

CHAPTER-III-

TARIFF MECHANISM FOR GROWTH & EQUITY IN POWER SECTOR.

Introduction

Tracing the changes in the legal provisions governing electric power tariffs and discusses the processes and methodologies adopted over time for tariff setting till the formulation of the Electricity Regulatory Commissions Act. 1998 (ERC Act).

Indian Electricity Act, 1910

The legal provisions for the regulation of tariffs of power utilities can be traced to the Indian Electricity Act 1910 (IE Act). Keeping with the perceptions of the times there was no attempt at being prescriptive by specifying, either the principles, or the methodology to be followed for tariff setting, beyond enjoining that tariffs must be non discriminatory and allow a reasonable return to the licensee.

Electricity (Supply) Act, 1948

The first attempt to closely regulate monopolistic power utilities by defining the basis on which tariffs could be charged was made in the Electricity (Supply) Act, 1948 (E (S) Act). At the time there were two types of entities in the power sector: Licensees under the IE Act and State Electricity Boards (SEBs) created by the E (S) Act.

Schedule VI of the E (S) Act prescribed the methodology to be followed for the determination of the tariffs of power utilities which were Licensees under the IE Act. This is a detailed cost plus methodology where the rate of return on the capital invested is regulated and a cap is imposed on the clear profit of the licensee. In the case of Licensees it has worked satisfactorily from the viewpoint of financial viability of the utility.

The SEBs was expected to supplement the efforts of the private Licensees. Section 59 of the E (S) Act therefore provided for the basis of tariff determination of the SEBs. As originally formulated, it simply enjoined the SEBs to adjust their charges from time to time so as not to conduct their business at a loss after accounting for subventions received from government. It also envisaged that there may be need to meet expenses on operation and maintenance from capital to be sanctioned by the state government. This was clearly in sharp contrast to the existing provisions for Licensees who were left free to recover charges as appropriate from the consumers. Act 23 of 197 amended Section 59 of the E (S) Act to specify that the tariff was to be so adjusted so that SEBs earned at least a surplus, after accounting for all subventions and costs, including tax. The rate at which such surplus (defined as income less expenditure, including interest and depreciation) was to be recovered was left to be specified by the state government. Act 16 of 1983 further amended the section to the form in which it stands till today. SEBs was required to so adjust tariffs so as to earn a surplus (defined as income less all costs, including interest on debt) of at least 3%. This floor rate for the generation of a surplus was possibly necessary

to safeguard against the continuing deterioration of the financial conditions of the SEBs. Surplus is defined as a return on the value of the fixed assets of the SEBs in service at the beginning of the year. State governments could also specify a higher rate for the generation of surplus. Generally states did not actually do so and SEBs has been unable even to generate the specified minimum surplus.

Till the establishment of central generating stations under the central government power companies from the early 1980's, vertically integrated SEBs and private Licensees dominated the industry. SEBs could purchase electric power from any person under the provisions of section 43 of the E (S) Act on terms as agreed between the contracting parties. However no defining principles were available for tariff setting and tariffs for individual stations were decided on the basis of mutual consent between the generator and the consuming SEBs. The absence of mandatory norms for tariff setting are said to have led to delays in settlement of commercial terms and required extensive negotiation de novo for every station. This was perceived to be inefficient. Consequently the central Government constituted a committee under the chairmanship of Shri K.P.Rao Member (E&C) CEA to recommend alternative methods for the determination of generation tariffs of central stations.

K. P. Rao Committee

The recommendations of the K.P. Rao Committee can be regarded as a landmark in the history of tariff regulation in India. While the entire set of recommendations, which were very wide ranging and proposed a substantial change in the methodology of tariff setting, were not implemented by the government, four recommendations, which were implemented, significantly altered the tariff setting methodology.

Firstly, the concept of "deemed generation" was introduced which compensated generators, in the event of a station being available but forced to back down due to system constraint.

Secondly, the concept of two-part tariff, comprising fixed and variable charges respectively was accepted, though it was only implemented in part.

Thirdly, efficiency enhancing changes were effected in the existing incentive structure. Till 1991, the single part tariff was calculated such that full recovery of fixed costs was assured at a PLF of 62.8%. Generation below this target level penalized the generator on the recovery of fixed cost, since the tariff got proportionately reduced. Conversely, generation above 62.8% resulted in significant excess revenue. The formula adopted post 1991 limited both the incentive and disincentive for recovery of fixed costs. The incentive beyond 68.5% PLF was lower than before while even with nil generation 50% of the fixed cost was recoverable.

Fourthly, for the first time operational norms were determined for station heat rate, auxiliary power consumption, specific oil consumption. More importantly, the norms were challenging relative to average performance levels at the time and hence laid the basis for performance based ratemaking.

Act No 50 of 1991 introduced Section 43A of the E (S) Act, which specifies that in the case of government owned generating companies the tariff would be decided by the state or central governments whichever owned the company. Tariff was determined on the basis of operational norms and PLF as determined by the CEA while the rates for depreciation and reasonable return were to be notified by the

central government. It was under these provisions that some of the recommendations of the K. P. Rao Committee were notified by the central government and came to be used in tariff determination of central stations.

Norms for Independent Power Producers

The Amendment Act No 50 of 1991 had also changed the definition of "generating company" to include privately owned generating companies. Accordingly a fresh set of norms were notified by the central government on March 30, 1992 to determine tariffs for both thermal and hydro generating stations to be set up by the Independent Power Producers (IPPs) in the private sector. These have been subsequently modified from time to time. Five primary changes were introduced in the determinants of tariff.

Firstly, the recovery of fixed costs was linked to deemed PLF (defined as PLF plus Deemed Generation) thereby making a departure from the past wherein the recovery of fixed costs was linked initially to the PLF achieved and then the deemed PLF. While deemed PLF is arithmetically the same as Availability, the latter has to be declared ex ante and requires the utility to commit to a certain level of preparedness for generation, while the former is a ex-post concept. The adoption of availability as a performance target for the recovery of fixed charges was therefore a natural culmination of the process of rationalization begun by the K.P.Rao committee.

Secondly, the incentive structure was further revised. In the case thermal generation the deemed PLF for full recovery of fixed charges was fixed at 68.5%. For hydropower the target availability was 90% (subsequently reduced to 85% in 1998). An incentive in the form of a increase in ROE of up to 0.7% points for every 1% point increase in deemed PLF (Availability in the case of hydro) was determined along with penalty calculated as a prorata reduction in the recovery of fixed cost for deemed PLF / Availability below the target level.

Thirdly, along with the increase in the rate applicable for the central generators from 10% to 12%, the Return on Equity for IPPs was fixed a 16% per annum.

Fourthly, against the notional debt equity ratio of 50:50 for central generators, the debt equity ratio for IPPs was revised and the minimum level of equity fixed at 20%. The minimum stake of the promoter to be held as equity was fixed at 11% of the total capital. A cap was imposed on financing from the Indian Financial Institutions at 40% of total outlay (which has subsequently been relaxed).

Fifthly, up to 100% foreign equity was permitted with foreign exchange risk protection.

With effect from November 1, 1998 (and later for licensees as well), the central government revised the return on equity for central government generators also from 12% to 16% without making any change in the notional debt equity ratio of 50:50 applicable for such stations.

Transmission Tariffs

Separate provisions for transmission tariff do not explicitly exist in any the electricity laws. This is not surprising since unbundled transmission did not exist till the establishment of POWERGRID in 1989. In fact POWERGRID treated as a generation company under the definition provided in the E (S) Act. The assets of POWERGRID, the sole central government transmission company, were transferred to it from NTPC and NHPC. Tariffs have been notified by the central government on

the basis of techno economic approvals of investment given by the CEA. Consequently the notification dated December 17, 1997 was the first attempt to formalize the methodology of tariff setting. It prescribes a single part tariff comprising all costs on account of interest on outstanding loans and working capital, return on equity, depreciation, O&M expenses as per norms and income tax. The full cost is recoverable at an availability of 95%. An incentive is given in the form of increase in ROE at the rate of up to 1% point for every 1% point increase in availability. A debt equity ratio within the norm of 80% maximum and 20% minimum has been used for POWERGRID while the rate of ROE is the same as for generation.

The cost plus approach has been predominant in tariff setting in India. A significant departure was seen in 1991 with the part adoption of the recommendations of the K. P. Rao committee, which introduced the concept of performance based rate making and bench marking of operational standards. This approach has helped to induce the regulated entities under this regime to significantly improve their performance and reduce operational costs. Unlike the international experience of such schemes, the tariff regime has been very stable. Some may comment that the tariff regime should have been reviewed more frequently than was done to ensure that the resultant efficiency gains are shared with the consumers. In 1998, prior to the coming into effect of the ERC Act five sets of norms for tariff setting were in force. One set of norms, specified by schedule VI of the E (S) Act, determines the tariff of Licensees under the IE Act which are all in the private sector. The second set of norms under section 59 of the E (S) Act determines the tariff of SEBs. The third set of norms specified by the central government under section 43 A (2) of the E (S) Act determines the tariff of central stations. The fourth set of norms under the section 43 A (2) specifies the tariff for IPPs. The fifth set of norms specifies the tariff for POWERGRID the sole central transmission company. There is a fair degree of commonality in all the five sets of norms though they are not identical. The effectiveness of all the five sets of norms, in providing incentives for continuous improvements in performance standards, can be questioned. Their relevance in the light of changes in the macro environment and the rapid evolution of the Indian Power Industry may also be in doubt. However it is well established that each represents an evolutionary stage which improved the effectiveness of the regulatory regime in place at the time that these norms were formulated. It is just as clear that significant adjustments are now required if the positive trend, in evidence since 1948, in the evolution of tariff regulation in India is to be maintained.

