ISSUES OF TARIFF PHILOSOPHY

Introduction

The Haryana Electricity Regulatory Commission (the Commission) was established in August 1998 under the Haryana Electricity Reform Act, 1997. The Commission has already issued basic documents and guidelines as regards its conduct of business, and other important areas such as Annual Revenue Report filing, Tariff filing and Commission Advisory Committee. Two new licences were issued in February 1999 - Transmission & Bulk Supply Licence and Distribution & Retail Supply Licence - after holding public hearings. The Commission will now address itself to some of the important parts of the new licences, i.e., the Filing of Annual Revenue Report and Tariff Proposals and the Principles of Tariff Setting. In December 1998, the Commission issued guidelines for the licensee (i.e., HVPNL) to be kept in view in making its revenue and tariff filings. These guidelines specify information requirements that the licensees are required to submit to the Commission when filing the Annual Revenue Report and the Tariff Proposal under the Act.

The Commission believes that it is now appropriate for the Commission's tariff regulatory framework to be more fully articulated so as to meet the Commission's responsibilities under Section 11(1) of the Act and to fulfil its role in successful achievement of the important purposes of the Act. The guidelines themselves cannot adequately meet these goals over the longer term. The Commission expects to issue Tariff Regulations to set up procedures for revenue and tariff filings, and to formulate the Fuel Adjustment Clause. In addition, the Commission expects to provide a set of principles for its tariff policy and a clear, fair and workable plan to achieve price regulation that will be applicable to the Haryana electricity industry.

When considering the issues discussed below it is important to keep in mind the following functions of the Commission as stated in Section 11(1) of the Act:

> "(d) to promote efficiency, economy and safety in the use of electricity in the State including and in particular in regard to quality, continuity and reliability of service and enable all reasonable demands for electricity to be met;
>
> (e) to regulate the purchase, distribution, supply and utilization of electricity, the quality of service, the tariff and charges payable keeping in view both the interest of the consumer as well as the consideration that the supply and distribution cannot be maintained unless the charges for the electricity supplied are adequately levied and duly collected;

(f) to promote competitiveness and progressively involve the participation of the private sector, while ensuring fair deal to the customers; …"

These specific functions as well as the overall stated purpose of the Act make it clear that the Commission has a responsibility to balance concerns and interest of consumers as well as licensees in developing a working tariff regulatory framework that will foster an efficient electricity market in Haryana. The Commission wishes to obtain the views and suggestions on the substantive issues of its tariff policy from the representative bodies of different sectors, interested persons as well as of the licensee. These issues have greater relevance to the immediate task before the Commission for taking up annual revenue reports and the tariff proposal filings.

The efficiency of tariffs and financial viability of the licensees call for the need to change in dealing with these issues. A comprehensive set of steps and measures is necessary to deal with the major draw-backs in this sector, as recently perceived by the public in Haryana - high power losses, supply interruptions, voltage and frequency fluctuations, etc. So long as the utility was one integrated and government-controlled utility, these areas remained fuzzy. With restructuring of the Haryana State Electricity Board (HSEB) and its unbundling into separate generation, transmission & bulk supply, and distribution & retail supply companies in Haryana, these new utilities will be judged from the perspective of well established principles of accountability, efficiency and adequacy of return.

Need for Change

It may be pertinent to know why there is a need for change, which justifies evolving of a new approach to tariff regulation in Haryana. Generally speaking, the State Electricity Boards have not been determining revenue requirements and fixing tariffs on the basis of realistic and economic costs of electricity, both in regard to raising sufficient resources to recover the costs and setting of efficient prices of electricity for consumers. The data published from time to time shows that over a significant period, the HSEB was not in a position to sustain its operations with its own internal generation of resources. The absence of applying commercial and financial principles and the prevalence of operational inadequacies and inefficiencies resulted in substantial financial and material losses. In addition, tariffs got distorted by grant of subsidies and cross-subsidies at the expense of efficiency and cost recovery. Resulting poor performance of the HSEB adversely affected all electricity consumers in the state in the form of poor quality of service. This situation is not sustainable any more. The new licensees are required by the Act to use their resources in an economical and efficient manner.

Direction of Change

The Commission is set to resolve the problems of the power sector licensees in Haryana through measures promoting the objectives of the Act. Adoption of an appropriate policy for setting tariffs of the licensees plays an important role in this process. In this document, the Commission provides a set of tariff policy conceptual issues, along with options for dealing with them, as the first step in evolving balanced and satisfactory solutions to the efficient tariff setting in Haryana.

Invitation for Comments

The Commission invites written comments on the conceptual issues to reach the Commission by 10/04/99.

CONCEPTUAL ISSUES OF ELECTRICITY TARIFFS IN HARYANA

<u>Issue 1:</u> ***Licensees to reduce technical and non-technical losses and install new and upgraded metering***

The most pressing need for reform in the electricity industry in Haryana comes in the areas of reduction of technical and non-technical losses and metering of customer consumption. The electricity industry in Haryana will remain inefficient unless these areas are taken care of. The purpose of the Act, indeed, one of the Commission's primary functions, is the elimination of such inefficiency. Losses threaten the licensee's financial health and keep prices unnecessarily high to the paying consumers. Estimates of unmetered consumption are a poor replacement for valid charges for actual use based on meter reading and inhibit the Commission's ability to insure that HVPNL is receiving the proper amount of revenue from each of its customers. In the longer term, the lack of time-of-use metering will limit the Commission's ability to have tariff prices properly reflect costs. Taken together, these problem areas affect in a very substantial way the commercial viability of the electricity sector as well as satisfaction of consumers in the State.

The existing situation with power losses in Haryana is unsustainable. The level of power losses in the Haryana transmission and distribution system is estimated at around 33% or more. A considerable part of this level is of a non-technical character, due mainly to power theft, improper estimation of non-metered consumption, tampered meters, and billing and collection problems. The remainder of losses is technical, caused by the poor technical condition and inadequate maintenance of transmission and distribution facilities. A comparison of HVPNL with other power sector licensees in India, Latin America, UK, and the US, reveals that power losses in Haryana are very high.

