POWER SECTOR REFORMS AND ITS IMPACT ON POWER TARIFF - AN EXPERIENCE OF ANDHRA PRADESH

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DECLARATION

I here by declare that the work embodied in this dissertation entitled, **"POWER SECTOR REFORMS AND ITS IMPACT ON POWER TARIFF - AN EXPERIENCE OF ANDHRA PRADESH"** is carried out by me under the supervision of Dr.V.B.N.S.Madduri, Department of Economics, University of Hyderabad is original and this has not been submitted for any degree either in part or full to any other University/Institute.

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This is to certify that the research work completed in this dissertation entitled **"POWER SECTOR REFORMS AND ITS IMPACT ON POWER TARIFF - AN EXPERIENCE OF ANDHRA PRADESH"** has been carried out by Perini Praveena Sri in fulfillment of the requirement for the award of the degree on DOCTOR OF PHILOSOPHY in Economics under my supervision. This thesis or a part thereof is not been submitted for any other degree at this University or any other University/Institute to the best of my knowledge.

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—Perini Praveena Sri.

TO

.MY BELOVED PARENTS.

&

……**BROTHER**…..

CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF GRAPHS

APPENDIX

A.8.1 Gross Domestic Product at Factor Cost, Sector wise at 1980-81 Prices, India

A.8.2 Gross Domestic Product at Factor Cost, Sector wise Shares, India

A.8.3 Consumer wise Electricity Sales (MKWH), India

A.8.4 Number of Consumers of Electricity (MILLION), India

A.8.5 Percapita Consumption of Electricity (KWH), India

A.8.6 Transmission and Distribution Lines (KM), India

A.8.7 Plant Load Factor and Auxiliary Consumption %. India

A.8.8 Transmission and Distribution Losses as a Percentage of availability in SEB's.

A.8.9 Cost Structure of State Electricity Boards (PAISE PER KWH), India

A.8.10 Commercial Profit / Loss (without subsidy) (Rs. Crores), India

A.8.11 Effective Subsidy For Agricultural Consumers (Rs. Crores), India

A.8.12 Subsidy for Domestic Consumers (Rs. Crores), India

A. 10.1 Power TarifTProjections for Rayalaseema Thermal Project Stage II (2 X210 MW) at 80% PLF for a Life Period OF 30 Years

A. 10.2 Power TarifTProjections for Rayalaseema Thermal Project Stage II (2 X210 MW) at 80% PLF for a Life Period of 30 YEARS (with cost escalation)

A. 10.3 Power Tariff Projections for Spectrum Power Generation Limited Stage I (208 MW) AT 68.5% PLF for a Life Period of 18 Years

A. 10.4 Power Tariff Projections for Spectrum Power Generation Limited Stage I (208 MW) at 68.5% PLF for a Life Period of 18 Years (with cost escalation)

A. 10.5 Power Tariff Projections for Spectrum Power Generation Limited Stage II (208 M W) AT 95% PLF for a Life Period of 18 Years

A. 10.6 Power Tariff Projections for Spectrum Power Generation Limited Stage II (208 M W) at 95% PLF for a Life Period of 18 Years (with cost escalation)

A. 10.7 Power Tariff Projections for GVK Jegurupadu Gas based Plant (216 MW) at 80% PLF for a Life Period of 15 Years

A. 10.8 Power Tariff Projections for GVK Jegurupadu Gas based Plant (216 MW) at 80% PLF for a Life Period of 15 Years

CHAPTER I

INTRODUCTION

1.0 INTRODUCTION

Power is a vital energy input for the economic development of any country and reforms have become an absolute necessity to keep the Electricity Supply Industry growing. For nearly a century in all countries the entire power industry scene in the world has undergone a significant transformation. Obviously all this has resulted from the most essential infrastructural requirement i.e. power requirement in today's world that is, the power requirement for residential customers, agricultural customers, industrial or commercial customers. In the transition from traditional regulated monopoly Electricity Supply Industry to modern deregulated Electricity Supply Industry, competition is more effective than regulation in promoting private sector participation through massive investments and efficiency in Electricity Supply Industry has increased sharply. But the potential for this kind of industry reform will vary by country- depending on whether the system is Government owned, investor owned or under mixed ownership. To realize the potential objectives of restructuring in most countries in terms of lower electricity costs for consumers, improve the efficiency of power system, recover the State Electricity Board losses, voltage fluctuations, system reliability, obligations relating to safety, supply and stability, reassurance to both consumers and investors in terms of tariff rate and fair rate of return, application of power models which are of competitive nature and largely self regulating, coordinating Electricity Supply through co-operation and negotiation can indicate better performance. For this the solutions are of three main types:

a) The power industry may be entirely public owned and thus subject to direct political control.

