ELECTRICITY PRICING IN LESS DEVELOPED COUNTRIES: INCORPORATING ECONOMIC EFFICIENCY AND EQUITY OBJECTIVES

ISAAC N. IWUAGWU,

Department of Electrical Engineering,
University of Nigeria, Nsukka.

ABSTRACT

Electricity tariffs suffer heavy distortions in many developing countries because of undue government influence. However, in view of increasing financing constraints in recent times and the need for increased energy efficiency, private sector participation in the electric utility industry in these countries is *crucial for the future success of the industry. Consequently, to encourage private sectors efforts, electricity tariffs must be adjusted to acceptable economic levels. This paper presents the use of expected system load duration curve (LDC) and power plant input-output function to establish the shadow price for electricity for a study period. The paper also examines how this marginal opportunity cost (MOC) may be adjusted to capture equity objectives. The use of LDC and actual generating unit production function offers the following advantages: better perception of price feedback effects and the ability to incorporate economic despatch into energy shadow prices. Furthermore, with the use of LDC and system generating unit capacity outage function, it is possible to establish price probabilities for the planning period.*

INTRODUCTION

Electricity tariffs in many developing countries are heavily subsidized below the opportunity costs by the government for a number of sociopolitical or equity reasons which may include: a) the need to make electricity affordable to very poor consumers; b) the desire to achieve an optimal mix in consumption pattern of available energy resources; and c) the need to stem rural-urban migration and thereby sustain rural agriculture. At present, governments in most developing countries are under pressure from lending institutions and the business community to review their role in the provision of infrastructure services and to promote private sector participation. Naturally, private investors would desire a removal of subsidies. However, to protect consumers from large price shocks, subsidy removal might be a gradual process and not a one-step radical operation. While subsidies remain, it is necessary that they be used cautiously in order not to erode the financial viability of the power industry. What is required in the applicable countries is a two- dose therapy. This cost ensures sustained investment, which is necessary for acceptable levels of system reliability and power quality. This cost may be determined in a manner that internalizes some externalities such as environmental damage. Second, this economic efficient cost is deliberately adjusted to achieve some country- specific equity objectives. Previous attempts to incorporate income redistributional concern into electricity pricing relied heavily on simplified economic theory of supply and demand curves [1, 2]. The use of load duration curve (LDC), generating until capacity outage function, and actual generating unit production function offers the following advantages:

1. Better perception of price feedback effects on power demand.
2. Ability to incorporate economic despatch into energy shadow prices.
3. With the use of capacity model of schedulable units, it is possible to establish energy price probabilities for the planning period.

DETERMINATION OF SHADOW PRICE OF ELECTRICITY

Utility costs are of three types: energy costs (or fuel costs); and customer-related costs. Therefore, a customer's bill may be any combination of three basic costs: demand charge or kW charge (which accounts for his contribution to the utility incurring capacity cost), energy charge or kWh charge (which relates to his kWh consumption over the billing period), and fixed charge or minimum charge or customer charge (which is a recurrent flat rate charged to recover costs associated with metering and billing). The basic approach is to make each customer category pay for the costs it imposes on the power utility. Therefore, the appropriate energy cost, capital cost and customer-related cost must be established for each category of customers.

2.1 ENERGY COST

Energy cost arises due to the cost of fuel expended at the thermal generating plants, which contributes about 70% in total generation in most system. Therefore, tariff adjustments often arise from large changes in fuel price such as oil shocks of 1973-1974 and 1979-1980. In view of fuel price unpredictability, generation planning should be on the premise of increased fuel price in the long run with adequate provision made for interfuel substitution. In the following analysis, and all-thermal system it is assumed; that is, hydro and other sources have been scheduled earlier.