Comparison of T&D losses

Name of the company	**Year**	**T&D loss**
HVPN	1997-98	33.4%
GRIDCO (Orissa)	1997-98	46.6%
CESC	1996-97	19%
BSES	1997-98	11.7%*
Surat Electric Company	1997-98	17%
Argentina	1998	17% – 18%
Brazil	1997	15% - 18%
Colombia	1998	22%
UK	1997	7.6%
USA	1999 (forecast)	7.1%

* Distribution loss

Reduction of power losses is a function of proper management and adequate investment. Non-technical losses can be reduced with the application of proper control of employees and consumers to eliminate power theft, discourage meter tampering, and improve estimation, billing, and collection procedures. This can be implemented with relatively little resources and in a short period of time, based on the experience in many countries in Latin American and elsewhere. Corporatisation and subsequent privatisation of Latin American utilities brought about new strategies to discipline employees and customers and reduce non-technical losses. For example, distribution losses of SEGBA, the former largest power utility in Argentina, were 26% in 1991. After SEGBA's restructuring and privatisation in 1992, the successor companies put significant effort into the elimination of non-technical losses. By 1995, the distribution loss level decreased below 14%.

Reduction of technical losses is typically a long-term and expensive process. Substantial investment is needed to upgrade all transmission and distribution facilities to improve technical characteristics of the system. Since there is a shortage of capital for this kind of investment in the Indian power sector, reduction of technical losses is likely to proceed gradually. However, initial investment projects should target areas where a relatively small amount of capital has a relatively major impact on technical losses. For example, old low voltage lines distributing electricity over long distances can be replaced with new high voltage lines. Such projects not only replace the old, poorly performing equipment, but also qualitatively improve the system. They tend to have a shorter payback period compared to the projects that merely replace old facilities.

The situation with power metering in Haryana is also far from satisfactory. A large number of consumers at the low voltage level have defective meters or none at all. HVPNL prepares bills for non-metered consumption based on estimates of consumption that use parameters, such as horse-power rating of hydraulic pumps, load factors or connected load. However, the estimated consumption does not properly reflect the actual level of consumption by non-metered customers. For example, some consumers replace pumps with higher rated ones, but do not notify the licensee. Other consumers frequently exceed the connected load or the load factor that are used for calculation of their bills. As a result, non-metered consumers often take more power than they are billed for and the utility experiences non-technical power losses. Installation of meters would eliminate these errors. If complemented with proper supervision of metering, the utility would correctly meter and bill its customers and substantially reduce non-technical losses.

Clearly, all these areas must be addressed by the Commission. The critical issue to be resolved as soon as possible is how a plan for their resolution should be developed. One option would be for the Commission to develop standards and impose them on the licensees. The advantage of this option is that standards for licensees' performance can be set very quickly. However, the disadvantage is that the Commission has little information to know whether the licensees can realistically meet the chosen standards. The standards set by the Commission may be severe enough to put the licensees' financial viability at risk or so unattainable that the licensees will not even try to meet them.

The second option is to require the licensees to develop appropriate plans to solve these problems within a reasonable time frame and present them to the Commission for consideration. The Commission could then if necessary hold public hearings on the matter(s) in order to subject licensees' proposal(s) to appropriate public and staff scrutiny. The advantages of this option are that the resulting plans would have a good chance of success, especially if the Commission builds in appropriate incentives/rewards, licensees' expertise in these areas could be brought to bear on the issues and subjected to reasonable scrutiny, and successor companies would know what was expected of them in making their bids for purchase of portions of the system. Additionally, customers would be assured that appropriate steps are being taken regarding these matters. The main disadvantage is that this option will probably take more time to develop a solution than the first option.

Issue 2: Licensee to reduce and eliminate subsidies and cross-subsidies in existing tariffs.

The efficiency criterion requires that tariffs should be cost-based without any cross-subsidisation. Cross-subsidisation takes place when one consumer group pays a part or all of the cost imposed on the system by another consumer group. For example, industrial users taking power at the EHT level cross-subsidise LT consumers if the revenues from EHT tariffs recover some costs incurred at the LT level in addition to the costs incurred at the EHT level.

The current levels of electricity tariffs in Haryana contain a large degree of cross-subsidy, with some categories of consumers paying well above the economic cost of supply, cross-subsidising other categories such as low voltage users. Low and subsidised tariffs initiate inefficiently high demand for power, which puts pressure on the system capacity and the quality of service. It has also been pointed out that high industrial tariffs induce large industrial users to look for alternative sources of power. Some of them find it economic to build captive generation and leave the system. Exit of large users from the system reduces the number of paying, low-cost consumers.

While the efficiency criterion calls for cost-based tariffs, the social criteria sometimes call for tariff relief to certain consumers. For example, provision of subsidised tariffs to low-income users is a reasonable call that policy makers should address. It is important, however, that the relief to one consumer’s tariff is not creating an unnecessary burden on another consumer. The cost of tariff relief should be recovered in a manner that does not create additional inefficiency in the sector. It is important to bear in mind that any tariff relief should not introduce or further increase cross-subsidies. If a subsidised tariff is sought, the subsidy should be provided from external sources, such as general government budget. Otherwise, the cost of subsidised tariffs will have to be borne by other consumers, which will lead to cross-subsidisation. Subsidised tariffs should be ideally financed from general government budget, because raising funds through a general tax system imposes lower costs on the society than creating a sector-specific tax system.

The Act follows these principles by assigning the responsibility for recovering the costs of subsidised tariffs to the Government of Haryana. The Act thus recognises the government’s right to pursue policies that give subsidised tariffs to some electricity consumers. At the same time, the Act requires the state government to compensate the licensees for the revenue shortfall caused by charging subsidised tariffs. The licensees are required to quantify this revenue shortfall and submit it for review by the Commission.

