An Economic Analysis of the Pricing Structure for Electricity with Special Reference to Iraq

by

Sajida Ibrahim Ali

A thesis
presented to the University of Manitoba
in partial fulfillment of the
requirements for the degree of
Master of Arts
in
Department of Economics
University of Manitoba

Winnipeg, Manitoba

ISBN Ø-315-33899-7

AN ECONOMIC ANALYSIS OF THE PRICING STRUCTURE FOR ELECTRICITY WITH SPECIAL REFERENCE TO IRAQ

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SAJIDA IBRAHIM ALI

A thesis submitted to the Faculty of Graduate Studies of the University of Manitoba in partial fulfillment of the requirements of the degree of

MASTER OF ARTS

DEDICATION

To my beloved parents.

ABSTRACT

This thesis examines the economic theory and the practice of electricity pricing. Special attention is given to the pricing of electric power in developing countries with special reference to Iraq. The purpose of the thesis is to determine the pricing system which will best serve the interests of society as a whole.

Initially, several criteria are established to provide a basis for the evaluation of alternative pricing systems. They include economic efficiency, financial viability, and equity. After an explanation of the general characteristics of electric power systems, a review of the relevant economic theory of pricing is presented. This review includes marginal cost pricing and average cost pricing, both short and long run, and various types of price discrimination. Long-run marginal cost pricing is found to be best on economic grounds.

Long-run marginal cost pricing is then applied to the general pricing of electricity. Problems of application are considered and a variety of social and political realities and practical considerations are recognized.

Following this analysis, a review of the application of marginal cost pricing in several developing countries is presented. Subsequently, the possible use of long-run marginal cost pricing in Iraq is analysed and discussed.

This sequence of economic analysis demonstrates that long-run marginal cost pricing, modified by overall national policy considerations and practical restraints, is the appropriate pricing method for an electric power system. Further, it contributes effecitively to the economic planning of national resource use.

The thesis concludes that the basic use of long-run marginal cost pricing is both desirable and feasible in developing countries such as Iraq.

ACKNOWLEDGEMENTS

First of all I wish to thank and express my gratitude to the Government of Iraq for granting me a study leave with full financial support, to give me this opportunity to get higher education from outside the country.

I wish to express my special gratitude and thanks to my thesis advisor, Professor Ralph F. Harris of the Department of Economics, for his supervision, encouragement, and patience during the thesis preparation, his constructive suggestions and the amount of time he spent to steer the work to its sucessful completion with care and understanding, his excellent ability and knowledge which guided me, and his editorial skill which enabled me to bring this thesis to its final form.

I would like to thank my external examiner, Professor John Atwell of the Faculty of Management, who made a number of constructive comments which helped to improve this thesis to its useful finished form. Also, I wish to thank Professor Kin Dennis of the Department of Economics, the other member of my committee, for his valuable comments. I am grateful to both of them.

I would like to thank Mr. Ernest G. Johnson and his wife Mrs. Mary Johnson for their skill in editing, which has been helpful in the preparation of the thesis. The main job of typing and correction was done by Miss Suzanne Doyle. I am so grateful to all of them for the time spent and their patience during the preparation of the thesis.

I would like to thank Professor Musa S. Khalidi, Department of Sociology, and his wife Mrs. Jihad Khalidi for all the support, caring and encouragement during my time here so far from my home country. Also, I wish to thank all my friends whom I met here, gave me so much support and respect. Thanks to all the staff in the general office of University College for their help and kind hospitality, I am so grateful to all of them.

I wish especially to thank my beloved parents, sisters, and brothers for their encouragement and patience, they missed me as I missed them during my long absence from home.

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Chapter I

INTRODUCTION

Electric power is often considered the most important of the energy resources in terms of range of use and for this reason it is important to understand and analyze its economic characteristics. The nature of the production cost of and demand for electricity raise a number of specific analytical problems. The demand for electricity fluctuates widely through the day, among seasons, and for different users in rural and urban areas. The electric power plants have an indivisibility constraint. The capacity of a plant is technically fixed and may not necessarily be equal to the quantity demanded in any particular period. Furthermore, there are complex problems in analysis of the cost of providing electric power for different uses. This gives rise to a number of problems regarding the choice of output and optimum capacity.

The problem of optimal pricing for a public utility has received much attention in economic literature. Proposals for pricing have included marginal-cost and average cost pricing, price discrimination and multi-part tariffs. Each of these has strengths and limitations in terms of economic welfare, economic efficiency, financing, or service during peak periods.

This thesis will provide an analysis of the pricing of electricity. An understanding of the general problem of pricing electric power in the industries will contribute to the analysis of the pricing of electric power in developing countries and more particularly in the country of Iraq.

1.1 OBJECTIVE OF THE STUDY

The need and demand for energy stems from various sources: production and consumption of goods and services, housing and urbanization, mobility, leisure activities and so on. With industrial development and an increasing demand for housing in developing countries the need for energy increases, at the same time the cost of producing energy has been increasing. The increase in cost is reflected in higher energy prices. The increase in cost of production has been a major factor contributing to the increase in the unit price of electricity, and this increase has emphasized the need for more conservation.

The purpose of this thesis is to analyze the structure of the pricing of electric power, in order to determine pricing policies to maximize the net economic benefits of electricity consumption for society as a whole. Pricing policy is an available tool for managing demand and reducing electricity consumption. By analysing the cost structure at the same time helps the authorities to find the weaknesses and inefficiencies in the various parts of the power system.

For example, weaknesses and inefficiencies caused by overinvestment, unbalanced investment, and excessive losses during generation, transmission, and distribution in different geographic areas.

This analysis will place special emphasis on the economics of electric power pricing for developing countries and give attention to preferable policies for Iraq.

There is a great deal of literature on the economics of electric power; unfortunately most is devoted to the study of the problem of optimal pricing for public utilities. Recently literature on the pricing of electric power in developing countries has been published and this is central to this study.

1.2 BASIC PLAN

Certain concepts of pricing are central to this study. Each has specific strengths and performance characteristics. They are:

1. Marginal cost pricing (MC): According to this approach, the price charged is equal to the marginal cost of the product. This ensures optimal allocation of resources.
2. Average cost pricing (AC): With this approach price is equated to average cost. This ensures that financial considerations of full cost coverage are met.

3. Price-discrimination (value-of-service-pricing): Under this rule, the price is charged according to the willingness to pay of different users. This price system can lead to revenue increases.
4. Multi-part tariffs: Here customers are charged in two steps. Two-part pricing is advanced as a solution for regulating decreasing-cost industries if economic efficiency is the primary criterion of social welfare.

In evaluating pricing tariffs for electric power pricing, the following criteria will be given special attention:

1. Allocative efficiency: Allocative efficiency implies that resources are most economically organized and used to meet consumer demands.
2. Fairness and equity: Fair allocation of costs among consumers in accordance with the burdens they impose on the system and the provision of a minimum level of service to persons who may not be able to afford the full cost.
3. Financial viability: Sales revenue should be sufficient to meet the financial requirement of the sector.
4. Simplicity: The power tariff structure must be simple enough to facilitate the metering and billing of customers.

5. Economic and political considerations: 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.

Electric power systems will be assessed in terms of achieving economic viability with due consideration to other elements of policy.

The methodology of this thesis will be based primarily on economic theory with appropriate application to the specific realities of the electric power industry and the characteristics of developing countries. The study proceeds through the basic analysis of economic costs, the economic principles of pricing, and the pricing of electricity. The study then considers the economics of electric power pricing in developing countries and focusses especially on Iraq. Finally, an assessment will be made of the policy implications of the thesis.

Chapter II

ELECTRIC POWER SYSTEM CHARACTERISTICS

Electricity is not a primary energy form. It is derived from the conversion of natural energy resources such as hydro, thermal, coal, gas and solar. It can provide heat, light and motive power at a high rate of efficiency and is used as an input by other industries and, as a utility by consumers.

There are particular characteristics of electricity and its consumption that have a bearing on its pricing. First, the demand for electricity is not uniform over time, but fluctuates between seasons, days, or hours of the day and this causes the problem of optimum capacity utilization.

Second, electricity can be transmitted to consumers only by distributors and its resale is not possible. Third, in regions with large variations in heating and cooling requirements there may be surges in demand that tax the capacity of the main electricity supply systems. This calls for the installation of adequate storage or supplemental seasonal supply capacity. It should be noted that electric energy cannot be stored in large quantities.

Finally, the elasticity of demand differs among users of electricity and this makes it possible to discriminate between buyers, and levy charges which are not proportional to the actual consumption.[1] [2]

2.1 ELECTRIC POWER (UTILITY) SYSTEMS

The electric utility system in every country has unique characteristics. However, the general purpose of power systems is to simplify the delivery of electricity from the source to users. Each system must balance user demand for electricity continuously with the most economical operation of the system, and try to use the lowest cost generating capacity available to meet the changing load by adjusting the mix of generating units in use or by purchasing energy from outside the system.

Economical system generation is highly dependent on the type and size of the actual consumer load. A large load affects the efficiency of a plant by allowing the plant to run at its optimal production level. This in turn affects the economical operation of the whole electrical system, because it is more efficient to have power plants running at favorable cost levels than to have underutilized available capacity. In an efficient system, the most

[1] M. Boiteux. "Peak-Load Pricing." Journal of Business, vol. 33, (April 1960), pp. 157-179.

[2] M. Munasinghe, "Principles of Modern Electricity Pricing." Proceeding of the IEEE (March 1981), Vol. 69, No. 3,

economical plants are kept operating at their best efficiency for the longest duration of time.

The unit cost of producing power is usually cheapest for the whole electrical system when the large generation plants are meeting the load and are operating at close to their designed capability. But the operating cost of producing power is only part of the total economics of power production. Fixed charges (interest on the plant investment, depreciation, taxes and insurance) must be paid whether the plant runs or not. These fixed costs are recovered by the electric utility from each individual plant's output, which must also share in covering the cost to the system of nonoperating plants.

Many of the highly efficient plants are not located close to the system load centers and their use may be constrained by higher costs associated by long-distance transmission. These plants may also, on occasion, be unavailable because of plant maintenance or other problems. In such cases the utility must use less efficient plants which will raise the overall cost of producing power.

The basic constituent elements of a power system can best be described in terms of their functions of generation, transmission and distribution. A brief description of each

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[3] R. Turvey. Optimal Pricing and Investment in Electric Supply. Cambridge, MA: M.I.T. Press, 1968, Ch. 2.

such function follows.[3] [4]

2.1.1 Generation

A utility's generating plants vary by size of the unit, fuel use, age, and intended usage. The major fuel sources for these power plants include coal, uranium, water, natural gas, and oil. Electric utilities are actively developing biomass and geothermal sources and, where available, solar, wind, tidal and other technologies are currently minor sources of power for generation.

The generator plants usually contain several sets or units, i.e. in the case of natural gas, oil or coal stations, this means combinations of boiler, turbine and other equipment. Utilities also have reserve or stand-by plants. These plants are usually older, less efficient, and more expensive to run. They operate if there is an unexpected increase in consumer load or to support the electrical system during a plant or transmission line outage.[5]

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[4] M. Munasinghe. Economics of Power System Reliability and Planning. Baltimore, MD: Johns Hopkins Press, 1979, Chs. 1 and 2.

[5] Annual Outlook for U.S. Electric Power 1985, Energy Information Administration and Annual Outlook for U.S.,

R. Turvey. Optimal Pricing and Investment in Electricity Supply, 1968, Ch. 1.

2.1.2 Transmission and Distribution

The transmission and distribution lines are the facilities for carrying the electric power from the source to the consumer. The former is used to carry a large amount of power over long distances, while the distribution line involves smaller power flows over shorter distances. The general principle of transporting power is that voltage level depends on distance and power flow.

The technical distinction between transmission and distribution facilities is usually made on the basis of their operating voltage. Although voltage standards vary greatly from country to country, broadly accepted definitions for voltage levels are as follows: Extra high voltage (EHV) transmission, more than 220 KV; high voltage (HV) transmission, 45-220 KV; medium voltage (MV), primary distribution, 6-25 KV; and low voltage (LV), secondary distribution, 110-380 V.[6]

2.2 PRODUCTION

Production of electric power comes from various sources: superheated steam produced through the combustion of some fossil fuel or nuclear energy, falling water, geothermal steam or hot water, direct combustion engines, energy in the form of wind, concentrated solar heat that produces steam,

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[6] Ibid.

or direct conversion through the use of solar cells.

The production of electric power from solar cells is the only form of electricity production that does not use electromagnetic induction. Costs are prohibitive except in remote locations or in space applications where alternatives are even more expensive.

Geothermal resources have been utilized for power generation in some countries for several decades. Geothermal power can be generated from either steam or steam/hot-water mixtures that are recovered from suitable hot-water bearing rock strata through the drilling of wells. Sources of steam are usually much more attractive because they can be used directly to drive a steam turbine, and because steam sources contain fewer contaminants. Steam/hot-water mixtures must be utilized by transferring the inherent heat energy from geothermal plants. However, this process requires a lot of space.

Overall, it can be assumed that in some countries with favorable geothermal potential, such power plants will become a major source of future power generating capacity.[7]

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[7] Ibid.

2.3 POWER SYSTEM OPERATION

In general the operation of power systems uses many generating sources linked to many load centers via an interconnected transmission network. Transmission interconnections may be used to tie the power systems of several different utilities together to form an even larger power pool. The distribution grid at a single load center would serve thousands of consumers. Furthermore, many other components, including protective and relaying devices, as well as load control and dispatching equipment, play important roles in a larger interconnected system.

Electric power systems must supply power to consumers whenever required. Shortages of electric power, as in the case of other goods and services, occur when the demand exceeds the supply. Power systems are usually planned so that the supply is sufficient to meet forecast demand. In general, however, there will be unexpected variations in the projected demand. One example is the demand placed on a system when unusually warm weather causes consumers to use their air conditioners unexpectedly. Similarly, the supply of power may also be subject to random variations. The unexpected failure or outage of the various components of a power system or the lack of water for hydroelectric generation caused by an unusual drought are two examples of potential supply problems.

In recognition of these random changes in supply and demand, system planners accept that the system may suffer a certain number of future shortages.

From the consumers' viewpoint, power shortages manifest themselves in several ways, including complete interruptions of supply (blackouts), frequency and voltage reduction (brownouts), and unstable service caused by the erratic frequency fluctuations which are likely to inconvenience and to impose costs on consumers. For example, interruptions will disrupt most activity, while a voltage reduction may cause lesser effects, ranging from the inconvenience of dimmed lights to excessive current drain, overheating, inefficient operation, and reduced lifetime of electric motors.

Sufficient redundancy and excess capacity throughout the system to meet unexpected contingencies are the major safeguards against shortages. Once a failure has occurred, the cause of the problem must be analyzed as quickly as possible.[8]

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[8] R. Turvey. Optimal Pricing and Investment in Electricity Supply, 1968, Chs. 1 and 2; M. Munasinghe. The Economics of Power System Reliability and Planning, 1979, Chs. 3 and 8.

2.4 INVESTMENT DECISIONS

Investment in the electricity sector is required for additional capacity cost, which basically includes the generation, transmission and distribution costs associated with supplying additional KW. The investment in new capacity and plant mix is related to total load growth and the characteristics of the whole system. The load demand forecast is made from all factors that might have quantitative relationships with future electricity consumption such as price, income, economic growth, population growth, energy distribution, etc. Thus the investment decision is economic in content.

Basically there will be several alternative long-run investment programs or system expansion plans which are designed to meet the demand growth, subject to various constraints. On the basis of these alternative plans the least-cost usually is selected as the optimal program.

Economic theory indicates that the benefit to society of electricity consumption will be maximized if the output prices set equal the marginal cost of supply, which is based on the least cost plan. But in practice, prices may be adjusted to reflect not only long-run marginal cost (LRMC) of supply, but also other financial, social, and political criteria. What ever future prices result, they must be compared to the prices which are assumed in making the

original demand forecast. If there is inconsistency, then the demand forecast may have to be adjusted and the investment reviewed again.

The electric power sector is often the most important element within the broader energy framework, and authorities should perform detailed analysis as a basis for the investment decision in this sector. The following points will describe briefly the characteristics of the peak demand, load forecast, and the power system cost.[9] [10]

2.4.1 Peak Demand and Load Forecast

Electric power utilities generate power 24 hours a day and 365 days a year, while the distribution of demand for electric power product is not constant over the daily cycle nor over the yearly cycle. But sometimes in any given year there is normally a maximum quantity of power that the electric utility should be prepared to generate. This is normally known as the "peak demand", thus, the electric power system should plan their capacity to make sure that it is sufficient to meet this peak demand at any time. As a result from other than peak periods (off-peak) the electric utility finds itself with excess capacity.

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[9] M. Munasinghe. Economic Power System Reliability and Planning, 1979, Ch. 8.

[10] R. Turvey and D. Anderson. Electricity Economics, Baltimore, MD: Johns Hopkins Press, 1977, Chs. 2 and 17; R. Turvey. Optimal Pricing and Investment in Electricity Supply, 1968, Ch. 8.

It is known that the nature of electric power product is non-storeable, and at the same time consumers have different time demands for this service during the day as well as the year. Thus, the demand fluctuations are further intensified because some demands such as heating and air conditioning are affected by seasonal characteristics, which condition will cause a peak demand.

The terms peak demand for electric power and load forecast are used interchangeably to indicate the importance of the structure of the requirements, of both electrical power and energy. The structure of demand for electric power includes disaggregation by geographic area, consumer categories, and time, as well as load and diversity factors and system losses.

The information on loads at the disaggregate level is important, because the demand characteristics vary by consumer type, geographic area, and with time. The properties of the aggregate demand, for example, of the system level may be quite different from the characteristics of individual loads. Disaggregate loads are important in the system planning process. For generation planning, the system may be modeled as one source feeding a single lumped load, but in designing transmission networks the characteristics of demand by region and by major load centres, such as a city, become important.

The load factor (LF), which is the ratio of average to maximum or peak KW during a given interval, may be specified at various levels of aggregation. The LF may be determined for a single consumer or for an entire system on daily or annual basis. The LF is important because the size or capacity, and therefore the cost of power system components are determined to a great extent by their capability to handle peak power flows. The LF is also a measure of the utilization of capacity. A load factor is estimated either in terms of peak power or of total energy consumed during a given period.

In general, the KW peaks of different consumers do not occur at the same time. The total amount of both KW and KWh generated at the source will be greater than the units which are consumed because of power and energy losses in the system. Generation losses are usually of the station use type. Transmission and distribution network losses are basically technical losses, including transformer losses. Theft is a common loss in some countries and must be considered in the demand forecast since it is also a type of electricity consumption.

Load forecasts are made for different periods. Very short-term demands are made on a daily or weekly basis, typically for optimizing system operation and scheduling of hydro units. Short-run forecasts range between one to three years. The horizon (long-run) forecast for medium demand is

about four to eight years, but may be for more than ten years to complete. Long-range demand projections are usually from 10-35 years.[11]

2.4.2 The Power System Cost

Estimation of the supply cost of electric power requires the calculation of a number of costs involved in the power system. Estimates must be made the valuation of assets which are used in the process of power supply and of a variety of annual operating and other costs incurred.

Two main approaches are used in the estimation of the supply cost. The first is the accounting approach. Here the basis for valuation of costs is found in the recorded transactions in the accounting system. The valuations which provide the supply cost estimates are primarily historical in nature. Such estimates unavoidably distort real costs during periods of inflation and deflation and is also limited to recognition of items in terms of business transactions which occur.

The second concept is the economic approach. Here the use of resources in the form of goods and services is estimated in terms of the economic characteristics of these

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[11] M. Munasinghe. Economics of Power System Reliability and Planning, Chs. 1 and 2; M. Munasinghe and J. J. Warford. Electricity Pricing, 1982. Ch. 3; R. Turvey. Optimal Pricing and Investment in Electricity Supply, 1968, Chs. 2 and 5.

scarce resources. Recognition can be given to costs under alternative production circumstances where these lead to a true valuation of costs in terms of the realities of the total economy. This concept is particularly useful and appropriate when system planning is being done and use of national resources is under consideration.

The process of system power planning and of determining the supply costs is usually affected by several problems, such as uncertainties, demand projection (load forecasts), error in the cost estimates, technological changes, construction delays, and environmental constraints.[12]

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[12] Ibid.

Chapter III

COMPARATIVE ANALYSIS OF PRICING METHODS

Analysis of pricing methods requires that attention be given to cost-output relationships over short and long periods. This chapter will present selected theoretical and analytical relationships which are relevant to the thesis which is being developed.

Cost-output relationships can be examined in terms of technical economies and pecuniary economies. Technical economies alter the physical production process used by a firm to deliver output. They involve the use of production (input-output) functions. Pecuniary economies reflect the prices of inputs of factors used to achieve output.[13]

Pricing is further determined by the nature of the market, or markets, faced by a firm and by the degree of market power held by that firm. Pricing alternatives reflect the policy choice made among different methods of pricing.

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[13] G. William Shepherd. The Economics of Industrial Organization. Second Edition, Prentice Hall, (1985) pp. 228-234.

3.1 THE THEORY OF COST CURVES IN THE SHORT AND LONG RUN

3.1.1 Average Cost Curves

In the short run the relationship between a firm's fixed and variable inputs is significant for its input-output performances. If an input is (or inputs are) varied while one factor is fixed we are able to generalize the results on the basis of an important empirical generalization, the law of diminishing marginal returns. This law states that if equal increments of an input are added, with the other input (or inputs) constant, the resulting increments of product will decrease beyond some point, i.e. the marginal product of the input will diminish (and eventually turn negative). It is this condition that is fundamental to the U shape of the short-run (i.e. when all inputs are not variable) average cost curve.

In the long run, when all inputs are variable, the effect of scale of operation becomes important. A long-run production function may give constant, increasing, or decreasing returns to scale. A production function with inputs X and Y and outputs of 100, 200, and 300 units is shown in Figure 3.1. Increasing returns are illustrated on the left and decreasing returns on the right.[14]

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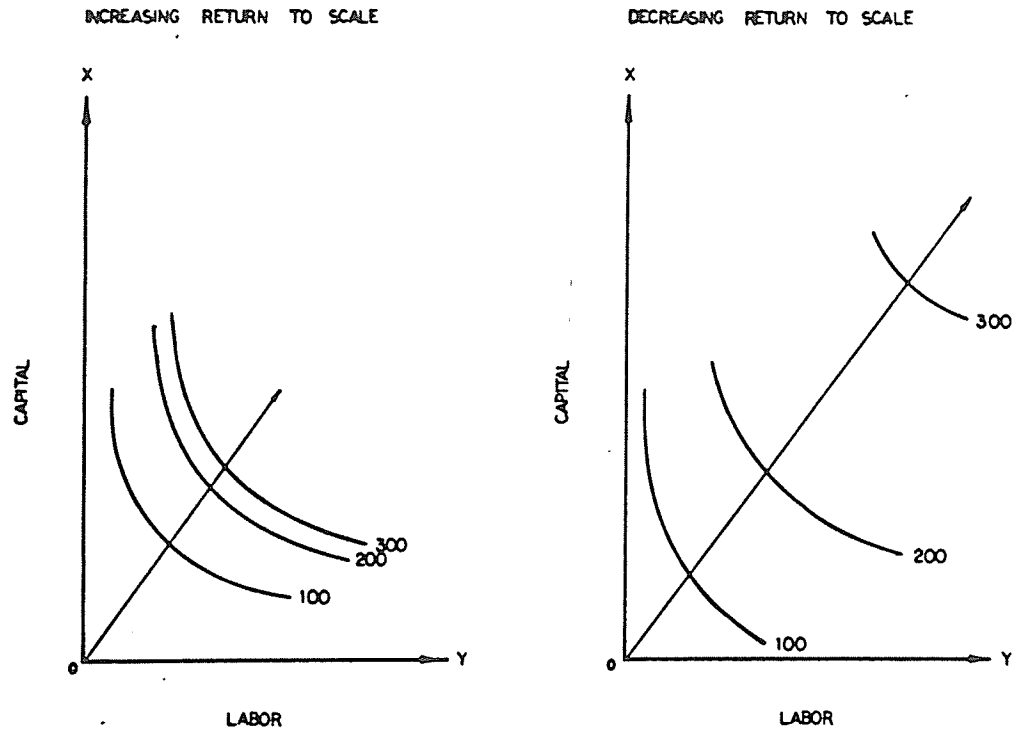
[14] A. Marshall. Principles of Economics. MacMillan and Co. Ltd., 1959, pp. 103-517; E. Mansfield. Microeconomics: Theory and Applications. Fourth Editions, New York: W. W. Norton, 1982, pp. 151.

Figure 3.1: Increasing and Decreasing Returns to Scale

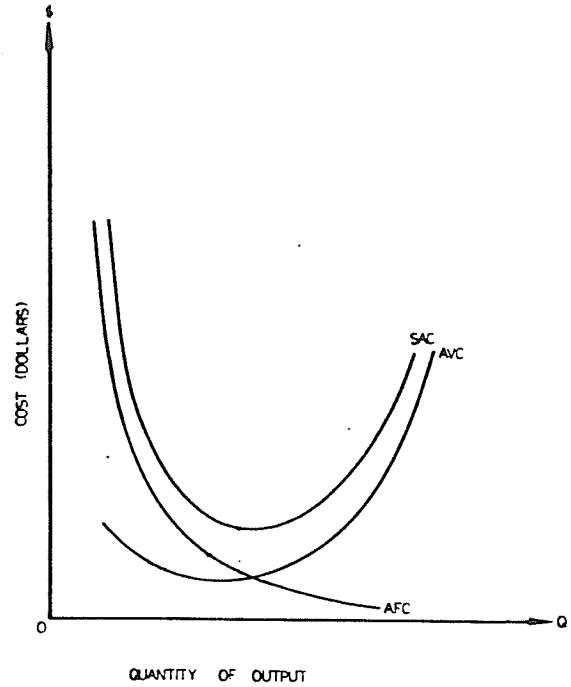


Increasing returns to scale will tend to give a long-run average cost curve decreasing costs or scale economies.

In turning to cost curves themselves, the short-run average cost curve results from the application of factor input prices to input-output relationships. The resulting short-run cost curves are shown in Figure 3.2 where the firm has a single output. Average fixed cost is AFC, average variable cost, AVC, and average total cost, SAC.

It is assumed in this analysis that factor input combinations and payments for inputs are managed efficiently.