The heat rate (input-output function) of a thermal generating unit is often represented with a linear function of the output power. However, it may be represented better as a quadratic polynomial. Formally,

$$H_i = \varphi_i(P_i) \qquad \text{[Mbtu/h]} \qquad (1)$$

Where $H_i and\, P_i$ are the heat rate and output power of unit i respectively. Pi may be expressed in MW (or kW). If the fuel cost for this particular unit is C_{fi} in \$/Mbtu then, the cost of function this unit may be expressed as

$$Fi = C_{Fi}H_I \qquad [\$/h] \qquad (2)$$

Since H_i is quadratic, Eq. (2) may be written as:

$$F_i = a_i + b_i P_i + c_i P_i^2 \qquad [\$/h] \qquad (3)$$

Where a_i, b_i and c_i are constants. Define:

$$\phi_i = \frac{F_i}{P_i} = \frac{a_i}{P_i} + b_i + C_i P_i \qquad [\$/kWh] \qquad (4)$$

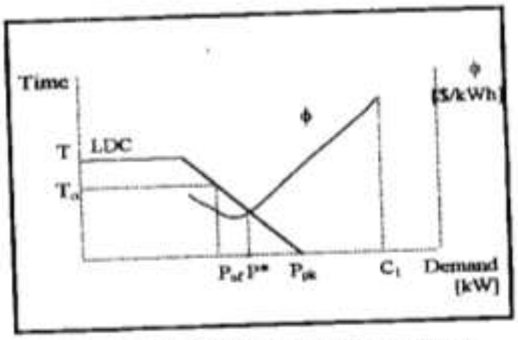

Figure 1. Variations of LDC and ϕ with P

This gives the production function in the form it is needed. $\emptyset_1$ is a marginal cost, that is, the cost of producing one extra unit (kWh) of electric energy due to an increase in demand. To help understand how a typical marginal cost, $\emptyset$, varies with power demand and to draw an analogy with economic theory of supply and demand, we illustrate the variations of ϕ and LDC with P on a common plane. This is shown in Figure 1. Compare this figure with Figure 2, which is based on the classical economic theory of variations in demand and supply with price.

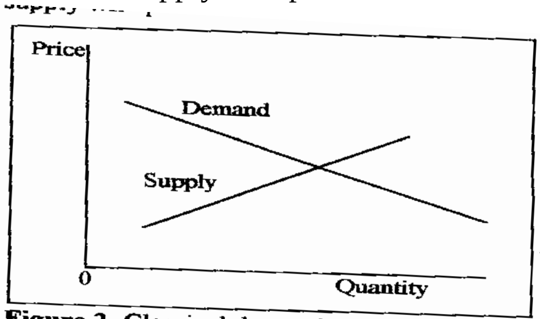

Figure 2. Classical demand and supply curve

The supply curve is the long run marginal cost, LRMC. In Figure 1, T is the planning period (i.e number of years, months, weeks, days or hours in the planning period). Curve LDC, which is the equivalent demand curve, is read from the left axis while $\emptyset$, the equivalent supply curve is the equivalent demand curve, is read from the right axis. The left axis represents the length of time (in the study period when load demand equals or exceeds a given level. For example, T_o is the length of time that load equals or exceeds P_{of}. By normalizing the time variable (usually by dividing by T), any point on the left axis represents a probability. For example, T_o/T is the probability that demand equals or exceeds P_{of}. The right axis has been graduated in a manner that allows Ø and LDC to intersect, as demand and supply intersect in Figure 2.

Each utility must define the threshold kW, P_{of}, beyond which load is regarded as being in the peak region. This would classify system generating units into off-peak units and peak units. In Figure 1, any period, for which load is less than P_{of} is an off-peak period, and any period for which load exceeds P_{of} is a peak period. In Figure 1, P_{pk} represents peak demand, and C_1 the installed capacity of schedulable units in the period under study. The difference, C_1-P_p is reserve margin.