The Commission needs to address both issues to improve the financial health of the sector as well as promote efficiency, and economic use of resources. There are two tasks before the Commission in this respect:

a) determine a plan for elimination of cross-subsidies in electricity tariffs in Haryana

b) quantify cross-subsidies and the short-fall in revenues caused by charging subsidised tariffs.

The options available to the Commission in determination of the plan for elimination of cross-subsidies are the same as in the Issue No. 1.: a) develop the plan itself, or b) ask the licensee to prepare the plan and submit it to the Commission for review. Since the Commission outlined arguments for and against each option in the Issue No. 1, it will not repeat them here.

The second task calls for a thorough examination by the Commission because of its financial impact on the licensees and the transfer from the State Government. The licensees are required to quantify cross-subsidies and revenue shortfalls caused by subsidised tariffs. Quantification of cross-subsidies is done by comparing the prevailing tariffs with the economic costs of the licensee. Similarly, quantification of the revenue shortfall caused by subsidised tariffs is done by comparing the prevailing tariffs with the cost-based ones. While the prevailing tariffs are known, the costs and the cost-based tariffs must be determined by using one of the following measures:

Option A: embedded cost

Option B: marginal cost

Option C: marginal cost plus efficient share of revenue gap

<u>Option A</u>

Embedded costs represent the historic accounting costs that the licensees incur in supplying electricity to consumers. The embedded cost-based tariffs are determined by allocating the overall revenue requirement into individual consumer classes by using a set of factors reflecting cost characteristics of the licensees. For example, the overall revenue requirement can be divided into demand, energy and customer portions to reflect various types of fixed and variable costs incurred in electricity supply. Each portion can be then divided among voltage levels and then consumer classes based on billing determinants, such as demand, energy consumption, or number of customers.

The advantage of the embedded cost approach is that the embedded costs and billing determinants can be measured based on data that is typically recorded in the books of the licensees. Additionally, the Sixth Schedule approach to measuring costs is based on embedded-costs. Therefore, the licensees should have experience in dealing with it.

The main disadvantage of the embedded cost approach is that the embedded cost-based tariffs do not reflect the economic costs going forward that consumers impose on the licensees through their electricity consumption. Embedded cost-based tariffs reflect the average historic costs of supply, which tend to be significantly different from the economic costs. As a result, the efficiency of embedded cost-based tariffs is poor and consumers make distorted decisions about the level of electricity consumption and investment in electricity consuming facilities.

Another major disadvantage of the embedded cost approach is the high degree of arbitrariness used in determination of tariffs. Regulators must make certain assumptions in deciding what allocation factors should be used in allocating the overall costs to functions and individual consumer classes. This opens a room for controversy and subjective decision making. As a result, the level and structure of embedded cost-based tariffs may vary significantly, depending on the type of allocation factors used in the tariff making process.

Option B

Some regulators have turned to the marginal cost in order to correct the efficiency problem of the embedded cost approach. Marginal cost represents the economic value that the licensee (or the society) has to give up in order to provide consumers with an additional unit of electricity. As a result, marginal cost-based tariffs provide efficient price signals to consumers and are suitable tools for measuring cross-subsidies. Since the Commission requires the licensees to submit estimation of marginal costs as a part of the tariff proposal filing, there should be adequate information available for the Commission's review.

The main disadvantage of marginal cost-based tariffs is that charging marginal costs as tariffs does not ensure appropriate cost recovery for the licensees. This is caused by the fact that marginal costs tend to be lower or higher than the average costs of supply, depending on the capacity utilisation of the transmission and distribution system. If the licensee charges all consumers marginal costs only, it experiences a revenue gap, i.e., difference between the revenues and the costs. This gap tends to be negative in the under-utilised system and positive in the capacity-constrained system. This disadvantage, however, does not represent a problem for measuring cross-subsidies, because they are measured as a difference between the prevailing tariffs and the economic costs. It poses a problem only if tariffs are set at the marginal costs. Even this problem is not insurmountable. It is possible to adjust the marginal costs in ways that minimise the distortion in the price signals, and still design tariffs that produce the appropriate amount of revenues. (See Option C)

Option C

The problem of a revenue gap of marginal cost-based tariffs led regulators to determine tariffs by adding to (or subtracting from) marginal costs an efficient share of the revenue gap. Regulators calculate the gap in revenues caused by charging marginal costs only and then allocate this gap to different consumer classes and tariff components based on efficiency criteria, such as elasticity of demand, incremental or stand alone costs of supply, etc. As a result, this approach ensures that the licensees recover exactly all their costs through tariffs as well as preserves, to the extent possible, the efficient price signals of marginal costs.

This approach is suitable for quantification of cross-subsidies and the revenue shortfall caused by subsidised tariffs. The difference between the prevailing tariffs and the tariffs determined under this approach measure the optimal amount of revenue transfer that takes place among consumer classes or is needed from the State government.

The main disadvantage of this approach is that the process of allocating the revenue gap among consumer classes involves a certain degree of arbitrary decision making. Lack of information often hinders application of clear-cut rules for the efficient allocation of the revenue gap. The regulators must estimate or approximate the missing data, which involves making certain assumptions. The level of the tariffs determined under this approach might vary, depending on the assumptions made during the estimation process. Correspondingly, the amount of cross-subsidies and revenue shortfalls might vary, undermining the quantification process by the Commission.

Issue 3: What general method of price regulation will the Commission employ for Haryana licensees, in both the short and long term?