TARIFF SETTING PRINCIPLES, METHODS AND ISSUES IN INDIA

Review of the legislative mandate, with respect to tariff determination, the guidelines as available in the ERC Act or as given by government policy, the regulations formulated by the Commission, the key principles for tariff design, the objectives, of the tariff policy to be achieve and the primary issues in executing its mandate.

Functions of the central commission

The ERC Act of 1998 established the CERC. The functions of the Commission are defined in section 13 of the ERC Act and are reproduced below:

The Central Commission shall discharge all or any of the following functions, namely: -

- a) To regulate the tariff of generating companies owned or controlled by the Central government;*
- b) to regulate the tariffs of generating companies, other than those owned or controlled by the Central Government specified in clause (a), if such generating companies enter into or otherwise have a composite scheme for the generation and sale of electricity in more than one state;*
- c) to regulate the inter-State transmission of energy including tariff of the transmission utilities;*
- d) to promote competition, efficiency and economy in the activities of the electricity industry;*
- e) to aid and advise the Central Government in the formulation of tariff policy which shall be*
 - i) fair to the consumers; and*
 - ii) facilitate mobilization of adequate resources for the power sector;*
- f) to associate with the environmental regulatory agencies to develop appropriate policies and procedures for the environmental regulation of the power sector;*
- g) to frame guidelines in matters relating to electricity tariff;*
- h) to arbitrate or adjudicate upon disputes involving generating companies or transmission utilities in regard to matters connected with clauses (a) to (c) above;*
- i) to aid and advise the Central government on any other matter referred to the Central Commission by the Government;*

Tariff Guidelines

Section 28 of the ERC Act, which is reproduced below, specifies the guidelines for tariff determination for the Commission. While these guidelines define the principles for tariff determination to be adopted, they are not mandatory.

The Central Commission shall determine by regulations the terms conditions for fixation of tariff under clauses (a), (b) and (c) of section 13 and in doing so, shall be guided by the following, namely:

- a) the generating companies and transmission utilities shall adopt such principles in order that they may earn an adequate return and at the same time that they do not exploit their dominant position in the generation, sale of electricity or in the inter-State transmission of electricity;*
- b) the factors which would encourage efficiency, economical use of the resources, good performance, optimum investments and other matters which the Central Commission considers appropriate;*
- c) national power plans formulated by the Central government; and*
- d) such financial principles and their applications contained in Schedule VI of the Electricity Supply Act, 1948 as the Commission considers appropriate.*

Role in Tariff Setting

The CERC's primary role in tariff regulation is set out in Section 13 of the ERC Act. Beyond this tariff setting role, the Commission is to aid and advise the Central Government in the formulation of tariff policy which must be fair to the consumers, while at the same time facilitating the mobilization of adequate resources for the power sector. This highlights the conflicts of interest, some of which could be as follows:

allowing an adequate return for electric utilities without unduly burdening the consumer,

ensuring that electric utilities do not exploit their dominant position while ensuring that investor interest is safeguarded,

encouraging the efficient and economic use of resources without being prescriptive on the solutions,

allowing free play for innovation,

promoting improved quality of supply and availability within the limits of least cost expansion in supply. assisting in the formulation of environmental regulations without unduly burdening the utilities or the consumers.

ensuring the stability of the tariff regime with the need for dynamic improvements in the efficiency of supply and demand.

The Process Of Tariff Setting

As required under the ERC Act, CERC has issued its Conduct of Business Regulations, 1999 (CBR), which prescribes the procedure to be followed for tariff related petitions. Regulation 79 of the CBR is reproduced below:

No generating Company, owned or controlled by the Central government and no generating Company other than those owned or controlled by the Central Government, which has entered into or otherwise has a composite scheme 1 for generation and sale of electricity in more than one State shall charge their customers any tariff for the supply of electricity without the prior approval of such tariff by the Commission. No generating or transmission utility shall charge any tariff for the inter-state transmission of energy without the prior approval of the Commission. Provided that the above regulation regarding tariff for sale of energy shall apply to the generating companies owned or controlled by the Central Government with effect from the date of the above regulation will be notified for operation by the Commission.

Provided further that the existing tariff being charged by the generating companies owned or controlled by the Central Government shall continue to be charged after the date of the notification as referred to in the above regulation for such period as may be specified in the notification.

Chapter II of the CBR prescribes the requirements for the filing of petitions, including petitions for approval or revision of tariff. The Commission may also initiate the process of tariff revision. The Commission is to issue detailed orders, specifying the terms and conditions, including the norms, which will be used by the Commission for tariff determination. These orders will specify the information requirements to be met by the utilities on an annual basis as well as at the time of tariff determination or revision.

Principles of Tariff Setting

Some of the factors which the Commission may apply, in the regulation of tariffs, have been specified in Regulation 82 of the CBR. Considering the following principles for inclusion in the proposed order on tariff principles and norms:

Tariffs should be unambiguous

Open to consistent interpretation.

The tariff setting process should encourage the reduction of transaction cost and timely completion of proceedings.

Tariffs should be determined in a transparent manner providing sufficient opportunity to all concerned.

Tariffs should provide appropriate incentives for efficiency enhancement and the rational use of energy to suppliers and users.

Tariffs should provide the correct pricing signals to investors for appropriate investment.

The tariff should be stable and predictable over-time.

The tariff regime should be flexible in its coverage of services and encourage market determination of prices where feasible.

Objectives of Tariff Setting

The variety of objectives as listed below:

Promote competition, efficiency and economy, including provision of incentives for operation at minimum costs.

Match supply to demand within reasonable time while ensuring good quality of supply and reliable and secure system operation.

Ensure optimization of the generation mix.

Explore the promotion of environmentally sound options.

Facilitate efficient system operation including the economic transfer of energy across states and between regions.

Ensure the settlement of commercial commitments, like timely payments, associated with energy supply and purchase.

Options in Regulatory Methods

There are a variety of methods for tariff regulation as reviewed below. The choice of the method will be dictated by factors like effectiveness of the method in achieving tariff objectives, appropriateness, in the light of the existing methods being used for the purpose and administrative convenience given the existing infrastructure and information systems.

Rate of Return + Cost of Service;

Marginal Cost based Price;

Performance Based Regulation (PBR);

RPI-X;

Competitive Bidding;

Rate of Return Regulation (RoR)/ Cost of Service

The rate of return approach requires the determination of allowable costs, a rate base and the rate of return to be allowed on the rate base. The rate base is the capital amount on which a return is allowed. Typically the rate base represents the historic cost of the assets employed, less the accumulated depreciation of the asset³. The data requirements for carrying out RoR regulation are the historic costs of investments (in the Indian system the gross block) together with the variable costs incurred in the test year. The test year is generally taken as the latest financial year for which complete data is available.

This form of regulation has a number of distinct advantages:

It provides predictable, steady returns for the utility, which is conducive to making further investments.

The method is conceptually simple and unambiguous, generally making use of historic accounting data.

It is perceived to be fair. The cost of the electricity service is related directly to the actual asset base, with the end user paying for the facilities used. Today's user pays for the system built to date.

It is a traditional approach, used over many years, and is familiar to electric utilities, users and regulatory agencies.

The strengths of this form of regulation like its simplicity and predictability, also create its limitations.

Once an investment is made it tends to remain in the rate base and earns a return, even if the investment becomes non productive due to future developments, resulting in "stranded costs".

Since the rate of return and the rate base are the two main variables in the determination of the return to the utility. There is a tendency to over invest. Higher the investment, higher the rate base and hence the return to the investor.

The process is backward looking. The end user pays the historic cost and there are no price signals regarding future costs. This is not conducive to the efficient use of energy.

Historic book values may not provide sufficient revenue for future investments and may result in inadequate investment for future needs.

This is an intrusive form of regulation. It provides little incentive for the supplier to reduce costs and make efficiency gains. Since the net return to the utility is fixed any reduction in costs or increase in revenue are passed through to consumers.