It would be helpful to represent all the thermal units in the system with a composite ϕ. Wood and Wollenberg [3] explain how to derive a composite function for F. This must be done in a fashion that incorporates economic dispatch into the function. This may be accomplished by dispatching the thermal units at equal incremental costs. From Eq. 3., the incremental cost is given by,

$$\lambda = \frac{dF_i}{dP_i} = b_i + 2c_iP_i \quad [\$/kWh] \tag{5}$$

Usually λ is varied for a range of values. For each value of λ, say λ_j, the cosrresponding total output from all the generators, P_j, is evaluated from

$$P_j = \sum_{i=1}^{N} P_i \tag{6}$$

While the corresponding combined fuel cost is determined from

$$F_j = \sum_{i=1}^{N} F_i \tag{7}$$

N is the number of units. For each value of λ, the corresponding value of F_i, is determined from Eq. (3) while, Pi is evaluated from,

$$\lambda_j = b_i + 2c_iP_i \quad i = 1,2,\ldots,N \tag{8}$$

In Eq. (8), if a unit hits its (upper or lower output) limit, it is held constant at that limit. A second order polynomial may be fitted to the points, generated in Eqs. (6) and (7) using a least-squares fitting method or more advanced curve fitting algorithms. The composite (or total) cost of the units may be expressed as

$$F = a + bP + cP^2 \quad [\$/h] \tag{9}$$

Where a, b, and c are constants and P the total output from the units. For the composite unit, ϕ is given by,

$$\phi = \frac{a}{P} + b + cP \quad [\$/kWh] \tag{10}$$

ϕ may be used to determine the generation, P*, at which the efficiency of the composite unit is a maximum. This is obtained by setting $d\phi/dP = 0$ so that P* = $\sqrt{(a/c)}$. The position of P^* is indicated in Figure 1. The use of ϕ to present MOC of energy has the following advantage: energy cost, and hence electricity tariff, can be determined easily for different kW demands. This information can be relayed to load controllers located at customers' premises because, although electricity is priced in kWh, the kW level at which consumption is made is very crucial to the utility. Furthermore, the use of ϕ to determine energy costs also ensures that peak users pay higher marginal energy costs for causing the run of less efficient thermal units (e.g gas turbines). Refer to Figure 1.

Estimating Price Probabilities From Capacity Model

An example, based on a simplified system, is used to illustrate the application of the formulation presented above. A capacity model similar to that used for power system schedulable units in the planning period (taking into account unit maintenance schedules), [3]. The required model would provide the probability of a given level of generation being available to match a load of the same magnitude. This could eventually be used to estimate the probability of different energy costs [&/kWh]. This approach assumes that a) thermal unit maintenance schedules have been taken into account in providing ϕ; and

b) incoming regional fuel prices are constant. However, the problem of effects of changes in fuel prices can be eliminated by expressing energy costs in MBtu/kWh. Consider a power system with the thermal unit characters given in Table 1.

Table 1. Sample System

Unit	Type	Max MW out	Min MW out	FOR
1	Coal-fired steam turbine	600	150	0.160
2	Oil-fired steam turbine	400	100	0.095
3	Gas-fired steam turbine	200	50	0.053

FOR is the forced outage rate in p.u. The fuel costs are: 1.10 $/Mbtu for coal, 1.05 $/Mbtu for oil, and 1.00 $/Mbtu for gas. The units have the following heat rates:

$$H_1 = 539 + 7.700P_1 + 0.001496P_1^2 \text{ [MBtulh]}$$

$$H_2 = 315 + 8.295P_2 + 0.001974P_2^2 \text{ [MBtu/h]}$$

$$H_3 = 80 + 8.300P_3 + 0.004200P_3^2 \text{ [MBtuIh)}$$

Therefore, the cost functions for the different units are,

$$F_1 = H_1 * 1.1 = 592.9 + 8.47P_1 + 0.0016456P_1^2)$$

$$F_2 = H_2 * 1.05 = 330.75 + 8.70975P_2 + 0.0020727P_2^2$$

$$F_3 = H_3 * 1.00 = 80 + 8.300P_3 + 0.004200\, P_3^2$$

A second order polynomial was fit to the points, generated in Eqs. (6) and (7) for this system to obtain the following composite cost function.

$$F = 1010.759/P + 8.480612 + 0.0007860362 \quad (11)$$

Table 2 shows the approximate values of F generated by Eq. (11) for different values of P. The actual values of F are obtained from Eq. (7)