The Commission has to decide what regulatory framework it will use to regulate the prices of Haryana licensees in conformity with the Act [(Section 26(6)], which requires that tariffs "…shall be just and reasonable and be such as to promote economic efficiency in the supply and consumption of electricity". While Section 26(2)(a) of the

Act sets sections 57 and 57-A of the Electricity (Supply) Act, 1948 and its Sixth Schedule as the baseline for Haryana tariff regulation, the Act also allows the Commission to depart from that baseline on valid reasons in determining the licensee's revenues and tariffs [Section 26(3)]. Clearly, if the stated purposes of the Act and the functions of the Commission would be better achieved by departure(s) from this baseline regime, then the Commission would consider making such changes by explaining the reasons for the departure in writing.

In the absence of natural monopoly, the best solution to the issue of determining prices and quality of goods and services is a market-driven solution. However, since there is the natural monopoly nature of some portions of the electricity industry, a free market cannot be introduced in all segments of the industry and we must substitute a regulatory framework for the natural efficiency of the market. The market solution would consistently provide the amount of power and the quality of service that consumers were willing to pay, supplied by the lowest cost producers of the service. This, then, becomes the goal for a Commission regulatory framework to achieve.

The Commission has two options in regulating electric power prices of the licensees:

a) Rate of Return Regulation

b) Performance Based Regulation

Option A

The traditional framework for setting electricity prices is Rate-of-Return (RoR) regulation, the current Sixth Schedule of the Electricity (Supply) Act, 1948, being one such methodology. It is sometimes referred to as cost-plus regulation because the regulated entity is able to collect from its customers all its prudently-incurred expenses plus a regulated return on its prudent investment. In general, this method sets the total allowed revenues of the utility according to the following formula:

$$RR = [RB \text{ X } RoR] + E_D + E_{O\&M} + T$$

Where:

a) RR = the total annual revenue requirement of the utility

b) RB = the rate base (required investment) of the utility

c) RoR = the allowed rate of return (debt and equity) on investment

d) E_D = annual depreciation expense

e) $E_{O\&M}$ = annual operation & maintenance (O&M) expense

f) T = annual taxes paid by the utility

Under this general framework, the utility has the burden of proving to the regulatory body's satisfaction that each proposed element of the revenue requirement formula is a prudently incurred cost required to serve the public's electricity needs. For example, investments made in capital plant must be shown to be prudent and used and useful in the provision of electric service, in order to be included in the RB term. Similarly, individual operating expense items (including purchased power costs) must be shown to be prudent and necessary for the provision of service in order to be included in the $E_{O\&M}$ term.

The revenue requirements of the regulated company are set based upon the values for the terms in the formula during a Test Year (see discussion of cost basis in Issue 4), usually a past year adjusted for known and measurable changes so as to reflect conditions expected to prevail during the time the proposed tariff will be in effect.

There are several advantages of RoR regulation. First, this approach fixes prices based upon a test year and they are unchangeable until the next tariff proceeding. After prices are set, the regulated entity's rate of return varies, depending upon variations in costs and sales and upon the company's ability to control those costs, which can be controlled. Second, and as a result of the first, there is some incentive for the utility to minimise costs between tariff proceedings, this incentive being higher the longer the period between those proceedings. Third, non-economic goals (from the power sector point of view), such as price relief for some categories of consumers are easiest to meet using this system. Last, the hearings on tariff changes provide consumers with frequent forums to present their views regarding the performance of the regulated utility.

This approach also has several disadvantages. First, its cost-plus nature blunts the incentive for the utility to minimise cost in the long run. Second, if the allowed rate-of-return is greater than the actual cost of capital then there will be an incentive for the utility to build a plant which may not be essential, and vice versa. Last, there can be fairly high administrative costs associated with regulatory scrutiny of utility costs in this system, and the hearings can be time-consuming. These disadvantages can be minimised to a certain extent when RoR regulation is combined with elements of the Performance Based Regulation (PBR) that introduce a system of rewards and penalties in relation to the performance of the utility.

Option B

Performance Based Regulation is a modification of Rate-of-Return/Rate Base Regulation. Under this system, the regulatory lag is stretched out. At pre-set intervals (often 5-10 years), baseline rates are reset using RoR principles. Between these baseline tariff cases, tariffs are adjusted based on specific formulas that include as variables measures of the utility's performance, cost indexes, etc. PBR seeks to eliminate some of the regulator command and control aspects of RoR regulation and substitute for it a system of incentives or penalties for performance by the regulated entity outside of a "normal" range.

A PBR system can be quite simple and focus on a single area of utility operations, such as generating plant reliability or system losses, or more complex and wide-ranging in its applicability, taking into account such things as customer satisfaction, outages at the consumer level, customer load growth, general inflation and prices to consumers, among others. Whether simple or complex, however, the purpose of these systems is to relinquish some of the regulator's review power over one or more elements in the revenue requirement equation set out above. Instead, monetary incentives for good results or penalties for bad results are substituted which the regulated entity can earn or pay, respectively, thereby affecting its profitability.

There are certain characteristics that are present in a good PBR system of regulation. First, the focus of the system should be on controllable aspects of the utility's operations. There is no point in creating a goal that the utility can never achieve. Second, the system should be put into effect for a period of sufficient length of time to recognise the short term and long term trade-offs made by the utility. For example, it is possible for a utility to pay a bit more in capital cost for a transformer with lower associated losses. Over time, the greater capital cost would be more than offset by reduced losses. Third, the many interrelationships between areas of utility operations should be recognised by a good PBR program. For example, heavy emphasis on the cost of operating the distribution system may simply lead to redefinition of former distribution assets as transmission assets by the utility. Fourth, the possible rewards and penalties under the program should be symmetric: for example, the maximum potential reward for improvement in system reliability should be the same as the maximum potential penalty for failure to improve reliability. Fifth, those rewards and penalties should be limited in size so as not to unnecessarily enrich the utility or threaten its financial viability. Sixth, the target(s) set for the utility should be a range of reasonable performance levels based on external standards so that the utility's own performance is not included in deriving the standard. Last, the focus of a good PBR program is results, not the methods used to achieve those results.

For proper design of a good PBR system, comprehensive and reliable data is an essential requirement. This data should be amenable to independent verification.