(b) The power industry may be entirely private but regulated explicitly or implicitly.

(c) The power industry may be mixed system in which the power sector is implicitly controlled by the potential of the remaining publicly owned system.

1.1 RESTRUCTURING OF POWER INDUSTRY

Due **to** restructuring of power sector India has made great strides. The investment has shown a sharp increase from **Rs.12** billion in **1951-56** to Rs.902 billion in 1997-2002. Commensurately electricity-generation capacity increased from 3400 MW in the First Plan to 120000 MW. There is a requirement of additional generation capacity of about 142000 MW over the 15 years covered by the Eighth, Ninth and Tenth Plans. This **indicates** that power sector is becoming energy intensive and capital intensive over a period of time in recent years. To minimize the gap between demand and supply, radical reforms in power sector are required. The per capita electricity consumption should increase by **10%** to achieve 7% to 8% growth in Gross domestic product in the country.

There was a global financing problem. The demand for electricity increased sharply after World War II in most of the countries. Until the oil shocks of the **1970's** and growing fear about nuclear power, the public criticism of power sector was muted. In developing countries the Electricity supply industry was almost invariably state controlled and its performance was frequently unimpressive particularly when high inflation followed the oil shocks of the **1970's.** Despite excess demand, prices hovered below long-run marginal costs and the rate of return fell so that profits could not finance needed investments. In 1991 only 60 percent of power sector costs covered by revenues, self-financing ratio's fell to only 12 percent of investment requirements. The developed countries have been motivated by the need to keep the industry efficient and competitive. Various economists like Bernard **Tenenbam** et **al** (1992), Mario **Zenteno(1995),** Don D Jordan(1995), Michael Weiner et **al(1995),** Hyman(1995),Chitru S Fernando et al (1990), Ahmed **Farqui(1996), Kwoka(1996)** emphasized the reasons for reform trend in ESI in both developed and developing counties. Electricity reform programmes have separated the distribution of electricity from the generation and transmission of electricity. The event of this varied across the World Economists like Bernard **Tenenbaum(1992),** Chitru S Fernando et **al(1996),** Paul L **Joskow(1997)** and Hunt & Shuttle **worth(1998)** have evolved and analyzed various models based on basically three models. They can be classified into : a) Competitive bidding (for new capacity additions) b) Wheeling (whole **sale/retail)** c)Pooling. They have analyzed them with examples from recent United States, United Kingdom & European experiences. Fundamental power sector reform was proposed as the solution which demonstrated the importance and feasibility of restructuring the industry

In many developed countries like USA, UK, Norway, Sweden, Finland, Colombia, Poland, Japan etc there is a strict separation between transmission and distribution on one hand and supply activities on the other. Transmission and distribution are provided by regulated monopolies and there is a central system operator for the short term stability of the system. On the generation side, hourly production plants are in effect, determined a spot market place where whole sale buyers and sellers trade electricity and hourly prices are determined. On the basis of bids they construct aggregate demand and supply schedules for each hour and compute the market clearing prices. With respect to transmission point tariffs are used . This means that at each location there is a given price per unit of power fed into the transmission system and this power independent of the location of the buyer of that power. In USA whole sale competition or supply refers to competition to sell electricity that will be resold to retail customers. Outside USA, it is referred as competition in generation. Retail wheeling is defined as competition to sell electricity to industrial, commercial, residential and end user customers. In Europe Wheeling is usually referred to as third party access It encompasses both whole sale and retail competition. Pooling refers to a formalized agreement between interconnected companies to utilize their power systems as far as to achieve specific common goals. There pooling arrangements are essential precondition to buy and sell all surplus power to and from pool members which can be exchanged with benefits to both parties that is the buyer can save money by buying and the seller can earn a profit. Electricity pools are now in operation in England & Wales, Norway, **Argentina,** Australia, Spain, Alberta(Canada), Chile and others.