Due to its intrusive nature the transaction costs are high the period of tariff review tends to be short. The nature of review is detailed as regulators have to overcome the inherent problem of information asymmetry between the regulated and the regulator

Performance Based Regulation (PBR)

Recent trends have been towards more "light handed" regulation i.e. least interference by the regulators. PBR moves away from the RoR method by providing incentives for the utility to improve efficiency and reduce costs. Rather than prescribe a return, the utility is given a set of performance criteria to follow. Performance criteria may include both operational and financial criteria. The return to the utility depends upon performance. Over achievement of the performance criteria can increase returns for the utility while underachievement will decrease returns. Performance targets are set using historic data, trends of system costs and operational characteristics. The establishment of an extensive data base for benchmarking performance criteria on the basis of industry best practice is an essential component for effective regulation under this method. A form of PBR is in actual use in India, where tariffs are based on normative parameters. With minor adaptation and reformulation of the normative values to this method has been used extensively in the US but there is a movement away as in California³ In some jurisdictions the rate of return is allowed on revalued assets. This tends to push up tariffs and is not widely used.

This method is being used in England and Wales and is being considered elsewhere, e.g. Ontario and Alberta, Canada. Performance criteria might include such items as, number of hours of system degradation (down time) losses expressed as a % of energy produced, expenditure on O&M, number of employees per 1000 consumers, lost time due to accidents, etc.

Hybrid And Sliding Scale Methods In PBR

The hybrid method of PBR combines some of the best features of ROR and PBR. The hybrid approach combines elements of both the methods to suit local conditions. For some elements of tariff, performance benchmarking could be applied, whereas with respect to other elements, the historic cost and rate of return may be applied. This would be effectively a refinement of the existing norm based ROR system.

This is a variation of the PBR method under which the performance criteria do not remain fixed but change over time. The purpose is to allow time to the utility to take the appropriate corrective steps before a tightening of the performance criteria.

RPI

This is the least intrusive form of regulation which has been extensively applied in the UK. It imposes a price cap which, over the tariff period, can be crossed only to the extent of the retail price inflation (RPI). This inflation rate is not fully available as an add-on to the price cap for the utility. It is reduced by a pre-determined efficiency gain (X). The strength of the scheme derives from the flexibility it affords to the utility

to incur costs and take actions as is commercially feasible so long as the objectives of good quality supply are met within the capped price. The problem is how to retain this simplicity in design, while at the same time ensuring that an appropriate price (sufficient for financial viability without being generous), is allowed, for generating stations of different fuel types, ages, technology and siting. In transmission the issue would be to price transmission of energy irrespective of the age of the line, the capacity and technology. The ROR type of approach would try and establish a unique price for these classes of generators. The RPI minus X approach is more aggregative and prices services rather than technologies or fuel usage. It leaves these choices to the utility. Hence, under this system, old stations may lose on operational parameters but gain on total cost due to depreciated rate bases. For the application of this method the following critical decisions have to be taken.

How should the price cap be determined? Determination of the base year price can be complex since the regulator must decide to what extent current inefficiencies should be allowed. However the decision is no different than that required under a PBR regime while setting performance criteria.

Which indices are to be used for inflation? In India, there are the wholesale price index (WPI), the consumer price indices (CPI) for agricultural labor, and the CPI for industrial workers. The latter has historically been higher than the former. Which of these is appropriate? There is also the problem of continuity and representativeness of the indices. If the basket of goods, measured for calculating the index changes, the continuity of application of the indices is lost. In the light of these factors would it be more appropriate to use a specially devised inflation formula rather than an existing index?

(c) Determination of the X factor, the proxy for efficiency improvements, is similarly complex. Time series data for the actual costs and efficiencies of a range of stations and transmission lines would be required to devise the X factor.

Decisions would also be required on the sharing of efficiency gains between the utility and consumers.

Competitive Bidding

This is an alternative to tariff determination. Under the mega-project-policy, government has specified that this method would be followed for the determination of tariffs. This is a market based approach and hence avoids scrutiny of costs, revenues, etc. which is necessary in other methods of tariff determination. Successful adoption of this method presupposes the existence of competitive forces at the bidding stage.

Marginal Cost Based Pricing Methods

From a theoretical perspective, marginal cost pricing methods provide the most appropriate signals for the pricing of electricity. Marginal pricing sends out a clear signal to the supplier and end user regarding the true value of the power being consumed. Marginal cost pricing emphasizes future economic signals rather than relying on financial signals based on today's performance and historic financial costs. Long run Marginal Cost is the future cost of power which takes account of additional investments, consequent capacities, and projected variable costs. Short run Marginal Cost is the variable cost of incremental production. The data requirements for the determination of the LRMC are the energy production and capital costs of all future plants included in the long-term expansion plan. To determine the LRMC, the system

expansion plan needs to be defined in terms of investment costs, variable costs and power and energy production. This is generally carried out with an investment horizon of 20 to 25 years.

The calculation of long run Marginal Cost Pricing is a necessary tool for estimating the efficiency of current tariffs. If the current price being paid to suppliers is lower than the LRMC, then a careful evaluation of the revenues being earned by them is necessary, to ensure that the utilities are being left with sufficient investible resources. Conversely, if the LRMC is less than the current prices paid to suppliers they are probably being over compensated. Short-run Marginal Cost captures only the operating cost and ignores fixed costs which are 'sunk' and cannot be changed in the short-term. Hence it provides appropriate signals to system operators for the dispatch of energy and to users for the use of energy. The rational user will always ensure that the incremental value added or the incremental "utility" of the use of energy is higher than the short run marginal cost of energy.

While providing a good theoretical basis for the determination of tariffs, there are a number of disadvantages to the marginal costing approach, most of the disadvantages relate to the practicality of the method. A number of assumptions used in the least cost expansion plan may be controversial and contestable. Some examples are uncertainties inherent in the energy and demand forecasts, system planning assumptions, unit costs used to establish the investment plan, size of the system or the discount rate. Marginal cost based tariff may be difficult to reconcile with the actual costs encountered in the system. The method uses economic, rather than financial concepts and so may overstate or understate financial requirements. In periods of falling capital costs the LRMC will decrease which may become lower than the costs required to recoup historic costs. Similarly in periods of escalating costs LRMC will tend to overstate the price required to recoup historic costs. This does not apply where the marginal price is determined through a bidding system, such as in the power pool in UK.

Issues in Tariff Setting

There are a variety of issues regarding tariff setting on which need thought and action. Some of these issues are listed below :

Rate of Return and Risk

The return to a utility, expressed in monetary terms, is calculated using two variables. The Rate of Return which is a proportion or percentage and the Rate Base which is also expressed in monetary terms. The rate of return, approved for a utility, consists of two principal components. A risk free cost of capital and an element representing adequate compensation for taking on the perceived risk associated with the investment. Broadly two alternative formulations may be followed. Either the utility may be approved a Return on Equity (ROE) or a Return on Capital Employed (ROCE). In India, the ROE is set at 16% for all investments, regardless of actual cost of capital or associated risk, the rate itself, which includes a risk component, and The ROE or ROCE is applied to a rate base to determine the return of the utility. Where ROE is used it will be applied to the funds of the owners or shareholders equity. In such cases interest cost on outstanding debt is a pass through. Alternatively, if a Return on Capital Employed (ROCE) is being used, the rate base will be the capital base, which represents prudent investments made by the promoter on which the return is calculated and provided in the tariff. The capital base consists of both debt

and equity. A strength of this method for allowing return is the flexibility it allows to the utility to optimize financial costs by varying the debt equity ratio inline with market trends.

There can be several determinants and classifications of risk. Some are listed below. country, political, regulatory risk, financial, cost overrun, foreign exchange, interest rate risk, project size and type, pre or post construction, fuel supply and price risk. Risk may vary also with the nature of ownership; public vs. private, foreign vs. local.

Of the two components of rate of return the risk free cost of capital is constant for all investments. However the risk premium will vary for different categories of investments. This implies that the appropriate rate of return will vary with the characteristics of the investment. Should not such variations be reflected in the rate of return allowed by the Commission?

Information Requirements

The determination of allowable costs and the rate base require significant amounts of information to be filed by the utility. Costs can be collected at the time of the tariff submission or annually, based on the audited financial statements of the utility. The commission must prescribe both annual filings as well as those, specific to tariff petitions. The intention is to develop a database over time for assessing the performance of individual plants. This type of data is required for implementing any performance based regulatory regime

Tariff Entity

Tariffs can be determined at different levels of desegregations. The choice can vary between a unit, station, region or company in generation, and at line, region or company in transmission, are issues to be addressed. The decision depends on the availability of data to support such unbundling and the anticipated efficiency improvements.

Treatment of Partially Completed / Commissioned Stations

How should common costs be allocated? At what stage and on what basis should they be allowed to be recovered through tariff. Infrastructure projects have significant levels of common costs. Since projects are implemented in modules or stages, a common cost like a gas import terminal may be incurred in a lump sum, because of the economies of scale, even though the generation capacity may be added in stages. Hence till the full generation capacity is added, only a part of the common facility may be in beneficial use. Currently the extent of common cost allowed is not linked, to the proportion of final output or capacity of the station or transmission line, actually made commercially available. Can alternative allocation methods avoid unnecessary lags between the creation of common assets and their beneficial use?