A good PBR system of regulation has advantages and disadvantages. The advantages are much the same as those listed for the RoR method with two important additions. First, a definite incentive for cost minimisation and improving service quality can be built into the system. Second, an effective PBR system may reduce the need for frequent tariff filings by the licensee(s), which would lead to reduced administrative costs. The first disadvantage of a PBR system is that, unless the system is carefully designed, there may be an incentive for the regulated entity to lower service quality while pursuing monetary incentives in other areas. Second, there is less regulatory scrutiny in a well-designed PBR system because incentives take the place of such oversight, at least between proceedings to reset the baseline tariffs. Third, there is less public input to the tariff process under this system because hearings are not held as frequently as under a RoR system.

The Commission needs to decide what methodology should be implemented in regulation of power sector licensees under the Act. The appropriate regulatory regime should provide incentives for the licensees to improve their financial performance and service quality. The Act allows the Commission to depart from the Sixth Schedule if it finds appropriate to promote the objectives of efficiency, good performance, and other factors specified in the Act. Consequently, the Commission could review proposals for departures from the Sixth Schedule in this respect if convincing grounds are made out.

<u>Issue 4:</u> ***How will the licensee's overall revenue requirement and allowed revenue be determined?***

The issues of revenue requirement and allowed revenue determination are closely interlinked. Determination of a utility's costs is just the first step in the tariff work. The second step is design of tariff elements that, when multiplied by sales, produce the allowed revenue that must be equal to the revenue requirement. As a result, the regulators must estimate both the costs and the associated power sales when they determine the overall revenue requirement and the allowed revenue.

There are three approaches to determining the revenue requirement and the allowed revenue:

a) actual historic accounting costs and sales volumes;

b) estimated future accounting costs and forecast loads; and

c) estimated marginal costs (usually long-run incremental costs) and forecast loads.

The main difference between these approaches is in the choice of a "test year," i.e., the period over which the regulators measure utility's costs and sales.

Approach A

Under the first approach, the regulators establish a "historical test year," which becomes a basis for measurement of costs of supply and sales of power. The "historical test year" costs and sales are then adjusted for "known and measurable changes" to reflect changes in costs and sales between the historical test year and the year when tariffs are going to be in effect. Examples of "known and measurable changes" are an increase in power purchase costs due to a new PPA or a decrease in load due to an exit of a major industrial customer from the system. Actual historic accounting costs and sales volumes have the virtue of being susceptible to audit because they are taken from the books and records of the licensee. The utility must document to the regulators that all changes in costs and sales are justified.

Approach B

However, since tariffs are set to be effective in some future time period and the level of costs incurred and sales experienced in the historical test year may not correspond with costs and sales expected to be incurred during that future period, it may be more appropriate to use a "forward-looking test year" as the basis for revenue requirement and allowed revenue determination. The "forward-looking test year" costs and sales are estimated based upon a forecast of future costs and future load. While the forecast may rely heavily on past experience, all expected changes are incorporated, not just "known and measurable ones."

Approach C

In an attempt to promote market-based pricing, the regulators sometimes use long run incremental costs (LRIC) in setting the revenue requirement. LRIC reflect the cost of the system expansion to satisfy the load forecast over a long time horizon. However, use of LRIC for this purpose raises some very real practical problems. Estimation of LRIC is difficult and sensitive to many subjective assumptions that must be made during the estimation process. As a result, the estimated costs, and therefore the revenue requirement, can vary significantly depending on the assumptions made. Revenue derived by charging LRIC costs as prices on estimated future sales can differ from the amount required to meet the financial needs of the licensee. This could either place the financial viability of the licensee in jeopardy or bestow a significant windfall upon it, unless the Commission intervened to correct the discrepancy.

The Commission must carefully weight benefits and costs in deciding what should be the basis for determination of the revenue requirement and the allowed revenue in Haryana. The "historical test year" approach has been traditionally used in the Indian power sector under the Sixth Schedule methodology. As a result, implementation of this approach in the power sector in Haryana should be relatively smooth. The Commission appreciates the desirability of being able to audit historical accounting costs and power sales. On the other hand, the Commission recognises the benefits of tariffs **that reflect future costs, either through the use of a Future Test Year or marginal cost. This would promote efficiency and other parameters defined in Section 26(2)(b) of the Act. However, there is little experience with these two approaches in the Indian power sector.**

<u>Issue 5:</u> ***If the overall revenue requirements are to be set using accounting costs, then what measure of asset value should be included in the rate base component used in the determination?***

Under traditional ROR regulation, asset value directly affects the revenue requirement, and therefore consumer tariffs, of a licensee. The allowed return, which is a multiple of the rate base and the appropriate rate of return, is one of the components of the overall revenue requirement of a licensee. The rate base represents the value of assets used in provision of electricity service to customers. Performance Based Regulation uses the same approach to calculate the allowed return. While the overall revenue requirement may be adjusted for performance targets under the PBR scheme, the allowed return still represents a significant portion of the revenue requirement. As a result, the issue of assets valuation is an important part of the regulatory tariff-making process.

There are five options for measuring asset value in the calculation of the rate base:

a) original cost of assets less accumulated depreciation;

b) reproduction or replacement cost of assets less depreciation;

c) asset value assigned by the Government when the assets were transferred to HVPNL, less depreciation since the transfer;

d) certified values being produced by HVPNL for privatisation under the Companies Act less depreciation since the transfer, and

e) market value of assets as determined by an independent assessor.

Option A

Original cost less depreciation is the easiest measure to understand and most widely used internationally. As the name implies, investment in the rate base is valued at its original cost to the utility[1] net of the accumulated depreciation expense taken on the asset. This method of valuation is viewed as being somewhat fair because the utility earns a return on the capital it spent in purchasing the asset. At the same time, it enables a utility to retain and attract new capital. The method is relatively easy to administer by the regulators, because most of the required information is in the accounting books of the utility.