Table 2 F values generated using Eq. (11)

P	F(actual)	F
300.00	3628.38	3625.69
310.81	3723.10	3722.52
321.61	3818.81	3819.54
341.12	3993.63	3995.15
379.51	4340.56	4342.45
429.86	4800.41	4801.47
490.14	5356.20	5356.32
550.43	5917.46	5916.88
610.71	6484.18	6483.16
671.00	7056.39	7055.15
731.28	7634.06	7632.85
791.57	8217.21	8216.67
851.85	8805.82	8805.40
912.14	9399.92	9400.24
971.13	986.590	9987.88
1020.6	10483.1	10484.9
1070.0	10984.2	10985.8
1119.5	11489.8	11490.6
1169.0	11999.8	11999.2
1200.0	12321.5	12319.3

The availabilities of different capacities are given in Table 3. Maximum unit capacities were used to construct the table. The second column refers to the various capacities available for dispatch, while the third column gives the availability of a given capacity state. The fourth column is more useful. It refers to the probability of having a given MW or more for dispatch. For example, the probability of having exactly 1000 MW available for dispatch is 0.0403 p.u. while the probability of having 1000 Mw or more available for dispatch is 0.7602 p.u. Therefore when the system load is 1000 MW, the probability of having energy cost being equal to that corresponding to 1000MW in Figure 1 is 0.7602 p.u.

Table 3. The capacity model of sample system

Cap state	Capacity available for despatch [MW]	Availability of exact capacity sate [p.u]	Availability of cummulative capacity sate [p.u]
1	1200	0.7199	0.7199
2	1000	0.0403	0.7602
3	800	0.0756	0.8358
4	600	0.l413	0.9771
5	400	0.0077	0.9848
6	200	0.0144	0.9992
7	0	0.0008	1.0000

2.1.2 Changes in Fuel Price

Investments in the power industry often have long lifetimes (20 to 30 years). Therefore, the capacity cost of a utility equipment, expressed in &/kW, and spread over its lifetime output stream is usually small relative to energy cost. Consequently, the cost of electricity from existing infrastructure often changes as a function of price changes in the fuel market Therefore, it may be adequate to investigate effects of electricity price on its demand using only the changes in MOC of electric energy.

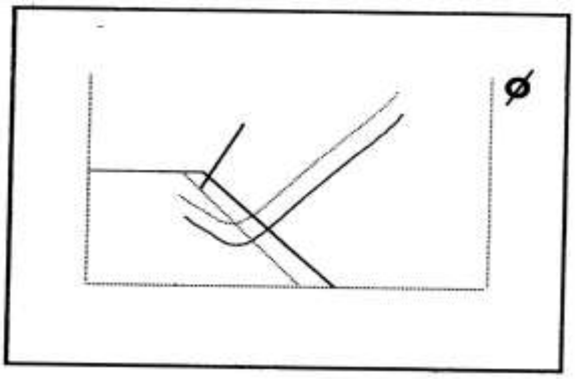

Figure 3. Effects of reduction in the price of fuel.

The effect of a reduction in fuel price is to shift the ϕ curve vertically down as shown in Figure 3. Suppose this fuel price reduction is followed by a proportionate reduction in tariffs for all categories of consumers, responses by customers could be acquisition of more energy-consuming appliances and/or increase capacity utilization of old ones. These responses would cause the LDC to extend right wards with the peak load growing by ΔP, where ΔP == (p" - p'). On the other hand, a relatively large increase in tariff, either as a result of increased energy cost, or as a part of government's demand management strategy for a particular type of fuel, is expected to discourage demand.