Periodicity of Tariff Setting

The period between tariff revisions could vary from one to five years. Currently tariffs are effective for five years, once the tariff has been established and the construction of a station is complete. The argument in favor of frequent reviews is that tariffs can be adjusted regularly and the rate of return to the utility controlled. However this removes any incentive for the utility to make efficiency improvements. Under a PBR system the utility must be allowed a sufficiently long period over which the tariff will remain effective. This enables it to make efficiency improvements and capture the efficiency before the review is required. Shortening the period between tariff reviews

also adds costs to the tariff setting process and increases the burden of regulation. What is the appropriate period between tariff reviews in the Indian context?

Dealing with Change between Tariff Filing Periods

In between normal tariff review periods, additional adjustments may be required. How should these be dealt with? What should be the scope for automatic adjustment? Clearly the method of adjustment will vary with the method of regulation. Under an ROR system all changes have to be considered and approved specifically. Under RPI minus X adjustments are built into the formula. Under competitive bidding the formulas are prescribed in the contract. Can the area of certainty regarding the pass through of unavoidable costs be enlarged for the supplier? How can the consumer be simultaneously assured that only reasonable cost escalations will be passed through? How can costly and time-consuming proceedings be avoided? Where a consumer wishes to challenge the cost escalations passed through by the utility, should it be necessary for the consumer to pay under protest, before it is taken up for consideration by the Commission?

Retrospective Adjustment of Tariffs

Retrospective adjustments arise on various counts including delays in finalization of project cost, which is approved post-construction for public sector projects. This approach is unusual in the sense that costs may be added to a project after its original approval. Consideration may be given as to whether this method should be continued. This is in contrast to IPP projects, where costs are contractually decided in advance. Post commissioning adjustments in tariff are not in the best interest of the buyer as it may insulate the supplier from the risks associated with plant construction. A clear definition of what may be reviewed retrospectively is required. The concept of allocation of risk needs to be considered. Should the buyer be responsible for all unforeseeable risk, or should the risk be shared between buyer and seller? A principle that might be adopted is that tariffs, once set, remain in place for that transaction. This implies that retrospective revision of bills would not be allowed other than for accounting errors. Any approved adjustment in tariff due to new investments could then be applied only to future years. The risk free interest rate is usually taken as the rate payable on long term government bonds. The 16% return on equity is allowed on achieving 68.5% availability / deemed PLF for Thermal generation, 85% availability for Hydro Stations and 90% availability in transmission. In the case of central Thermal Stations in existence prior to 1992 the 16% return on equity is allowed on a notional equity of 50% of the capital cost. Generators who achieve higher than targeted availability can earn higher returns.

Efficiency of Operational and Cost Norms

Under a regulated tariff regime, how can a regulator ensure that the norms being used for judging performance and thus allowing incentives or imposing disincentives, are challenging, without being burdensome for the utility? How should incentives be set, so that they induce continuous improvements in the efficiency of supply and demand?

Treatment of Depreciation and Asset Life.

Considering accepted asset life, the depreciation rates in use in India have the effect of front loading the tariff.

Typical asset lives used internationally 11 are:

Hydro power unit 30-40 years

Thermal (coal) unit 25-30 years

Transmission lines 25-35 years

This would indicate that depreciation rates in the range 3-4% would be appropriate based on straight line,. It may be useful, to review actual asset life of various types of plant in India, as opposed to the notional asset life indicated by the depreciation rates. If asset life in India is actually lower than the international norms, this indicates that the asset replacement is taking place far more frequently than the norms of good utility practice would allow.

Allocation of Common Overheads

Correct allocation of and accounting for overheads and common services is required to ensure that there are no cross subsidies between stations or between plants, of different vintages and technologies. Similar concerns apply to cross regional allocation of overheads for the transmission network.

Linkages Between Tariff And Payments

A very significant problem today is delayed or non-payment by state level utilities against energy supplied by generators. While the unremunerative retail tariff structure may be one of the causes, this cost cannot be passed backwards to the generators or the transmission utilities. With the changes taking place at the State level, including the introduction of State level regulation, along with the rationalization of retail tariff, additional pressure will be brought to bear on the SEBs to pay on time for the power purchased by them. This is necessary to reduce the overall perceptions of risk and hence, the cost of capital and increase the volume of capital supply, for the power sector. The transaction of selling and consuming electric power should be seen as completed only when the power is generated, transmitted, consumed and paid for.

Adoption Of Multiple Tariff Setting Methodologies

It is possible that different methodologies may be adopted for separate sets of services or segments of the industry. As has been stated earlier the Mega Power Policy of the central government prescribes competitive bidding for the sale price of bulk power. In one proposal for a mega generation station in the private sector, which predates the policy, a negotiated approach has been adopted by the central government. The tariff of private transmission licensees may also be decided using the competitive bidding approach. Clearly, the adoption of multiple methodologies raises issues concerning the consistency of principles and their applications, across all methodology. Assure a level playing field, consistency in the applications of basic principles of tariff determination and a non distortionary tariff regime, which maximizes efficiency and pays due regard to the interest of the consumer.

AVAILABILITY BASED TARIFF

ABT has been under discussion since 1994 when M/s ECC, an ADB consultant, first supported it. GOI constituted a National Task Force in February 1995. It had ten meetings till end 1998 where all the related issues were discussed. A draft notification was prepared for issue by government. With effect from May 15,1999 the jurisdiction was vested in the CERC.

Why ABT?

1. India plans to have an integrated National Grid. This will assist in meeting demand with the least cost supply. Five Regional grids already exist. Some linkages between Regions are also in place.

(1) The five Regional grids work at vastly varying operational parameters today. Frequency level is one such operational parameter. The target frequency prescribed by the Indian Electricity Rules is 50 Hz

(2) Integrated grid operations require the normalization of frequency across all five Regions. The alternative is to insulate each Regional Grid by Back to Back HVDC links. This is an expensive option. Normalization of frequency requires proactive load management by beneficiaries and dispatch discipline by generators.

(3) There is currently no formal system of financial incentives to promote grid discipline.

(4) The ABT provides this mechanism.

2. Chronic surpluses in the East and shortages in the South, have resulted in sustained functioning of these grids at frequencies which are far beyond even the normal band.

(1) Continued functioning at non-standard frequency results in long-term damages to both generation and end use equipment this is a "hidden cost" which is borne by the customer in the long term.

(2) The ABT will induce corrections in the prevailing frequency to bring it within the permissible band.

3. Frequent fluctuations in frequency caused by short-term variations in the demand supply gap due to the tripping of load or outage of a generator or a transmission line impose substantial costs on generators and consumers.

(1) The ABT will address this problem by inducing grid discipline.

4. Economic efficiency dictates that least cost power should be dispatched in preference to more costly power (merit order dispatch). This becomes difficult without a two part tariff for all stations. States tend to compare the total cost of central generators with the variable cost of their own stations, since for them the fixed costs of state level stations are sunk costs. This results in making central generation appear artificially more expensive than state level stations even though on variable cost basis the former may be cheaper.

(1) The two-part tariff of the ABT by making the payment of fixed cost a fixed liability of the states converts it into a sunk cost thereby leveling the playing field between central generators and state level plants.

5. Currently beneficiaries are not liable for payment of the fixed cost associated with the share of capacity allocated to them. If a beneficiary decides not to draw any energy he can escape payment of the fixed charge, which then gets paid by the person drawing energy. This is unfair since it increases the cost of energy even for those beneficiaries who may be drawing energy within their entitlements.

(1) The two-part tariff of the ABT assures that each beneficiary will be liable for payment of the fixed cost associated with its share of allocated generation capacity.

6. Currently generators have a perverse financial incentive to go on generating even when there may be no demand. This results in high frequency in the grid as is endemic in the East

(1) The ABT will discourage such behaviour by pricing generation outside the schedule in relation to the prevailing frequency.

What is ABT?

It is a performance-based tariff for the supply of electricity by generators owned and controlled by the central government

It is also a new system of scheduling and dispatch, which requires both generators and beneficiaries to commit to day-ahead schedules.

It is a system of rewards and penalties seeking to enforce day ahead pre-committed schedules, though variations are permitted if notified One and one half hours in advance.

The order emphasizes prompt payment of dues. Non-payment of prescribed charges will be liable for appropriate action under sections 44 and 45 of the ERC Act.

It has three parts:

A fixed charge (FC) payable every month by each beneficiary to the generator for making capacity available for use. The FC is not the same for each beneficiary. It varies with the share of a beneficiary in a generators capacity. The FC, payable by each beneficiary, will also vary with the level of availability achieved by a generator.

In the case of thermal stations, where the fixed charge has not already been defined separately by GOI notification, it will comprise interest on loan, depreciation, O&M expenses, ROE, Income Tax and Interest on working capital.

In the case of hydro stations it will be the residual cost after deducting the variable cost calculated as being 90% of the lowest variable cost of thermal stations in a region.

An energy charge (defined as per the prevailing operational cost norms) per kWh of energy supplied as per a pre-committed schedule of supply drawn upon a daily basis.

A charge for Unscheduled Interchange for the supply and consumption of energy in variation from the pre-committed daily schedule. This charge varies inversely with the system frequency prevailing at the time of supply/consumption. Hence it reflects the marginal value of energy at the time of supply.