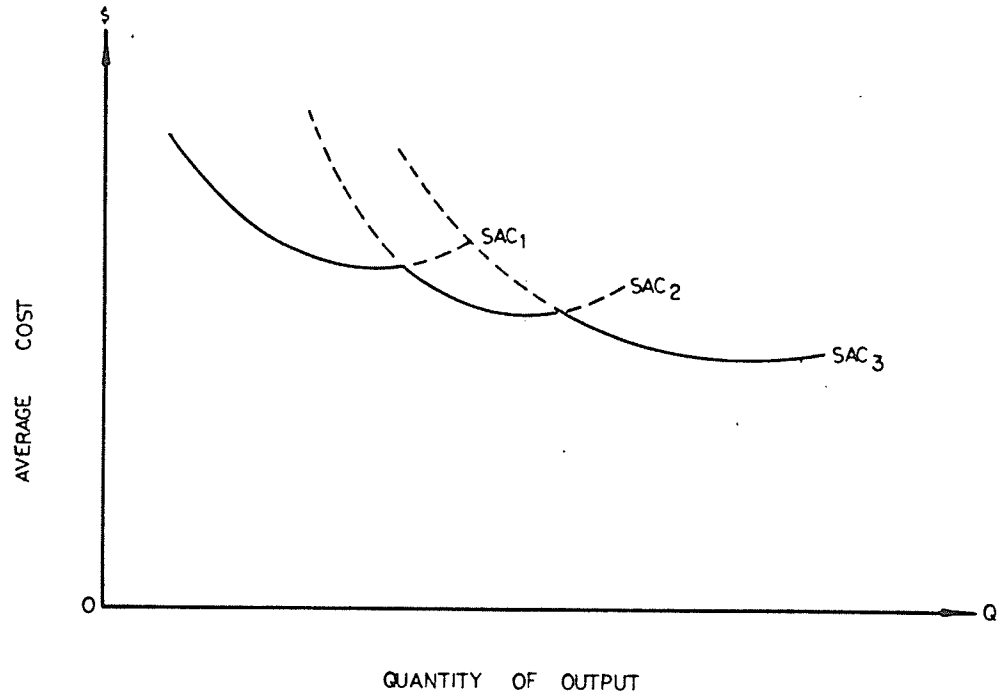
Figure 3.2: Average Costs



Long-run average costs are dependent on short-run relationships and are more complex. The long-run average cost curve (LAC) is made up of a series of short-run average cost curves representing plants of different size. Figure 3.3 shows the three SAC curves representing three plants of different capacity.

The dotted portions of the SAC curves are economically inefficient. The remaining solid lines form a LAC curve, or envelope curve as it is sometimes known, because it envelopes the short-run average cost curves. It is also known as a planning curve because it encompasses not only the size of plant which is in use (with its SAC curve) but

Figure 3.3: Three SAC Curves



also possible larger plants which could be considered under expanded economic conditions.[15]

If a sufficient number of plants are considered, the LAC curve will become smooth in its U shape. It is worth noting, however, that where plant sizes are quite discrete, and not incremental, in size, that such an indivisibility condition will lead to a "bumpy" curve.

The LAC curve may have decreasing costs (i.e. economies of scale), constant costs, or increasing costs through its most significant portions. Ultimately it may be expected to have a U shape on theoretical grounds. The balance between

[15] Ibid., p. 173.

decreasing costs and increasing costs in the shape of this curve is an empirical question in the case of a particular industry.

Certain theoretical points may be made, however, about the reasons for the general U shape of the long-run average cost curve. Why does this curve decline with output and then rise? The following reasons are generally accepted as explanations of the declining tendency of long run average cost curves:

1. Increased specialization made possible by the fact that the aggregate of resources is larger.
2. Qualitatively different and technologically more efficient units or factors, particularly machinery, made possible by selection from among the wider range of technical possibilities opened up by larger resources.
3. Geometric economies arising from the use of equipment such as pipes and containers. The material required for their construction depends on surface area whereas capacity depends on volume.
4. Pecuniary economies resulting from the fact that a larger operation may enable some or all of its inputs to be bought more cheaply.

The rise in the cost curve is generally believed to be caused by the difficulties involved in organizing and

coordinating the operation of a large enterprise. These difficulties may be expected to occur before the minimum point of the cost curve is reached. Their magnitude eventually becomes great enough to offset the effort of the favourable economic elements.[16]

3.1.2 Marginal Cost Curves

While average cost curves are important as guides to the financial viability of economic operations, marginal cost curves play a strategic role in decision-making directed to the most economic use of resources. The short-run marginal cost curves, like the average cost curve, derives its shape from the total cost curve. It reflects incremental changes in the slope of the basic curve and has, like the average cost curve, a U shape. It cuts the short-run average cost curve at the latter's minimum point because the slope of the increment and of the average cost, calculated from the origin of the total cost curve, coincide. The relationship is seen in Figure 3.4.

The long run marginal cost curve (LMC) has a similar relationship to its corresponding average cost curve (LAC). The relationship among the short run and long run curves is shown in Figure 3.5.[17]

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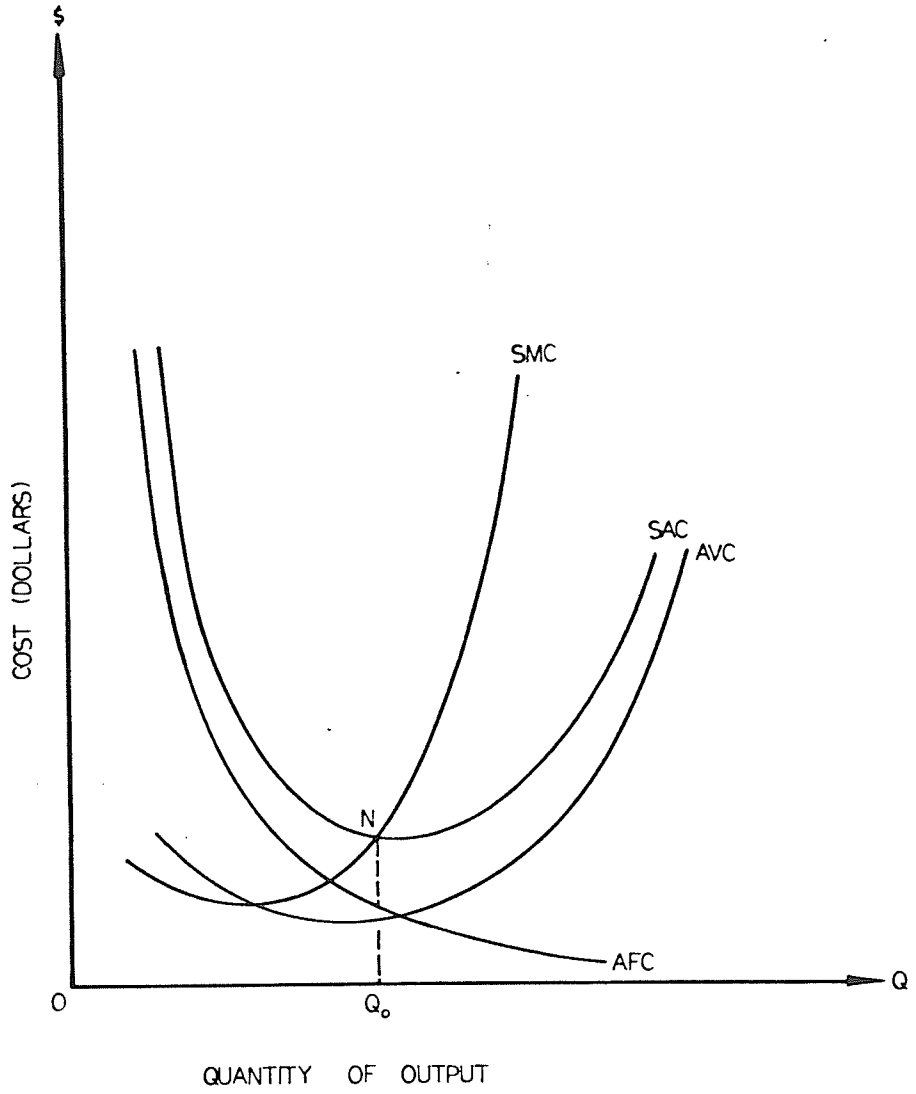
[16] E. H. Chamberlin. The Theory of Monopolistic Competition. Harvard University Press, 1933, pp. 231-259; C. E. Ferguson and J. R. Gould. Microeconomic Theory. Homewood, Irwin Co., 1975, p. 209.

Figure 3.4: Average and Marginal Costs



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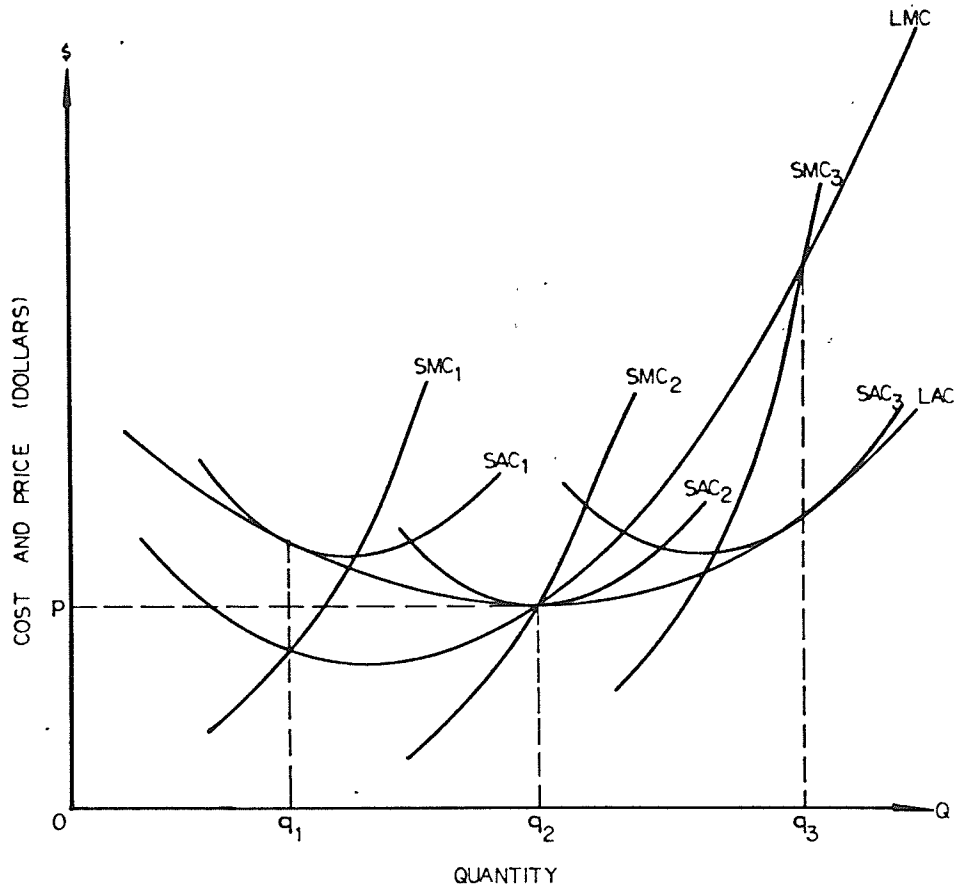
[17] G. J. Stigler. The Theory of Price. Third Edition, 1952. New York: MacMillan Co., Ch. 8.

Figure 3.5: Long-Run Adjustment



3.2 THE ANALYSIS OF PRICING METHODS

Pricing determines how a price system allocates resources, provides finance to firms, and has income distribution implications. There are several ways in which the pricing of output by a firm may be done. The most important alternatives are marginal cost pricing, average cost pricing, and price discrimination. The following analysis directs attention to these methods.

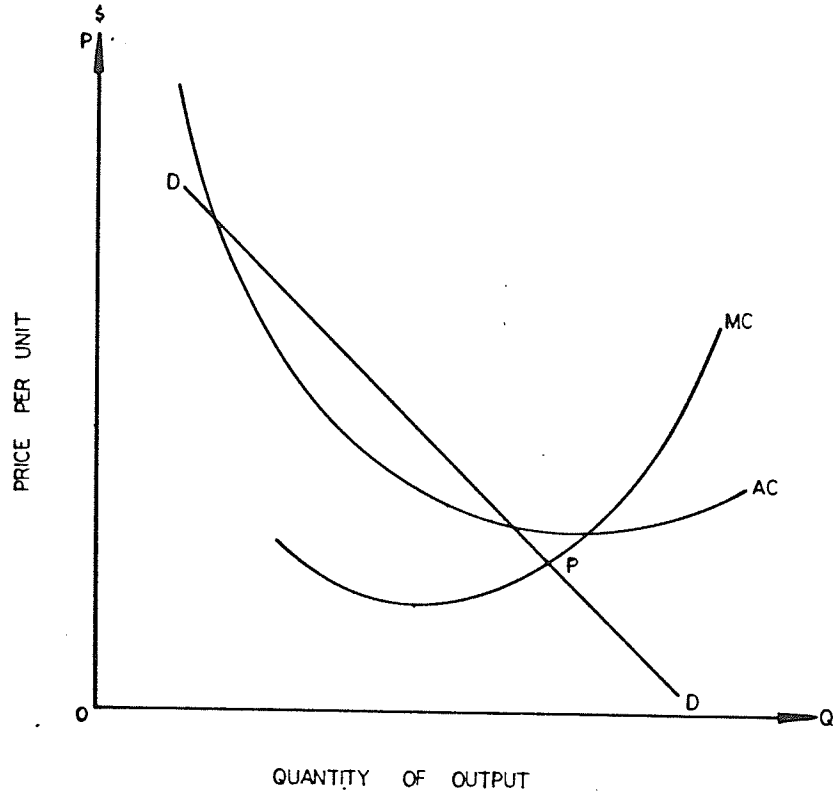
3.2.1 Marginal Cost Pricing Analysis

Marginal cost pricing has as its primary advantage the efficient allocation of resources. On the assumption that cost has been minimized at each level of output by managerial efficiency in the use of factor input combinations and the payment of input prices, marginal cost pricing guides a firm to the appropriate level of output in terms of the demand for output. The price-output decision making by the firm is based on a system of comparisons at margins. Equilibration, in the economic use of resources is attempted by ensuring that no move to use more, or fewer, resources would result in economic gains. It is a guide to an economic optimum. The application of marginal cost pricing is illustrated in Figure 3.6 which shows a decreasing average cost curve in the range of effective demand. The marginal cost price is P.

It is important to note that, under decreasing cost conditions, a deficit occurs. This does not mean that resources use has not been optimized. It does mean that there is a financial problem. A move to remove the deficit situation by a price increase could succeed from the financial point of view but it would restrict output and would imply an under-allocation of resources.

A related situation is present when, even though the existing plant is used to capacity, long-run average cost

Figure 3.6: Optimum Price by Marginal Cost



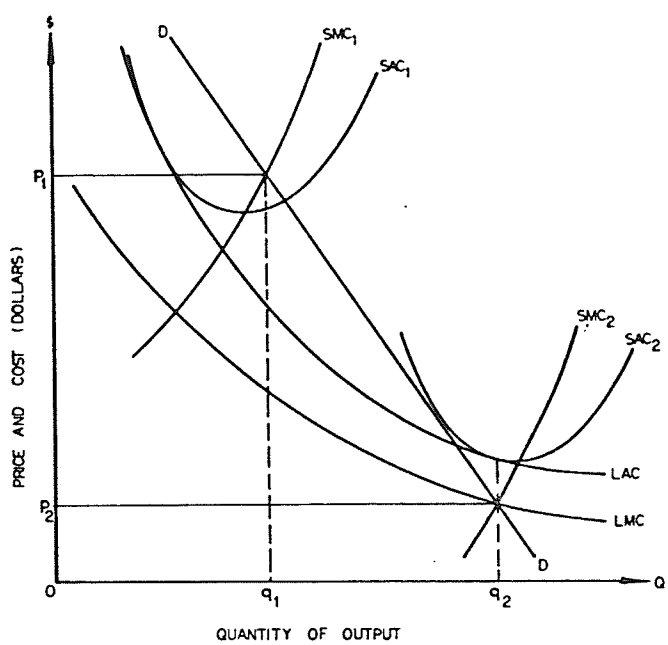
would decline (i.e. economy would result) if capacity and output were increased, because the economics of large-scale production are not yet fully realized. This introduces the question of the use of long-run or short-run marginal cost.

Both short run and long-run marginal cost pricing fit the logic of allocative efficiency. Long-run marginal cost pricing has a wider economic scope, however, because it includes future plant options. by use of long-run marginal cost pricing, consideration is given to the amount of future resources used or saved by user decisions. Such prices act as a signal to users in terms of the economic value of future resources needed to meet consumption changes. They

act to avoid overinvestment and waste, or underinvestment, and the cost of unnecessary scarcity. They avoid unnecessary investment to meet peak demands which can be managed by short-run devices. Also, this approach leads to greater price stability for consumers or users.

Ultimately there is a consistency between short-run and long-run marginal cost pricing. The link is established by optimum investment policy. Consider the situation presented in Figure 3.7. Here there are decreasing costs. The existing plant is shown by the curves SAC_1 and SMC_1 and a planning, or investment, possibility is shown by a plant with curves SAC_2 and SMC_2. The link between the plants is provided by the long-run curves LAC and LMC.

Figure 3.7: Investment Plan



Optimum investment policy, guided by long-run marginal cost pricing will lead to least-cost output and to a price equal to marginal cost.

To achieve a least-cost solution, an investment guide is provided by the SMC and LMC curves. When price equals SMC, and SMC > LMC, new capacity or investment, is called for. Conversely, disinvestment should occur when LMC > SMC and price equals SMC.

In Figure 3.7, marginal cost pricing on a short-run basis for the existing plant results in a price P_1 at output q_1. Here SMC_1 > LMC and more capacity is needed. The investment optimum is reached with the larger plant where marginal cost pricing, short run and long run, gives the price P_2 at output q_2. Here SMC_2 = LMC and no economy can be achieved by further investment, or disinvestment. Economy in cost, and price, is obtained but a deficit remains.[18]

3.2.2 Average Cost Pricing

According to the average cost pricing rule, the price charged is equal to the average cost of the product. This ensures that no losses or deficits occur. As before, both short-run and long-run situations may be considered. Figure 3.8 illustrates average cost pricing. Again a decreasing

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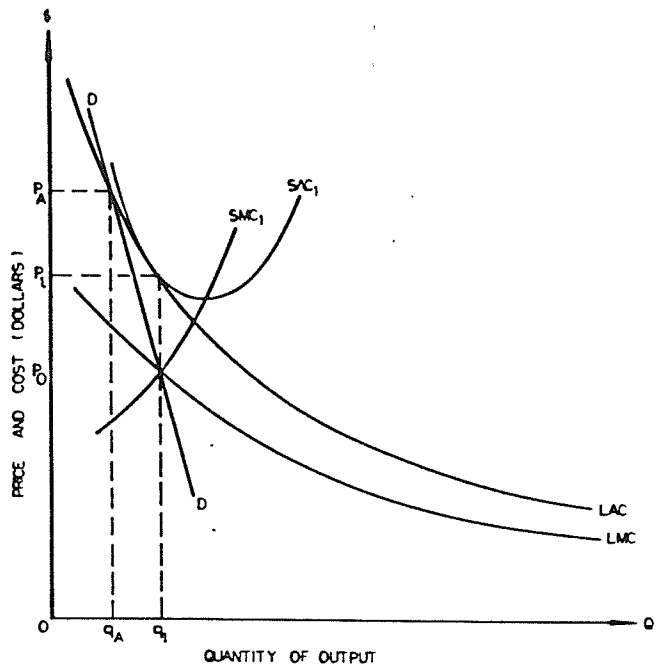
[18] G. M. Webb. The Economics of Nationalized Industries. Nelson, 1973, Ch.7; R. Turvey. "Marginal Cost." Economic Journal (June 1969), pp. 282-99.

cost case is used.[19]

Figure 3.8: Average Cost Pricing



Here, average cost pricing leads to the price PA with output OqA. This price meets both SAC_1, and LAC, i.e. both short-run and long-run criteria. For comparison, marginal cost pricing (short-run and long-run) leads to the price P_1 with output Oq_1. Since the marginal cost pricing result gives an efficient solution in terms of resource allocation, it appears that the average cost pricing result leads to output restriction and an under-allocation of resources. No

[19] W. G. Wilson. Economic Analysis of Intercity Freight Transportation. Bloomington: Indiana University Press, pp. 135-67.

deficit, however, results.[20]

Further, it may be noted that the average cost price is higher than that given by marginal cost pricing. This may be detrimental on income distribution grounds because of the higher cost levied on lower income consumers. Further, the output restriction inherent in average cost pricing may be deficient on broad social grounds in industries where social benefits arising from externalties are present in the use of an industry's output.

3.2.3 Price Discrimination

Price discrimination is defined as the sale of the same goods or services at different prices in different markets where there is no equivalent difference in the cost of supply. Price is charged according to demand considerations, or willingness to pay, and involves the exercise of market power by the firm which markets goods and services. For its practices, price discrimination requires that a firm's output be sold in markets which differ in demand characteristics or in quantity acquired. No resale across market lines can be practiced as such resale could act to destroy the structure of price discrimination.

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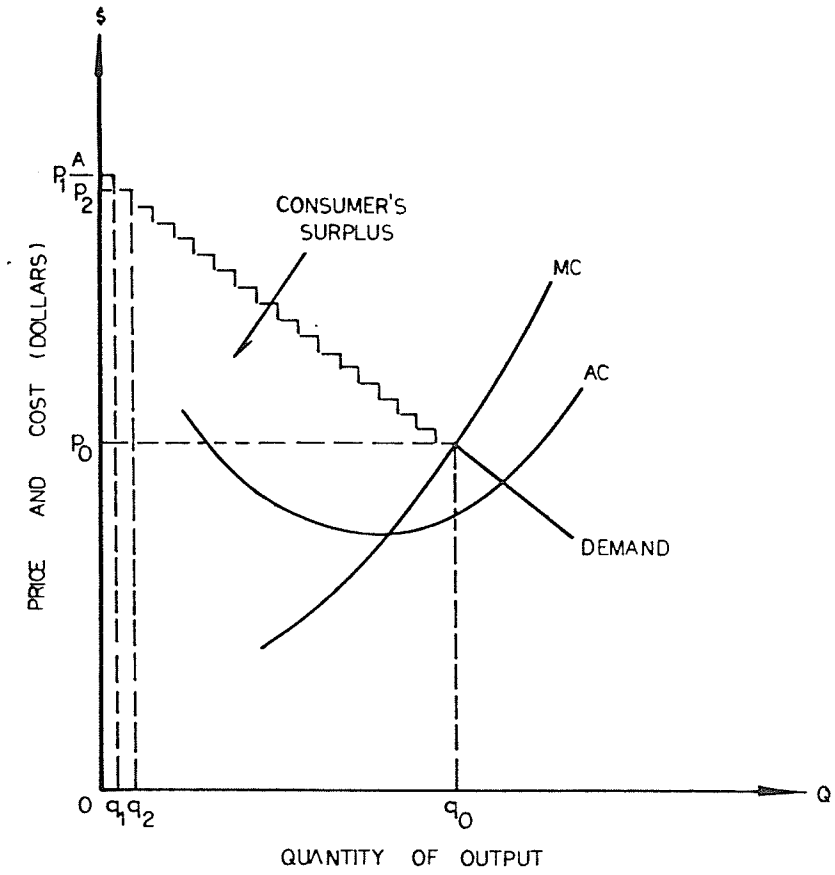
[20] G. J. Stigler. The Theory of Price, 1952, Ch. 10.

In economic theory, price discrimination is divided into three classes.[21] First degree price discrimination involves charging each buyer exactly what he/she will pay for each unit. In such a case, the price exacted for each unit is equal to the demand price for it and no consumer's surplus is left for the buyer. Figure 3.9 shows this case.

Figure 3.9: Consumer Surplus



[21] J. Robinson, The Economics of Imperfect Competition, 1959, Ch. 15; W. G. Shepherd, The Economics of Industrial Organization, 2nd ed., 1985, Ch. 13; A. C. Pigou, The Economics of Welfare, Macmillan, 4th ed., 1952, pp. 275-89.

If the firm charges P_0, the uniform price, the consumers surplus is area P_0AB. But, if the firm discriminates, the consumer is forced to pay P_1 for the first unit, P_2 for the second unit, and so forth for the rest of the units. There will be no consumer's surplus.

Second degree price discrimination is the same in principle as the first but the price differences are less close together. It is a cruder, but more realistic, form of price discrimination. This form of price discrimination is often practiced by public utilities such as telephone systems, electric power systems, etc. It is illustrated in Figure 3.10 where consumers are charged progressively less as their consumption reaches higher levels.

Third degree price discrimination is found where a firm divides its demand into two or more markets with different demand elasticities. This may occur where it sells its output to different types of consumers, e.g. residential, commercial, and industrial. Or the consumers may be in different geographic regions. Figure 3.11 illustrates this case. MC is assumed to be a horizontal straight line for analytical simplicity. There are two markets with different demand curves, DA and DB. Their corresponding marginal revenue curves MRA and MRB are summed to give ΣMR. The intersection of this ΣMR curve with MC gives the total amount of output sold. By tracing back horizontally form this intersection to MRA and MRB the allocation of these

Figure 3.10: Declining Block Discrimination

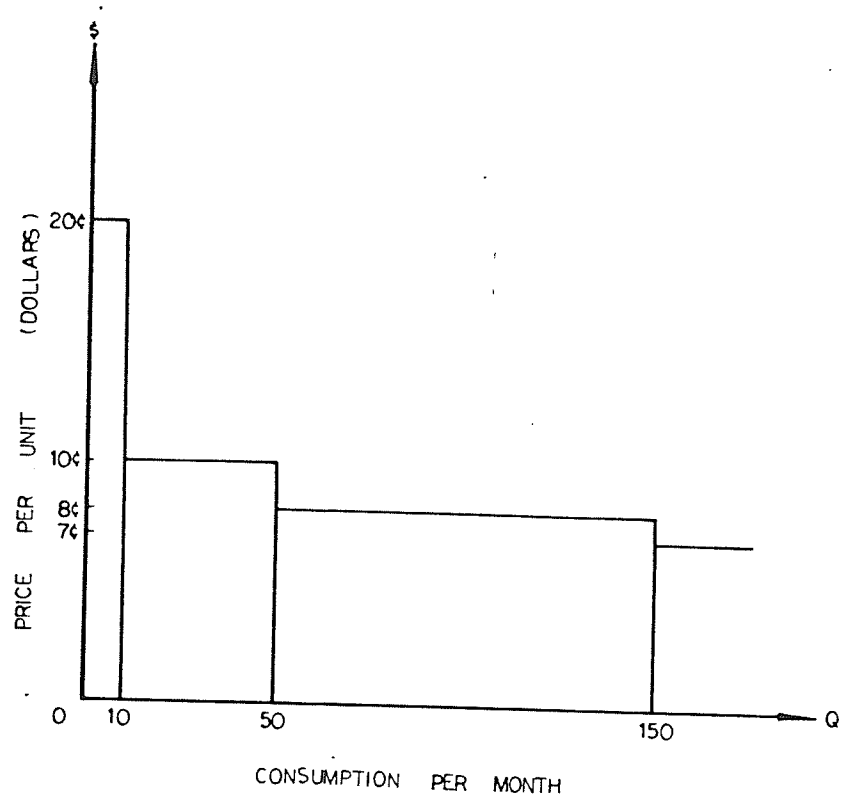
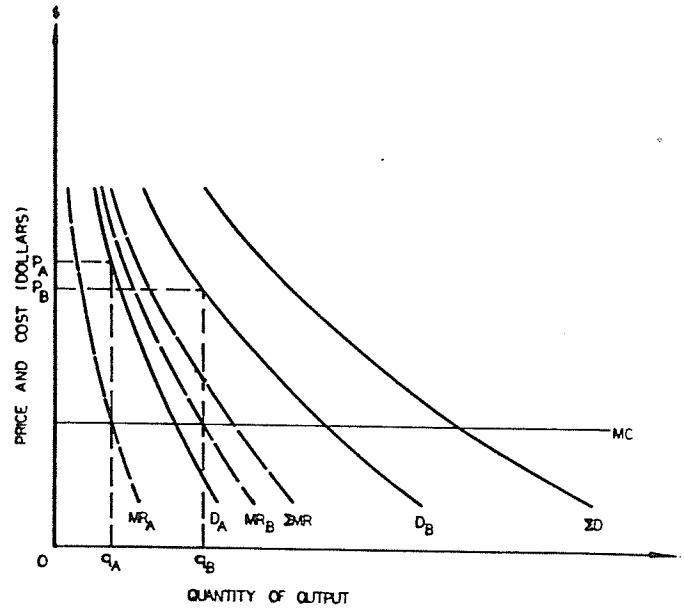


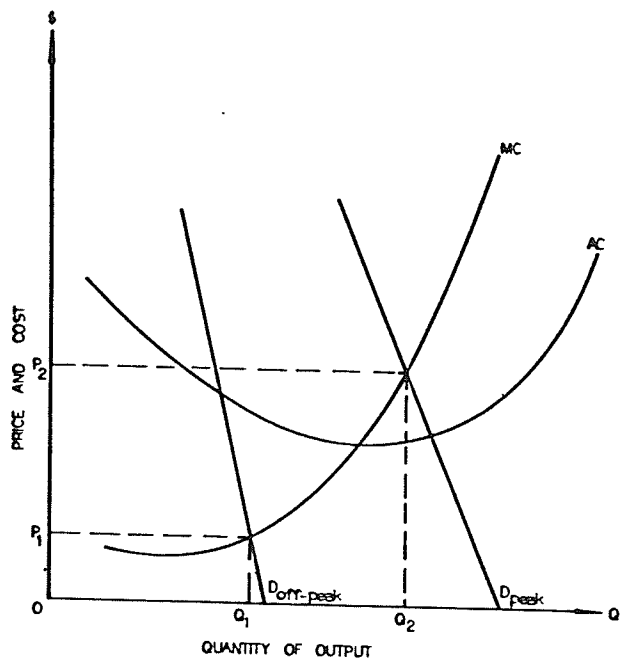
Figure 3.11: Third Degree Price Discrimination



sales between the two markets is obtained. It is OqA and OqB. The price discrimination is revealed by the vertical intercepts with the demand curves, DA and DB, which give the prices PA and PB.