Although the consumption of commercial energy in developing countries is small relative to that of the rest of the world, demand growth is expected to be fairly high because of increasing urbanization and industrialization. Therefore, higher fuel prices (especially for oil) should be anticipated. It is often hypothesized that a steady increase in the price of a particular source of energy (especially oil) can induce a shift towards cheaper (non-oil) alternatives, like gas, coal, nuclear, and renewables. However, fuel switching does depend on energy cost alone. Other factors such as controllability in use, environmental concerns, reliability of supply, and availability of associated technology and competent labour must also be considered. Therefore, system planning in the longer term must incorporate generation shifting possibilities right from the outset.

2.2 Capacity Costs

In section 2.1.2 we demonstrated how a probable reduction in tariff could raise peak demand by ΔP. The growth in peak demand might also be due to expansion in the economy. In either case, capital investment is required to raise installed capacity by Δp if we are to have the same reserve margin. Investment are also required to reinforce (or upgrade) some transmission and distribution facilities for sustained reliability. If these huge investments are passed on to customers in one step, it might result to price shocks that could reverse the load growth. This problem may be solved by the use of LRMC for capacity costs. This approach involves the distribution of the cost of a generator, for instance, among its output stream throughout its lifetime [2].

2.2.1 Marginal Cost OF Generating Capacity

The marginal cost of a generator unit may be expressed as

$$\text{LRMCg} = \frac{A*C}{R}$$

where A*C= Annualized capital cost [$/yr]
R= Unit capacity [kW]
C = Total capacity cost [$]
A= Annuity rate
$= \frac{r(1+r)^n}{(1+r)^n - 1}$
where r = discount rate [p.u.]
n= life of generator [yr]
$LRNC_g$ is an annuitized cost per KW.

The calculation of LMRC for transmission and distribution may be based on available voltage levels (EHV, HV, MH, and LV). Customers at each voltage level are charged only upstream costs. The detailed treatment is given elsewhere [2].

2.3 Consumer Costs

Consumer cost fall into two broad categories: nonrecurring cost .are associated with service drop lines, meter, and installation labor, while recurrent cost arise from metering, billing,administration, etc.

3 ADJUSTING THE LRMC OF ELECTRICITY TO ACHIEVE OTHER OBJECTIVES

As stated earlier, the first step in tariff formulation is the determination of the strict LRMC electricity. The second step involves the adjustment of the LMRC to achieve a number of sociopolitical objectives. The factors which affect the final tariff setting, are summarized in table 4.

4. RECOMMENDATIONS

4.1 Simplicity of tariff structure

Tariff structure and metering policy should be clearly understood by customers so that they can respond to price signals by adjusting consumption. For example, a consumer should know that demand during peak period is more expensive than off-peak consumption and should therefore know when peak load occurs.

4.2 PEAK PERIOD PRICING

The objective of differential pricing policy based on time-of-the-day or time-of-use (TOU) is to discourage demand during peak periods. However, time-of-the-day pricing may be difficult to implement in most developing countries because of the absence of effective load management (and probably distribution automation) infrastructures, such as remote load controllers that respond to electricity tariff signals. In view of this weakness (especially in metering domestic consumption), one may rather recommend a time-of-the-year pricing policy so that tariffs are adjusted from month to month, being highest for peak load months. It may be easier to implement this proposal because electricity bills are prepared on monthly basis. However, TOU metering may be more applicable to large HV and MHV customers. The responses from this class of customers may include [4]: a) Replacing electricity with natural gas, oil, coal and lignite; b) Switching from heavy industries to light industries; c) Investments to improve energy efficiency (e.g the use of energy-efficient equipment and processes); and d) Shifting some production activities to off-peak periods. In addition, the utilities may consider the use of technical and non-technical peak-clipping measures including propaganda and energy conservation investments.

4.3 Consumer Costs

Domestic consumption is often the largest segment of the electricity market in many developing countries (more than 50% in Nigeria). Many households do not use separate meters: as many as seven households may share a meter. Naturally, consumption by households with separate meter would be more responsive to Electricity price signals than that by households with shared meters. Therefore it would be helpful if the utility could encourage individual households to use separate meter. It could do this by providing meters for the individual customers and distributing the cost (including those of service drop lines and labour for installation) over several years. In Nigeria, these are currently lump- sum payment. Furthermore, if individual households were provided with separate meters it would reduce the incidence of meter theft.