How is ABT different from normal proceedings to determine generation tariff?

1. The ABT proceeding has not attempted to consider most of the cost drivers like ROE, Operational Costs, depreciation rate, composition of the Rate Base, capital structure etc. Proceedings to redefine these norms are being held separately. Hence the ABT proceedings have been concerned more with tariff design rather than definition of tariff norms or determination of tariff levels.

2. It's incidence is a function not only of the behaviour of a generator but also of the behaviour of a beneficiary. Disciplined beneficiaries and generators stand to gain. Undisciplined beneficiaries and generators stand to lose.

Broad features of ABT design.

1. It implements the long held view that electricity tariffs should be two-part comprising of a fixed charge and a separate energy charge.

2. It increases the target availability level at which generators will be able to recover their fixed costs and ROE from 62.79% deemed PLF at present to 80% (85% after one year) for all thermal stations, 85% for Hydro in the first year and 77% (82% after one year) for NLC.

3. Misdeclaration of availability entails severe penalties.

4. It rationalizes the relationship between availability level and recovery of fixed cost.

The draft notification provided for recovery of (annual fixed costs minus ROE) at 30% availability and recovery of ROE on pro-rata basis between 30% and 70% availability. This order provides for payment of capacity charges between 0% and target availability (as indicated in item 2 above) on pro-rata basis.

5. The draft notification had provided for payment of capacity charges for prolonged outages. This order disallows such payments.

6. It delinks the earning of incentive from availability and links it instead to the actual achievement of generation. Hence incentives will be earned by generators only where there is a genuine demand for additional energy generation unlike the prevailing situation, or the proposed draft received from the GOI, under which it is earned purely because the generator is available.

7. Draft notification linked incentives to equity. This order preserves the status quo of one paise per kWh per each 1% increase in PLF above target availability.

8. It increases the minimum performance criterion for the earning of an incentive from 68.5% deemed PLF at present to 80% (85% after one year) for all thermal stations, 85% for Hydro and 77% (82% after one year) for NLC.

9. It introduces severe financial penalties for grid indiscipline along with significant rewards for behaviour, which enforces grid discipline for both generators as well as beneficiaries.

10. The order permits market pricing for the trading of surplus energy by beneficiaries and generators.

11. The order urges the GOI to allocate the unallocated capacity a month in advance so that beneficiaries know their exact share in capacity in advance and can take steps to trade surplus power.

12. It will be implemented in stages from April 1,2000 starting from the South. The new norm for incentive will however be applicable from this date for all central stations. In the case of NPC, GOI to decide applicability of the order.

**COMPARISON OF EXISTING TARIFF SYSTEM AND AVAILABILITY BASED
TARIFF**

Sl. No	Description of Item	Existing System	Draft ABT Proposal	ABT Order
1.	Capacity / Fixed Charge	<p>Annual Fixed Charge (AFC) include :</p> <p>a). Interest on loan</p> <p>b). Depreciation</p> <p>c). O&M</p> <p>d). Return on Equity</p> <p>e). Income-Tax</p> <p>f). Interest on Working Capital</p>	Fixed charges excluding ROE i.e. all other five items of the existing system. ROE treated separately	Capacity charge as per existing system
2.	Basis of recovery	<p>Recovered at 62.79% deemed PLF.</p> <p>50% AFC at 0% PLF and full recovery at 68.49% deemed PLF.</p>	<p>FC excluding ROE recovered at 30% availability on pro-rata basis between 0% and 30% availability.</p> <p>ROE recovered on pro-rata availability between 30% and 70%</p>	<p>Pro-rata recovery of capacity charge for :</p> <p>i) NTPC stations:</p> <p>Between 0 to 80% availability in the first year and 0 to 85% availability in the second year</p> <p>ii) NLC Stations</p> <p>Between 0 to 77% availability in the first year and 0 to 82% availability in the second year</p> <p>iii) NHPC Stations</p> <p>Between 0 to 85% availability in the first year and availability in the second year to be announced by the commission</p>

				separately.
3.	Incentives	Above 68.49% deemed PLF, incentives at 1 paise/KWh for each 1% increase in PLF.	Incentive beyond target availability of 70% is as follows: 70% to 85% - 0.4% of equity for each 1% increase in availability beyond 85%.	1 paise/KWh/each percentage increase in PLF of 80%/ 85% in the first/ second year for NLC and 85% in the first year for NHPC..
4.	Sharing of fixed cost	Based on actual energy drawals	Based on allocated capacity	Based on allocated capacity
5.	Recovery of variable cost	Based on actual energy drawals	Based on Scheduled Energy	Based on Scheduled Energy
6.	Deviations from schedule – UI charges	No penalties for such deviation	Varying between 0 to 360 paise/kwh for the frequency range of 50.5 Hz to 49 Hz	Varying between 0 to 420 paise/kwh for the frequency range of 50.5 Hz to 49 Hz
3.	Incentives	Above 68.49% deemed PLF, incentives at 1 paise/KWh for each 1% increase in PLF.	Incentive beyond target availability of 70% is as follows: 70% to 85% - 0.4% of equity for each 1% increase in availability beyond 85%.	1 paise/KWh/each percentage increase in PLF of 80%/ 85% in the first/ second year for NLC and 85% in the first year for NHPC..
4.	Sharing of fixed cost	Based on actual energy drawals	Based on allocated capacity	Based on allocated capacity
5.	Recovery of variable cost	Based on actual energy drawals	Based on Scheduled Energy	Based on Scheduled Energy

6.	Deviations from schedule – UI charges	No penalties for such deviation	Varying between 0 to 360 paise/kwh for the frequency range of 50.5 Hz to 49 Hz	Varying between 0 to 420 paise/kwh for the frequency range of 50.5 Hz to 49 Hz
7.	Norms for tariff determination	GOI Tariff notification	GOI Tariff notification	GOI Tariff notification till such time Commission finalizes its views
8.	Procedure for payment of capacity charge if ABT is introduced in the middle of a financial year	Not applicable	Not specified	Specified
9.	Prolonged Outages	Included in item (2) above	Provided for payment of adjusted capacity charges	Does not provide for payment of capacity charges
10.	Marketing of surplus energy	Not applicable	Not specified	Encouraged and will not require commission's approval
11.	Splitting up of capacity and energy charge for hydro stations.	Capacity charge covered depreciation and interest on loan. Energy covered ROE, income tax, O&M and interest on working capital.	Capacity charge covered depreciation and interest on loan. Energy covered ROE, income tax, O&M and interest on working capital.	Till such commission notifies peak and off-peak energy rates for hydro-stations, primary energy charge would be taken as 90% of the lowest variable charge of the thermal power station in the concerned region. The balance of total charges would

				be recovered as capacity charges.
12.	Payment of dues to generators	As per agreements	As per agreements	As per orders of the commission
13.	Applicability	All central generating stations	All central generating stations staggered region wise	<p>i). ABT implementation is staggered region wise</p> <p>ii) Fixed charge recovery and basis for incentive payments revised from 1st April, 2000.</p> <p>iii) GOI to decide about ABT for automatic power stations.</p>
14.	PLF for incentives during interim period	Not applicable	Not specified	Till the introduction of ABT in other regions and after 1.4.2000, the actual PLF for incentive purposes for NTPC shall be 80% instead of deemed PLF of 68.49%. The PLF in the first year for incentive purposes for NHPC shall be 85%.

Note. 1. For lignite based power stations of Neyveli Lignite Corporation, the target availability/PLF shall be 77% for the year 2000-2001 and 82% for the year 2001-2002.

2. The target availability for hydro power stations shall be 85% for the year 2000-2001 and for the year 2001-2002, the target availability will be notified by the Commission separately.

THE NORDIC SYSTEM OF POWER TRADING

The Nordic system of power trading is one of the best in the world. It has the following nations Norway, Sweden, Finland and Denmark. In the year 2001 their total installed capacity Was 87 000 MW. It was distributed in the following manner

Hydro 53%	
Nuclear 14%	
Other 32%	Thermal
Wind-power 1%	

Source. Nordic Co-operation - Nordel

Interconnectors between the Nordic countries developed from the 1950's. NORDEL was established in 1963. Technical co-ordination of the Nordic electricity system formulation of technical framework for Nordic electricity co-operation. Contacts with other players, organisations and authorities in the electricity sector

Possible lessons from the Nordic experience

The legal basis is decisive as national energy acts have been the starting point of the process in each country.

Objectives: Open access to the transmission system on non-discriminating conditions and lowest possible transactions costs.

National political support is of vital importance.

The system operators play a vital role. Central Grid operators/owners are system operators. System operators must be independent and neutral regarding the actors in the market.

Regulation is necessary to secure the objectives of liberalisation and harmonisation of conditions for market and network access. Pro-active regulation based on good professional analysis and knowledge of the electricity sector is important.