Finally, in industries which cannot store their output, discrinimatory pricing can be used to cope with demand fluctuations which create peak load problems. This case is shown in Figure 3.12.

Figure 3.12: Demand Fluctuation



Here marginal cost (short-run) pricing is used to give a high price for peak load use of output and a low price for

the use of off-peak output. The argument for this case is based on the fact that efficient pricing requires that the price for the last unit sold to each customer, and not the price for each unit sold, should be equal to marginal cost. Different times of sale of non-storeable output enable price discrimination to occur which the peak-load price, P_2, is above average cost and the off-peak price, P_1, is below it.

3.3 PROBLEMS IN THE APPLICATION OF PRICING METHODS

There are a number of problems with pricing methods in the case of a public utility. It is important to examine the importance of these major questions.

3.3.1 Difficulties in the Selection of Projects

With decreasing costs the policy of marginal cost pricing requires a subsidy to cover the costs. It becomes difficult to decide whether or not the project is worthwhile. In industries without decreasing costs, the profit or loss gives an indication about whether to expand or contract the industry. This test is not valid in the decreasing cost industry.

The problem in decreasing cost industries is that the optimum output does not cover its costs. Therefore one must choose between a subsidized operation at the best level of output (with some uncertainty as a whole as to whether it

would not be better to shut down completely) and a self-supporting operation in which the optimal output is not being produced.

In some special situations, it may be possible to recover costs by discriminatory pricing without misallocating the resources. Coase has suggested that this result can be achieved by "multi-part pricing," in which the total amount charged from each customer is the sum of a flat "customer charge" for each consumer, regardless of the quantity of the service taken, and a charge per unit of service taken, set at the marginal cost level.[22] Such a system achieves the desired result only in a limited number of cases.

The Coase solution can also be successful in another case where the demand is homogeneous and the commodity nontransferable. This holds true in a case where an electric utility supplying only domestic service to a community in which the consuming households are all of the same size, income and taste.

In Figure 3.13 Dh is the demand curve for all households. It intersects the long-run marginal and average cost curves, A and M respectively. The optimum level of output OQ_0 is determined by the intersection of Dh and M. It is worthwhile to operate the utility if the area under the

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22 R. H. Coase, "The Marginal Cost Controversy," Economica, (August 1946), 169, pp. 169 - 182.

demand curve exceeds the area under the marginal cost curve between the axis and the ordinate at the proposed output. In this case, it is possible to produce the optimum output OQ_0 and still recover the total cost OQ_0EF by charging any of a number of multi-part price system such as KLNRSM or GHJPM.

A difficulty arises when demand is not homogeneous. Suppose there is a number of lower income households having an individual demand curve d. For these consumers, the relevant marginal cost is represented by the line UVM. Here the area TWP' is much less than the area TUV. The optimum use of resources requires that these consumers consume an amount Oq as long as the area under the demand curve exceeds that under the marginal cost curve.

In this case, if a multi-part schedule is to be used, it must not exceed the area Oqp'w under the demand curve. But such a schedule, if applied to all the consumers, will not cover the costs. Thus one is forced either to subsidize or depart from the optimum consumption. It is, however, possible to reduce the severity of this problem by discriminating on the basis of some index of the intensity of demand, like size of the house or apartment. In Figure 3.13, for example, it is possible to levy schedule KLNRSM for the larger houses and KlnrsM for the smaller houses.[23]

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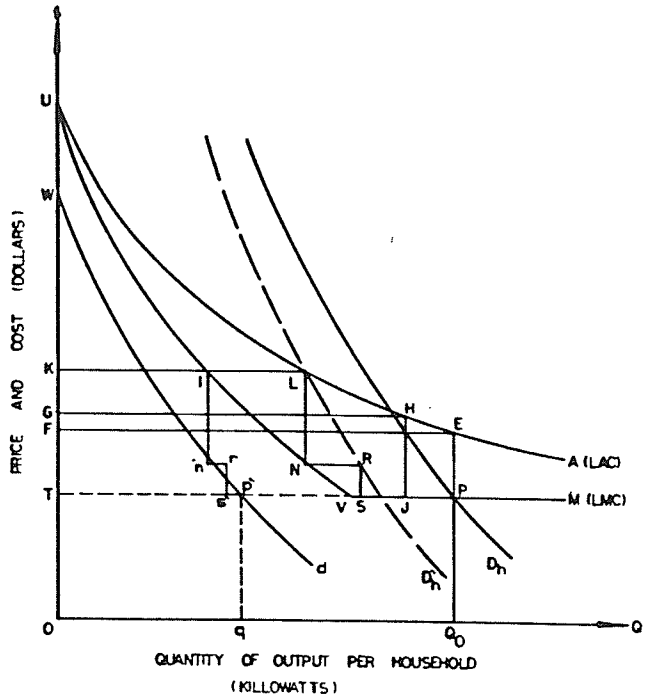
[23] W. Vickrey, "Some Objections to Marginal-Cost Pricing," Political Economic Journal, 1949, pp. 218-238.

Figure 3.13: Output Per Household



3.3.2 Difficulties in the Computation of Marginal Cost

Another objection to the use of marginal cost pricing is based on the fact that marginal cost is not easy to determine. It is therefore suggested that the average cost pricing is not easy to measure either. What the accountant measures is not the measured (ex ante) average cost of future output but is the historical cost of past output, determined after it has been produced. This cost basis, whether average or marginal, is inappropriate for decision-making.

Furthermore, there is also the question of the allocation of the capital cost to the output of various periods. In the case of decreasing cost industries, the allocation of the depreciation allowance is completely arbitrary. In this case average cost pricing is not appropriate.[24]

3.3.3 Fluctuation Problems

Marginal and average cost pricing are also subject to extreme and erratic variations. For example, in the case of aircraft, if an additional plane is required for a marginal passenger, the marginal cost is extremely high. On the other hand, if the marginal passengers fill the plane, the marginal cost is very low.

In practice it is possible to charge differential rates over time. A higher price can be charged during the peaks and a lower price during the off-peak periods. By observing the demand over a period of time, a level of capacity can be provided. This capacity would ensure the least fluctuations in the marginal cost. Such a plan would result in about as close an approach to the efficient allocation of resources as possible. The prospective consumers are offered service at various rates during the different periods. The rates vary according to the demand. The individuals for whom the date of departure is flexible would have an incentive to adjust their plans as to produce a fuller utilization of the

[24] Ibid., pp. 218 - 235.

service and leave a wider choice for the less flexible ones. At the same time, quantity would always be available for the marginal users.[25]

3.3.4 Sociopolitical Considerations

In decreasing cost industries, the main political issue is not whether there should be a monopoly but whether the monopoly should be private or public. The subsidization of monopoly greatly reduces the problem of control as compared to an operation aimed at covering total cost. Whether the operation is in public or private hands, where rates are set to cover the total costs of the operation, there is need for refined judgement so as to cause the least misallocation of resources. In practice, such a system is difficult, especially where there are different classes of consumers. The main problem in this case is to decide which class is to bear the "overhead costs." An example can be seen in the cases of Ontario Hydro-electric Power Commission and the Niagara Hudson Power Company in New York. Ontario was alleged to have improperly distributed its infra-marginal costs so as to favor the residential consumer, while the Hudson Power Company was charged with having favored the industrial user at the expense of the residential consumer.

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[25] Ibid., pp. 218 - 235.

Furthermore, marginal cost pricing, accompanied by subsidy, eliminates the need for public monopolies to cover their costs. Whenever it is necessary to cover costs from revenues, it is often deemed necessary to prohibit private competition. Even some private monopolies are protected in this manner. The problem with such restriction is that it removes a valuable outside check on efficiency.

There are other situations when subsidization based on political and social considerations may be set aside on the basis of practical judgment. It may be unreasonable to cover large overhead costs through subsidy if only a few units are demanded. For example, it is not worthwhile to subsidize the writing, editing, and typesetting of everything that would sell a few hundred copies at prices which covered only printing, binding, and distribution costs. In addition, such subsidy could threaten freedom of the press.[26]

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[26] Ibid., pp. 235 - 238.

Chapter IV

THE PRICING OF ELECTRICITY

In the previous chapter the basic theory of pricing of goods and services was discussed. The basic principles are applied to a public utility. This chapter will analyze the principles of pricing in their application to the electric power sector and consider the pricing criteria which were summarized in Chapter I, Section 1.2.

4.1 MARKET STRUCTURE

In the preceding discussion of basic pricing theory emphasis was placed on cost curves with decreasing average cost characteristics. Is this emphasis relevant to the pricing of electricity? This is an empirical question to which the answer appears to be "yes". In a review of industry studies of cost functions, Mansfield[27] cites six studies of the electricity industry in the U.K. and the U.S.A. The results were:

1. LRAC of production declines (no analysis of distribution).

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[27] E. Mansfield. Microeconomics: Theory and Applications. Shorter fourth Edition, New York: W. W. Norton, 1982, pp. 190-191.

2. SRAC of production declines (no analysis of distribution).
3. SRAC falls, then flattens toward constant MC up to capacity.
4. Average costs of administration are constant.
5. LRAC including transmission costs declines, then shows signs of increasing.
6. Substantial economies of scale.

Generally the industry functions as a natural monopoly, i.e. an economic condition where there is room for only one efficient firm. The generality of use of electricity, and its practical non-storablilty, establish conditions where the full range of price discrimination practices may be applied.

4.2 PERFORMANCE CRITERIA AND THE RELEVANCE OF LONG RUN MARGINAL COST PRICING

Pricing and investment decisions in the electricity industry are made in the context of uncertainty about plant investment, which may be distant in time, and short-run changes in input prices such as oil prices, limited or no information on user or consumer attitudes which could have facilited forecasting, problems in the development of power distribution systems in some areas, capital mobilization problems caused by periods of large capital expenditures and by subsidy requirements, problems of institutional

organization and control aggravated by the wide scope of power systems, difficulties with the maintenance of equity among different users, and problems with the priorization of political considerations in system development.[28]

A comprehensive approach to electric power pricing considers the objectives and criteria discussed in Chapter I, Section 1.2, but these objectives or criteria are not all mutually consistent.

First, the allocative efficiency objective should be to allocate the resources efficiently, not only among different sectors of the economy but also within the electric power sector. This implies that prices reflect the marginal costs of supplying needs for electric power so that supply and demand should be matched efficiently even if a deficit results.

Second, fairness should be considered by:

a) Allocating costs among consumers according to the cost imposed on the system by their consumption of the product or service.
b) Providing a minimum level of service to persons who cannot afford the full cost.

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[28] R. Turvey and Anderson. Electricity Economics. Baltimore, MD: Johns Hopkins University Press, 1977. Chs. 2, 7, and 15; R. Turvey. Optimal Pricing and Investment in Electricity Supply, 1968, Ch. 5.

c) Setting a reasonable price level.

Third, stability should be maintained by avoiding undue price fluctuations from year to year.

Fourth, the electric power prices should raise sufficient revenue to meet the financial requirements of the sector.

Fifth, the technology for metering electricity consumption should be simple to facilitate the metering and billing of consumers.

Sixth, political and other economic constraints should be considered.

The long-run marginal cost (LRMC) approach is to set prices of electric power which provide allocative efficiency in resource use on a long run basis. A thorough application of the LRMC approach takes into account all the characteristics of electric power use by different consumer categories, in different seasons, at different hours of the day, at different voltages levels, and in different geographical areas. The LRMC approach can be varied to serve demand with better utilization of capacity and to avoid unnecessary investment to meet peak demand.

Characteristically, the capacity costs of electric power are joint in nature. Further, electric power cannot feasibly be stored for the future by the electric power system or by consumers. Yet electricity must be supplied at

any given time. These facts create problems of capacity and pricing. The electric power system has the responsibility for building adequate capacity in advance of load requirements. Consumers have responsibility for the creation of peak loads at certain times of the day or season. It may be argued that peak load consumers should be at a proportionately higher border of capacity costs, in addition the higher marginal costs to constrain peak load pressures.

The LRMC approach provides fairness and equity in dealing with future costs and results in from five to ten years of stability in prices. The smoothing out of costs during a long period will be important in the case of a large-size power system investment. With the traditional accounting approach fairness is often defined in terms of constraints on new tariffs, often with an implicit stipulation that no consumer should suffer from an increase in his bill of more than a certain percent within a given period.

In the traditional approach, the calculation is made to cover the accounting costs and possibly to earn sufficient revenue to finance a certain proportion of future expenditures. These requirements are necessary to support financial stability and mobilize financial resources for expansion or innovations and for improving efficiency. The enterprises which rely on having their deficits met by

government do not have the same problems.[29] [30]

4.3 APPLICATION OF MARGINAL COST PRICING

The basic rationale of marginal cost pricing was illustrated in Chapter III, Sections 3.1.2 and 3.2.1. In this section an attempt will be made to apply this theory to the electric power sector. Marginal cost pricing of electricity means a tariff structure such that the cost to any consumer of changing the level or pattern of his consumption will equal the cost to the electricity supply industry.

The argument in favor of marginal cost pricing for public utilities dates back to the efforts of French engineer J. Dupuit in 1844.[31] But most of the present day discussions of marginal cost pricing take for their basis the work of H. Hotelling. Ruggles provides a comprehensive review of work on the subject up to the 1940's. The development of the

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[29] R. Turvey and Anderson. Electricity Economics. Baltimore, MD: Johns Hopkins University Press, 1977, Ch. 2.

[30] M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study. Baltimore, MD: Johns Hopkins University Press, 1982, Ch. 1.

[31] P. Dupuit. "De l'Utilite et de Sa Mesure." La Reforma Soziale. (Turin, 1932); H. Hotelling. "The General Welfare in Relation to Problems of Railway and Utility Rates." Economica. Vol. 6 (July 1938), pp. 242-69; N. Ruggles. "The Welfare Basis of the Marginal Cost Pricing Principle." Review of Economic Studies Vol. 17 (1949-50), pp. 29-46; N. Ruggles. "Recent Developments in the Theory of Marginal Cost Pricing." Review of Economic Studies Vol. 17, (1949-50), pp. 107-26.

theory, especially for application in the electric power sector, received a strong impetus from the work of Boiteux, Steiner, and others in the 1950's.[32] Recent work has led to more sophisticated investment models that enable analysis to structure marginal costs more accurately, to project the results of peak load pricing, and to consider the effects of uncertainty and the cost of power shortages.

The theory of electricity tariff setting is a branch of welfare economics. Thus, the marginal cost principle is intended to ensure that consumers can buy according to their preferences at prices that accurately reflect the relative scarcity of their purchases. Since the electricity industry is only a small part of the economy as a whole, it does not have much influence on the total available amounts of factors of production and distribution of money incomes. In this discussion money income is assumed to be fixed, and all factors of production are fully employed at an optimal level in the long run.

Therefore, for pricing purposes it is important to distinguish between those costs as mentioned above that are a function of consumption and those that are not, costs will be marginal at some times and non-marginal at others. For example, if the electric power system needs additional

[32] M. Boiteux. "Peak-Load Pricing," 1960, pp. 157-79; P. Steiner. "Peak-Loads and Efficient Pricing, 1957, pp. 585-610; O. E. Williamson. "Peak-Load Pricing and Optimal Capacity Under Indivisibility Constraints," 1966, pp. 810-27.

operating and maintenance costs, these are referred to as a short-run marginal cost (SMC). Long-run marginal costs are referred to as the sum of SMC and marginal capacity costs (e.g. building new generators, transmission and distribution lines to accomodate and additional unit of consumption).

Marginal cost pricing designed for the optimum use of existing capacity will frequently not be suitable as a guide for investment. Long run marginal cost pricing with appropriate investment decisions is needed to integrate short-run and long-run considerations.

Problems associated with setting prices on a cost basis are particularly apparent in the presence of capital indivisiblity. This condition is encountered in one-product enterprises such as electricity and telecommunications, where demand is growing through time, and where capacity can only be increased in large lumps, with each capacity being sufficient to cover several years' growth in output.

For example, if the objective is to fully meet demand, capacity additions to the power system (especially generation) need to be large and long lived in order to have available a supply that will be needed to meet future demand. The initial costs of constructing generation, transmission, and distribution are relatively high in relation to operating and maintenance costs. Thus, marginal cost pricing in these kind of circumstances would result in

significant fluctuations in price, which in turn would be a source of considerable uncertainty for consumers and would create problems for planning long term investment in facilitates electric consumption. Even where it is technologically possible to extend capacity in fairly small increments, fluctuation in the availability of finance can mean that capacity must be extended in somewhat larger lumps. Strict MC pricing in these circumstances may require periodic large changes in prices.

If, in such circumstances, the price is set equal to marginal system cost, price would equal short-run marginal cost when capacity is less than fully utilized; and when demand increases so that existing capacity becomes fully utilized, the price will be raised in order to ration the fixed capacity. As known the capacity level for the power system is limited, exploitation of these capacities give rise to the problems of capital indivisibility. The following is the illustration of the capital indivisibility and divisibility for electric power system.

4.3.1 Capital Indivisibility and Divisibility

This phenomenon, which is illustrated in Figure 4.1 where capital is divisible, shows that MC (supply) curve is supplying the additional units of output and demand curve is determined by the Kwh of electricity demand per year at any given average price level are presented by AS and ED_0

respectively. The equilibrium price and quantity are P_0 and Q_0 respectively. If the demand curve shifts from ED_0 to D_1, a new price quantity solution (P_1, Q_1) is obtained by the intersection of AS and D_1. By using marginal cost the consumption benefit at point Q in terms of this equilibrium is shown by the consumers' willingness to pay. This is the area under the demand curve OEFJ. The cost of supplying the output is the area under supply curve OAHJ. The net benefit is the area AEFH, but the maximum net benefit is the area AEG achieved when price is equal to MC of the optimal level at point G as shown in Figure 4.1.

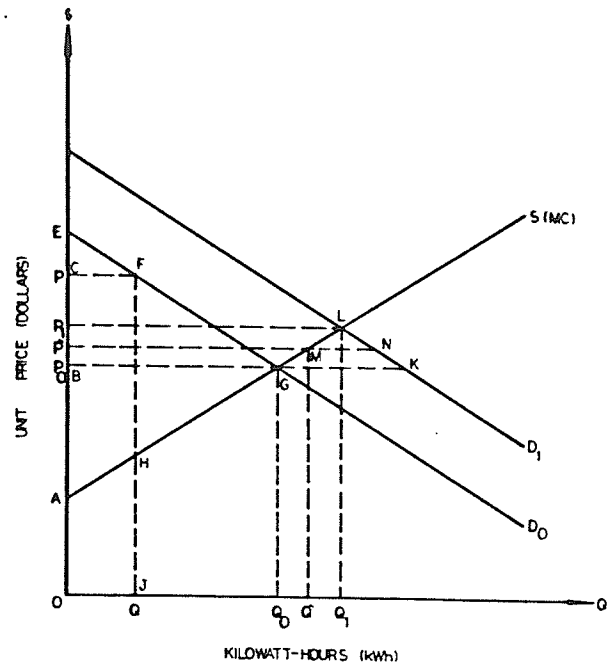
In mathematical terms, the net benefit (NB) is given by:

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

where P(Q) and MC(Q) are the equations of the demand and supply curves, respectively. The formula $\Delta(NB)/\Delta Q = P(Q) - MC(Q) = 0$ shows the equilibrium point where demand P(Q) and marginal cost MC(Q) intersect at (P_0, Q_0) and maximizes NB.

Let us consider the demand growth which is shifted from year zero to year one (D_0 to D_1). In the year zero the market clearing price is P_0, but by shifting demand to year one, excess demand will occur which is equal to GK. Thus, the supply should be increased to Q_1 and the new equilibrium level (L) optimal market, which established new price is P_1. But it may be that the information in the market is not complete, so it will be difficult to reach point L.

Figure 4.1: Supply and Demand for Electricity Consumption



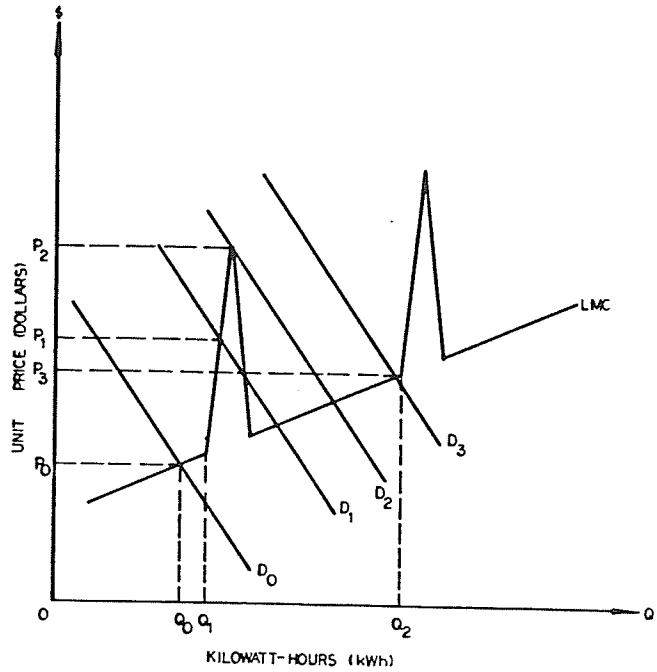
From the technical economic relations point of view in the case of the production function, the marginal cost curve is accurate, leads the price, and quantity can increase continuously until it reaches point L. This example shows how it is possible to move along the MC curve toward the optimal level. This is the basic rule of setting a price equal to the marginal cost and expanding supply until the market clears.[33]

This procedure will continue up to the point where those demanding more service will reveal their willingness to pay a price for additional service equal to short-run marginal cost (SMC) plus an annual equivalent of marginal capacity

[33] M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study, Ch. 2.

cost. It is at this point, where existing capacity is fully utilized and consumers are paying a price that equals long-run marginal cost (LRMC), that the investment in additional capacity can be justified. Since capacity cannot be increased by a small amount, the phenomenon requires that a minimum size of plant has to be added for increasing capacity. If an attempt is made to increase production beyond capacity, there will be a sharp increase in MC (according to Williamson, MC becomes infinite at that level). That is, MC does not follow its usual trend, if production is increased with the existing plant beyond capacity. At capacity level, therefore, the LMC curve becomes vertical. If, however, new capacity is added, LMC returns back to its usual trend. This phenomenon is

Figure 4.2: The Effect of Capital Indivisibilities on Price



presented in Figure 4.2. The LMC curve implies increasing marginal cost by following a regular trend up to capacity level Q_0. If the demand curve is D_0, the price quantity solution is given by P_0 and Q_0 at which D_0 intersects LMC. The capacity output for this plant is Q_1. At this capacity level, LMC becomes vertical, which implies that LMC increases tremendously for a marginal increment in electricity output. The meeting of a higher demand D_1, (or D_2) with this plant size will imply a higher equilibrium price P_1 (or P_2) If, however, new capacity is added, and the cost of new capacity becomes a sunk cost, the MC curve will move back to its trend line. This capacity will be able to supply in the long run an even higher demand reflected in D_3, for an even lower price P_3, where $P_3 < P_2$ and $D_3 > D_2$.[34]

4.4 CALCULATION LONG-RUN MARGINAL COSTS

The analysis underlying this section is the calculating of long-run marginal cost (LRMC) for the electric power sector. Characteristically, the total cost of an electric utility is composed of capacity costs, energy costs, and consumer costs, while a unit of quantity refers to kilowatts

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[34] E. O. Williamson. "Peak-Load Pricing and Optimal Capacity Under Indivisibility Constraints." American Economic Review (September 1966), pp. 810 - 827; Sounders, Warford & Wellenius. Telecommunications and Economic Development. Baltimore: Johns Hopkins Press, 1983, pp. 266 - 267; Staff working Paper No. 340, World Bank, Washington D.C., (July 1979); M. Munasinghe and J. J. Warford. Electricity Pricing, 1982, Ch. 2.

(Kw), or kilowatt-hours (Kwh), or customers.[35] Therefore, the calculation of marginal costs undertakes to measure the change in the level of kilowatt capacity, the number of kilowatt-hours generated, or the number of customers on the system. This can be shown as:

$$MC = \frac{\Delta C}{\Delta Q}$$

Where:

C = capacity costs + energy costs + customers costs,
Q = kilowatts, or kilowatt-hours, or customers.

4.4.1 Marginal Capacity Costs

Marginal capacity costs which are the costs of investment in generation (G), transmission (T), and distribution (D) facilities to supply additional kilowatts (Kw), are measured as the summation of additional per-kilowatt generation costs, transmission costs, and incremental costs per-Kw of the portion of the distribution system which is related to maximum demand levels. These costs will be added to the total system cost, due to the increase in the level of demand.

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[35] S. Werner and G. G. Thomas, Applications of Economic Principles in Public Utility Industry. University of Michigan, Graduate School of Business Administration, Division of Research, 1981, pp. 53-71.