There has been a lot of controversy about which of these models is the best one to pursue and also how they might be combined effectively. There are reasonable differences of opinion about how best to create an efficient competitive electricity market that properly reflects all of the physical complexities of electric power networks. In all models of restructuring electricity industry, the firms own and operate both competitive assets (generation) and regulated monopoly assets (transmission). The first approach involves structural separation of G, T & D by creating separate transmission companies through vertical divestiture of generating plants. This is structure in England & Wales, Norway & Argentina, The second approach would require functional separation of G, T & D within existing vertically integrated firms. That is separating the regulated & competitive portions of the firms into separate divisions with separate cost accounting. The third approach is a half way house between the first two. Many other economists like Richard Gilbert(1996), Richard Abdoo(1995), Zbigniew(1998), T. Doudiet(1995), Larry E. Ruff(1996) and Augusto and others have also evolved and analyzed various models based on above basic models. Different countries follow different models and different strategies in different places. Developers tried to recognize that there is no fixed model for privatization. For a developing country like India it is useful to review the experiences of some of the countries that have been successful in reforming the power sector, before evolving appropriate policy measures and strategies for restructuring Indian ESI. The restructuring of ESI has involved reforms in both policies and institutions to create markets and encourage competition in feasible activities. This involved institutional reforms to unbundled G,T & D ending the role of statutory monopolies. Privatization and corporatization of important segments of the industry has called for evolving a proper regulatory authority to regulate prices & monitor competition. If one wants to manage transition in the Indian electricity sector from the present monopolistic public sector to a competitive industry then we have to adopt an integrated approach towards reforms. This approach will help in achieving efficiency in the electricity sector and reducing the cost of electricity to end use customers. (V. Ranganathan et al 1998).

There are several studies which analyzed electricity pricing pattern in power industry. Economists advocate if unbundling of ESI is done properly cream-skimming, adverse selection and associated waste and inequities can be mitigated. Economists like Mohan MunaSinghe and Jeremy Warford(1982), Cicchetti, Gillen & Smolensky(1977), H.R. Outhred et al(1988), Surinder Kumar(1985), Caramanis , Bonn and Scheweppe(1998) and N.S.S. Arokia Swamy(1982) are of the opinion that the price should be related to the marginal cost of supply . This suggests that removing inequities by relating prices more closely to costs is a benefit in its own right or for reasons of allocative efficiency. They considered marginal **pricing** efficient in the sense that it reflects future costs that do not depend on or past management of companies and thus enables consumers to evaluate their future needs. In addition since marginal costs are equivalent to market prices in a competitive economy, the optimum operation of a power system is automatically achieved when there are several generation companies operating on the same system, even when the operating decisions are decentralized. Each power plant increases its output until its marginal cost equals that of the system. Financial equilibrium is attained when the electric system is optimally adapted to the demand, that is when demand is met at minimum cost and capacity matches demand. In this way marginal pricing induces efficiency on the part of producers and consumers and thus constitutes the most logical choice from an economic point of view. But according to Turvey & Anderson **(1997),** G.P. **Keshava(1990)** and Peter G. **Soldatos(1991)** the price should be related to the real costs of fuel are noted that the celebrated theories of marginal cost pricing or average cost pricing are beset with many limitations concerning, particularly the aspect of cost allocation and they have given rise to a very extensive controversy among economists. During decades of experience and practice, however the least controversial design of the rate structure for electricity utility services has been found to be based on what has been called differential pricing. There should be more emphasis on the application of the principles of economic efficiency.

1.2 HYPOTHESIS ESTABLISHED FROM THE EXISTING LITERATURE

The following set of hypothesis has been drawn based on the literature existed in the area of research.

(1) Unbundling of Electricity Supply Industry allows competition to effectively take place of regulation in generation. Independent generators will be actively competing in setting the price.

(2) Vertical de-integration creates competitive pressures at stages where entry is feasible and results in overall improvements in efficiency sufficient to offset the inefficiencies of transactions through the network.

(3) Vertical de-integration is also hindering cross-subsidization and makes **pricing** more transparent.

(4) Restructuring also puts competitive pressure on fuel supply industries, costly fuels such as coal and nuclear are replaced by gas, prices may rise as subsidies to capital and fuel are removed.

(5) In many countries efforts to privatize electric utilities to reduce public debt have been hampered by low tariffs and unsatisfactory regulation.

1.3 DATA BASE

For the purpose of present study it under takes a comprehensive and detailed analysis of power sector in India and Andhra Pradesh. The study collected data from secondary sources. It also collected data from different published, unpublished and project works. The present data concentrated on Andhra Pradesh power data. The study considered the time period from 1993-94 to 1999-2000. In some other occasions data analysis was also undertaken for other time periods to get clarity in the subject matter concerned.