The main drawback of this method is that the efficiency of price signals to consumers may suffer. This is caused by a difference between the original depreciated book cost and the economic value of the asset. This difference can be negative or positive, reflecting the fact that the original depreciated cost of the asset is below or above the current economic value of the asset. As a result, consumers may end up paying more or less for electricity than they would pay if the economic value of the asset was used instead.

For example, if the revenue requirement is based on the original depreciated cost of a twenty year old distribution lines, which value has been significantly reduced, effectively, by high inflation from the date of acquisition, consumers are led to believe that electricity is cheaper than in the case when the revenue requirement is based on the economic value of these lines. An opposite case will occur if the revenue requirement is based on the original (mostly undepreciated) cost of new lines, the economic value of which is lower because of technological change, loss of customers in the area, or other factors.

Option B

In an effort to address the inefficient pricing aspects of the use of original cost valuation, some jurisdictions use asset values based upon either the reproduction cost or the replacement cost of the assets involved less appropriate depreciation. The reproduction cost measures the cost of replacing the exact same asset today. For example, the reproduction cost of a ten-year old watt-hour meter is the cost of buying the same meter today. On the other hand, the replacement cost measures the cost of an

[1] In some jurisdictions the cost of asset when originally dedicated to utility use is the measure as opposed to the original cost of asset to the current owner.

asset that will fill the same need today. The replacement cost may be the cost of a different type of asset. For example, the replacement cost of a ten-year old watt-hour meter may be the cost of a new electronic meter rather than the cost of the same meter bought today.

A significant drawback of the reproduction/replacement cost methodology is that it may not, after all, succeed in producing more efficient price signals. Providing a capital-attracting rate of return on an inventory of all new assets produces a higher revenue requirement than one derived from incremental costs. Consequently, consumers may be forced to pay more for electricity than is economic. The regulators must make adjustments in the allowed rate of return on capital for the fact that the reproduction/replacement value of assets is different from the original cost value.

The second drawback of this approach is that its practical implementation is very complex. Ideally, it requires a complete and accurate asset register kept by the utility and considerable work effort by experts knowledgeable in the field of utility asset costs for proper value determination. It is not clear whether HVPNL has such a register and whether the relevant experience exists in India.

The third drawback of this approach is that it might increase a regulatory risk. In practice, in the jurisdictions in which this approach is used, the asset value is usually the result of negotiations between the utility and the regulators. This might lead to highly unpredictable outcomes of regulatory proceedings in this matter. An increased regulatory risk would be undesirable for both the consumers and the licensees in Haryana.

<u>Option C</u>

Another measure of asset value available to the Commission is the value certified by the Government during transfer of assets from HSEB to HVPNL. The Commission can use the transfer value of assets plus any prudent capital additions made by the licensee at original cost and less accumulated depreciation to calculate the rate base of the licensees. The advantage of this system will be that the asset values will be based on a relatively recent evaluation and any additions in assets will be adequately recorded. This will eliminate a potentially complex and difficult task for reviewing the historical structure of licensees' assets in the absence of proper record keeping. This approach, under RoR and PBR methods, will also match tariffs to the Government's valuation of the assets, increasing the likelihood that a subsequent sale of these assets will produce similar values. Before this option can be considered, however, the Commission needs to know the cost basis used for asset valuation under the Government's transfer scheme.

Option D

As part of the run-up to privatisation, the Commission understands that certified values for all assets in service will be prepared. It is likely that these values will differ from the original cost as well as from the transfer value of the assets. As in Option C, the Commission does not know the basis for measurement of these values. It is certain, however, that this issue will emerge in future tariff filings by the licensees that have purchased the assets.

Option E

The last option available to the Commission is an independent assessment of the market value of licensees' assets by a professional assessor every time the licensees file tariff proposals. The apparent advantage of this approach will be an independent and professional evaluation of the assets. However, there are several major practical problems and disadvantages of this approach.

First and the most important, the market value of assets, unless determined by a market function, e.g., a competitive bid, cannot be reliably used in determination of the revenue requirement by the regulators. The market value of the assets of a regulated monopoly depends upon what tariffs the regulators allow the utility to charge. Since the regulators use the market value of assets to determine the revenue requirement, and therefore tariffs, the calculation becomes circular and thus unreliable. Second, it is extremely difficult, if not impossible, to determine a market value for T&D equipment for which there is no market, unless the licensees sell the equipment. Third, the independent evaluation of assets can be a lengthy and costly process. It may postpone the implementation of new tariffs. Since the cost of the evaluation would be incurred in complying with the regulatory requirements, it would have to be recovered through tariffs. Fourth, the rate of return on the market value of assets must be adjusted to reflect the difference between the book and market value of assets. Finally, it is not clear whether an independent assessor would be able to make a better job in the evaluation of assets than HVPNL, given the poor record keeping at HVPNL.

Consequently, the Commission needs to formulate a policy on how asset values will be measured for tariff purposes. Licensees and other parties can send their views on this issue.

<u>Issue 6:</u> ***What should be the allowed rate of return on the licensee's rate base***

RoR or PBR regulation of tariffs sets the appropriate rate of return on capital which investors employ in operation and expansion of power sector facilities. This rate of return should adequately compensate investors for the risks they assume by committing capital to the power sector or the individual utility. This capital takes the form of either debt, which represents a loan to the utility, or equity, which represents an ownership stake in the utility. The return, which investors require on their investment, should be equal to the return on other investments with comparable risk characteristics. It should generate enough resources to cover debt and equity payments to investors and allow the utility to attract new capital as needed.

The role of regulators is to give investors an opportunity to earn the appropriate rate of return that reflects the principles mentioned above and promotes efficient allocation of capital to the sector, and ensures that consumers of electric power are paying only the economic costs of investment. These are the same objectives as specified in Sections 26(2)(b) and 26(2)(c) of the Act.