Some Challenges

All countries are affected by the dynamics of the process towards liberalisation of the electricity sector, but problems and challenges vary from country to country. Efficient international competition and markets in electricity presupposes a functioning national (or regional) market framework and structure. Diffuse domestic political commitment and lack of a clear legal and regulatory framework can be a barrier. Physical spot-markets are the backbone of an efficient electricity market. System operators play an important role. Thus there is a necessity for a properly functioning Electricity Trading Market,

Also co-ordination between system-operators is important, both for overall system security, and to organise cross-border trade. Harmonisation of network regulations,

tariff structure and transaction systems can be a challenge in the longer run, for different nations and regions may have different system in place. But the success of electricity liberalisation is in my opinion more dependent on initiating a dynamic transformation process with clear objectives, than setting up detailed and complicated rules and procedures.

Council of European Energy Regulators (CEER) has given the following directions in order to make the system better.

Co-operate in order to achieve competitive European markets in electricity and gas, in which the principles of transparency and non-discrimination are ensured.

Set up co-operation, information exchange and assistance amongst The members, with a view to establishing expert views for discussion with the institutions of the European Union, and in particular, with the European Commission.

Provide the necessary elements for the development of regulation in the fields of electricity and gas.

Where possible work to establish common policies among Members towards agreed issues.

Conclusions

The regulatory authorities will play an increasingly important role in the electricity sector. Pro-active and professional regulations have been an important and decisive factor in successful restructure processes. Different regions face different structural and regulatory challenges and thus the needs of each should be taken into consideration. Exchange of ideas and experiences between regulators are crucial to further success, for without it there can not be a coordinated effort towards the common goal of an efficient Electricity Market. Interconnected systems too need co-ordinated regulation so that there are no discrepancies and conflict of interests

SUBSIDY DESIGN IN THE POWER SECTOR

Introduction

The issue of subsidies in the power sector is attracting increasing attention from policy makers because of two factors. First, the power sector in many developing countries is moving away from total state control to a more competitive environment. As a result, prices tend to move towards their marginal cost, thus reducing any subsidy element that may have been present. Second, it is increasingly accepted in both the developed and developing worlds that electricity subsidies, particularly those encouraging electricity consumption by keeping prices below cost, impose a heavy weight on economic efficiency, government budgets, and environmental performance. Subsidies are also increasingly seen as causing inequity.

It is also becoming apparent that removing electricity subsidies supports the three principal aims considered necessary for sustainable development: economic growth, social welfare, and environmental protection. For example, removal of subsidies boosts economic growth through improved efficiency, lowers budget costs, and reduces the tax burden. Funds supporting subsidies may be redirected to social benefits and redistributing income, and proper electricity pricing could reduce local and global pollution. Over the longer term, per capita welfare increases by eliminating one source of over-consumption, and technologies capable of enhancing sustainable development are stimulated.

In view of the extensive use of subsidies in the Asian Development Bank's (ADB) developing member countries (DMCs), not only for electricity but other commodities as well, ADB established a policy on subsidies in 1996. The framework suggests that subsidies be provided in specific instances, for example, pure public goods while, at the other extreme, private goods should not be subsidized. ADB's energy policy views electricity as a private good that should generally not be subsidized, except in cases where poverty is a factor or where sudden and large price increases have adverse economic impacts.

The policy on subsidies has implications for ADB lending to the power sector for two reasons. First, ADB provides project, sector, sector development program, and program loans to the power sector in its DMCs, so the issue of subsidies must be addressed in all ADB loans to this sector. Second, the power sector in Developing countries is often subsidized, either through explicit or implicit subsidies. Therefore, there is a need to determine whether subsidies are justified and, if so, what form they should take.

Definition Of A Subsidy

What is a subsidy? In broad terms, a subsidy is created when, as a result of public policy, the price received by the producer is increased above what it would otherwise have been in the absence of the policy or, in the case of the consumer, the price paid is lower than what it would otherwise have been in the absence of the policy. A subsidy can be viewed as a negative tax in that there is a payment from the government to the individual or firm, rather than the other way around.

When prices depart from the economic cost of production as a result of subsidies, distortions are introduced into the economy with consequent negative impacts on welfare. Thus, the relevant measure of a subsidy is the difference between the price of the good in question and its economic marginal cost. In ADB's view, such subsidies should be measured accordingly so that they can be reduced and eliminated.

Subsidies in the power sector are the general rule rather than the exception in most Developing countries. They are often the result of public policy and usually rest on the assumption that low-priced electricity is critical to accelerating economic and social development. Electricity is also often seen as a public good and therefore should be subsidized. In some cases, subsidies are simply the remnants of a tariff structure that has not changed sufficiently to reflect the changing level and structure of costs.

Most power utilities are the beneficiaries of subsidies. Subsidies in the form of lump sum or per unit output transfers from the government budget to the utility are rare because budgetary resources are usually scarce. For this same reason, subsidies granted directly to consumers to lower the price of electricity are also uncommon. Subsidies to the power sector are usually indirect and often lack transparency. The following are the main forms in which subsidies are found.

Tax Exemptions. Public policy often exempts power utilities from paying income taxes, or taxes on some inputs in the production of electricity, such as capital equipment and fuel. Although taxes are transfer payments and not economic costs, preferential tax treatment of public power utilities creates an uneven "playing field". Such a policy introduces economic distortions if firms in other sectors are required to pay tax.

Fuel Subsidies. Fuel may be sold to the utility at a below-market price or below the economic cost of production because the government has a monopoly or controls hydrocarbon production, refining, and pricing. The effect of this subsidy is to lower the cost of producing electricity and to lower electricity tariffs paid by all consumers connected to the power supply system.

Interest Subsidies. Implicit subsidies are often found in the financing of capital expenditure programs. The government budget may provide loans to the power utility at below market interest rates. Power utilities may also receive government guarantees on debt issued by the utility. This has the effect of lowering the interest rate of the debt issued and, in both cases, lowers the cost of debt servicing. Below-market interest rates lower revenue requirements and lead to lower electricity tariffs.

Inadequate Returns on Equity Capital. Normally, power utilities are required to earn a rate of return on equity capital to meet shareholder requirements, or to reflect the opportunity cost of this capital in the case of a public sector power utility. If the rate of return on equity capital earned is consistently below the market rate, there is an implicit subsidy provided the consumer. This subsidy also lowers the revenue requirement and subsequently the price of electricity.

Environmental Subsidies. The generation of electricity from thermal plants results in the emission of greenhouse and other undesirable gases; hydro generation often results in water diversion and land erosion; and land acquired for the right-of-way of transmission projects often leads to deforestation and other land degradation. In most cases, the production of electricity has significant environmental costs. However, only in rare cases are the costs of the negative environmental effects of power projects recognized and included in the price of electricity. The absence of environmental costs in the design of tariffs is an implicit subsidy.

Cross Subsidies. Cross subsidies are defined as one group of consumers paying a higher price for a good or service, so that another group of consumers may be charged a lower price. By definition, cross subsidies in electricity tariff have no impact on the revenue requirement of the utility and thus the average tariff level. In the power sector, cross subsidies occur in a number of ways. The most common cross subsidy is in the electricity tariff paid by domestic and other consumers. Industrial/commercial consumers typically pay more for electricity than domestic consumers, consumers engaged in agriculture, and other rural consumers, even though the cost of supply for industrial/commercial consumers is normally lower than that for domestic and rural consumers. The usual reason given for the cross subsidization is social and political considerations.

Many tariff structures include a lifeline block that provides a low price for the initial units of monthly electricity consumption and is provided for social reasons. Although all domestic consumers are eligible for the lower price of the lifeline block, it is normally targeted at poor households that use little electricity. The lifeline block is usually subsidized by a higher charge on electricity in excess of the lifeline block or by other consumer groups.

Cross subsidies are often found between regions where the cost of supply differs and a uniform electricity tariff is in place. In this case, the region with the lower cost of supply subsidizes the region with the higher cost of supply. Uniform tariffs are usually implemented nation-wide and are normally based on political considerations.

Cross subsidies are also found in consumption of electricity at the different times of the day, for example, during the peak and offpeak periods, when the same tariff schedule applies. Since the cost of production of electricity usually varies widely between these two periods, offpeak consumption, when cost is lower, subsidizes peak consumption when cost is higher. This form of cross subsidy may be reduced by designing a tariff that reflects the variation of costs over time (time-of-use tariffs), thus altering consumers' consumption patterns.

Impact Of Power Sector Subsidies

A locative Impacts

Subsidies to the power sector have substantial impacts on the economy in terms of welfare. A subsidy to the consumer or producer lowers the price of electricity, increases demand, and subsequently changes the allocation of resources in the economy. A subsidy to the consumer for electricity consumption (on a per unit basis) results in substitution and income effects. The lower price encourages more consumption of electricity at the expense of other goods (the substitution effect). Lowering the price of electricity is also the equivalent of increasing the consumer's purchasing power and income. Thus, the income effect encourages more consumption of electricity as well as other goods. This ultimately leads to greater investment in the power sector than otherwise would have been needed. Thus, investment resources are redistributed in favor of the power sector. Subsidies to the power utility (on a per unit basis) have similar impacts. Moreover, subsidies change the relative cost of electricity with respect to other energy sources and encourage electricity-intensive production technologies. In Developing countries where capital and energy are typically scarce resources, substitution away from more labor-intensive production techniques has negative development impacts.