The following is the calculation of LRMC of generation, transmission, and distribution costs:

a) Marginal generation costs, are the costs of additional capacity to the system's generating capacity. The company can estimate the costs by calculating the costs of a project, for example, over 5 to 10 years, which calculations will include all the details of the type of equipment and other facilities to be added to the electric power system. The calculation of long-run marginal capacity (LRMC) costs per Kw (generation (G)) is:

$$\text{LRMC} = \frac{\text{The costs of additional generating capacity}}{\text{The quantity increase in peak-load}}$$

b) Marginal transmission costs can use a similar procedure to calculate long-run marginal transmission costs, (LRMC). The capital budget for transmission facilities for 5 to 10 years is divided by the project increase in peak power demand over that period, which gives the LRMC per-Kw for transmission facilities.

Generally, all costs of investment in transmission and distribution should be allocated to incremental capacity, because the designs of these facilities are determined principally by the peak Kw that they carry, rather than Kwh.

An example of the system using the average incremental cost (AIC) method to estimate the LRMC of transmission and

distribution is as follows: suppose in year N, ΔDn and In are the increase in demand served (megawatts) and the investment costs, respectively. Then, the calculation of AIC of capacity is given by:

$$AIC = \frac{\left[\sum_{n=0}^{T} In/(1 + r)^{n}\right]}{\left[\sum_{n=L}^{L+T} \Delta Dn/(1 + r)^{n}\right]}$$

Where:

r = the discount (interest) rate (for example, the opportunity cost of capital)

T = is the number of years for which electricity expenditures and attributable output are forecast (planning horizon for example, 5-10 or up to 50 years)

L = is the average time delay between the investment and commissioning dates for new facilities

This formula above is to determine AIC, calculated by discounting all incremental costs which will be incurred in the future to provide the estimated additional amount of electricity which will be demanded over a specified period, and dividing that by the discounted value of incremental output over the period.

Therefore, the AIC defines long-run marginal costs, where the estimates smoothes out the lumps in the expenditure

stream while at the same time reflecting the general level and trend of future costs which are incurred as electricity consumption increases. Where the unit costs are lumpy the AIC estimate will not be equal to the long run marginal cost.

AIC can be distinguished from the long run marginal costs definition. AIC takes a longer view of costs looking beyond the next incremental in capacity. This can be particularly important where rapid technologocial change is taking place or significant scale economies are being experienced. AIC also has the attribute of avoiding severe price fluctuations although it does not adhere closely to long run marginal cost.

From the discussion above it can be seen that not only must capacity be constructed, but that it should be operated and maintained. The company annually should estimate the expenses of the operating and maintenance, and the costs associated with additions of generation, transmission, and distribution capacity. The LRMC analysis at the generation, transmission and distribution levels helps the company to establish whether these incremental costs are excessive because of overinvestment, high losses, or both.[36]

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[36] M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study, 1982, ch. 4; Charles, J. C. and John, L. J. Studies in Electric Utility Regulation. Ballinger Co. Cambridge, Mass., 1975, Ch. 2; R. K. Davidson. Price Discrimination in Selling Gas and Electricity. Baltimore: Johns Hopkins Press, 1955, Ch. 6; H. S. Houthakker, "Electricity Tariffs in Theory and

4.4.2 Marginal Energy Costs

Marginal energy costs are the fuel and operating costs needed to provide additional Kwh from a thermal plant, whereas in a hydroelectric system it is a part of the investment cost which is associated with storage related to energy.

Most utility systems add energy in the most economical and efficient way. They generate the maximum number of Kwh from the unit with least expensive running costs. If more energy is needed, the system will move to its cheapest plant.

To calculate long-run marginal cost (LRMC) of energy during the peak period, take the total cost for the most recent period available divided by total Kwh production at the point of generation during that period. This would be a measure of marginal fuel costs.

The LRMC of off-peak energy corresponding to a load increment during the off-peak period would usually be the running costs of the least efficient base-load, or cycling plant used during this period.[37]

Practice." Economic Journal (March 1951), pp. 169-82.

[37] Ibid.

4.4.3 Marginal Customer Costs

Marginal customer costs are the incremental costs directly attributable to consumers, including costs of hook-up, metering, and billing.

Some electric utility costs vary neither with peak demand nor energy consumption, but directly with the number and types of customers that are served. Some of these costs represent capital expenditures on plant and equipment, while other costs which are primarily wages and salaries to working staff associated with maintenance are incurred annually. Capital costs incurred merely by adding an additional customer are associated with hook-up equipment, meters, billing equipment, administration office space, and to some extent distributional costs associated with basic territorial coverage.

Capital costs associated with hooking-up and providing meters for additional customers are easy to estimate from recent historical data for different types of customers. Billing equipment, office space, and territorial coverage are not as easy to isolate by particular types of customers. Practically, the way to calculate marginal customer costs could be by fitting a statistical costs related with the number of customers.

In general, electric power systems vary in allocating incremental (non-fuel) operating, maintenance, and

administrative costs among the three basic cost categories, namely capacity, energy, and customer. This requires an analysis of specific systems.[38]

4.5 COST STRUCTURE OF THE TYPES OF SYSTEMS

The structuring of the costs of an electric power system is the first step in selecting an appropriate pricing or rating period, but it is known that the characteristics of demand for electric power fluctuates over time. To calculate long-run marginal costs (LRMC) it is important to first examine and describe the load duration curve (LDC) and generation schedules to determine the periods during which demand presses on capacity and supply costs are highest. In an electric power system the cyclical critical periods (load and noload demand), may be caused by daily demand variations, (e.g., evening lighting load), seasonal variations (e.g., summer air-conditioning load), and supply (e.g., dry seasons for hydro systems). These cases have different effects depending on typical plant systems either all-thermal, all-hydro, or mixed hydro-thermal systems.

First of all, this section will describe the load duration curve LDC in terms of electric utility. Secondly, the calculation of marginal cost of the typical electric power system, when the plants are of specific types.

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[38] Ibid.

An important feature of the demand for electricity is that it fluctuates greatly with time. Because it is expensive and impractical to store electricity in most cases, it should be produced at the time it is required.

Figure 4.3 illustrates the hourly electricity demand that faces a typical electric utility during a one-day period. The demand for load is measured in kilowatts or megawatts, and the area under the curve is the approximate total energy demanded that day. As shown in Figure 4.3 the demand is lowest during the night hours.

Figure 4.3: A Typical Daily Load Curve for an Electric Utility

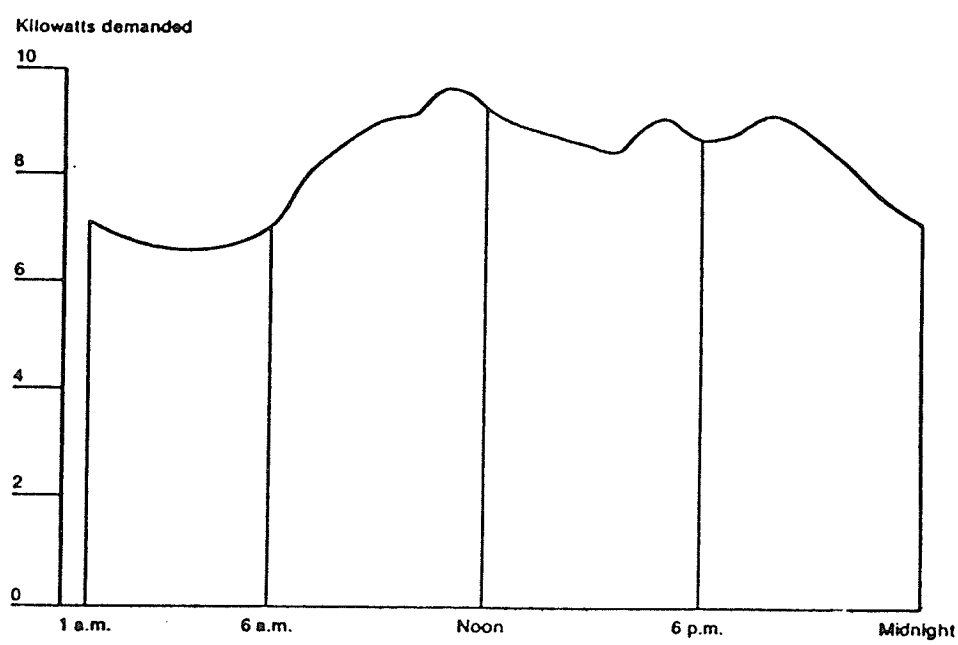


Figure 4.4 shows the hourly demand facing a utility for every hour of the year arranged chronologically and shows that the demand is generally much higher in the summer months when demand for electricity (for example, air conditioning) is high. Thus, the peak demand or peak hourly

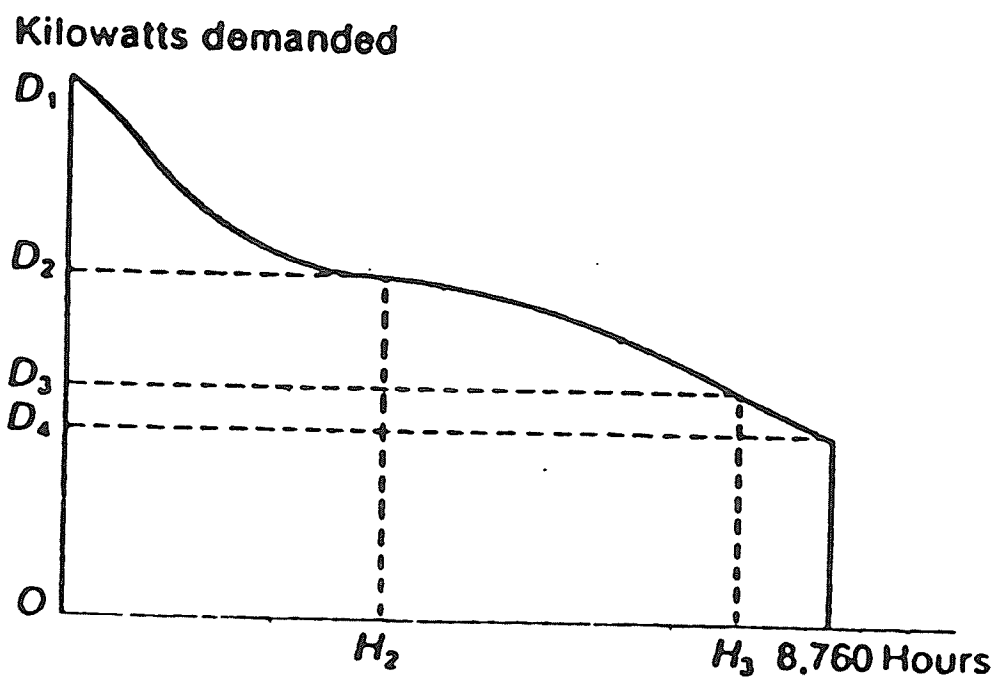
Figure 4.4: A Typical Annual Load Curve for an Electric Utility

load for the year usually occurs on a very hot summer day. It is important to know when the peak demand occurs during the year for planning purposes, because it shows the maximum amount of electrical power that the system should be prepared to supply at any point in time within the year. The utility system should have sufficient generating capacity to meet this peak demand.

Moreover, because of the long period of time required to plan for and construct large generating stations, utilities should plan their generating system based on a forecast of peak demands for many years into the future. In addition, the utility should maintain reserve capacity in excess of its projected peak demand. This allows for factors such as forecasting errors, equipment breakdowns, outages, etc.

The hourly loads for a year shown in the preceding graphs can be reordered in terms of the highest to lowest hourly loads. This reordering and presentation of loads in the form of a graph gives what is known as an annual "load duration curve (LDC)." An example is shown in Figure 4.5.

Figure 4.5: A Typical Annual Load Duration Curve for an Electric Utility



The number of hours in a year is 8.760.

Figure 4.5 shows that the highest demand attained in any hour during the year is D_1 kilowatts and the lowest is D_4 kilowatts. For H_2 hours of 8,760 hours in a year, demand is equal to D_2 kilowatts, similarly for H_3 years of the year demand is equal to D_3 kilowatts for 8,760 -- H_3 hours in the year. The area under the LDC is the quantity of energy demanded during the year.

The annual load factor is defined as the ratio utility of the average of hourly demand for the year to the peak hourly demand in the year, which is equivalent to the ratio of the area (energy) under the annual LDC to the area of the rectangle bounded by the peak demand in kilowatts and to the right by the total number of hours in the year -- the total energy that would be demanded if the peak demand occurred during the year. Similarly you could find daily or a monthly load factor. Thus, the annual load factor is a measure of the regularity or flatness of the LDC. For example, the maximum possible annual load factor of unity would indicate equal hourly demands throughout the year and a horizontal annual LDC. A low value for the load factor would indicate that the annual LDC falls steeply to the right.

Generally, most utility systems prefer to have a higher rather than lower load factor because this allows them to

reduce generating costs per unit of output. A flatter curve would require behavioural or technological changes by users who are required to change their consumption patterns. This in turn will impose costs on those users, because the utility caused the shape of the LDC to change in order to minimize costs for society as a whole. The LDC is heavily dependent upon the pricing policies of the electric utility.

The conclusion from Figures 4.3, 4.4 and 4.5 is that the peak demand hourly during the day or seasonly will create problems for electric power systems. The electric utilities should have sufficient capacity to meet the peak demand, and the system should maintain generating facilities utilized less than full time. This could mean that certain generating facilities might be utilized for only a very small number of hours in a year.

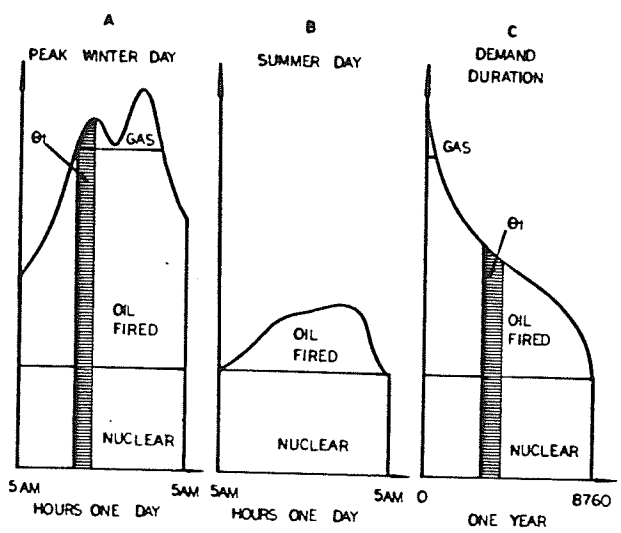
4.5.1 All-Thermal System

The preceding discussion of the LDC concept has been general. This discussion will explain the calculation of LRMC and use of the LDC concept for an all thermal plant.

Consider a power system that has only three types of thermal plants namely gas turbine, oil-fired, and nuclear. Figure 4.6, (in A and B) shows the daily demand of winter and summer for all thermal plants, and C shows the LDC for one year, which is the aggregate of the system. Figure C

also shows the projection of the plant capacity horizontally through the daily curves, at the times when different plants are started up, placed on load, taken off load and shut down on different days. By continuing this situation horizontally through the demand duration curve LDC, the total operating time of each plant during the year can be shown.

Figure 4.6: Load Dispatching in an All-Thermal System



The area under the daily use or demand curves (for winter and summer) is the energy delivered by each plant and is the basis for the total system operating costs. The plants are placed in order with the plant with the lowest operating cost per unit of output at the bottom. The plant with the hightest operating costs is at the top and in this illustration it will not be used in the summer.

The estimation of operating costs is shown in Figure 4.6 (A and C). Here the weighting at each time interval is indicated by $\emptyset_t$ where $\emptyset_t$ is the output of the plant in that interval. Cost can then be estimated on the basis of the types of plant use for each time interval $\emptyset_t$. The LDC in Figure 4.6 (C) integrates and makes cost estimation much simpler than would be the case if the curves shown in Figures 4.6 A and B were used.[39]

Figure 4.7 shows the LDC as ABEF. Consider that the system started from year zero (beginning of the year where the demand is zero), and that there are two demand peak and off-peak periods during the year. As demand grows, the peak demand is shown by the shaded area in Figure 4.7. In Figure 4.8 the LDC is shown by D starting from year zero (D_0) and at the peak demand shifting the curve D to D + ΔD curve, as shown by the broken line in Figure 4.8.

The LRMC calculation of the generation is equal to $\Delta C/\Delta D$ where the increment of demand ΔD is marginal both in time and megawatts. In theory ΔD can be either positive or negative, that is, both increments and decrements should be considered symmetrically. Generally the ratio $\Delta C/\Delta D$ will vary with the sign as well as the magnitude of ΔD.

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[39] R. Turvey and D. Anderson. Electricity Economics, 1977, Ch. 13; M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study, 1982, Ch. 4; J. R. Nelson. Marginal Cost Pricing in Practice. Englewood Cliff, N.J.: Prentice Hall, Inc., 1964, Ch. 5; M. G. Webb. The Economics of Nationalized Industries, 1973, Ch. 5.

Some companies use a computerized model to calculate LRMC, which makes it easier to determine the ΔC (change in capacity costs) by simulating the expansion path and system operation with and without the increment or decrement in demand ΔD.[40]

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[40] Ibid.

Figure 4.7: Typical Annual Load Duration Curve

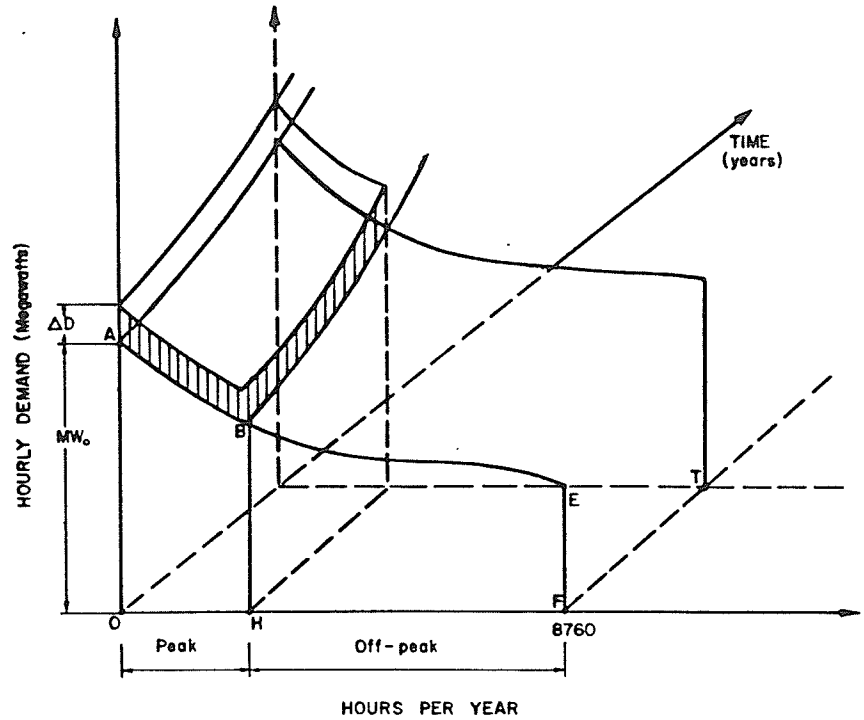
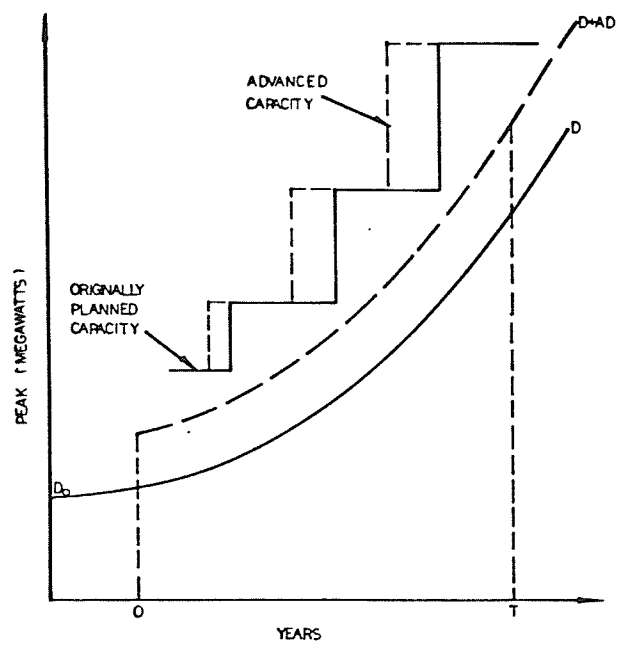


Figure 4.8: Forecast of Demand for Peak Power



4.5.2 All-Hydro System

The calculation of the LRMC of generation of an all-hydro power system depends on the seasonal variations, which are the special characteristic of pure hydro systems. During the year there is a single wet and a single dry season, thus, the water has to be put in storage in the wet season to help the system meet the requirements in the dry season. The analysis for this typical system requires:

a) The treating of a set of reservoirs and hydro plants in terms of a single equivalent.
b) That the analysis should cover a single year.
c) That deterministic or expected values of water inflows and outflows should ignore the effect of uncertainties.

Figures 4.9 and 4.10 show the hydroelectric system when the water inflow and outflow varies during the seasons. The river flow of water into the system typically fluctuates and the inflow is measured by kilowatt-hours (Kwh) of potential energy a day. Figures 4.9 and 4.10 show that the storage water drops from point A to B during dry season, which discharged water is measured in gigawatt-hours. In the wet season the water increases from B to C at which point the reservoir is full and any excess water should be spilled. Then the spilling or sluicing water or both will continue as long as energy demand is below the energy inflows (from

point C to D). In the wet season the water inflow exceeds the desired outflow as shown in the Figures from B to D. Again this cycle of water flow will repeat from the start of the dry season which begins from point D.

If the system is provided with water from one or two large rivers, then the spilling or sluicing period from C to D will be long, since the energy inflow exceeds wet season energy demand, and eliminates the need for water to be stored. Thus, extra output can be produced in the wet season, if there is sufficient turbine capacity. Thus, the marginal costs of output in the wet seasons is zero.

During the dry season the energy inflows are less than energy demand, thus the marginal costs will rise, because extra energy is needed to produce power to meet the extra demand. But in this situation the system cannot meet this demand without the provision of extra storage capacity, so the marginal costs of energy at any point in time during the dry season are the marginal costs of providing storage capacity.

The conclusion from the above discussion is that in an all-hydro system the LRMC of generating capacity incurred during the peak period would be based on the cost of increasing peaking capability, that is, additional turbines to expand capacity. The incremental energy costs which are attributable to the dry season would be the costs of

reservoir storage. During the wet season, the incremental energy costs are small usually involving operations and maintenance costs only.[41]

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[41] R. Turvey and D. Anderson. Electricity Economics, 1977, Ch. 15; M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study, 1982, Ch. 4.

Figure 4.9: Water Inflow and Outflows of an All-Hydro System

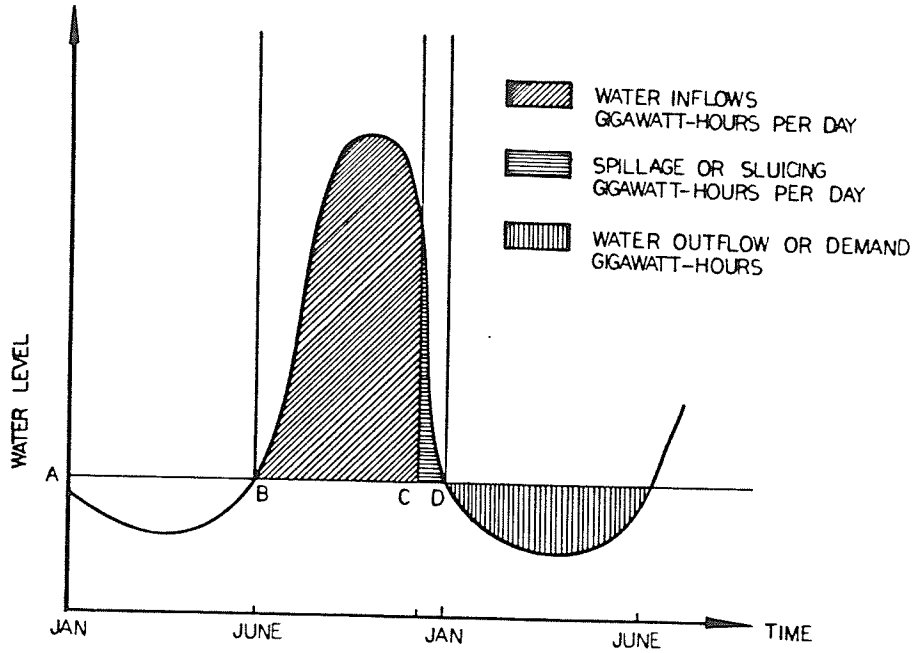
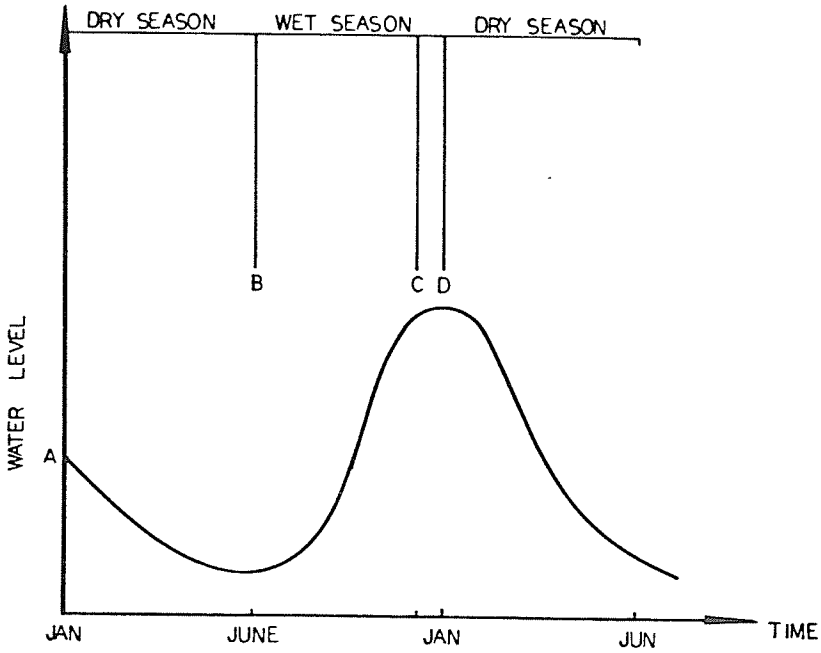


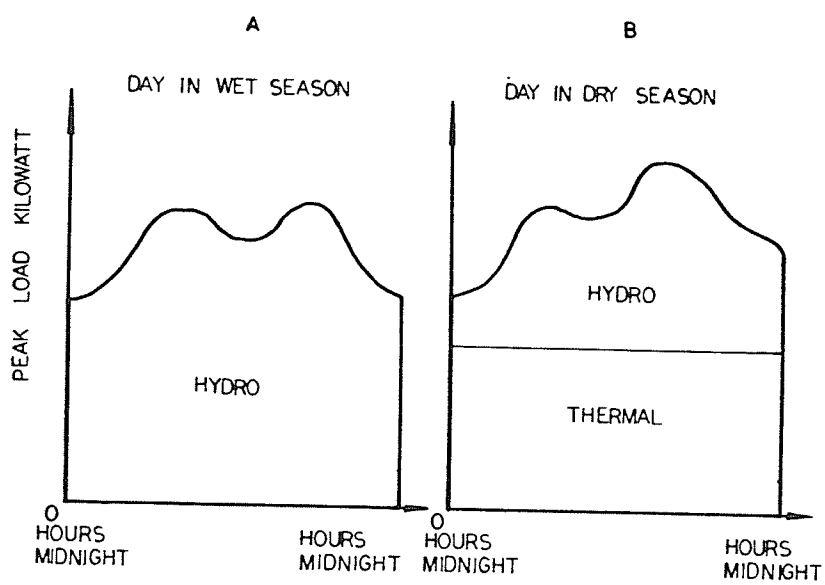
Figure 4.10: Reservoir Level of an All-Hydro System



4.5.3 Mixed Hydro-Thermal Systems

The costs of LRMC in mixed hydro-thermal systems depend on the mix of generating plants used at different times and under different conditions. First, when thermal generation supplements hydro generation in the dry season the hydro system is available throughout the year. In the wet season, the hydro energy inflows exceed energy demands, and the marginal costs of energy are equal to zero. Figure 4.11 in A shows the daily peak demands in the wet season, which approach the systems's power capacity. In the dry season however marginal costs rise accordingly to reflect the

Figure 4.11: Hydro-Thermal System Operations With Thermal Backup For Dry Season

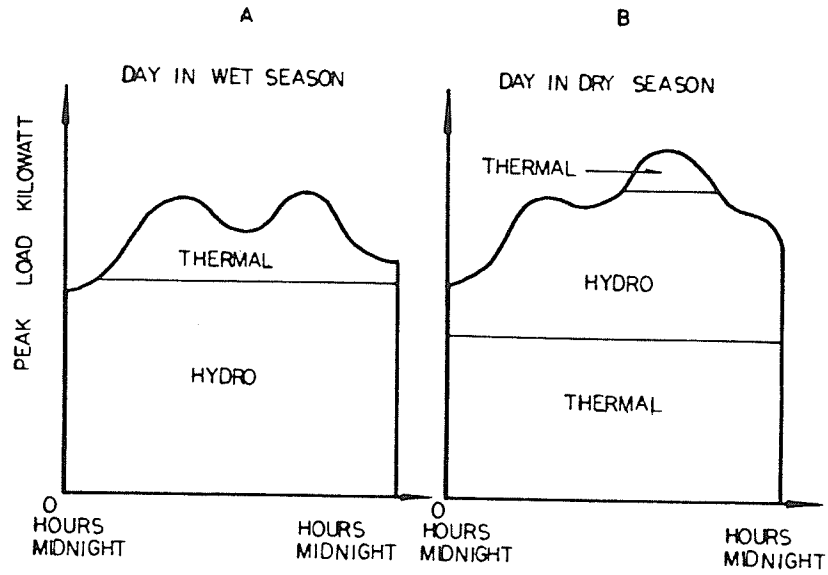


marginal costs of providing additional capacity.

