of wide difference in energy use patterns, tastes and climate. Meanwhile, even some simple initial steps such as the elimination of promotional decreasing block tariffs [see PURPA, Section 111(d) (2)], would often constitute a significant improvement in rate structuring.

While the more extensive application of peak load pricing based on LRMC is clearly justified in the U.S., the transition period may take many years. First, the truths and myths regarding modern tariff structures must be well understood by customers, utility managers and regulators. The rate hearing process and other means of disseminating information will play a key role in this respect. Second, the application of new tariffs could begin with the larger customers at HV and MV levels, because they are less numerous and may be sensitized more easily. Over the years, more and more customers including LV users would become subject to the new tariffs. Third, the changes in tariff structure should be initially small, to avoid customer resistance due to unfamiliarity or hardship caused by large increases in the total electricity bill. Later, tariffs could be altered more rapidly to approximate LRMC better. Finally, alternative rate structures could be offered simultaneously (i.e., both the conventional and new tariffs), and customers could gradually be won over to the new tariff. We conclude by noting that the implementation and effectiveness of future pricing structures will depend critically on the development of new hardware and techniques. For example, advances in solid state technology may permit cheaper metering and justify more complex tariff structures even at the LV level. Also, as load management techniques improve, centralized control of customer appliances by the utility could be used more effectively, in conjunction with more accurate and practically instantaneous pricing signals. In fact the complexity of the tariff structure would be limited only by the ability of customers to comprehend it. These ideas are embodied in the concept of homeostatic utility control where sophisticated devices including microprocessors would be used to perform a wide range of switching, metering and signaling functions. Such developments envisage an era in which the "new" philosophy of adjusting the demand to meet the available supply would increasingly supplement the existing practice of merely adjusting supply to follow variations in the demand [41].

Appendix I
Allocation of Capacity and Energy Costs Among Peak and Off-Peak Users

The simplified model of a typical electric power generation system is used below to show from a conceptual viewpoint, how a long run marginal cost (LRMC) analysis based on the optimal system expansion plan yields the following idealized conclusions:[1]

1) peak users should pay the peak LRMC of capacity as well as energy costs;
2) off-peak users should pay only off-peak LRMC of energy;
3) LRMC of peak capacity = LRMC of base load capacity − net fuel savings due to this base load plant.

Consider an all thermal generation system having the annual LDC shown in Fig. 7. There are only two types of plant whose linearized cost characteristics are given in the table below, and also in the figure. We ignore for the moment, all losses, reserve margin, etc.

Plant Type	Capacity Cost per kW Installed (annuitized)	Operating Costs per Hour
1) Peaking (e.g., gas turbines (GT))	a	e
2) Base Load (e.g., steam)	b	f

Total cost of 1 kW which is used h hours per year:

$$\text{GT:} \quad a + e \cdot h$$
$$\text{Base:} \quad b + f \cdot h$$

Let H be the hours of operation which corresponds to the

[1] A more realistic system model would have to consider a number of complicating factors such as a larger number of rating periods and plant types, noncoincidence of the rating periods with the economic crossover points between different plant types, economies of scale and variable heat rates for a given plant type, hydroelectric plant including pumped storage facilities, reserve margins and stochasticity of supply and demand, and so on. The most important difference with respect to the general case is that some capacity costs would have to be borne by consumers outside the peak period. However, the bulk of the capacity costs would still be allocated to peak period users. A simplified exposition of this result is provided in [56].