Subsidies to the power sector tend to discourage the private sector from participating in the provision of electricity in the larger power markets. Electricity tariff levels that are below cost are often the main cause of financial distress in public power utilities and their cash flow problems are serious impediments to negotiating contracts for the purchase of power from independent producers. As a result, the private sector often requires contract guarantees from the government and higher risk premiums on returns to equity capital for operating in a financially unpredictable environment. Recent experience (Hub River in Pakistan and Dhabol in India) has demonstrated that, even with guarantees, government assurances are not entirely ironclad.

Cross subsidies also have welfare impacts. When one consumer group subsidizes another, more electricity consumption by the latter group of consumers will be encouraged at the expense of the former. A common cross subsidy is found in tariffs where industrial/commercial consumers subsidize domestic consumers. Thus, the demand for electricity by domestic consumers rises in proportion to this consumer group's price elasticity, and conversely the demand for electricity by industrial/commercial consumers falls. Although dependent on the relative magnitude of the price elasticities of the two consumer groups and their size, the usual outcome is that electricity demand rises in the aggregate and signals the need for more investment in the sector. There is also the undesirable situation where the cross subsidy results in electricity prices approaching the cost of alternate sources of generation, say diesel generation. This often leads to a shift to auto-generation by the industrial/commercial consumers and away from purchasing power from the

utility. In most cases, this results in economic and technical inefficiencies, and can significantly erode the revenue base of the power utility.

Cross subsidies as a result of a national uniform tariff policy also have welfare implications. Consumers in areas of high supply costs receive a direct economic benefit through cheaper electricity. There may also be increased employment as the disincentive of higher electricity costs on investment is reduced. However, the economic benefits received by consumers in high supply cost areas are offset by the economic losses in low supply cost areas that finance the cross subsidy. These losses are often in terms of lower output, employment and decreased competitiveness. The overall effect may be positive or negative and can only be verified empirically.

The social costs of the negative environmental effects of power projects are usually not considered when developing tariffs. The exclusion of environmental costs in the production of electricity lowers the price of electricity away from the socially optimal level. Thus, the demand for electricity and consequently the supply are higher than they would have been if these costs were accounted for in the price. The environmental damage from this incremental amount of electricity consumption is attributable to the subsidy.

Macroeconomic Impacts

The macroeconomic effects of subsidies may also be substantial. Subsidies affect the fiscal performance of the government through its expenditure and taxation functions, and budget deficits. If the expenditure on a subsidy is financed through increased borrowing, there will be upward pressure on inflation, real interest and exchange rates in the economy with implications for investment, trade, and capital flows. Moreover, the borrowed funds must eventually be repaid with higher taxes in the longer term. If taxes are raised to finance the subsidy (for example income taxes, consumption taxes and import duties), output, employment and competitiveness will be affected. Subsidies may also be financed through a reallocation of the budget thus avoiding borrowing and increasing taxes. The decision whether budgetary resources are better spent on electricity subsidies as opposed to, for example, health, education or other social services is a political one and an important governance issue.

Subsidies to the power sector have balance of payments implications. Subsidies that cause an increase in the demand for electricity will lead to greater imports of capital equipment for the production and distribution of electricity, as well as higher consumption of crude oil, other fossil fuels, and petroleum products. The burden of these imports will be more acute for countries that have limited production of these commodities and have balance of payments difficulties. If subsidies lead to increased petroleum imports, Developing countries increase their energy dependence on the outside world and the vagaries of the world energy markets. Thus, energy security is reduced.

Electricity Subsidization In Developing Countries

Out of a sample of 12 Developing countries for which data is readily available, only 3 Developing countries do not provide economic subsidies to the power sector. Table 1 illustrates the magnitude of subsidies to the power sector in selected Developing countries. While India and the Central Asian Republics subsidize heavily the power sector, in particular domestic and rural consumers, PRC has made significant strides

in recent years to bring the electricity tariff closer to marginal cost. The tariff in most parts of the Philippines exceeds long-run marginal cost (LRMC) because the financial cost includes high-cost generation from the private sector. The Government of the Philippines and its agency, the National Power Corporation, entered into take-or-pay contracts with private sector generators of electricity in the mid-1990s in response to critical power shortages at the time. Since that time, demand for electricity has been less than anticipated and purchases from the independent power producers have been reduced subsidies are an ever-increasing burden on the state's finances. Nevertheless, as a result of ADB loan conditions, electricity tariffs have been moving towards marginal cost in recent years, and the amount of subsidy has consequently been substantially reduced. The magnitude of the subsidy relative to gross domestic product (GDP) can be substantial – greater than 1 percent of GDP in the few cases for which data is available – and its removal should have a significant positive impact on the government budget.

As an illustrative example of tariffs and their relation to marginal costs, Table 2 provides tariff and marginal cost data for Thailand for 2000. The average residential tariff closely reflects marginal costs. However, although not implicit in this table, the residential tariff comprises an increasing block structure that contains a cross subsidy where larger consumers of electricity pay higher prices so that smaller consumers may be charged a lower one. Consumers engaged in agriculture are heavily subsidized, as are government institutions, although to a much lesser degree. To pay for the subsidy, general service consumers pay a tariff in excess of marginal costs. Overall, the tariff is slightly higher than the average marginal cost.

The Gujarat Electricity Board in India provides a stark contrast (Table 3). Low voltage consumers, especially domestic, agricultural and public services, have been heavily subsidized. Electricity for irrigation is close to being a free good and it is not surprising that this category accounts for 40 percent of total energy sales. It is well known that much of the electricity sold in this category was not used as intended and there was substantial diversion to non-irrigation purposes. Some of the subsidy received by the low voltage consumers was a cross subsidy provided by high voltage consumers, such as industry and railways. The balance was a subsidy from the state government's budget. The state government paid for almost one half of the electricity consumed in Gujarat. With a rapidly growing demand for electricity in Gujarat,

Table 1: Subsidies to the Power Sector in Selected Developing countries

Developing countries	Subsidy as a Proportion Of LRMC (percent)	Magnitude of Subsidy (percent of GDP)
Bangladesh (2001)	21	0.5
China, Peoples' Republic of		
- Hebei Province (2001)	12	n/a
- Liaoning Province (2000)	5	n/a
- Northeast region (1997)	26	
n/a		

- Yunnan Province (1997)	9	n/a
India (1993)a 1.3	50	
- Gujarat Electricity Board (1997)	29	0.2
Indonesia (2000)	55	2.1
Kazakhstan (1999)b n/a	57	
Kyrgyz Republic (2000)	75	n/a
Maldives		
- Male (1997)	tariff > LPMC	n/a
- atolls (2001)	tariff = LPMC	0.0
Nepal (2000) 1.0	35	
Philippines (1999)	tariff > LPMC	n/a
Tajikistan (2000)	90	n/a
Thailand (2000)	tariff > LPMC	n/a
Uzbekistan (2000)	80	n/a
Vietnam (1996)	32	1.4

a World Bank

b Organization for Economic Cooperation and Development;

LPMC = long-run marginal cost

Source: Asian Development Bank

Table 2: Comparison of the Average Retail Tariff with Marginal Costs for Thailand (2000)

Average Tariff (baht/kWh)			
Customer Category Difference(%)	Marginal Cost	Existing	Tariff
Residential	2.31	2.27	(2.0)
Small General Services 7.6	2.47	2.68	
Medium General Services 4.1	1.94	2.03	
Large General Services 13.6	1.90	2.20	
Specific General Services 11.9	1.78	2.03	

Government Institutions (5.4)	2.31	2.20
Agricultural Pumping Services	2.37	1.73 (37.1)
Street Lighting	1.83	0.00
Total 6.3	2.08	2.22

Source: National Energy Policy Office, Thailand.7

According to ADB's *Electric Utilities Data Book* (1997), out of 47 electric utilities for which financial data is available, the great majority (94 percent) is not required to pay income tax to the government. The one out of the three cases that pays income tax is a private sector utility (Meralco of the Philippines). Almost a half (45 percent) of these 47 utilities receive direct subsidies from the government. Except for 7 of these utilities, all are electric utilities in India. Only one utility pays a dividend to the government out of its earnings – the State Electricity Company of the Maldives.

Out of the 30 Developing countries power utilities, 83 percent earned below market rates of return on equity because of low profitability or negative earnings. Although there is no published data, experience indicates that most, if not all, publicly owned utilities raise debt financing at subsidized interest rates or at interest rates where the debt is guaranteed by the government. Debt financing is received either from the capital market directly or, more commonly, through the government budget. The inadequate returns on equity capital and the subsidization of the financing of debt are the main government vehicles for providing subsidies to the power sector in the Asia region.