In the dry season, an increment of energy demand can be met by more output from the thermal plant, where there is additional capacity available from a thermal plant in the system. In that case the marginal costs will be the marginal costs of fuel. This situation occurs if there is an overinvestment in thermal capacity. Figure B shows the thermal plants on base load operation, in which case an increment of energy demand will require extra thermal capacity. It is desirable however to keep the extra capacity down to minimum and to use it fully by spreading the extra thermal output over all the hours of the dry season. Then the calculation of LRMC per Kwh in this case is done by adding these elements which are: a) marginal fuel costs; b) marginal capacity cost of thermal plant divided by the number of hours in the dry season; c) marginal capacity costs of hydro plant divided by the number of hours in the dry season.

Second, consider the case when thermal energy is required in both seasons. In the wet season hydro generally will be on base load, and thermal plants will be providing for peak demand. But in the dry season the situation is different. With the thermal plants on base load hydro provides for peak demand which operation is shown in Figure 4.12.

Figure 4.12: Hydro-Thermal System Operations With Thermal Backup For Wet and Dry Season With Thermal Peaking



An increase of demand in the wet season will require extra output from the thermal plant if the hydro is operating at capacity. The marginal costs will be equal to marginal costs of fuel plus marginal costs of providing capacity at the peak demand period. But at off-peak demand in the wet season, the thermal plant may not be operating at all, and the hydro plant may be operating below capacity. However, in this case the hydro output will have to be reduced at a later time and thermal energy will be required to restore storage to the desired level. Then, the marginal energy costs will equal marginal fuel costs.

In the dry season, the thermal plant will provide for the base load, and extra output should come from the thermal plant at the peak load, so marginal costs will equal

marginal fuel costs plus marginal capacity costs. Throughout the dry season the thermal plant is working at full capacity and extra thermal capacity will be needed to meet extra demands whenever they occur.[42]

4.6 MODIFICATION OF LONG-RUN MARGINAL COSTS

In the previous sections discussed the tariff structure of the LRMC pricing, but the tariff structure will be affected directly and indirectly where there are constraints to the economy and particularly in the electricity industry, which make it difficult to reach the equilibrium level. These constraints produce deviation in the final tariffs relative to the LRMC, and can be divided into two groups. The first consists of economic distortions such as uncertainty of future input prices, plant availability, forecasting the load under assumption of weather condition; social lifeline problems of low income consumers. The second group are based on political, financial consideration for example, changes in government or their plans often according to their political view; revenue may be insufficient to finance a certain proportion of future capital expenditures and other financial charges. The problems of metering and billing such as the difficulties to allocate the cost equitably as possible among consumers through the tariff structures. To meet these constraints

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[42] Ibid.

the tariff structure should be derived by modifying the LRMC. The process of adjusting LRMC generally will result in deviations in both the magnitude and structure of the LRMC, and take into account the type of users, level of income, and the difficulties of metering and billing.

The distortions which are mentioned above and which produce a deviation in the final tariff relative to the LRMC, there are ways to cope, for example the distortion which occurs basically within an economic framework requires the shadow pricing, second-best solution i.e. a subsidized or lifeline price for low-income consumers. The second group, which includes the other considerations, namely financial, sociopolitical and difficulties of metering and billing requires a different solution which will be dealt with later.[43] [44]

In the following analysis the possibilities of modifying LRMC pricing are discussed.

4.6.1 Shadow Pricing

The shadow prices are used to compensate for the effect of distortions of the economic resource costs of inputs used to produce electricity. This section presents a brief

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[43] R. Turvey. Optimal Pricing and Investment in Electricity Supply. (1968), Ch. 8.

[44] M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study, 1981, Ch. 5.

introduction to shadow prices in the electricity sector, developed in the context of a national economy, and particularly relevant to the developing countries.

Generally, when market imperfections occur, shadow prices may be used instead of the distorted market prices to represent the true economic resource costs of various goods and services in the economy. Such shadow prices have their roots in the theory of welfare economics and cost-benefit analysis.

Under perfect competition, the prices which reflect the true marginal social costs, scarce resources are efficiently allocated, and for a given income distribution no one person can be made better-off without making someone else worse-off (condition of pareto-optimal). But in the real world, the situations are different; there is distortion in the economy such as monopoly practice; external economies and diseconomies; interventions in the market process through taxes, duties, and subsidies; all of which result in market prices for goods and services different from true economic value or shadow prices. All these considerations require appropriate shadow prices instead of market prices for economic analysis, especially in the developing countries where market distortions are frequent.

To estimate shadow prices it is necessary to divide economic resources into tradeable and nontradeable inputs.

The values of directly imported or exported goods and services should be in terms of border prices, with the foreign exchange costs converted at the official exchange rate. Locally purchased items valued at domestic market prices should be converted to border prices by multiplying by a appropriate conversion factor (CF). The tradeable and nontradeable are treated differently as the following discussion will show.

In the case of tradeables with infinite elasticities of world supply for imports and world demand for exports, the cost of insurance and freight border prices for export and import may be used with suitable adjustment for the marketing margin. The free trade assumption is not required to justify the border prices, because domestic price distortions are not effected but could be adjusted by netting out all taxes, duties, and subsidies.

The case of nontradeable economic resources has two types of commodities both conventionally defined as a commodity whose domestic supply price lies between the free on board (f.o.b.) and cost, insurance, freight (c.i.f.) prices for export and import, respectively. The other items are not traded at the margin such as bonds or rigid quotas on commodities. For example, if increased demand for a given nontradeable good or service causes the domestic supply or imports to expand, the associated border prices marginal social cost (MSC) of this increased supply is the relevant

resource cost. If consumption of other domestic or foreign users decreases, the border-priced marginal social benefit (MSB) of this foregone domestic consumption or of reduced export earnings would be a more appropriate measure of social costs.

In the case of electric power the most important tradeable inputs are capital goods and petroleum based fuels. Some countries may have other domestic fuels available such as natural-gas or coal deposits. If no clear-cut export market exists for these indigenous energy resources, they cannot be treated as tradeables. In addition, if there is no alternative use for the fuels, an appropriate economic value is the marginal social cost of production, that is, of extracting gas or coal pulls a markup for the discounted value of future consumption foregone or "user cost". If another high value exists for this fuel, the opportunity cost of not using the resource in the alternative use should be considered as the economic cost of the fuel.

The most important nontradeable primary factor inputs are labor and land. Let us consider a typical case of unskilled labor in a country with surplus labour, for example, rural workers employed for dam construction. The foregone output of workers used in the electric power sector is the dominant component of the shadow wage rate (SWR). Complications rise because the original rural income earned may not reflect the

marginal product of agricultural labor. The efficiency shadow wage rate which include the foregone marginal output and overhead costs (such as transport expenses) of labor in domestic prices and should multiply with conversion factors to convert these values into border prices.

The shadow value for land depends on its location. Usually, the market prices of urban land is a good indicator of its economic value in domestic prices. The application of an appropriate conversion factor, such as the standard conversion factor (SCF), to this domestic price will yield the border-priced cost of urban land inputs. Rural land that can be used in agriculture may be valued at its opportunity cost, the net benefit of foregone agriculture output. The MSC of other rural land is usually assumed to be negligible, unless there is specific reason to the contrary. Examples might be the flooding of virgin jungle because of a hydroelectric dam that would involve the loss of valuable timber, or spoilage of a recreational area that has commercial potential.

The shadow price of capital is usually reflected in the discount rate or accounting rate of interest, which is defined as the rate of decline in the value of the numeraire over time.[45]

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[45] Ibid., and Ray Anandarup. Cost-Benefit Analysis. Baltimore: Johns Hopkins, 1984, Chs. 2, 3, 4 and 5.

4.6.2 Second-Best Considerations

Theoretically, the concept of the second-best "is the best allocation of resources, that can be obtainable when various constraints preclude attaining true economic efficiency."[46] An electric power system characteristically can substitute and complement inputs, but where the prices of the inputs elsewhere in the economy do not reflect marginal costs, then, the second-best solution may be required.[47] The Baumol-Bradford proposition is that "prices which deviate in a systematic manner from marginal costs will be required for an optimal allocation of resources, even in the absence of externalities."[48] This is necessary to obtain a proper balance of resource allocation.

The price distortion will effect the inputs into the production of electric power and output of other sectors that are electricity intensive such as the aluminum industry. Because of these matters modifying LRMC subsidizes the electric power system.

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[46] W. Nicholson. Microeconomic Theory. (2nd ed.), Dryden Press, 1978, p. 684.

[47] S. Roger and V. Michael. "Second Best Pricing with Stochastic Demand." American Economic Review, (March 1978), 68, pp. 42-53.

[48] W. J. Baumol and D. F. Bradford. "Optimal Departures From Marginal Cost Pricing." American Economic Review (June 1979), pp. 265-283.

Let us consider the case in developing countries. For example, subsidies for imported generators or diesel fuel exist in many developing countries which may make it advantageous for users to establish their own plants, even though for the economy as a whole this is not the least expensive way to meet the demand. The first-best solution in this case is for the government to cut off the subsidy for generators or to restrict the importation of generators and to set the price of electricity at the LRMC. But in the case of the importation of subsidized diesel fuel the situation is different. Government policy dictates the need to maintain subsidies for this kind of fuel with the result that the price of electricity lower than LRMC. Thus, the second-best solution would be required. The extent of the deviation from the LRMC is determined by the size of the subsidy and the degree of substitutability of the alternative energy source.[49]

4.6.3 Subsidized Social or Lifeline (Increasing Block) Prices

In some developing countries the government subsidizes the input (e.g. fuel), such as kerosene, because the costs of consumption of electric power units are high relative to the low-income of the consumer. This subsidy is in favor of lifeline to supply the basic electricity needs at prices

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[49] M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study, 1981, Ch. 3.

which the low-income consumer can afford. In theory, a lump sum cash transfer policy to low-income households to meet their basic needs such as electricity service would be a simple way to solve this problem. But this policy would be ineffective in some views as the electric power utilities could act as discriminating monopolists by using an increasing-block tariff, and could get advantages in addressing these issues.

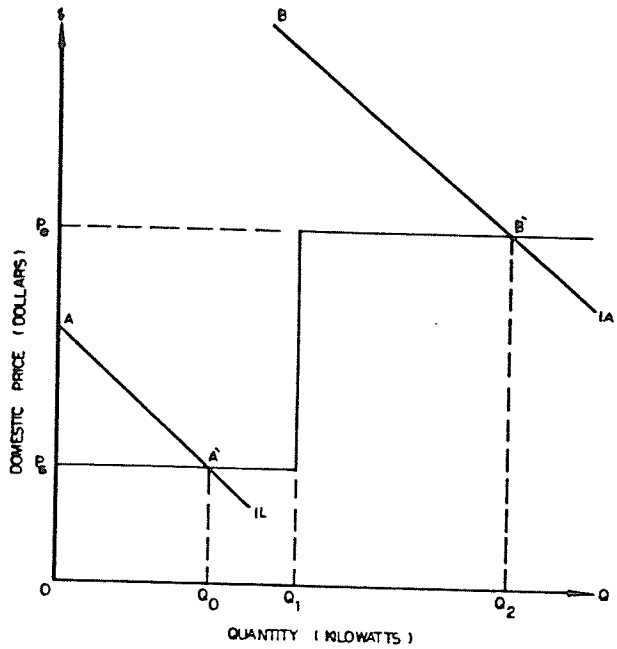
The concept of increasing (inverted) block tariffs is the counterpart to the declining block tariffs, and is a form of conservation pricing. The price for each block rises with each successive block, and at the same time both the marginal and average costs of electricity to the consumer increases with his or her usage. In other words capacity expansion causes the cost of electric power units to increase.

The increasing block tariff suffers from several deficiencies, such as: efficiency and insulation incentives which may be induced by building codes or tax incentives may be more effective; implementation of the conservation method may be outside the electricity regulatory sphere; imposing a penalty for the larger user may not result in significant use reductions or abandonment of service, but may lead to the system resorting to self-supply; the system may not significantly reduce the system peaks or slow down the system expansion, and the unit costs may be increased

further. Some views hold that this type of tariff is an inducement to decrease the consumption of electric power (reduce demand), thus, the inverted block or lifeline may be the best solution to the problem of excessive revenue.

Let us now illustrate the concept of subsidizing social (increasing-block or lifeline) rates for low-income consumers. This concept has another important welfare economic rationale based on income distribution. In Figure 4.13 there are two demand curves for low-income (IL) and average-income (IA) for domestic users which are denoted by AA', BB' respectively. The efficient price (Pe) is the level based on marginal cost and (Ps) is the social price, which prices are shown in Figure 4.13. The minimum consumption block is from O to Q_1, and the average consumption block is from Q_1 to Q_2. Then the poor consumer (low-income) can consume the quantity of Q_0, but he or she cannot afford to consume the quantity Q_2. If we assume the actual price P=Pe, then the average household consumer will be consuming up to the optimal level Q_2. By measuring the benefit for the two income level consumers the concept of consumer surplus is used. If increased benefits accruing to the poor have a high social weight value, then the consumer surplus which is the area APsA' should be multiplied by an appropriate social weight, which is denoted by Wi, where Wi > 1. With nominal market prices, if the point A lies below Pe, the socially weighted distance OA would be greater than the marginal cost of supply.

Figure 4.13: Economic Basis for the Social or Lifeline Rate



Adoption of the increasing block tariff (shown in Figure 4.13), which consists of the lifeline rate Ps followed by the full tariff Pe, helps to capture the consumer surplus of the poor consumer. But this cannot effect the optimal consumption pattern of the average consumer at the level of quantity Q_1. In practice the minimum quantity Q_1 should be carefully determined to avoid subsidizing well-off consumers, and should be based on acceptable criteria for identifying the two levels of consumers.[50]

[50] Ibid., Ch. 5. P. C. Mann, "Rate Structure Alternatives for Electricity." Public Utilities Fortnightly (January 20, 1977), pp. 29-34; M. Munasinghe and J. Warford. Electricity Pricing Theory and Case Study, Chs. 5 and 6; J. L. Neufeld and J. Watts. "Inverted Block or Lifeline

4.6.4 Financial Constraints

The financial objective for an electric power system is to provide break-even or surplus revenue. The surplus may be too high when the utility sectors are regulated subject to a ceiling on earnings, or the surplus may be low in the case of a public enterprise where the target is minimum earnings. Financial constraint requires modification of the pricing policy in both cases. The price should be set below marginal cost in the case of a higher surplus, and the price should be set above marginal cost in the case of a lower surplus.

When the electric power industry is owned by the private sector, the most efficient solution for adjusting LRMC is to set the price equal to MC and to rely on government subsidies or taxes to meet the financial needs of the industry. In some views the marginal cost pricing policy fails to achieve the minimum financial target to enable operations to continue.

When the electric power industry is owned by the public (government), as it is in most developing countries, the target rate of return in the minimum requirement necessary to resist sociopolitical pressures to keep prices too low. This system will face the problem of revaluating the asset

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Rates and Micro-Efficiency in the Consumption of Electricity." Energy Economics (April 1981), pp. 113-121.

base. In a normal case the requirement would be consistent with LRMC, but when the system expands rapidly and requires the utility sector to make a reasonable contribution to its future investment program from its own revenue, then the self-financing ratio is often expressed by the available amount remaining after operating expenses and debt service.[51] However, the financial constraints raise some serious problems which are:

a) When capital costs are rising rapidly and the costs of the power system at today's prices have to be incurred to replace it with an equivalent system, and the system adopts the base of LRMC. In this case LRMC pricing should be adjusted through an iterative process until the financial constraints fall within an acceptable range. The adjustment should take into account consumer categories (e.g. residential, and industrial), as well as the different periods (peak and off-peak), to determine the share of the revenue burden to be borne by each user group in a given pricing period.

b) As demand and cost are interdependencies between different times in tariff structure, welfare loss problems will occur. The solution requires more knowledge of elasticities and cross-elasticities. According to Baumol-Bradford "inverse elasticity rule

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[51] R. Turvey. Optimal Pricing and Investment in Electricity Supply, 1968, Ch. 8.

the greatest (least) divergence from the strict LRMC occurs for the consumer group and pricing period where the price elasticity is lowest (highest)." This proposition is the most satisfactory adjustment procedure from the viewpoint of economic efficiency in the case of the electric power sector. The price adjustment will be smallest for consumers whose electricity users are most sensitive to price changes (e.g. residential) and largest for users who are least sensitive (e.g. industrial).

Assuming that in the electric power system there are two kinds of users, the mathematical expression of the elasticity rule is as follows:

$$\frac{(1-LRMC_1/P_1)}{(1-LRMC_2/P_2)} = \frac{(1/e_1 + 1/e_{12})}{(1/e_2 + 1/e_{21})}$$

Where LRMC and Pi are the long-run marginal cost and price, respectively, of users; where as:

$$ei = \frac{(\Delta Qi/\Delta Pi)}{(Qi/Pi)} \quad \text{and} \quad eij = \frac{(\Delta Qi/\Delta pj)}{(Qi/Pj)}$$

$$(i,j = 1,2)$$

These formulas are the own and cross-price elasticities, respectively, of demand (Q) with respect to price (P). This can be interpreted as the electricity consumption of the two consumers in the same pricing period or the consumption of

the same consumer in two distinct pricing periods. As a practical matter, the system usually has a larger number of a consumer types and rating periods which should be considered, but because of the lack of data on price elasticities, this technique may appear to penalize some consumers more than others, thus violating the fairness objectives. The following is the discussion of the type of price-elasticity of demand tariff structure.[52]

4.6.4.1 Price-Elasticity of Demand Tariff

Traditionally, the users of electric power are classified on the implicit basis of price elasticity theory. This theory measures the sensitivity of changes in quantity demand according to price changes and is defined by the equation:

$$EQ, P = \frac{\Delta Q}{\Delta P} \cdot \frac{P}{Q}$$

Where:

EQ, P = the price-elasticity of demand,
Q = the quantity of Kwh,
P = the price per unit Kwh.

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[52] M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study, 1981, Ch. 5; G. Robert Faust and H. Gary Larson. "International Valuation Procedures for Electric Utilities." Public Utilities Fortnightly (August 14, 1980), pp. 19-25; and Baumol-Bradford, "Optimal Departures from Marginal Cost Pricing." American Economic Review (June 1979), pp. 265-283.

The price elasticity in terms of electric power reflects that the consumers are able to substitute their capacity and are willing to adjust their use patterns.

In the case of commercial and industrial users price-elasticity assumes that the price elasticity of demand for an electric power unit which is sold by such commercial and industrial users (demand for electricity is a derived demand), can be passed on to their own consumers.

Consumer classification for electric power is reflected in the price elasticity differentials. For example, the quantity demanded by residential users is relatively insensitive to price changes (price inelastic), since their ability to substitute and to pass increases onto others in minimal. The quantity demanded by commercial and industrial users is relatively more sensitive to price changes (more price elastic) and their ability to substitute is greater than residential group users (self-generation). But the commercial and industrial users can reduce the sensitivity of price elasticity by increasing their ability to pass electricity cost increases onto the consumer, and thus decreasing the firm's total cost for electric power.

There are some views supported by some evidence that the price elasticity of demand for electric power is more price elastic in the long-run than in the short-run. This is because of the consumers ability to substitute electric

power with other utilities and the electric power company's ability to devise or employ more efficient management of electricity use. According to Taylor, the result of his study is that the elasticity of demand for electricity service for all consumer classes (residential, commercial, and industrial) was much greater in the long run than in the short run, which indicates that the long run elasticity coefficient exceeds 1.0 (price elastic).[53]

4.6.5 Peak-Load Pricing

The phenomenon of peak-load is characteristically found where the products or services are technologically nonstorable such as electric power, where the alternative storage costs are high. Peak load problems may occur on a daily basis or arise from short run plant capacity restrictions during a high use season.

The problem of the peak-load pricing has been analysed by W. Arthur Lewis (1941), M. Boiteux (1949), and O. E. Williamson (1966). It has also been treated recently by A. Harberger and N. Andreatta (1963).[54] The approach they

[53] L. D. Taylor. "The Demand for Electricity: A Survey." The Bell Journal of Economics Vol. 6 (Spring 1975), pp. 74-110.

[54] W. A. Lewis. "The Two-Part Tariff." Economica (August 1941), pp. 249-70; M. Boiteux. "Peak Load Pricing," pp. 157-79; H. Houthakker. "Electricity Tariffs in Theory and Practice." pp. 169-82; I.M.D. The Price of Fuel. 1953; P. Steiner. "Peak Load and Efficient Pricing," pp. 585-610; E. O. Williamson. "Peak Load Pricing and Optimal Capacity Under Indivisibility Constraints." pp.

have suggested is to base prices on marginal costs. By exactly matching marginal costs with consumers' willingness to pay for additional output, a balance is achieved between the social costs of increasing production and consumer satisfaction.

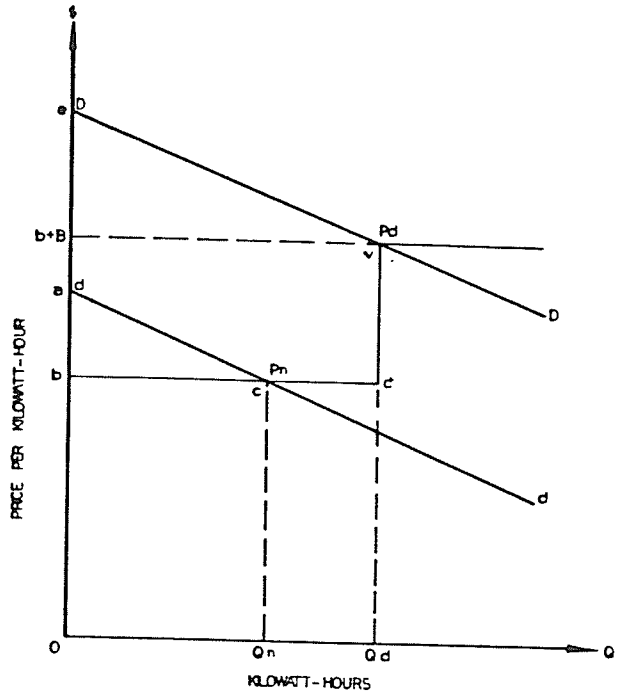
In the case of electric power the demand fluctuates according to the time of day or the season. For example, the demand is higher at 5:00 p.m. than at 1:00 a.m. on any typical day. The point is that the electric power system will face the problems of the peak and off-peak periods, which technically means that if the peak demand is to be satisfied by available output capacity at the time of peak demand the capacity must be not less than the size of that peak demand.

In such cases it might be argued that all capacity costs should be borne by the consumers responsible for the peak demand, for it is that peak demand which will determine the amount of capacity required. From this it would follow that if capacity charges were met by demand in the peak periods, then during the off-periods consumers would only have to pay a price related to running costs, since they would be using existing capacity. In the analysis which follows, an attempt to illustrate these cases will be made by using diagrammatic methods.

810-27. A. Harberger and N. Andreatta. "A Note on the Economic Principles of Electricity Pricing." Applied Economic Paper (March 1963), pp. 37-54.

Let us consider the electric power system that has two demand curves for a typical day which is shown in Figure 4.14. Day and night demand curves, DD could represent the peak demand during the day when electric loads are large, and dd would indicate the off-peak demand during the night hours when loads are low.

Figure 4.14: Peak Load Pricing Model



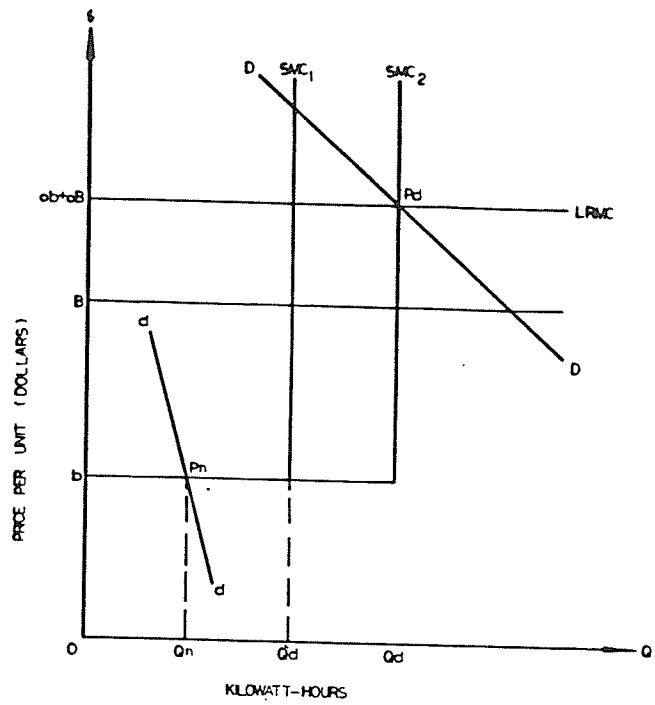
The marginal cost (MC) curve is simplified by assuming a single type of plant with the SRMC of fuel, operating, and maintenance costs given by the constant b, and the added capacity given by constant B, where B is the cost of providing a unit of capacity. Adding to capacity could

involve, for example, investment costs suitably annuitized and distributed over the lifetime output of the plant. The unit running cost is ob and that capacity has an output limit of Qd in each period. Here the capacity output during the off-peak is Qn and during peak period is Qd. Then the price will be higher during the peak which is Pd and lower during the off-peak which is Pn. The prices result in an aggregate social benefit of abc + berc', which is the maximum obtainable. The prices act as a rationing device to allocate available output among potential consumers.