1.4 OBJECTIVES OF THE STUDY

The studies analyzed so far is to **find** out guidelines for power sector in Andhra Pradesh. The study has concentrated at micro level. The study has focused at macro level by analyzing All India data. The following are the objectives:

(1) To indicate directions for reforms in pricing policies to promote private sector participation in Electricity Supply Industry.

(2) To adopt strategies like telescopic structure of domestic tariff, competitive tariffs and demand side management techniques to achieve the two conflicting objectives fiscal and welfare. The fiscal objectives emphasize fair return on capital investment where as welfare objectives imply maximization of public interest.

(3) To calculate the power tariff in case of coal based power plants and gas based power plants in pro-restructuring and in the process of restructuring in Andhra Pradesh.

(4) Compare the two different tariff streams in case of coal based and gas based power plants.

(5) To analyze the impact of tariff fluctuations for a life period of 30 years in case of coal based project and 18 and 15 years in case of gas based projects.

(6) To identify the economic implications of restructuring Andhra Pradesh State Electricity Board.

1.5 HYPOTHESIS TO BE TESTED

The hypothesis consists of establishing a relationship between unbundling of Electricity Supply Industry which allows competition to take place in generation segment of ESI. In several studies it was highlighted that there is a direct relationship between restructuring of power sector and competition in generation segment. It implies that due to unbundling of ESI or Vertical De-integration creates competitive pressures in generation side and results in private sector participation. This will be tested in the present study, with respect to selected five case studies in Andhra Pradesh. This is to test the relative competitiveness of coal based and natural gas based power plants by taking in to account factors such as fixed and variable costs.

1.6 METHODOLOGY

The units of measurement used in this study are Installed capacity in (MW), Plant load factor in (Hrs/ year), Net Generation (Million Units), Fixed charges in (Rs.Crores), Variable charges i.e., Cost of fuel (Rs.Crores) and power tariff in (paise per kwhr). The power tariff in coal and natural gas based projects was estimated to identify the role of restructuring in power Industry of Andhra Pradesh.(APGENCO).

The study examined five case studies for computation of power tariff namely Rayalaseema Thermal power Station- Stage I (2x210 MW)—A coal based project (pro-privatisation period), Rayalaseema Thermal power station—Stage II (2x210MW)—A coal based project (privatization Period), Spectrum power generation Limited Stage I (208 MW)—A natural gas based project (Privatisation Period), Spectrum power generation Limited Stage II (208 MW)—A natural gas based project (Privatisation Period),GVK Gas power plant StageII (216 MW)—A natural gas based project (Privatisation period). These examples are worked out to explain the tariff calculation and for the appreciation of the problems. It should be the endeavour to peg the tariff at a level of US cents or around Rs.2.55 Paise per KWH which is considered fair to both the players. The selection of these case studies for the present study has been undertaken on the basis of the available fixed costs and **variable** costs which reflect the nature of power tariff in all **five** case studies.

In case study I (Rayalaseema Thermal power **station-stage-I (2x210MW)-** A coal based project (pro-privatization period) the cost of generation (i.e. power tariff) has been estimated with certain assumptions. Based on the assumptions the power tariff is calculated which is not a competitive tariff compared to other four case studies.

FIRST PROPOSAL

In case study II Rayalaseema Thermal power station **StageII (2x210** MW)- **Stage-II** -A coal based project (privatization) in collaboration with Chinese government company which will commission two units by 2004. Here the power tariff is calculated as per CEA guidelines. For making the power sector more market driven only the parameters having impact on the tariff in the succeeding years have been evaluated. The power tariff in case study II has been calculated and is considered as competitive tariff. The power tariff projections for a life period (Coal based project) of 30 years have been calculated by assuming Constant Economics based on **Techno-Economic** Clearance. The parameters used in variable expenses are assumed to be constant and the parameters in fixed expenses that is Return on Equity is to be maintained at 16%, should recover Operation and maintenance costs (2.5%), depreciation (7.84%) are maintained same through out 30 years where as the loan repayment schedule and interest loan computation are made. As return on equity, depreciation, operation and maintenance are recovered the power tariff is considered competitive tariff in Stagell unlike in **StageI** Rayalaseema Thermal power station. For the remaining four case studies also where there is private participation and the fixed charges are recovered by maintaining return on equity at 16%, depreciation (7.84%), Operation and maintenance (2.5%) the power tariffs are considered competitive tariffs. The projections of power tariffs in case of natural gas based **projects—spectrum** power generation limited at 68.5% PLF and Spectrum power generation Limited at

95.0% PLF for a life period of 18 years in Stage I and 18 years in stage II, GVK Gas power plant Stage II at 80% PLF for a life period of 15 years are made by assuming Constant Economics based on Techno-Economic Clearance.