Power sector licensees in India are allowed to earn the rate of return that is specified in the Sixth Schedule of the Electricity (Supply) Act, 1948. Under the Sixth Schedule, the level of the rate of return is different for three vintages of assets:

- assets acquired before 1956 earn the allowed rate of return of 7%,
- assets acquired between 1956 and 1991 earn the allowed rate of return based on the Reserve Bank of India's rate (RBI rate) plus a 2% premium,
- assets acquired after 1991 earn the rate of return of the RBI rate plus a 5% premium.

If the licensee employs assets with different dates of acquisition, each portion of the asset base earns a different rate of return, depending on the date of asset acquisition.

Some people think that the methodology employed by the Sixth Schedule does not set the allowed return based on efficiency principles. The level of the allowed rate of return is not linked to the risk of the investment and the underlying cost of capital for the licensees. Different assets of the licensees may earn different rates of return even if they provide the same service and have the same risk characteristics. While the RBI rate may distantly reflect the risk-free cost of borrowing, the 2% and 5% premiums charged above the RBI rate have no direct relationship to the risk nature of electricity assets. The rate of return on assets acquired before 1956 is fixed at an arbitrary value of 7%, which does not reflect the costs of capital.

Furthermore, the Sixth Schedule's allowed rate of return is on the original cost of assets only.

The Sixth Schedule allows the licensees to recover the costs of borrowing, but the allowed return on equity may feel to be inadequate. The licensees can expense interest payments on a portion of their debt, leaving them with the obligation to pay shareholders and interest on the remaining portion of the debt from the allowed return. Evidence from the Indian capital market suggests, however, that this return does not appropriately compensate the equity holders for the risk of their investment.

Comparison of Interest Rates in India (as of February 5, 1999)

Type of Asset	**Interest Rate**
RBI Rate	9%
Prime Lending Rate	12.75% - 13%
I.D.B.I. Rate	14%
Yield-to–Maturity on a 10+ year Government of India T-Bill	11.5% - 12.9%
Yield-to–Maturity on State Government securities	12.2% - 12.9%
Allowed Rate of Return under the Sixth Schedule - assets acquired before 1956 - assets acquired between 1956 and 1991 - assets acquired after 1991	 7% 11% 14%
Estimated Return on Equity in Electricity Distribution in India	18% - 20%

The table above illustrates that the allowed rates of return on assets acquired before 1991 are below the costs of capital. The rates of return of 7% and 11% allowed on assets acquired before 1991 are even lower than the long-term cost of borrowing for the government and the primary commercial establishments in India. This cost currently stands between 12% and 14%. The governments are perceived as relatively risk-free borrowers, because of their ability to raise revenues through taxes. Power sector licensees are, however, somewhat riskier borrowers than the government, because their ability to raise revenues is controlled by the Commission and is affected by many factors outside the licensee's control. Therefore, the licensee's cost of borrowing could be higher than the government's and likely to be around the Prime Lending Rate which, currently stand between 12.75% and 13%.

If investors do not receive adequate compensation for their investment in power sector assets, they will not commit their capital to the sector. Without additional investment in transmission and distribution facilities, it will be impossible to improve the existing situation in the power sector in Haryana. Implementation of plans for reduction of technical losses, installation of meters, improvement of service quality, etc., will be extremely difficult to achieve. As a result, consumers will continue to suffer without hope for improvement in a reasonable time frame.

The Commission needs to decide whether it should continue to use the Sixth Schedule methodology for determination of the allowed return or whether it should depart from it and adopt an alternative approach, such that the goals of the Act are promoted.

Issue 7: ***Should HVPNL's tariff be unbundled so as to identify separately the bulk supply, transmission, retail supply, and distribution portions of any charges?***

Bundled tariffs are those in which more than one function is combined in the same charge for service and usually occur because the same entity provides more than one function and simply combines all of its costs into one set of charges per customer, per kWh, per kW, etc. To the degree that pricing for the individual functions can be separated within a monopoly structure, consumers receive clearer signals regarding the costs of the different components of their service with an unbundled tariff structure. However, this information is not useful because they cannot purchase different amounts of the various services, or purchase any of these services from an alternative supplier. Customers may become confused if their bills contain unnecessarily unbundled charges. However, the eventual introduction of competition or privatisation places new significance on unbundled tariffs. Tariffs separated into their functional components inform both consumers and potential investors of the cost and revenue stream attributable to each functional entity.

Presently, while the marginal cost model would separate HVPNL's costs into functional categories, the individual components now are combined into a single retail tariff. As disaggregation and privatisation of distribution approaches, however, it will become increasingly valuable to investors to be able to estimate the revenue stream for the functional entity that interests them and, thereby, the value of the underlying asset. From that estimation, the investor will be able to assess whether, given the expertise he will bring to the transaction, the enterprise is or can be made a profitable one.

The conditions of HVPNL licensees require HVPNL to unbundle the costs of transmission and bulk supply from the costs of distribution and retail supply. It is unclear, however, what degree of unbundling the Commission should adopt, given the upcoming incorporation and privatisation of distribution entities. The Commission considers the following two alternatives.

Alternative 1

HVPNL shall prepare and file separate tariffs for bulk supply, transmission, retail supply, and distribution functions. This approach would fully unbundle HVPNL’s functions and give an important price signal to potential investors in distribution entities in Haryana. However, it is questionable whether such a degree of unbundling will be feasible and implementable in the upcoming period. At the same time, retail consumers will not be able to utilise price signals of unbundled retail (distribution and retail supply) tariffs, because the implementation of the model of retail competition in Haryana is not feasible at present.

Alternative 2

HVPNL shall prepare and file separate tariffs for transmission and bulk supply, and a bundled tariff for retail supply and distribution. This approach would unbundle functions that are most likely to be used separately by entities in the power sector in Haryana. A bulk supply tariff will serve both future distribution entities as well as other potential buyers of bulk power. A transmission tariff will be used by other SEBs and large industrial users to wheel power through HVPNL’s transmission network. Finally, a retail tariff comprising retail supply and distribution will be used by final consumers served by distribution entities.