Let us consider that the electric power system has two plants (SMC_1, SMC_2) which are shown in Figure 4.15. The off-peak consumers pay a price equal to ob, while the peak period consumers pay the price ob + OB, which exceeds the price ob by an amount sufficient to cover the marginal cost of providing a unit capacity OB. If capacity with an output in excess of Qd were constructed, then the price which should be paid by peak period is ob + OB. Figure 4.15 shows that the capacity constructed with output Q'd is paid for by the price paid in the peak-period which exceeds the price (Ob + OB) by Ob. This example shows that the capacity charges (OB x Qd) are borne by peak consumers.

In the case of joint demand for capacity, costs are allocated according to the strength of the respective demands. The capacity is constructed with output similar to the example of case two, but the price will be higher to

Figure 4.15: The Pricing of Peak Load With Two Short Run Plants



cover charges 2Ob + OB, where OB is the cost of providing an additional unit of capacity for the whole demand cycle.

These cases indicate that the pressure on capacity arises because of the peak demand DD, and off-peak demand dd does not infringe on the capacity output. The optimal pricing rule has two parts corresponding to two distinct pricing periods which are differentiated by the time of day, peak-period price Pd = ob + OB and off-peak period price Pn = ob.

The logic of this theory is that users during peak-periods, 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 pay only the capacity costs. The explanation for marginal-cost pricing techniques is that peak-period consumers will have to pay a higher price than off-peak users, since marginal increases in peak demand entail expanding capacity in the long run, whereas increased off-peak simply incurs incremental production costs on existing units.[55] Therefore, peak-load pricing or time-of-day pricing conveys the LRMC of supply of electric power to consumers as accurately as possible. The capacity expansion in electricity will cause higher unit costs. The reasons for increasing costs due to increasing expansion include rising costs power of generation, increased cocts of plant location and environmental protection, high inflation rates, and the exhaustion of the economies of scale in generation and transmission.

As mentioned above, there are differential rates for peak and off-peak hour consumption, with the higher rates usually at the peak-load hour. This is consistent with the electric power objectives which are to penalize peak use in the

[55] M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study, Ch. 2; M. G. Webb. The Economics of Nationalized Industries. Thomas Nelson and Sons Ltd., 1973, Ch. 8; Michael A. Crew. Problems in Public Utility Economics and Regulation. Lexington Books, 1979, Ch. 1.

short-run and to improve load-factors and economize the system capacity.

The end results of peak-load pricing are to avoid unnecessary capacity expansion; to postpone some capacity expansion; to decrease the unit costs; to reduce peak-load; and to decrease the use of relatively inefficient standby capacity. In summary, a peak-load pricing structure gives recognition to the notion that peak demands inflate required capacity and force into service relatively inefficient standby equipment and that the peaking and reserve plants incur higher operation costs than base plants.

The criticism of peak-load pricing is that because the consumer alters consumption from peak to off-peak hours a problem of wandering peaks will be created. Also the cost of implementing a peak-load pricing system relative to the cost of significant intermittent unused capacity and capacity expansion could be substantial.[56]

4.6.6 Metering and Billing

In practice there are several kinds of pricing per Kwh (e.g. single Kwh, declining block, peak-load (Time of Use) two period, etc.). Thus the pricing structure (LRMC pricing) should be adjusted according to the difficulties

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[56] P. C. Mann. "Rate Structure Alternatives For Electricity." Public Utilities Fortnightly (January 20, 1977), p. 110.

found in setting a practical price and in the economies of metering and billing. The other problem which faces the pricing structure is that the pricing tariff should be comprehensible to the average consumer. Because individual consumption cannot be adjusted a single price cannot be used. However, the number of consumer categories, the pricing period, consumption blocks and voltage levels should be limited, so that the pricing structure is not too complicated. The various types of pricing are discussed below.

4.6.6.1 Metering Single Kilowatt Tariff

Traditionally, kilowatt-hour (Kwh) meters are designed to record only the total Kwh consumption at that service point. However, when price incentives are offered to influence customers to shift consumption to off-peak hours or to reduce demand, the utility should be able to measure Time of Use (TOU) consumption and maximum demand. A tariff structure could be used as sophisticated as the metering device which is used to measure the consumption.

There are several kinds of metering kilowatt-hours which are found in practice. One of them, metering a single Kwh rate, will be described.

Metering single kilowatt-hour tariff consists simply of the price (P) per Kwh equal to the weighted average of marginal cost (m) for n periods as shown by the formula:

$$P = \frac{M_1Q_1 + - - + MnQn}{Q_1 + - - - - + Qn}$$

Where:

P = the price per Kwh,
Q = the group of consumer in different period is Q_1,---Qn,
M = marginal costs per Kwh in each period is given as M_1,-Mn,
n = number of periods during the period (year), 1,---n.

Practically,by weighting the marginal costs M_1,----,Mn in the different periods according to their respective heavy consumption periods for example, (residential consumer) such as at breakfast time and other times during the day, consumption can be shifted to periods of smaller consumption during the day. The reduction in price P will stimulate the time of consumption for many to small consumption periods during the day. Thus, the price coincides with optimum capacity only if the elasticity of demand is the same for time periods.

The objective for this type of pricing is to establish a single, simple, and correct Kwh tariff demands.[57]

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[57] R. Turvey and Anderson. Electricity Economics. Baltimore, MD: John Hopkins University Press, 1977, Ch. 16; V. B. Sanford. Innovative Electric Rates. Lexington Books, 1983, Ch. 15.

4.6.6.2 Declining-Block Tariffs

Traditionally, the concept of declining block tariffs involves a specific price for kilowatt-hour (Kwh), where the initial consumption has the highest price followed by successively cheaper blocks, or the price declines with each successive block. With lower prices for each successive block consumed both the marginal (incremental) and average costs of electricity to the consumer decreases with increasing consumption (use).

The advantage of declining-block tariff is relatively simple and easily understood by consumers, but there are some arguments against this type of tariff structure which are:

a) the declining block tariff is highly regressive and unfair, because it penalizes poor consumers who generally use less electricity but would pay higher prices on average of each unit purchased;
b) the electric power system will recover some of the fixed costs from the initial block (which is charged the higher price), even if the consumer's consumption was low;
c) the first block corresponds to the higher cost of supplying the customer's peak period load, whereas additional consumption is mainly caused by off-peak appliance use that can be supplied at a relatively lower cost;

d) by encouraging consumers to increase his or her consumption an expansion of the system could become necessary. This expansion however, due to economies of scale in production, could result in lower costs;

e) the declining block tariff is a type of discriminatory pricing, which could be used to extract the maximum revenue from smaller users who have lower price elasticities of demand, while also encouraging consumption of larger users who are more sensitive to higher prices;

f) in fact that if any block under this type of tariff is significantly below LRMC, it signals to the consumers that electricity is much cheaper than it really is. In other words the system will encourage wasteful consumption rather than conservation, and the systems expansion results in further economies of scale.[58]

4.6.6.3 Two-Period Tariffs

The metering, for two-period tariff by the Time-of-Day (TOD) is more complicated because of the practical problems of installation and maintenance. The net benefit of metering can be estimated by a cost benefit analysis which is illustrated as follows:

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[58] P. C. Mann. "Rate Structure Alternatives For Electricity." Public Utilities Fortnightly (January 20, 1977), pp. 29-34; R. Turvey and Anderson. Electricity Economics, 1977, Ch. 16; M. Munasinghe. Electricity Pricing and Case Study, 1982, Ch. 6.

Let us illustrate this analysis of metering for two-periods, TOD tariff by the help of Figure 4.16. Dp and Do are the demand curves for an average hour during the peak and off-peak hours of the day, respectively. The peak and off-peak hours are denoted by H and (24-H), respectively. If the system is charged a uniform price which is average price (Pa) for the two periods, then the daily consumption will be Q'pH and Qa (24-H) for peak and off-peak periods, respectively, as shown in Figure 4.16. If the system charges a price according to the peak and off-peak periods, then the prices will be different which are (Pp, Po) respectively, levied throughout the day. The consumption levels are QpH and Q_o (24-H) Kwh.

Suppose the LRMC of supplying a Kwh during the peak and off-peak periods are MCp and MCo respectively, and MCp consists of the capacity costs plus energy costs, and MCo consists of just energy costs.

The calculation of the net benefit for the charging a uniform price (Pa) is as follows:

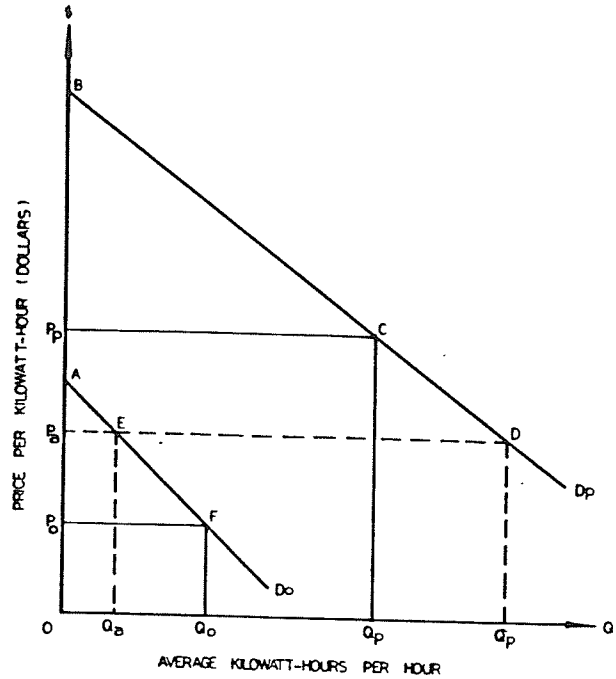
$$\begin{aligned} NBa &= Ba - Ca \\ &= [(\text{area } OBCDQ'p)H + (\text{area } OAEQa)(24-H)] \\ &\quad - [Q'pHMCp + Qa(24 + H)\ MC_o] \end{aligned}$$

The net consumption benefit calculation in the case of charging the two period tariff is as follows:

$$\begin{aligned} NBt &= Bt - Ct \\ &= [(\text{area } OBCQp)H + (\text{area } OAFQ_o)(24-H)] \\ &\quad - [QpHMCp + Q_o\ (24-H)\ MC_o] \end{aligned}$$

The change in net benefit, therefore, is,

Figure 4.16: The Metering Decision to Implement a Two-Period, Time-of-Day Tariff



$$\Delta NB = NBt - NBa$$

$$= [(\text{area } QaEFQ_0)(24-H) - (\text{area } QpCDQ'p)H]$$

$$+ [(Qa-Q_0)(24-H)\ MC_0 + (Q'p-Qp)H\ MCp]$$

By simplification of the two equations, the two period tariff reflects the theoretical LRMC, that is, Pp = MCp and Po = MCo.

For very poor consumers receiving a subsidized rate, a simple current limiting device may suffice. Thus the cost of simple Kwh metering can create a problem as the additional cost may exceed its net benefit. The other

problems the pricing structure face occur during maximum demand Time-of-Day metering, when different peak load pricing levels would be applicable to large MV and HV users which are industrial and commercial, respectively.

Most low voltage (LV) consumption especially for households, is metered only on a kilowatt-hour basis, and the Kwh price is based on combined capacity and energy costs.

Another problem is that some meters are affected by power outages. This problem can be solved technically, by using advanced technology, automatic meters, etc., as are used in some developed countries. This will be discussed in the following section 4.6.7.3.[59]

4.6.7 Other Tariff Structure Issues:

There are several issues of electricity tariff structure and these are discussed in the following pages.

4.6.7.1 Flat Rate

This type of rate is charged at a certain specified amount per day, per week, month, or year, without considering the quantity of energy actually consumed by a customer or the hours when the energy was consumed. The

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[59] M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study, 1981, Ch. 5.

customer pays a lump sum per period and has the privilege of consuming any quantity of energy he/she desired without further payment. This kind of flat rate is not commonly used since it is obvious that the fixed price discriminates between customers with different rates of consumption and could not be readily adjusted to reflect this difference.

The modification of flat rate charges is quite widely used and is based on the size and number of electric lamps and the rated power consumption of a customer's connected appliances. The customer pays a fixed sum which is based on the rated power consumption of all his appliances, and is independent of the quantity of energy actually consumed. The simple flat rate cannot reflect differences in capacity costs between customers; the adjusted flat rate does not either, except to the extent that consumption of a customer at the system's peak was proportioned to the total rated power consumption of all his connected appliances.

Customer costs are lumped with all other costs to be covered by the fixed charge, and in as much as such costs are relatively the same for all customers, the flat rate adequatly covers this cost. Since the quantity of energy to be used by the customer is not specified in the usual variety of the flat rate, the payment made by the customer does not adequately reflect the variation of energy costs when the quantity of energy consumed varies between customers.

The flat rate is still used in some systems which extend for street lighting and for sign and display lighting under contracts which define the hours of use and the number and size of bulbs. Under such contract the costs of service would be reflected only if the utility company, in calculating the lump-sum to be paid by the customer per period, takes into account the difference in peak and off-peak costs. In any situation in which the hours of use, the total energy to be consumed, and the maximum rate of consumption during system peak hours are not definitely specified, the flat rate does not reflect differences in capacity and energy costs between various customers.[60]

4.6.7.2 Value-of-Service Pricing

Value-of-service pricing is a type of price-discrimination. According to Pigou's analysis "the value-of-service principle is a discriminatory monopoly of the third degree." Davidson's proposition states "many writers argue that an alternative pricing procedure based on value-of-service is socially preferable. Value-of-service pricing is discriminatory pricing under another name and is justified by its proponents as resulting in larger output and lower rates."[61]

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[60] R. K. Davidson. Price Discrimination in Selling Gas and Electricity. Baltimore: Johns Hopkins Press, 1955, pp. 77-78.

[61] R. K. Davidson. Price Discrimination in Selling Gas and Electricity. Baltimore: Johns Hopkins Press, 1977, p.

The concept of the value-of-service in terms of electric power utilities is that the cost of electric power (product) is the value-of-service (demand) differences according to different users. In other words the different rates are charged for different user groups which are residential, commercial, and industrial. For example, value-of-service rate for residential users generally exceeds commercial and industrial users; industrial users are different than commercial users as commercial users are limited by self-generation.

The value-of-service pricing involves rates based on price elasticity of demand differences. User groups having higher price elasticities will be charged lower electricity rates; user groups having lower price-elasticities are charged higher electricity rates.

There are some criticisms regarding this type of tariff, which are directed at its elusive and uncertain character. This is because the value-of-service pricing involves the rate with price-elasticity and the latter has many serious problems. Generally, it is difficult to estimate the value-of-service for different groups in the case of large commercial or industrial users. The other important factors in determining the price-elasticity of electricity demand for different users (commercial, and industrial), are the cost of electricity in total and the price-elasticity of the

110.

demand for the goods and services, which are sold by commercial and industrial users. Most of the commercial and industrial users have relatively high values of service for other goods, thus, they are indifferent to electricity price changes. Since the electricity services are a small portion of total cost the large users find it relatively easy to pass electricity cost increases on to other consumers.[62]

4.6.7.3 Load Management Technology

The concept of the load management technology tariff generally involves meters to measure both kilowatt-hour (Kwh) usage and maximum kilowatt demand. Recently, there is more advanced technology in local management devices such as remote radio control of water heating and air conditioning, multichannel recording devices, and ripple control. The cost of these devices are different than the cost of standard metering.

The following is an example of the practical use of these advanced technological developments in load management techniques. Ripple control and remote control systems can be used to level peak load by way of total, or partial discontinuance of consumer service during the peak-hours.

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[62] C. J. Bonbright. Principles of Public Utility Rates. New York: Columbia University Press, 1961, pp. 378-385; R. K. Davidson, Price Discrimination in Selling Gas and Electricity, p. 148 and pp. 98-110; P. C. Mann, "Rate Structure Alternatives For Electricity." Public Utilities Fortnightly (January 20, 1977), pp. 29-34.

Ripple control involves high-powered frequency signals originating at main supply sources over existing power lines to consumer terminals; the audio signals can operate load switches for uses such as water heating and air conditioning. Briefly, ripple control is used as a signaling-sensory mechanism to control electricity flows and thus facilitates load control, or daily peak-load pricing, or both.[63]

4.7 CONCLUSION

This chapter presents the framework and the analysis for electric power pricing. It reviews the structure of the basic theory of marginal cost pricing, applies it to the power sector, and summarizes the recent development of marginal cost approach. Adaptation of the LRMC theory for practical application in relation to the objectives of electric power pricing policy is seen to result in a two stage procedure for tariff setting as follows:

a) The long run marginal costs of suppling electric power are calculated. This meets the criteria of economic efficiency and stability over time.

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[63] Sanford V. Berg. Innovative Electric Rates, Lexington Books, 1983, Ch. 15; and P. C. Mann, "Rate Structure Alternatives for Electricity." Public Utilities Fortnightly (January 20, 1977), pp. 29-34.

b) The long run marginal cost is modified in the light of appropriate practical and broad tariff structure policies for the particular economy under consideration. Modifications may include second-best consideration; social-lifeline consideration; shadow pricing; peak load pricing; financial problems; and metering and billing problems.

It can now be concluded that not only does long-run marginal cost pricing lead to the most economical use of resources but also that it can be applied to electric power systems and adapted to the political and practical realities found in nations or regions.

Chapter V

THE PRICING OF ELECTRICITY IN DEVELOPING COUNTRIES WITH SPECIAL REFERENCE TO IRAQ

This chapter presents an analysis of the principles of pricing for the electric power sector in developing countries. Recently several developing countries have considered the marginal cost pricing approach. Adoption of long-run marginal costs (LRMC) pricing meets the economic efficiency criterion in terms of real economic resource costs. The LRMC can be modified to derive an appropriate realistic tariff structure which satisfies other constraints in the economy such as financial requirements, social considerations, fairness and equity, and metering and billing as discussed in Chapter IV, Section 4.5. In terms of long-run real costs, for example, oil prices are uncertain and thus it is necessary for more conservation in the electric power system in every developed and developing country.

Conservation in the electrical sector is necessary because of a variety of factors such as high costs of building new generating capacity, regulatory delays associated with capacity expansion, changing growth rates in electricity demand, consumer concern for high and rising electricity prices and the growing realization that energy

conservation and load management options are economically attractive.

The objective of this chapter is to present the analysis of the principles of pricing of electricity in developing countries with particular reference to the World Bank Publication, Electricity Economics, by Ralph Turvey and Dennis Anderson, and Electricity Pricing Theory and Case Studies, by Mohan Munasinghe and Jeremy J. Warford. This publication presents typical samples of case studies for the following developing countries: Indonesia, Pakistan, Sri-Lanka, the Philippines, and Thailand.

This chapter is divided into four parts. The first and the second parts describe the case studies in developing countries and cover the calculation of LRMC pricing. The third part, the pricing of electric power in Iraq, covers organization, existing pricing, the computation and modification of LRMC pricing. The fourth part covers policy issues and states the conclusions.

5.1 DESCRIPTIONS OF THE CASE STUDIES IN DEVELOPING COUNTRIES

This section presents the analysis of electricity tariffs in developing countries. The objective of the tariff analysis done by Munasinghe was to evaluate the best pricing policy for the electric power sector in developing countries in terms of maximizations of the net economic benefits of electricity consumption to society.

All cases followed the rule of LRMC pricing. The methodology for all case studies used is the same, but there are differences in institutional, physical, and technical characteristics as well as in the quantity and quality of available data. For example, Indonesia and Sri-Lanka have only one electric power authority to determine the tariff policy and it is responsible for generation, transmission, and distribution. Thailand has to consider the tariff structure of three authorities to determine the tariff policy. Its primary system is responsible for generation, and sells in bulk to two other electric power authorities, which are responsible for distribution of the electricity for the whole country. Similarly, Pakistan has two main electric power system institutions and several smaller ones. The Philippines has to consider the tariff structure of numerous authorities that are involved. The primary system (generating) authority, sells power to large distributors and to a host of municipal, private, and cooperative utilities, some of which also have generation facilities.

The type of generation can vary from country to country. This is critical to the application of the methodology to estimate marginal generation costs. Further, a country's physical characteristics determine whether or not one grid or several will be the most cost-effective means of distributing electricity. Although small systems operate separately from the main grid in all these countries, the

Thailand, Sri-Lankan, and Pakistani studies essentially use one grid. Effectively this is also true of the Indonesia because data on the large grids serving islands outside the city are unreliable.

The electric power losses vary with the system and the economic and other issues are different. This is especially pertinent in Indonesia and Pakistan. The issue of losses covers normal loss levels which are not easy to define because of the individual characteristics of each power system. There are technical losses which result because of inadequate planning, and non-technical losses such as poor operation and maintenance; government constraints on the utility's budget and revenue capability, and theft and unpaid bills. All case studies show that the costs resulting from both technical and nontechnical losses are imposed on the paying consumer. This practice has serious effects, especially when losses are high, and the system then should implement methods to reduce losses to acceptable limits.

Use of LRMC pricing helps to reduce the magnitude of this problem. First, the lower prices resulting from the LRMC approach reduce the incentive for theft. Second, LRMC pricing involves planning which can provide standards to support a systematic attack on the problem.

The description of the calculation LRMC pricing for these case studies mentioned above follows.[64]

5.2 CALCULATION OF LONG-RUN MARGINAL COST

Calculation of LRMC for the case studies is generally straightforward, except for the estimation of generation capacity costs which differ according to the institutional, technical and physical characteristics of the countries.

The LRMC's are composed of three broad categories, capacity, energy, and customer costs. All costs have to be adjusted for losses which occur up to the point of delivery to customers. For example, in the Indonesian case the capacity costs per kilowatt are converted to annual costs per kilowatt by annuitizing the costs over the lifetime of the equipment.[65]

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[64] M. Munasinghe and J. J. Warford. Electricity Pricing Theory and Case Study. Baltimore, MD: Johns Hopkins Press, 1982, Ch. 7-12.

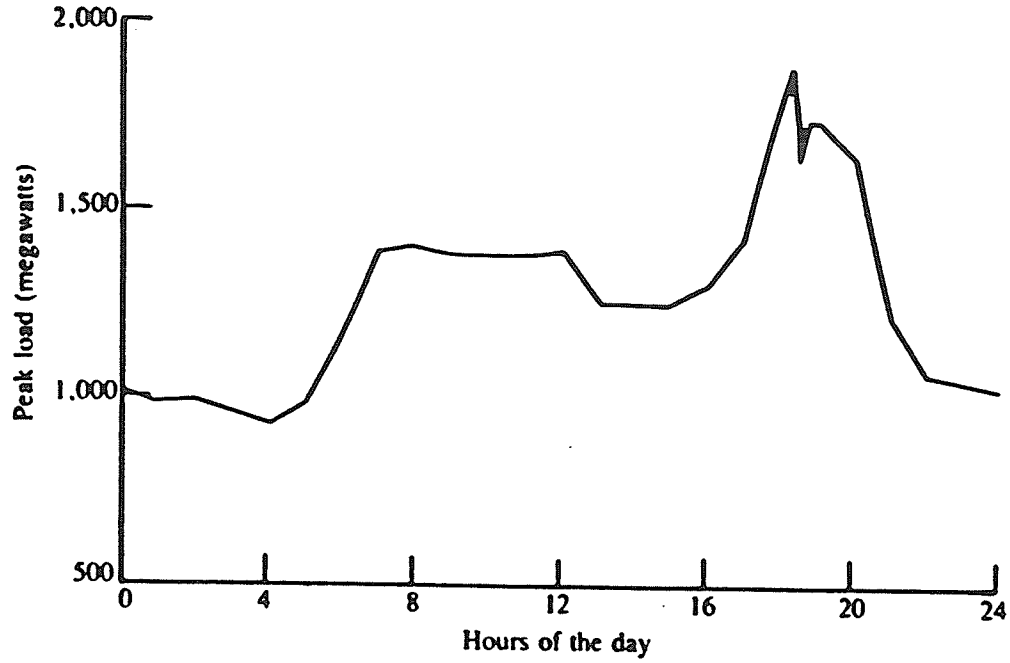
[65] The annuities are used for a stated time or for life such as this term. The annuitized value of per kilowatt is defined as the fixed annual payment over the lifetime of the investment, whose present value at the given discount rate is exactly equal to the original expenditure. Annuitizing the investment is conceptually equivalent to advancing the capital outlay by one year. For example, if the investment cost of gas turbines is $800 x 0.1107 = $88.136 per kilowatt per year, at a discount rate of 10 percent, over twenty five years. The annuity factor of 0.1107 may be read off a set of standard tables. See Richard S. Burington, Handbook of Mathematical Table and Formulas, 5th edition (New York: McGraw Hill) 1973, pp. 444-445.

In the Pakistani and Sri-Lankan cases, the structuring of LRMC uses the load duration curve method (LDC), by examining the system's LDC, and selecting the appropriate rating periods such as peak and off-peak. The peak period is the period during which demand presses on capacity at a particular time of the day or in given season of the year. The Indonesia, Pakistan, and Sri-Lanka cases select only two periods during the day which are peak and off-peak. The typical Figures 5.1, 5.2 show the LDC during the day and annually for the electric power system in Pakistan. In Figure 5.1 (daily load curve), the system faces peak demand during a four-hour period. Figure 5.2 shows that the system met the four-hour peak demand by operating a mix of gas turbines and steam units.

The calculation LRMC in the Thailand case uses the method based on all types of generating plants as an average of capacity costs and then corrected for the net fuel saving which offsets some of the higher capacity costs of base-load machines. But in the Philippines case no such correction is made so that the kilowatt charges imposed on peak-period consumers may be sometimes overestimated.