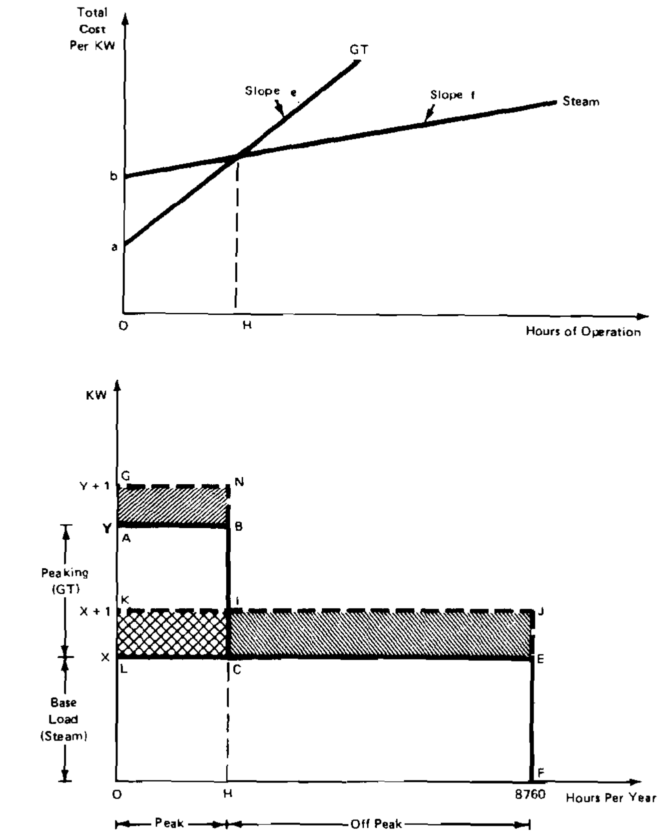

Fig. 7. Plant costs and annual LDC.

crossover point for which GT and base load plant total costs are equal.

Therefore,

$$a + e \cdot H = b + f \cdot H$$

$$H = \left(\frac{b - a}{e - f}\right).$$

The most economic use of plant can be determined by examining the LDC, *OABCEF:*

1) for planned base load operation (i.e. more than H hours per year), use base load plant; X kW;
2) for planned peak operation (i.e., less than H hours per year), use GT; $(Y - X)$ kW.

Total annual costs of meeting the demand depicted by the LDC is:

$$C_0 = X(b + f \cdot T) + (Y - X)(a + e \cdot H).$$

Case 1: Only peak period demand increases by 1 kW (as shown by shaded area $AGNB$ in Fig. 7).

The optimal system planning response is to increase GT by 1 kW. Total annual cost is $C_1 = X(b + f \cdot T) + (Y + 1 - X)$ $(a + e \cdot H)$. Therefore, increase in cost $C_1 - C_0 = a + e \cdot H$.

This is the increase in system costs incurred because of the 1-kW increase in marginal (or incremental) demand during the peak period, and thus the peak period user must pay this cost. The peak costs consist of

1) capacity charge $= a$ per kW per year
2) energy charge $= e$ per kWh.

It may be seen that peak users payment $= a + e \cdot H =$ increase in system costs.

Case 2: Only off-peak period demand increases by 1 kW (as shown by shaded area $CIJE$ in Fig. 7).

The optimal system planning response is to add 1 kW more of base load plant. But now there is 1 kW less of GT required than before. Total annual cost $C_2 = (X + 1) \cdot (b + f \cdot T) + [Y - (X + 1)]\ (a + e \cdot H)$. Therefore, increase in cost:

$$\begin{aligned} C_2 - C_0 &= (b + f \cdot T) - (a + e \cdot H) \\ &= (b - a) + (f - e) \cdot H + f(T - H). \end{aligned}$$

Substituting for H from equation on (1.1)

$$C_2 - C_0 = (b - a) + (f - e) \cdot (b - a)/(e - f) + f \cdot (T - H)$$

$$C_2 - C_0 = f(T - H).$$

Therefore, the increase in system cost incurred due to the 1 kW increase in marginal off-peak demand is equal to the energy cost of operating the base load plant during this period, and thus off-peak users must pay only this energy charge f per kWh. There are no capacity costs incurred by off peak users, since off peak users payment $= f(T - H) =$ increase in system cost.

In particular, we note that the base load capacity cost (b) is exactly offset by the total cost saving due to GT which is not required any more (i.e., capacity cost 'a' plus net fuel cost saving $(e - f) \cdot H$ inside the shaded area $LKIC$). In other words: Peak capacity cost = Base load capacity costs - net fuel savings: $a = b - (e - f) \cdot H$.

Case 3: Both peak and off-peak demand increases by 1 kW. This case is a linear combination of Cases 1 and 2, and therefore consumer charges are:

1) peak capacity charge $= a$ per kW per year;
2) peak energy charge $= e$ per kWh;
3) off-peak energy charge $= f$ per kWh.

Clearly, total peak and off-peak users payment $= b + f \cdot T =$ increase in system cost. These results may be generalized to include more types of generating units, and rating time periods; e.g., n plant types and n rating periods, where these rating periods are chosen to coincide with the economic crossover points between competing types of plant.

In this case LRMC prices would be:

0 to H_1 = peak period:	capacity charge a_1 per kW per year, and energy charge e_1 per kWh
H_1 to H_2 = second period:	only energy charge e_2 per kWh
H_{n-1} to $T = n$th period:	only energy charge e_n per kWh

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