4.4 Use of lifeline rates [2, 5]

For equity considerations, the use of lifeline rates for very poor customers may be justified. To do this, the utility must first define a minimum kW/month. Q_{min} . The applicable customers pay for the first block of electric energy, Q_{min}, at subsidized constant rate. Customers in this class who may demand more than Q_{min} in month will pay for the extra kilowatt hours at increased rates. The concept is illustrated in Figure 4, where LR represents the life rate. The subsidized social block, Q_{min}, may be determined through a survey to ascertain the kWh an average "poor" family needs to meets its basic necessities (e.g. lighting, heating, appliances) in a month. The criteria for identifying low- income residential customers may include: a) number of phases a customer is supplied with; b) customer's supply voltage; and c) area of domicile (G.R.A, urban squatter camps, rural area etc).

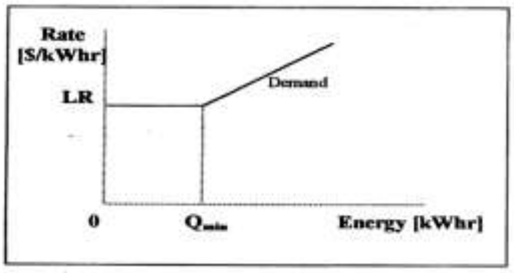

Figure 4 Illustrating the use of lifeline rate

5 CONCLUSION

The major contribution of this paper is the use of the actual generating unit energy production function to estimate MOC of electrical energy. This gives the actual cost at which each kWh is delivered relative to load kW. Such information may be relayed to dedicated remote load controllers installed at customers' premises. In addition, this formulation may be used to estimate energy price probabilities for the planning period. Furthermore, the paper made suggestions on how the shadow price of electricity could be adjusted to meet other objectives that are specific to developing countries. Such objectives include equity considerations, environmental conservation, energy efficiency, and sustained rural agriculture and industry.

6 REFEEERENCES

[1] Munasunghe, M. "An Integrated Framework for Energy Pricing in Developing Countries", The Energy Journal, Vol. 3, July 1980, PP. 1- 30.

[2] Munasunghe, M. "Principles of Modern Electricity Pricing", Proceedings of the IEEE, Vol. 69, No.3, March 1981, PP. 332-348.

[3] Wood A.J. and Wollenberg, B.F. 1984, Power Generation, Operation, and Control, Wiley, New York.

[4] World Bank The Energy Transition in Developing Countries, The World Bank, Washington D.C. 1983.

[5] Iwuagwu, I.N. "Demand-Side Management in a Developing Economy", *The Proceedings of International Conference on Power Systems Operation and Planning* - III ICPSOP "9" Abidjan, Cote, d" Ivoire, January 14-17, 1997, PP. 224-228.

Table 4 Factors affecting final tariff structure

Factor	***Reason (s) for considering factor***	***Means of incorporating factor***
Financial viability of the utility	*Sustained investment in the power industry*	*Set a target financial rate of return on fix assets*
Customer type e.g residential commercial, and industry	*a) Equity considerations; b) To obtain desired mix in energy demand; c) To account for externalities such as network congestion, and environment damage*	*Adopt pricing policy based on voltage level: LV, MH, and HV*
Income redistribution e.g. low- income, middle-income, and high -income residential customers	*Equality or sociopolitical considerations*	*Use lifeline rate*
Government policy to effect optimal mix in energy consumption	*Foreign exchange, energy, and environmental conservation*	*a) Adopt differential energy pricing policy for the different sources (coal, oil, gas, bbetc.)* *b) Use increasing block rate*
Peak load pricing	*Discouraging peak demand helps to achieve load shifting and postponed (or avoided) utility investment*	*a) Use TOU metering; b) Classify some loads as "interruptible loads" which can be shed during periods of Insufficient power*
Geographic area	*a) To stem rural- urban migration; b) To sustain rural agricultural base*	*Use lifeline rate.*