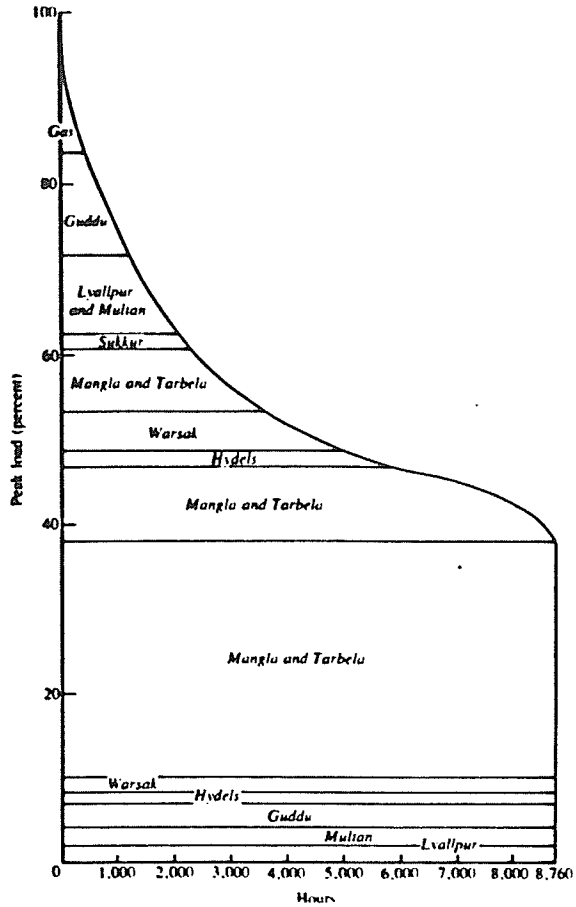
The following is the description of the calculation of LRMC categories by Munasinghe.

Figure 5.1: Daily Load Curve for December 20, 1978



Source: WAPDA data (from M. Munasinghe and J. Warford. Electricity Pricing Theory and Case Studies. 1982, p. 146).

Figure 5.2: Annual Load Duration Curve for the WAPDA System, 1979



5.2.1 Marginal Capacity Costs

Marginal capacity costs are the investment in generation, transmission and distribution facilities as discussed in detail in Chapter IV, Section 4.4.1. The case studies analysis shows that the calculation of capacity costs for each of the countries Indonesia, Pakistan, and Sri-Lanka, is based on the peak period demand; that the peak capacity costs for each kilowatt delivered are determined at the voltage level at which they are incurred and converted to

costs per kilowatt annually by annuitizing twelve percent over the plant's life. The method of annuitizing is shown in Table 5.1. The annual capacity costs for every kilowatt at a lower voltage level are determined by dividing by an appropriate power loss factor.

TABLE 5.1

Capacity Costs

(1979 rupees)

Voltage level	*Capacity cost per kilowatt, BP*	*Capacity cost per kilowatt, DP*[a]	*Annuitized capacity costs per kilowatt per year*[b]
Generation	8,875	10,440	1,330
HV transmission	5,997	7,055	856
MV distribution	1,478	1,739	222
LV distribution	3,203	3,768	480

a. The CF is 0.85.

b. The assumed lifetimes for generation, HV, MV, and LV capacities are 25, 40, 25, and 25 years, respectively. With an assumed opportunity cost of capital of 12 percent, the resulting annuitizing factors are 0.1275, 0.1213, 0.1275, and 0.1275 for the respective capacity investments.

Soure: WAPDA data (Ibid., p. 156)

The type of electric power system in these countries varies with use of a combination of hydroelectric, gas-fired, and thermal plants. Thus, expansion of the system in order to meet the incremental load (peak load), can be done by advancing the commissioning date of new plants or inserting units such as gas turbines as in Pakistan or peaking hydro as in the Indonesian case.

The LRMC of transmission (T) and distribution (D) for these countries is calculated by considering all T and D as an investment cost and allocating them to incremental

capacity because the facility designs are determined principally by the peak kilowatts that they carry rather than by the kilowatt-hours. T and D capacity costs can be estimated using the average incremental cost (AIC) method as discussed in Chapter IV, Section 4.4.1. Tables 5.2 to 5.7 show the typical estimation of the incremental demand for various voltage levels high voltage (HV), medium voltage (MV) and low voltage (LV) distribution which is used in those systems.

TABLE 5.2

Load, Demand, and Loss Forecast

(megawatts)

Year	Generation (gigawatt-hours) (1)	Load factor (LF) (2)	HV demand peak (3)	After 6 percent loss[a] (4) = 96 × (3)	HV consumers' peak demand (5)	Demand after HV consumption (6) = (4) − (5)	After 10 percent MV loss[b] (7) = 9 × (6)	MV consumers' peak demand (8)	Demand after MV consumption (9) = (7) − (8)	LV demand peak after 13 percent loss[c] (10) = 87 × (9)	LV demand peak, Colombo (11)	LV demand peak, non-Colombo (12)
1978	1,384	0.54	291	274	13	261	235	128	107	93	55.8	37.2
1979	1,508	0.56	319	300	13	287	258	148	110	96	58.6	37.4
1980	1,718	0.545	360	338	21	317	285	168	117	102	61.5	40.5
1981	1,924	0.545	403	379	28	351	316	188	128	111	64.6	46.4
1982	2,145	0.55	445	419	35	384	347	209	138	120	67.8	52.2
1983	2,381	0.55	494	464	35	429	386	235	151	131	71.2	59.8
1984	2,643	0.55	549	517	35	482	434	264	170	148	74.8	73.2
1985	2,931	0.56	597	561	35	526	473	295	178	155	78.5	76.5
1986	3,242	0.565	655	616	35	581	523	330	193	168	82.4	85.6
1987	3,582	0.57	717	674	35	639	575	367	208	181	86.6	94.4
1988	3,958	0.57	793	745	35	710	639	409	230	200	90.9	109.1

a Station use and HV transmission (66/132 kilovolts)
b Primary feeders and substation (11/33 kilovolts)
c. Secondary lines and distribution transformers (230/380 volts)

Source: The Ceylon Electricity Board (CEB) data (from M. Munasinghe, and J. Warford. Electricity Pricing Theory and Case Studies. p. 214).

The calculation of LRMC at various voltage levels consider the three supply voltage categories, HV, MV and LV. Consumers for each different voltage level are charged

TABLE 5.3

Incremental Load or Demand Forecast

(megawatts)

Year	Demand peak HV (1)	Demand peak MV (2)	Demand peak LV (3)	Demand peak increment HV (4)	Demand peak increment MV (5)	Demand peak increment LV (6)	Discount factor at 10 percent (7)	Discounted increment HV (8)=(4)×(7)	Discounted increment MV (9)=(5)×(7)	Discounted increment LV (10)=(6)×
1978	291	235	93	—	—	—	—	—	—	—
1979	319	258	96	28	33	3	1.000	28.0	33.0	3.0
1980	360	285	102	41	27	6	0.9091	37.3	24.5	5.5
1981	403	316	111	43	31	9	0.8265	35.5	25.6	7.4
1982	445	347	120	42	31	9	0.7513	31.6	23.3	6.8
1983	494	386	131	49	39	11	0.6830	33.5	26.6	7.5
1984	549	434	148	55	48	17	0.6209	34.1	29.8	10.6
1985	597	473	155	48	39	7	0.5645	27.1	22.0	4.0
1986	655	523	168	58	50	13	0.5132	29.8	25.7	6.7
1987	717	575	181	62	52	13	0.4665	28.9	24.3	6.1
1988	793	639	200	76	64	19	0.4241	32.2	27.1	8.1
Discounted totals	—	—	—	—	—	—	—	220.5 (1981–87)	177.5 (1980–86)	48.5[a] (1980–86)

Note. Increment with respect to previous year
— Not applicable.

a Colombo = 15.8; Non-Colombo = 32.7.

Source: CEB data (Ibid., p. 214)

TABLE 5.4

HV Transmission Investment Costs

((Rs × 10^6) – 66/132 kilovolts)

Year	Total costs (DP) (1)	Total costs[a] (BP) (2)=(1)×0.836	Discount factor (10 percent) (3)	Total discounted costs (4)=(2)×(3)
1979	62.06	51.88	1.000	51.88
1980	91.22	76.26	0.9091	69.33
1981	69.34	57.97	0.8265	47.91
1982	152.56	127.54	0.7513	95.82
1983	246.30	205.91	0.6830	140.64
1984	334.84	279.93	0.6209	173.81
1985	343.74	287.37	0.5645	162.22
Discounted total for 1979–85	—	—	—	741.71

— Not applicable.
a. Same conversion factor (0.836)

Source: CEB data (Ibid., p. 216)

TABLE 5.5

MV Distribution Investment Costs

(Rs × 10^3)

Year	Urban costs (1)	Rural costs (2)	Total costs (DP) (3)	Total costs (BP)[a] (4) = 0.873 × (3)	Discount factor (10 percent) (5)	Total discount costs (6) = (4) × (5)
1979	119.92	57.0	176.92	154.45	1.000	154.45
1980	244.6	57.0	301.00	263.30	0.9091	239.37
1981	22.40	57.0	79.40	69.32	0.8265	57.29
1982	21.95	57.0	78.95	68.92	0.7513	51.78
1983	72.20	57.0	129.20	112.79	0.6830	77.04
1984	72.62	57.0	129.62	113.16	0.6209	70.26
1985	66.38	57.0	123.38	107.71	0.5645	60.80
Discounted total for 1979–85	—	—	—	—	—	710.99

— Not applicable.

a. Includes costs of consumer substations and spur lines, that is, average cost to meet all MV peak demand.

Cost item	Fraction	×	Conversion factor	=	Weighted value
Foreign (15 percent duty)	0.25		0.87		0.218
Domestic material	0.225		1.0		0.225
Skilled labor	0.21		1.0		0.21
Unskilled labor	0.315		0.7		0.22
	100 percent		Total conversion factor =		0.873

Source: CEB data (Ibid., p. 217)

TABLE 5.6

LV Distribution Investment Costs

((Rs × 10^3) – 230/400 volts)

Year	Total costs Colombo (DP) (1)	Total costs non-Colombo (DP) (2)	Total costs Colombo[a] (BP) (3) = 0.873 × (1)	Total costs non-Colombo[a] (4) = 0.873 × (2)	Discount factor (10 percent) (5)	Total discounted costs (6) = (3) × (5)	Total discounted costs (7) = (4) × (5)
1979	2.50	—	2.22	—	1.000	2.22	—
1980	2.63	140	2.30	122.22	0.9091	2.09	111.11
1981	2.79	140	2.44	122.22	0.8265	2.02	101.01
1982	2.89	140	2.52	122.22	0.7513	1.89	91.82
1983	3.04	140	2.65	122.22	0.6830	1.81	83.48
1984	3.19	—	2.78	—	0.6209	1.73	—
1985	3.35	—	2.92	—	0.5645	1.65	—
Discounted total for 1979–85	—	—	—	—	—	—	13.41

— Not applicable.

a. Same conversion factor (0.873)

Source: CEB data (Ibid., p. 218)

TABLE 5.7

Incremental Costs Summary (at Source)

(rupees)

Item	*Cost per kilowatt*	*Cost per kilowatt per year*
Generation	*GT*, Hydro, 7,147	1,013
HV transmission[a]	$\frac{742 \times 10^6}{221 \times 10^3} = 3{,}360$	357
MV distribution[b]	$\frac{711 \times 10^6}{1{,}775 \times 10^3} = 4{,}010$	425
LV distribution—Colombo[b] (220/380 volts)	$\frac{13.4 \times 10^6}{15.8 \times 10^3} = 850$	90

a. Allow two-year lag between investments and incremental megawatt benefits. Annuitization factor = 0.1061 (10 percent over thirty years).

b. Allow one-year lag between investments and incremental megawatt benefits. Annuitization factor = 0.1061 (10 percent over thirty years). Non-Colombo costs, especially for rural electrification, are too arbitrary to provide accurate results.

Source: CEB data (Ibid., p. 219)

only upstream costs, and, thus, capacity costs at each supply voltage level should be identified.

Operation (O) and maintenance (M) as well as administrative (A) and general (G) costs are calculated as annual costs per kilowatt. These costs are apportioned only among the capacity costs of generation, transmission, and distribution.

The calculation of LRMC capacity costs differ because of different characteristics of electric power systems. The systems are very complicated. All generation of power from the aggregation of various plants is controlled by the major system which is responsible for generation and transmission. The other systems are responsible for the distribution of electric power.

The peak demand used to calculate the marginal cost is obtained from the total peak generation requirement minus the associated power loss in the transmission grid considered as a pool. The losses in the electric power system are common because there are many authorities involved in the distribution of energy in the overall power system.

The calculation of LRMC capacity costs is considered separately for each system and include incidental costs of operation excluding the fuel cost and seventy percent of total maintenance and administration cost. The estimation of the additional maintenance can be obtained from the information of past experience regarding maintenance cost per kilowatt-hour as a multiplier against the additional Kw of energy generation for each year. The method (AIC) is used to calculate the added kilowatt cost. The typical Table 5.8 shows the marginal capacity costs for the major system in Thailand which include the generation, transmission, operation, maintenance, administration and general costs.

In the Philippines case study, the electric power system is more complicated, because the system authority is composed of government and private utility firms. Thus, numerous authorities are involved which makes the electric power sector difficult to organize. The major system which is owned by government National Power Corporation (NPC) is

TABLE 5.8

Marginal Capacity Costs for EGAT (Typical)

(baht per kilowatt)

Cost for	Generation cost (per year)	Transmission cost (per year)	O&M and A&G costs (per year)	Total	
				Per year	Per month
Generation at pool	1,951.68	—	24.91	1,976.59	164.72
MEA[a]	1,990.71	92.73	29.27	2,112.71	176.06
PEA and direct customers[b]	2,068.78	215.83	35.37	2,319.98	193.33

— Not applicable.

a. From pool to MEA delivery point, 2 percent of power is lost.

b. From pool to PEA and direct customers at delivery point, 6 percent of power is lost.

Source: The Electricity Generating Authority of Thailand (EGAT) data (Ibid., p. 233)

responsible for generation and transmission and selling power to a large number of local authorities for distribution.

The calculation LRMC capacity costs, by the incremental capacity costs of NPC bulk power supply, consists of investment in additional generation and high voltage (HV) transmission plant facilities plus the increase in operation and maintenance costs involved in plant expansion. This is shown in the typical Table 5.9, which covers all the grid in the country and takes into account the voltage level.

TABLE 5.9

Annual Incremental Capacity Cost at the HV Level for NPC

(pesos per kilowatt per year of coincident HV maximum demand)

Grid	*Capital cost*	*O&M cost*	*Total*
Luzon grid	1,555	51	1,606
Mindanao grid	1,735	170	1,805
Visayas subgrids	1,710	118	1,828
Cebu	1,437	120	1,557
Negros	2,182	120	2,302
Bohol	1,896	166	2,062
Panay	1,887	164	2,051
Leyte-Samar	1,777	89	1,866
Country average	1,610	63	1,673

Source: National Power Corporation (Philippines) NPC data (Ibid., p. 176)

5.2.2 Marginal Energy Cost

The calculation LRMC of energy consists of the fuel costs of the power station, transmission losses, and a small portion of general and administrative expenses which are included in the category of energy costs. These costs vary with the total quantity of kilowatt-hours sold. The problems are incurred in the transmission and distribution of electric power from the point of generation to the point of final consumption, but the loss factors from adjusting off-peak costs will be smaller than the the loss factors for the peak period. For example, resistive losses are a function of the square of the current flows and are greatest during the peak period.

The treatment of losses generally raises several important issues. Total normal technical losses including station uses varies from system to system. Losses may be caused by engineering techniques, theft, and unpaid bills.

The LRMC calculation of energy in most case studies considers peak and off-peak energy costs. The peak energy costs for a block of incremental peak consumers will essentially be the cost of running the gas turbines such as in the Indonesian case study. In the Sri-Lankan case study the system uses a mix of gas turbine and hydro power generation. The LRMC of generation uses hydro costs, estimated from hydro storage costs, as incremantal energy costs. The consumer bears the burden of these upstream energy costs. The kilowatt-hour costs at any given voltage level, EHV, HV, MV and LV, involve both gas turbine and hydro costs.

The LRMC of energy during the off-peak period is the cost of running the marginal base-load stream plants, and is determined at various voltage levels EHV, HV, MV and LV and line losses should be considered. Table 5.10 shows typical marginal energy costs calculated as peak and off-peak energy respectively, and at the various prices for different voltage levels.

Most developing countries face the problem of variation in fuel prices between local and international prices.

Thus, the costs per kilowatt of generation can be computed using two values, the first being high speed diesel (HSD) which is the international price and the second being local prices as shown in the typical Table 5.10.

TABLE 5.10

Marginal Energy Costs

(rupees per kilowatt-hour)

Voltage level	At market price of gas		At HSD equivalent price		Best estimate[c]	
	Peak[a]	Off-peak[b]	Peak[a]	Off-peak[b]	Peak[a]	Off-peak[b]
Generation[d]	0.0862	0.0420	0.9286	0.8908	0.266	0.255
HV (66/132 kilovolts)	0.0947	0.0452	1.0204	0.9578	0.292	0.275
MV (11/33 kilovolts)	0.1052	0.0486	1.1214	1.0300	0.321	0.296
LV (400 kilovolts)	0.1403	0.0615	1.4951	1.3037	0.428	0.375

a Relative weights of Guddu, Lyallpur/Multan, and gas turbines are 0.354, 0.531, 0.115, respectively, and corresponding heat rates are 12,488, 11,815, and 20,084 BTU/kilowatt-hour

b Relative weight of Guddu is 1.0

c Gas valued at Rs20 per 10^6 BTU, based on value in alternative uses (data from Pakistan Oil and Gas Sector Memo of October 5, 1978, EWT Dept., World Bank, Washington, D.C.)

d Including station use of 2.1 percent

Source: WAPDA data (Ibid., p. 153)

The Thailand and Philippines case studies estimate the average fuel costs for all kinds of fuel expenses that are used in various plants included in their electric power system, and also the additional expenses of total system energy sales. The different kinds of plants are diesel, oil-fired, nuclear, and steam-geothermal. The fuel costs are usually applied to the projected annual stream of plant generation in order to arrive at the annual fuel cost for each grid. Increases in fuel expenses over the period resulting from increases in energy generation requirements are used to obtain the incremental energy fuel cost at the generation level such as in Thailand.

In the Philippines case the energy costs calculation is derived from the costs of fuel associated with the various types of plants scheduled for operation over the ten-year planning period, plus the generation and HV transmission costs, and plus plant- operation and maintenance expenses required for energy production and deliveries.

5.2.3 Customer Costs

The calculation of marginal customer costs in most developing countries include providing service connections, labor, metering and biling as discussed in Chapter IV, Section 4.4.3. Calculating marginal customer costs by fitting a statistical costs function relating the number of customers to the aggregate customer capital costs, will tend to overcharge small users. Recurrent customer costs stem from meter reading, billing, and other administrative expenses. These could be imposed as a flat charge on a repeated basis in addition to the usual Kw and Kwh charges. In some electric power systems, such as in Indonesia, the costs of meter reading and billing are included in the administrative and general costs. The typical Table 5.11 shows the standard costs for service connections in Sri-Lanka, and Table 5.12 shows the calculation of customer costs in Pakistan which is divided among consumer categories.

TABLE 5.11

Standard Costs for Service Connections
(rupees)

Rating	*Fixed cost*	*Variable cost per meter of the cost*
Single phase, 15 amperes	315	9
Single phase, 30 amperes	375	12
Three phase, 30 amperes	710	22
Three phase, 60 amperes	1,000	33
Loop service, single phase, 15 amperes	225	11
Extra charges (all inclusive):		
Poles for a single-phase line		570 each
Poles for a three-phase line		600 each
Pole used as a strut		400 each
Stay		315 each
The average cost per customer for meter reading and billing is Rs37.50 per year.		

Source: CEB data (Ibid., P. 220)

The calculation of customer costs for the electric power system in Thailand include the incremental consumer-related expenses of reading and maintaining meters, as well as billing. The consumer and the utility agree on the amount that the consumer should contribute to cover all or some percentage of the cost of a new connection. This includes extensive service connections, distribution transformers, meters, and meter installation.

As mentioned above the electric power system in Thailand is complicated. It has three authorities and thus some administrative costs for metering and billing are lumped together in the total administrative cost. Estimates of consumer related costs are based on the records of the average cost of reading and billing for both the primary and secondary system. The typical table 5.13 shows the consumer

TABLE 5.12

Customer Costs

Category	*Average cost per connection to* WAPDA	*Customer contribution*
Domestic and commercial	334	WAPDA bears full costs for up to 100 feet of secondary lines, and customer pays excess, if any, as a lump sum or monthly service rent. Customers who supply their own meters are given priority among waiting list of about 17,000.
Industrial	9,200	LV customers pay line costs only. MV and HV customers pay all costs: line, transformer, substation, and so forth.
Agricultural	8,500	WAPDA bears full costs up to Rs15,000. If transformer is required, the cost will exceed Rs15,000, and customer must pay the excess.

Source: WAPDA data (Ibid., p. 156)

related costs for the secondary system, dividing the costs among consumer categories and voltage level.

The calculation of customer costs in the Philippines includes administrative and general expenses and meter installation. Although, some administrative and general expenses are not directly related to customers, in this case study the entire administration and general expenses were considered, since a considerable amount of such expenses is associated with accounting, customer billing, collection and other related services.

TABLE 5.13

Consumer-Related Costs for MEA and PEA

(baht per kilowatt)

Consumer category	*Total cost*	
	MEA	PEA
Residential	17.31	15.97
Small business		
220–380 volts	32.15	29.87
11–33 kilovolts	316.01	313.73
Large business and industrial		
220–380 volts	109.67	103.90
11–35 kilovolts	334.38	348.61
69 kilovolts	354.38	—

— Not applicable.

Source: EGAT data (Ibid., p. 236)

5.2.4 Summary of LRMC

Practically all case studies show that the LRMC is composed from the categories capacity, energy and customer costs. These are determined at various voltage levels such as in the Indonesian and Pakistani cases. Most developing countries face the distortion arising from differences in fuel prices, which are domestic and international, and thus the calculation of energy costs should be modified according to these differences. The typical Tables 5.14 and 5.15 show the LRMC in Indonesian and Pakistani cases.

TABLE 5.14

Strict LRMC for Java

Supply voltage	Kilowatt cost (rupiahs per kilowatt-hour per year)					Fuel cost (rupiahs per kilowatt-hour)[a]			
						Oil price (A)		Oil price (B)	
	Capacity cost	O&M	A&G	Facilities	Total kilowatt cost	Base	Peak	Base	Peak
Shadow priced									
HV consumers peak	66,070	11,302	2,412	2,875	82,659	15.55	30.46	12.96	25.54
MV consumers peak	97,072	17,125	3,652	4,356	122,205	16.33	33.47	13.61	28.06
LV consumers peak	278,201	52,448	11,185	13,344	355,178	19.44	47.82	16.20	40.08
Not shadow priced									
HV consumers peak	68,016	11,302	2,412	2,875	85,605	10.20	21.51	8.50	18.04
MV consumers peak	100,600	17,125	3,652	4,356	125,733	10.71	23.64	8.93	19.83
LV consumers peak	288,010	52,448	11,185	13,344	364,987	12.75	33.77	10.63	28.32

a. Fuel prices in U.S. dollars per barrel are: shadow priced, base (fuel oil) = 12, and peak (*HSD*) = 15.5; and not shadow priced, base (fuel oil) = 10, and peak (*HSD*) = 13.

Source: Perusashaan Umum Listrik Negara (Indonesia) PLN data (Ibid., p. 130)

TABLE 5.15

Summary of Strict Long-Run Marginal Capacity and Energy Cost (DP)

(rupees)

Voltage level[a]	Capacity cost (per kilowatt per year)												Energy cost (per kilowatt-hour)	
	Generation			EHV/HV			MV			LV				
	Annual capacity	O&M + A&G	Total[b]	Annual capacity	O&M + A&G	Cumulative total	Annual capacity	O&M + A&G	Cumulative total	Annual capacity	O&M + A&G	Cumulative total	Peak	Off-peak
Generation	1,330	156	1,486	—	—	—	—	—		—	—	—	0.266	0.255
EHV/HV	—	—	1,633	856	212	2,701	—	—		—	—	—	0.292	0.275
MV	—	—	—	—	—	2,968	222	122	3,312	—	—	—	0.321	0.296
LV	—	—	—	—	—	—	—	—	4,416	480	264	5,160	0.428	0.374

Note: Underlined figures indicate the total *LRMC* of peak period capacity at each voltage level.

— Not applicable.

a. The losses of incoming peak power, as presented in Table 9-9, equal 9 percent for EHV/HV and MV, and 25 percent for LV. Station use equals 2.1 percent. Average losses of incoming equal 7 percent for EHV/HV and MV, and 21 percent for LV.

b. *O&M* plus *A&G* costs equal 1.5 percent, 3 percent, 5 percent, and 7 percent of capacity costs per kilowatt for generation, EHV/HV, MV, and LV capacities, respectively.

Source: WAPDA data (Ibid., p. 157)

5.3 THE PRICING OF ELECTRICITY IN IRAQ

On any realistic basis electric power is necessary for economic, cultural and social development in a nation. Electricity is a strategic source of energy. Thus, the aim of generating, transmitting, and distributing electric power in National Development Plans (NDP) coincides with advanced industrial development, in addition to the increasing demand and the meeting of household consumption. Therefore, the electric power sector aims to develop this sector by using advanced technology in order to support the implementation of NDP.

The goals of the National Development Plans include the increase in the production of electric power. This requires an increase in generating capacity. The plan defined the aims of the electricity sector as follows:[66]

1. The augmentation of necessary projects for electric power generation and transmission in excess of demand, and recognition of this sector as being a distinct and important one for the various branches of industry.
2. The exploitation of water energy in Iraq, capitalizing on the fact that this energy is more economical. This can be accomplished by the

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[66] Ministry of Information, Republic of Iraq. The Economy of Iraq Development and Perspectives 1958-1980. Madrid, (November 1977), p. 123,

construction of dams.

3. Acceleration of the process of completing the studies and research pertaining to the exploitation and augmentation of other energy sources, such as solar and nuclear.
4. Emphasis on rural electrification in order to develop and advance the Iraq countryside.

Consequently, to reach the goals of the National Development Plan, the electric power sector should adopt the best power pricing policies in order to maximize the net economic benefits of electricity consumption to society as a whole and to provide for the most economical provision of electric power that is possible.

Before 1975, the electric power pricing policy applied a decreasing-cost approach, where the average cost is decreasing in the range of the demand curve. The aim of this pricing policy was to operate at lower costs of production as well as decrease prices per unit (Kwh), when demand (consumption) increases. But there are several disadvantages incurred through use of this policy which leads the system to financial deficits, misallocation of resources and the fluctuation in demands for electric power. Thus, price will vary among consumers (see Chapter III).

In 1975, the electric power sector began to use increasing block pricing. The objective of this policy was

to increase price per unit and to reduce the consumption level.

5.3.1 Organization of the Sector

The electric power authority in Iraq, the State Organization of the Electricity (SOE), is responsible for generation, transmission and distribution. The power system is interconnected between regions (North, South and Central) by transmission lines through the National Network (NN). There are several secondary networks which are responsible for distribution of electric power to residential, commercial and industrial (small factories). The NN is responsible for transmitting the electric power directly to the industries and secondary networks. There are several Directorates for Electricity Distribution Boards (DED) in the country, which are branches of the General Directorate for Electricity Distribution, (GDED), which is responsible for distributing the electric power to all consumer categories in the city and rural areas.[67]

The electric power sector in Iraq, the (SOE) is owned by the government. Total generation capacity up to 1976 was 1387 megawatts, 57 percent of which was in the form of thermal (steam and diesel turbines), 37 percent from gas turbines and 6 percent from hydroelectric plants as shown in

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[67] N. B. Guyol. The World Electric Power Industry. University of California Press, 1969, p. 209.

Table 5.16.