Table 3: Comparison of the Average Retail Tariff with Marginal Costs for the State of Gujarat, India (1996/1997)			
Average Tariff (rupees/kWh)			
Customer Category	Marginal Cost	Existing Tariff	Difference(%)
Low Voltage Consumers			
Residential	5.20	1.50	(71.2)
Commercial	3.72	3.20	(14.0)
Industrial	3.39	2.81	(17.1)
Agricultural (Irrigation)	3.05	0.20	(93.4)
Public Water Works	3.22	1.50	(53.4)
Public Lighting	4.47	1.91	(57.3)
High Voltage Consumers			
Industrial/Non-Industrial	2.23	2.86	28.3
Traction, Railways	2.19	3.17	44.7
Bulk Supply to Licensees	2.12	2.10	(0.9)
Total	2.99	1.62	(45.8)

Source: Asian Development Bank

Power Sector Subsidies And The Poor

Although it is clear that subsidies to the power sector have negative economic and environmental impacts, a key question is, who benefits from subsidies? Typically, in Developing countries, less than half of the population has had access to electricity (Table 4). The rich have access and the poor (mostly rural households) do not. Electricity subsidies have been the grist of politics resulting in poor targeting, so the better off are primarily the beneficiaries. Moreover, consumption increases more for the wealthy than for the poor as price decreases, thus electricity subsidies tend to be socially regressive.

If the goal of subsidies is to improve the standard of living of the poor, there may be other ways to do so. Electricity is but one component of a household's basket of consumption, which includes food, water, shelter, clothing and education. If an effective income transfer system were in place, income transfers would allow the poor to choose the best solutions for themselves. Market failure also provides little justification for electricity subsidies. There are few economies of scale and scope to exploit and the power sector is becoming increasingly competitive. There may be some positive externalities resulting from electricity usage but, by and large, electricity is a private good. For these reasons, electricity should not be subsidized.

Table 4: Percentage of Population with Access to Electricity, 1994

Country	%
Bangladesh	12
Cambodia	10
Fiji	64
Indonesia	39
Lao PDR	14
Mongolia	15
Myanmar	10
Nepal	11
Pakistan	46
Papua New Guinea	27
Philippines	58
Sri Lanka	38
Viet Nam	15

Source: Asian Development Bank

Nevertheless, experience has demonstrated that even a small amount of electricity can bestow large benefits on the poor. Electricity costs less than kerosene, provides ten times more and better light, and powers many labor-saving devices. Electric lighting extends the day and allows children to study longer, thus raising education levels. It reduces air pollution inside homes, kerosene poisoning, and the number of burn victims. However, the poor often have difficulty in gaining access to electricity services. The cost of connection can range from \$100-600 per household, depending on the distance from the electric power grid, a cost well beyond the means of most poor. Electric utilities often cannot justify the initial high costs of serving the poor. Most Developing countries lack the social service infrastructure needed for effectively managing income-based transfer programs, so electricity may justify some form of subsidy when targeted at the poor.

There are many ways that subsidies can be structured and financed, but the method selected will essentially depend on the country's institutional endowment and on government policies. In any case, they should be cost-effective, efficient, well targeted and should have two main goals. First, the subsidy should assist the poor in gaining access to electricity, which points to having a subsidy that helps lower front-end costs. Second, the subsidy should provide business incentives to serve rural and poor consumers who would otherwise not be served, without significantly distorting the electricity market and without having the government as the major customer for equipment. The government should also be involved in providing technical assistance in the form of information, research, and advice to communities on energy options..9

Subsidizing Access

The welfare gain of a subsidy that eases access to electricity will likely be much higher than the long-term costs of providing the electricity service. Such a subsidy has a direct income effect on the beneficiaries and does not generally introduce price distortions into the economy. Thus, the target population for the subsidy should be those without service, typically the poorest third of the population. Subsidies may be provided for the entire connection cost or for part of the cost with the balance rolled into monthly bills, depending on the affordability of the subsidy to the government. In either case, entire communities should be encouraged to avail of the subsidy and connect to lower the average cost of distributing electricity.

One approach to subsidizing access to electricity services that has been successful in Latin America (Argentina, Chile and Panama) is output-based contracting. Its focus on outputs gives operators the flexibility and the incentive to innovate and to respond to consumer preferences. Typically, output-based contracting involves bidding by distribution companies and others for subsidies and the right to connect a specified number of new consumers to the grid. The operator with the lowest bid, that is, the lowest subsidy requirement, wins the contract. The evaluation of the bids may include other criteria in addition to the subsidy requirement, such as benefit-cost criteria, the operator's and consumers' investment commitment, and social impact. Such subsidy schemes normally partly fund the cost of connection because experience has shown that the willingness to pay for part of the investment is a good test of user demand and preferences. The competition to provide electricity supply may be based on either the smallest grant for a given number of consumers or the largest number of consumers for a given grant. The subsidy is usually financed through the government's budget.

Subsidizing Consumption

When the poor are connected to a power grid, a well-targeted lifeline tariff can also result in substantial welfare gains. A lifeline tariff enables the poor who use minimal amounts of electricity to pay a lower price than wealthier households using higher levels of electricity. The lifeline tariff should be set on the basis of minimum electricity requirements of domestic consumers. These requirements can vary from 50 kilowatt-hours per month in some Developing countries where lighting is the main usage to higher levels in others where climate and latitude are factors. It is important that the lifeline block of consumption be set low so that the poor are the principal beneficiaries of the subsidized electricity. A level that is set too high would include a greater proportion of the population and negate the potential benefits of the subsidy to the poor.

A more efficient and perhaps potentially better targeted electricity tariff provides a lump-sum discount on the electricity bill to consumers that live in poor regions. The amount of the discount depends on the affordability of the agency financing the discount (normally the government) and degree of poverty of the target population. The advantage of such a subsidy scheme is the ease of targeting and the subsidy results in minimal economic distortions.

Time-of-use tariffs designed to reflect the peak and off-peak costs of electricity production could result in a greater consumption of electricity by poor consumers, especially if the majority of the electricity consumption coincides with off-peak periods when costs of production and the tariff are low. Although a subsidy scheme similar to the one just mentioned. The welfare gain from a cross subsidy in the form of a lifeline block in the electricity tariff is likely positive if the tariff is appropriately designed and targeted. The lifeline block is normally subsidized by a higher charge on electricity in excess of the lifeline block and, if sufficiently small, the welfare gain could be substantial to consumers who consume small amounts of electricity could be implemented together with time-of-use tariffs, there may be a substantial increase in electricity consumption without a subsidy if consumption patterns shift significantly to off-peak periods. Whether the electricity tariff includes a subsidy or not, time-of-use tariffs should be considered in any case to lower overall costs of electricity generation and consequently the tariff payable by the poor.

Subsidies to the power sector are normally a political decision in most Developing countries. ADB's view is that electricity should not be subsidized because it has few public good characteristics and is essentially a private good. Moreover, subsidies to the power sector tend to lead to economic distortions and usually have significant adverse welfare, budgetary and environmental implications. The main impacts of electricity subsidies include increasing demand for electricity and investment in capacity beyond the socially optimum level; lowering output, employment and competitiveness; increasing inflation, tax, interest and exchange rates; adversely affecting the balance of payments; and environmental degradation. Most electricity subsidies are poor mechanisms for income redistribution because they are difficult to target and are often socially regressive.

Nevertheless, there are some instances where the welfare gain of a subsidy substantially outweighs the cost of providing it. There is a growing consensus that subsidizing access to electricity can result in large welfare gains for the poorest portion of the population. Implementation of lifeline blocks in the tariff, providing lump sum discounts on the electricity bill, and time-of-use pricing also result in substantial

benefits. Such subsidies are easier to target because poor communities are readily identifiable.

Rapid economic growth in the Asia region is leading to greater demands for electric power and higher levels of investment in capacity. The public sector is not capable of satisfying all these demands alone and there is a need to rely more on cost recovery mechanisms and the private sector to meet future demand. Therefore, there is a need to encourage power utilities and governments to bring electricity prices in line with costs. This could be accomplished much more readily if a sound policy of subsidization of electricity to the poor was in place.

The process of reforms in different infrastructure sectors was initiated in India in the early nineties. However, the progress till date has not been satisfactory. A clear appreciation of the barriers in this regard and finding out ways for mitigating these appear to be of utmost urgency and importance. While governments take up reform initiatives, and they are primarily responsible for charting a pragmatic reform path, it should not be forgotten that other stakeholders also have a role to play in facilitating the process. The regulator's role comes to special focus in this context. The IPR (Industrial Policy Resolution) 1956 of the Government of India clearly envisaged the need to create a self-sufficient and developed economy. In the electricity sector, amendments were carried out to the existing legislation to pave the way for private sector participation. With a view to providing a level playing field to all investors and to bring in rationality in the tariff structure, "independent" regulatory commissions were envisaged. So far, 15 such commissions have been established. However, if we look at the realization of end objectives, the view is far from satisfactory. In spite of the initial hype, very little generating capacity has come up by way of IPPs (Independent Power Producers). In the case of reforms in the distribution segment, which holds the key for the success of the entire reform programme, the end result has been the least encouraging. What happened in Orissa, which was the first state to embark on a massive restructuring programme, is well known.

Past experience has given us a fair idea of the barriers in restructuring and privatization.