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<u>Issue 8:</u> ***How will licensee revenue requirements be assigned to service classes/tariff schedules?***

After the total revenue requirements of the regulated entity are determined, it is necessary to distribute the total load to the various classes of service, and to tariff schedules within those classes. This distribution can be done with or without a basis in cost in the following three options:

a) social tariff making

b) embedded cost-based tariffs

c) marginal cost-based tariffs

To some extent, it is also possible to combine the options. For example, total revenue requirement can be allocated to service classes on the basis of embedded costs, with tariff structures within a service class based on marginal cost relationships, and adjustments made to achieve social objectives.

<u>Option A</u>

An assignment to classes and schedules without reference to costs can be referred to as social tariff making. In this methodology, social policy objectives determine the level of revenues from each class and there is no relationship between the costs a customer imposes on the system to provide electricity and the price the customer pays. For example, the objective to provide free power to agriculture will lead to a zero tariff to agricultural users. The cost of this measure, however, will have to be recovered from external sources, such as the government's budget. Otherwise, the cost would be recovered from other users, which would lead to cross-subsidies and all negative consequences mentioned in Issue No. 2. The inefficiencies inherent in the social tariff making method are very substantial, and ultimately in conflict with the Act and the Commission's assigned goals. .

<u>Option B</u>

The embedded cost methodology determines tariffs based on embedded or historic costs of the utility. This method assigns revenue responsibility using the results of a cost study based on an allocation to each tariff of the historic, embedded costs of the utility. In such an exercise, a test year's revenue requirement is allocated to classes of service or tariff schedules based on an assortment of allocation factors. These factors can be based on the contributions of the classes to the total demand on the peak day of the utility, the kilowatt-hours purchased by each class as a percent of total sales, the number of customers in the class as well as many other factors and combinations thereof. The benefits and shortfalls of this methodology are described in Option A of Issue No. 2.

Option C

The most economically efficient assignment of the utility's revenue requirement is the use of marginal costs as the basis for class revenue development. This is done by determining what the revenue realisation would be if marginal costs were charged as prices to each class and then comparing the total to the revenue requirement of the utility. Almost certainly the two totals will differ, but it is possible to adjust the allocations and close this revenue gap in such a way as to minimise damage to efficiency. The benefits and shortfalls of tariffs based on the marginal costs plus the efficient share of the revenue gap are described in Option C of Issue No. 2.

In the coming period, the Commission will need to decide on what basis it will allocate costs and design tariffs of the licensees. The Commission requires the licensees to work out and submit both the embedded cost study and the marginal cost study. Both studies can be used for development of tariffs. Implementation of any cost-based methodology may involve rationalisation of tariff schedules and tariff structures if the existing ones do not correctly reflect cost characteristics of the licensees. Licensees will be expected to propose changes in levels, class definitions, structure, or other parameters of tariffs in order to encourage efficiency and economic use of resources.

Issue 9: ***If cost variations warrant them and metering is cost-effective, should seasonal and time-of-use tariffs be instituted for wholesale and retail sales?***

The marginal cost analysis of HVPNL (Volume IV of the Recommended Reform Program, 1995, produced by the National Economic Research Associates) indicated that seasonal cost differences are currently large enough to warrant seasonally-differentiated prices for electricity at both the bulk and retail levels. Such a change in pricing policy would increase the efficient use of electricity in HVPNL's service territory. NERA's marginal cost analysis also found that sufficient differences exist in the cost of power across the hours of the day to warrant the institution of time-differentiated prices for bulk service and retail service to very large industrial customers, where meters are already in place. The advisability of instituting time-of-use (TOU) tariffs for retail service in a large scale depends upon the cost-effectiveness of the special meters, not currently in place, that would be needed to make such pricing possible.

As previously noted, prices for electricity that reflect differences in cost as much as possible, are usually more efficient, and that rule applies equally to differences related to time as to geography. This is particularly true in the case of seasonal and TOU tariffs.

It is desirable that seasonal tariffs are instituted as soon as possible. Similarly, TOU tariffs are desirable for large customers where adequate metering exists for this purpose. Other large customers should be put on TOU tariffs as soon as adequate meters can be provided. The Commission will review proposals from HVPNL and other parties regarding the timing and the nature of introduction of seasonal tariffs for all consumers and TOU tariffs for large consumers, and steps required for the introduction of TOU tariffs for other large consumers.

Issue 10: ***Licensees to institute a system of accounts using recognised accounting standards***

The licensees have to adopt a proper system of accounts and accounting procedures that will allow detailed and accurate financial, cost, and consumption data on their operations to be developed. In addition, the licensees must develop proper techniques to measure power losses, supply interruptions, voltage and frequency variations and other parameters of power supply. These data lie at the heart of the Commission's ability to regulate effectively the tariffs of all Haryana licensees.

In addition to their importance to the establishment of effective regulation of tariffs, these data are important to the privatization process in another way. All potential purchasers of portions of the existing HVPNL system must be able both to understand the regulatory method under which they will have to operate and to assess the financial viability of the entity involved in order to establish a bid for the entity. Absent this knowledge, their bids may be lower than they would otherwise be leading to a lower overall recovery by the Government for the system.

The Commission believes that, over the long term, it will not be able to fulfill its responsibilities under the Act properly without the appropriate data from the licensees.

The Commission contemplates setting out a system of accounts or accounting procedures for the licensees pursuant to Section 22 of the Act by issuing regulations and guidelines that will implement Condition 8 of the both the Transmission & Bulk Supply and the Distribution & Retail Supply licences. In addition, the Commission intends to exercise its considerable influence over the licensees, particularly through tariff relief, to give the licensees incentives to develop the data required to implement such systems.