TABLE 5.16

Installed Capacity up to 1976

(megawatts)

Type of Generation	Total Installed Capacity	Rate Percent
Thermal	793	57
Gas	510	37
Hydro-electric	84	6
Total	1387	100

Source: SOE data

The end of 1983 the production was 15600.28 million Kwh and total consumption 11743.60 million Kwh, thus, the benefit of electricity was available to all consumers in different categories up to 1983 as shown in Table 5.17.

The SOE's system of power plant generation is interconnected by high voltage (HV), 132 Kv transmission lines, which transmit directly to the National Network, and from NN power is transmitted to the secondary network and to the direct industrial consumer by high voltage (HV) 66

TABLE 5.17

Quantity of Electricity Produced, Consumed, and Losses During 1979-1983

	Years				
	1979	1980	1981	1982	1983
Production	9466.73	10675.82	10374.55	13107.80	15600.28
Consumption	7389.48	8263.90	7499.66	8921.55	11743.60
Losses	2077.25	2411.92	2874.89	4186.25	3856.68
Losses as Percent SOE's System	21.90	22.60	27.70	31.90	24.70
Average	-	-	-	-	25.76

Source: Statistical Yearly 1984
Ministry of Information, Republic of Iraq
Table 4.15, p. 115.

kilovolts transmission lines. The SOE's system suplies power in bulk to the General Directorate for Electricity Distribution (GDED), which in turn supplies power in bulk to Baghdad Electricity Services and all Electricity Services for provinces in the country. Each Electricity Service distributes the electricity to different consumer categories and areas.

The major transmission line in the country is 132 KV, directly connected to the main generator and to a secondary generator for distributing the power to the entire NN. The 132 KV line carries the heaviest load to the NN. The 66 KV

line transmits power to the smaller network of northern and central cities. The 33 KV and 11 KV lines transmit and distribute power directly to wholesale outlets.

In response to the rapid growth of industrial and agricultural sectors, which has created an increased demand for electricity, the building of larger generators has become imminent. These generators will be able to fill a heavier load of electricity demand, and will require the building of a larger network carrying 400 KV to fully supply needs by 1995.

Table 5.18 shows the transmission lines in Iraq during the period 1970-1975. All the lines increased annually, excluding the 66 KV line, which is slated to change to 132 KV in the future.

All the transmission lines will be upgraded to higher voltage lines, enabling the transmission of power from the generator to the consumption area. The largest generator will transmit larger quantities of power to the factories and industrial sectors during the fifth planning stage, which will be completed in 1995.

Table 5.19 shows the transmission lines which will be built during the fifth planning stage in order to provide more complete distribution of power through the country, between cities, villages and rural areas.

TABLE 5.18

Transmission Lines during 1970-1975

(Kilometers)

Voltage Level Kilovolts (KV)	Year				
	70-71	71-72	72-73	73-74	74-75
132 Kv	3450	3600	3886	3955	4000
66 Kv	244	244	244	244	244
33 Kv	1200	1300	1285	1360	1600
11 Kv	83876	166863	218588	594912	264123

Source: SOE data

TABLE 5.19

Extension Transmission Lines up to 1995

(Kilometers)

Voltage Level Kilovolts (KV)	Years	
	1985-90	1990-95
33 Kv	3020	2820
11 Kv	12830	12300

Source: SOE data

The distribution of electric power throughout the country is by overhead lines and underground cables. But the rapid

growth of the country has emphasized the need to develop these lines and extend them to all cities, villages and rural areas.

5.3.2 Demand and Supply

In 1976 the peak demand for power from the State Organization of Electricity for Iraq (SOE) system was 763 megawatts, having risen more than tenfold since 1966, an average growth rate of twelve percent a year. The peak demand was increased from 261 megawatts in 1966 to 763 megawatts in 1976, reflecting this growth rate.

The installed generating capacity rose as well from 561 megawatts to 1387 megawatts during the same period 1966-1976 as shown in Table 5.20.

TABLE 5.20

SOE Installed Capacity and Peak-Period During 1966-1976

(megawatts)

	Years									
	66-67	67-68	68-69	69-70	70-71	71-72	72-73	73-74	74-75	75-76
Total Installed Capacity	561	561	561	561	561	645	645	769	757	1387
Peak-Load MW	261	277	316	366	396	459	525	598	640	763
Increasing Percent	-	6	14	16	8	16	14	14	7	19
Average	-	-	-	-	-	-	-	-	-	12%

Source: SOE data

Table 5.21 shows the consumption of electric power during 1973-1980 divided among consumer categories (industrial, and others) for the whole country. The consumption increased rapidly during these periods by an average growth rate of 18.4 percent a year.

The consumption in 1973 was 2363 million Kwh and in 1980 reached to 7763 million Kwh. The reasons for the rapid growth in consumption of electric power in Iraq was due to the large increase in industrial and agricultural developments, and an improvement in people's standard of

living. In addition, rural electrification, which was implemented during the same period contributed to increased consumption of electricity.

TABLE 5.21

Electric Power Consumption During 1973-1980

(million Kilowatt-hour)

Consumer Categories	Years							
	1973	1974	1975	1976	1977	1978	1979	1980
Industrial	964	1070	1349	1427	1984	2532	2944	2732
Others	1399	1528	1855	2494	2545	3241	4110	5031
Total	2363	2598	3204	3921	4529	5773	6054	7763

Source: Statistical Yearly 1981,
Ministry of Information, Republic of Iraq.

5.3.3 Power Development Plan

The fifth development plan for the State Organization of Electricity for Iraq (SOE) system was formulated to supply enough electric power in order to meet the heaviest anticipated load. The expansion program covers generation, transmission, distribution and rural electrification.

The generation expansion program includes gas turbine, 240 megawatts; hydro generator, 5446 megawatts; thermal plants, 4160 megawatts. Thus the installed capacity for

SOE's system will be increased by 9846 megawatts by 1995, as shown in Table 5.22. There is the expectation that most of the old generation plants will be phased out gradually, especially the diesel turbines.

TABLE 5.22

Generation Expansion Program

(megawatt)

Year	Project	Installed Capacity (MW)
1977	Gas turbine/new	240
1978	Thermal units/expand	160
1980	Thermal units/new	1600
1981	Thermal units/new	400
1983	Thermal units/new	1000
1985	Thermal units/new	1000
1980	Hydro plant/new	4000
1981	Hydro plant/new	290
1985	Hydro plant/new	56
1986	Hydro plant/new	1100
Total	--	9846

Source: Ministry of Information, Republic of Iraq
The Economy of Iraq Development and Perspective
1958-76-80. pp. 123-124 and SOE data.

Expansion and rehabilitation of transmission and distribution for SOE's system is planned to meet the rapid growth of electrical consumption in the country during the period 1976-1995. Table 5.19 shows how the transmission lines will expand during the fifth planning stage in order to provide more complete distribution of power through the country between cities, villages and rural areas.

Rural electrification in Iraq is intended to serve both economic and social aims. The village is considered the basic unit for the agricultural economic sector, thus, the transmission and distribution of electricity to all villages and rural areas is vital if there is to be an increase in productivity and in the standard of living.

The number of villages in Iraq is approximately 9780 and the population of the villages is approximately four million. Table 5.23 shows the number of villages in the country. In 1976 there were 2734 villages which were already receiving electricity and 1176 villages which were in the process of being electrified.

The investment costs of all expansion planned during the period 1976-1995 are estimated at 637 million Dinar[68] which are distributed as follows: Generation costs of 318 million Dinar; transmission and facilities costs of 219 million Dinar and other facilities costing 220 million Dinar.[69]

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[68] The Iraqi currency

TABLE 5.23

Village Electrification up to 1976

Villages	Number
Electrification	2734
Under Construction	6946
Total	9780

Source: SOE data

5.3.4 Computation of LRMC

For the State Organization of Electricity for Iraq (SOE), marginal costs should be derived from the three categories, capacity costs, energy costs, and consumer costs. For this specific case of Iraq, there are difficulties in calculating LRMC for the electric power sector, because most of the data is not available. In order to explain the method of marginal cost pricing for SOE's system it will be necessary to use hypothetical examples in the following analysis.

Let us consider the SOE's system by use of the peak demand method to calculate marginal cost pricing. First of all, for the SOE system it is necessary to consider the

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[69] Ministry of Information, Republic of Iraq, The Economy of Iraq Development and Perspectives 1958-1976-1980. Madrid, (November 1977) pp. 123-124 and SOE data.

problem of power losses, by obtaining total peak requirements minus the power loss, as losses are normal in power systems. It was estimated that in the SOE system during the period 1979-1983 there were 25 percent losses. These include losses in generation and other parts of the system (transmission lines, station service, and distribution), as shown in Table 5.17.

Secondly, the calculation of marginal cost categories should be based on the expansion program.

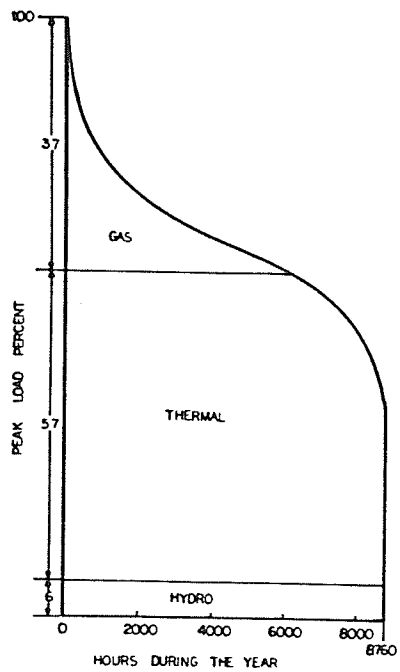
5.3.4.1 Marginal Capacity Costs

The SOE's system uses a combination of thermal, gas, and hydroelectric generators. Therefore, the incremental capacity costs of SOE's power supply should consist of the investment cost of additional generation of high voltage (HV) transmission plant facilities plus the increases in operation and maintenance costs which are involved in plant expansion, as shown in Table 5.22. The investment program for generation and transmission plant projects was developed according to the requirements of the fifth development plan (1976-1995).

SOE's system uses the method of the load duration curve (LDC), as shown in Figure 5.3. The mixed operating system which, mentioned above, is comprised of 57 percent thermal plants, 37 percent gas turbine, and 6 percent hydroelectric

generators up to 1976. Therefore, the peak demand had to be met by this operating mix. The peak demand period in Iraq is during the summer season, June, July, August, and September. The peak during the day is from 11 am to 7 pm during the summer time. To meet the highest demand the LDC would be increased by inserting gas turbines, or operating thermal plants as shown and described in Chapter IV, Section 4.5.

Figure 5.3: Load Duration Curve for the SOE System



Source: SOE data

The calculation of marginal capacity cost determines the ratio of the change in the system capacity cost ΔC associated with an incremental increase in the long run peak

demand ΔD. Then, the capacity cost of generation $\Delta C/\Delta D$ should be annuitized over the lifetime of the plant in terms of the present value. The expectation of peak demand during the fifth development plan (1976-1995) will increase four times over the peak load in 1976, i.e. it will increase 3000 megawatts more. This means that the SOE's system should expand the installed capacity level to meet the heaviest demand. The investment cost projected to expand generating capacity as mentioned in Section 5.3.3 will be 318 million Dinar. The result of such expansion would be that marginal generation cost be equal to 928.56 Fils kilowatt-hour per year as shown in Table 5.24.

Table 5.24 shows the approximate marginal transmission costs, operation (0) and maintenance (M) costs, and other costs which are equal to 639.48, 100.00, and 642.40 Fils per kilowatt-hours per year, respectively.

5.3.4.2 Marginal Energy Costs

The SOE's system uses different kinds of fuel such as diesel, fuel-oil, gas-oil, natural gas and others in its operation to meet the load changes, especially during summer seasons.

The calculation of marginal energy cost should be calculated for a peak and an off-peak period for this hypothetical example. The LRMC of energy for the peak

TABLE 5.24

Marginal Capacity Costs For SOE's System

(Dinar per kilowatt)

Marginal Capacity Cost	Cost Per Kilowatt DP (a)		Annuitized Capacity Costs (b) per Kilowatt
	Per Year	Per Month	Per Year
Marginal Generation or Purchase Cost	928.56	77.38	109.11
Marginal Transmission and Distribution Cost	639.48	53.29	75.41
O & M Cost	100.00	8.33	-
Other Cost	642.40	53.53	75.48

a. Domestic Price (DP)
b. Assumed lifetime for generation, T, and D capacities are 20 years. With an assumed discount rate (for example, the opportunity cost of capital) is 10 percent, the resulting annuitizing factor is 0.1175 for the respective capacity investment (see Richard S. Burington. Handbook of Mathematical Tables and Formulas, 5th edition (New York: McGraw-Hill, 1973), p. 445).

period, is the total of the fuel cost divided by the total kilowatt-hours production at the point of generation during peak periods. For off-peak periods the LRMC of energy is the running costs of the least efficient base-load plants, which are in use at that period together with a percentage of maintenance costs for future plants as discussed in chapter IV, Section 4.4.2.

The marginal energy costs of the SOE connected system varies from year to year and depends on the type of plant used. For example, during the period 1966-1976 the natural gas consumption was increased from 38 to 62 percent and fuel-oil was decreased from 62 to 38 percent. These figures show that the SOE's system was inserting more gas turbine thermal and using less thermal plant during peak periods.

Marginal energy cost should be estimated from average fuel costs from all kinds of fuel expenses that are used in the various plants of the SOE's system. Most of the fuel used by SOE's system plants comes from a local refinery, for which SOE's system pays a lower price. Unfortunately, because the data is not available, there are difficulties in calculating LRMC of energy for SOE's system. Therefore, it is necessary to consider a hypothetical example, as shown in Table 5.25. This table shows the marginal energy costs for SOE's system, considering peak and off-peak periods for different consumer categories and voltage levels.

5.3.4.3 Customer Costs

The calculation of marginal consumer costs is related to the expenses of reading and maintaining meters, as well as billing. The consumer should pay some percentage for new connections, including labor, meter installation and administrative costs. These costs are different among consumer categories and voltage levels. Table 5.26 shows a hypothetical example for calculating consumer costs.

TABLE 5.25

Marginal Energy Cost

(Dinar per Kilowatt-hour)

Voltage Level	At Domestic Price: Peak Period	Off-Peak Period
Generators	0.967 a	0.869 a
HV (66/132 Kilovolts)	- b	- b
MV (11/33 Kilovolts)	-	-
LV (230/400 volts)	-	-

a. - approximate value
b. - not available

TABLE 5.26

Customer Costs

(Dinar)

Customer Category	Average per Connection to SOE	Customer Contribution
Residential and Commercial	-	SOE's system bears the full costs up to limit some feet/ kilometers and customer pays the excess.
Industrial	-	LV customers pay line costs only and should pays the other facilities. MV and HV customer bear all costs line, connection and etc.
Agricultural and Others	-	SOE's system bears full costs up to limit cost. If the cost exceed this, should the customer pay the excess.

5.3.4.4 Summary of LRMC

The hypothetical examples for the long run marginal costs for SOE's system are summarized in Table 5.27. Table 5.27 shows the total marginal costs for the whole SOE system with combined capacity, transmission, energy and other costs among voltage levels.

TABLE 5.27

Summary of Long Run Marginal Cost for SOE's System

(Dinar per kilowatt per month)

	Marginal Capacity Costs					Marginal Energy Cost	
	Generation Costs	T. & D. Costs	O & M Costs	Other Costs	Total Costs	Peak Period	Off-Peak Period
Generation	77.38	-	8.33	53.53	192.53	0.967	0.869
HV (66/132 Kv)		53.29	-	-	-	-	-
MV (11/33 Kv)		-	-	-	-	-	-
LV (230/400 V)		-	-	-	-	-	-

- not available
Source: Derived from previous tables

5.3.5 Modification of the LRMC Concept

The various elements of SOE cost structure and existing tariffs are summarized in Table 5.28. As mentioned in Section 5.3.1 the electric power system for Iraq sells bulk power to GDED. Below is the analysis of the cost and tariff structure for Iraqi electric power which is authorized and organized by SOE as a whole system.

Table 5.28 shows the summaries of the cost and tariff structure for electric power in Iraq as follows:

1. For residential and commercial consumers whose average consumption is up to 300 kilowatt-hours (Kwh) a month, there is a monthly fixed charge (0.008 Fils) as a flat rate.
2. For residential and commercial consumers in the capital city, whose average consumption is more than 300 Kwh a month, the SOE's system uses the increasing block tariff method, and the charges are 0.010, 0.020, and 0.030 Fils per Kwh for the different consumption units as shown in Table 5.28.
3. For residential consumers in rural areas and other provinces, the SOE's system uses the same increasing block method but the charges are different: 0.005, 0.008, and 0.015 Fils per Kwh respectively.
4. For commercial consumers in rural areas and other provinces, whose average consumption is more than 300 Kwh, the charges are 0.008, and 0.015 Fils per Kwh, respectively.
5. For industrial consumers, there is a monthly fixed charge as a flat rate, which is considered the maximum demand (peak-load Kw) plus the tariff charges per unit Kwh of consumption, and both tariffs are different among voltage level HV, MV, and LV as shown in Table 5.28.

6. Others, which include government and public lighting. There are monthly fixed charges as a flat rate 0.10, and 0.015 Fils per Kwh respectively.

The current cost structure per unit Kwh, which is equal to 3.84 Fils per Khw, covered at forty percent of capital costs, fifty percent of input (including energy) costs, and ten percent of other costs. This total cost per Kwh unit is the cost of supplying electricity to consumers as shown in Table 5.28.

Consequently, this cost per unit Kwh seems to be, first of all, higher than the charges per Kwh as shown in Table 5.28 compared among different consumer categories, which in turn means that the system earns less revenue. Second, the ratio of input to capacity charges is highly distorted. The system might incur a deficit, and faces difficulties, because (a) there is expansion of the system needed in order to meet the rapid development in the country, (b) the current base cost structure causes the capacity to be underutilized, (c) consumers face difficulties in switching from peak to the off-peak period and vice versa during the day and seasons, because of lack of facilities for this.

The SOE's system should consider the objectives that were mentioned in Chapter I, Section 1.1, and in addition other considerations which are: the promotion of rational investment; the setting of pricing policy for the long term;

TABLE 5.28

Summary of Main Features of Current SOE Tariffs and Cost Structure

(Dinar per kilowatt-hour Kwh)

Consumer Categories	Current Tariff (e)	Cost Structure			
	Total Charge Dinar per Kwh	Capacity Cost	Input Cost	Other Cost	Total (f) Cost
A. Residential and Commercial 1-300 Kwh as a flat rate	0.008	-	-	-	-
B. Residential and Commercial					
B.1 Capital City					
a. 1-360 Kwh	0.010	-	-	-	-
b. 361-900 Kwh	0.020	-	-	-	-
c. >901 Kwh	0.030	-	-	-	-
B.2 Residential in Rural and Other Provinces					
a. 1-150 Kwh	0.005	-	-	-	-
b. 151-360 Kwh	0.008	-	-	-	-
c. >361 Kwh	0.015	-	-	-	-
B.3 Commercial in Rural and Other Provinces					
a. 1-360 Kwh	0.008	1.52	1.94	0.38	3.84
b. >361 Kwh	0.015	-	-	-	-
C. Industrial					
C.1 230-400 volts	0.007	-	-	-	-
plus peak load per Kw	0.400	-	-	-	-
C.2 11-33 kilovolts	0.006	-	-	-	-
plus peak load per Kw	0.400	-	-	-	-
C.3 132 kilovolts	0.003	-	-	-	-
plus peak load per Kw	0.600	-	-	-	-
D. Others					
D.1 Government	0.010	-	-	-	-
D.2 Public Lighting	0.015	-	-	-	-

Source: SOE data
- not available
e. Equivalent cost per Kwh as a general among different consumer categories/voltage level and areas.
f. Total equivalent cost per Kwh

the efficient utilization of capacity and energy; and guidance for consumers of electricity. All of these considerations suggest that the structure of electricity demand might be significantly influenced if these tariffs are made more consistent with long run marginal cost LRMC.

Section 5.3.4 illustrated the hypothetical example, where the SOE tariff was based on the marginal cost approach. Thus, the marginal cost calculation could be used to charge for the two periods (peak and off-peak). The consumer is charged the basic marginal energy cost per Kwh used for off-peak periods, and at the peak period the consumer is responsible for both Kwh usage and Kw demand which is reflected in the basic energy and capacity charges (see Chapter IV).

Modifying LRMC pricing might help the SOE's system to solve most of the problems which the system faces. The principal changes suggested for the tariff categories are:

1. Residential and commercial consumers: The best method for the consumer whose average consumption per consumer is small, is the single kilowatt meter as discussed in Chapter IV, Section 4.6.6.1. For a smaller consumption of less than 500 Kwh per month the method of a flat rate per Kwh might be used as a fixed charge which reflects consumer related costs and costs of energy. It would be more expensive using the Time-of-Day (TOD) metering method.

The best tariff for medium and large consumption could be the TOD (peak load) tariff. This would mean for residential and commercial consumers (medium consumption) adding more blocks to the existing increasing block tariff and at the same time increasing the amount of consumption per Kwh for each block. The first block increases to 500 Kwh (which is the fixed charge) reflects consumer-related cost, and the other increasing blocks are the energy charges plus the capacity charges. In other words the first block covers the consumption units from 0-500 Kwh per month which would be charged at a relatively low lifeline rate.

The second block covers the amount of consumption from 501-1000 Kwh. This block reflects the charges at the rate of fully marginal cost and usually is at an increasing rate because at this amount of consumption the energy cost increases. Thus, for the second, third and others, the charges are higher (increasing) than the first block in order to cover its marginal cost and the subsidy of the life line rate.

2. Industrial consumers (large size). The (TOD) metering might be appropriate for those consumers. There is a monthly fixed charge reflecting consumer related costs, which should be provided for both the

medium voltage level (MV), 11-33 kilovolts, and the high voltage level (HV), 132 KV. The tariff should be set for two periods, peak and off-peak, and for the different seasons. The tariff for peak demand is a charge based on a maximum demand within the period and a flat rate charge at the off-peak period.

3. Agricultural consumers (large size). TOD metering might be appropriate for agricultural consumers, the tariff set being similar to the tariff for industrial consumers as discussed above.
4. Public lighting. The monthly fixed charge as a flat rate should be eliminated. This is the energy charge, which is the marginal energy cost at the medium level kilovolts.

5.4 POLICY ISSUES AND CONCLUSIONS

This chapter has presented empirical studies of the electric power pricing in developing countries. In this context a review of the pricing of electricity in Iraq has also been presented. Within this framework, the application of long run marginal cost pricing is examined. In this application it was found that a long run marginal cost approach to electric power pricing would need adjustment and modification in the light of national planning objectives and practical considerations. Introduction of marginal cost pricing would also require some phasing of its introduction

on a planned basis. Significant specific considerations were:

1. Provision for low income consumers of access to at least a minimum supply of electricity at a subsidized rate.
2. Maintenance of financial viability of the electric power industry in the face of deficits.
3. Allowance for substantial changes in LRMC, arising from major changes in future prospects, to be made with fairness in the light of the prevailing tariff structure.
4. Recognition of divergences between input prices and marginal costs. For example, the value of natural gas, a domestic energy resource used in the power sector, should be more accurately determined to provide a better estimate of cost per Kwh.
5. Adjustment (usually an increase) in kilowatt charges wherever possible to bring them closer to the LRMC. The setting of tariffs should be a continual process and more accurately reflect the LRMC.
6. Considerations of the fact that the cost of metering (particularly time of day tariff) may exceed the benefits.
7. Recognition of the "losses" problem, which needs further analyses. Losses need to be reduced by at least 15 percent by 1995 in Iraq.

8. Regulatization of the analysis of marginal costs. These need to be handled on a continuing basis as the data is continually changing over-time.
9. Provision for inflationary effects so that they are recognized and the impact minimized.
10. Mobilization of adequate capital for investment.
11. Consideration of issues such as connection policy, i.e. whether the full connection charges should be passed onto low income consumers.

The mutual support that long-run marginal cost pricing and national economic cost pricing and national economic planning give to each other should be emphasized. Such pricing is the guide to economic investment decisions in the electric power sector and will be supportive of the economy as a whole. In turn, national planning must incorparate appropriate financial support so that a succession of short-run expedients in power pricing will be avoided and truly economic pricing will be instituted. Finally, adaption of LRMC pricing can be adopted to broader objectives and practical limitations in a systematic manner.

Chapter VI

CONCLUSION

The central theme of this thesis has been the economics of electricity pricing wth specific emphasis on developing countries. The specific purpose of the thesis has been to develop the best pricing policy for Iraq.

For some time electric power has been a strategic energy resource in most countries. Pricing policy has become a more sensitive issue with the increased complexity of economics, the rapid growth of demand, price shocks to factor inputs such as oil, and the range of technological conditions of supply. Electricity consumption has grown at a faster rate in developing countries than that realized in developed countries. In the 1973-78 period consumption in developed countries grew at a rate of 8 percent per year[70] in Iraq the rate was 16 percent.[71] This rapid growth, combined with the other conditions just cited, has led to increased emphasis on the use of economic principles in order to achieve greater efficiency in the development and use of electricity resources. In a country such as Iraq this search has operated in an environment of national

[70] M. Munasinghe and J. J. Warford. Electricity Pricing and Case Studies, 1982, pp. 5-6.

[71] Derived from previous Table 5.17.

planning objectives and practical limitations.

Analysis of electricity pricing has included an examination of various types of pricing. They are marginal cost pricing, average cost pricing, price discriminations and multi-part tariffs. These pricing methods have been evaluated in the light of the following criteria: economic efficiency, fairness and equity, financial viability, simplicity, and broader economic and political considerations.

Basic analysis of the nature of economic costs was conducted and this was then incorporated into the analysis of pricing. It was found that long run marginal cost pricing provided the most substantial guide for the economic use of resources. It avoids the price instabilities that arise when short run marginal cost is used under conditions of significant indivisibilities in the provision of output capacity and provides a consistent rationale for the application of pricing under complex conditions of supply and use. In elaborating the analysis in terms of electric power pricing the appropriateness of these characteristics for this industry became clear.

Limitations to the use of long run marginal cost pricing were identified. Under conditions of decreasing cost, deficits will arise and the issue of financial viability must be addressed. On occasion, the theoretical merit of

long run marginal cost pricing must be modified by practical considerations. Further, in terms of broad political economy, such a pricing principle is subject to the public policy objective of social equity, economic limitations and other factors.

The application of long run marginal cost pricing was applied to developing countries and, in particular, to Iraq. The application for Iraq was done in the light of national planning objectives and the realistic circumstances existing in that country. It is argued that the institution of long run marginal cost pricing is clearly better on economic grounds than alternative pricing methods which have been in use in Iraq. Long run marginal cost pricing not only provides a more stable basis for pricing practices but enables long run planning to proceed on a systematic and coherent basis. Further, departures from long run marginal cost pricing on identifiable public policy grounds, and for practical considerations, can be accomodated in the national pricing tariff without undue difficulty. In fact, use of long run marginal cost pricing facilitates the incorporation of such considerations in electricity pricing because of the stable comprehensive pricing standard which it provides. It is not in conflict with such considerations. Rather it leads not only to the economic provision and use of electric power resources but to a clear application of national social principles and assessment of practical limitations.

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