SECOND PROPOSAL

The power tariff projections for a life period (Coal based project) of 30 years have been calculated by assuming cost escalation based on Techno-Economic Clearance. The parameters used in variable expenses are assumed to be increased in terms of increase in 6 % of fuel cost and the parameters in fixed expenses that is Return on Equity is to be maintained at 16%, should recover Operation and maintenance costs increased by 6 %, depreciation (7.84%), loan repayment with foreign exchange escalation (6.68%), total loan interest with foreign exchange escalation (6.68%) are maintained through out 30 years RTPP Stage II. The projections of power tariffs in case of natural gas based projects—spectrum power generation limited at 68.5% PLF and Spectrum power generation Limited at 95.0% PLF for a life period of 18 years in Stage I and 18 years in stage II, GVK Gas power plant Stage II at 80% PLF for a life period of 15 years are made by assuming escalation in parameters of fixed costs and variable costs as per CEA guide lines.

1.7 NATURE OF THE PRESENT STUDY

The present study has been divided in to 12 chapters. The first chapter provides a general introduction to the existing problem and other methodological aspects. The second chapter deals with link between energy efficiency and electricity. The third chapter emphasis is on characteristics of electric utility as an economic justification. The fourth chapter deals with cost structure of Electricity Supply Industry in which it analyzes the marginal cost of electricity analysis in coal based power plants, hydro electric plants and mixed hydro thermal systems. The fifth chapter deals with reasons for restructuring in Electricity Supply Industry in various countries and its importance. The sixth and seventh chapter concentrates on restructuring experiences of various power models used in different countries in the World and in particular, India and also discusses the theoretical aspects of electricity pricing and controversial views of various economists which helps to find the core problem of power pricing (Energy). The eight and ninth chapters examines the restructuring of Electricity Supply Industry with Indian Experience and reform trend in Andhra Pradesh power industry, which provides an overall view of power trends in All India and with respect to Andhra Pradesh. The tenth chapter estimates the power tariff in five case studies with the aid of cost analysis. The eleventh chapter makes a equilibrium analysis in Electricity Supply Industry with the help of data and graphs. The final chapter provides summary and conclusions of study along with policy recommendations.

CHAPTER II
ELECTRICITY

2.0 INTRODUCTION

Electricity is a uniquely valuable form of energy, offering unmatched precision and control in application as well as efficiency. Certain other energy forms can meet the need more efficiently than electricity but they are limited in their range of application. Electricity can help to alleviate many of the concerns facing the world, today in a unique manner such as:

a) It is available from various sources at a reasonable cost
b) Its versatility allows it to be readily converted into easily and efficiently usable form.
c) Its efficiency at the end use comes from its versatility.

2.1 THE LINK BETWEEN ELECTRICITY, ENERGY EFFICIENCY, AND ECONOMICS

Electricity, energy efficiency and economics are inextricably linked. In order to reduce the demand for electricity one approach would be to use electricity wisely and introduce efficiency in end use. Today, the world still needs to consume energy prudently, since electricity increasingly drives productivity and innovation. The conservation ethic of coming years is energy efficiency. Increasing efficiency at the end use is the key to the long term prosperity of utility customers. Energy efficient technologies also raise productivity and reduce waste.

The net effect of these improvements are:

a) Energy efficiency reduces capital requirements and lowers production costs.
b) Increasing the competitiveness of individual businesses and entire industries.

These advantages spread through out the country, supplying the nation with economic benefits as well as increasing competitiveness in world markets. In addition, increases in energy efficiency offer the most cost effective approach for reducing long term environmental concerns.

2.1.1 Energy efficiency **and** its Link **with** Electricity

Energy efficiency is a measurement of output achieved per unit of energy input. The term often refers to the performance of specific end uses or energy services such as lighting, heating, cooling and motor drives. Because of today's technological advances particularly, in electricity using equipment, all consumers can optimize energy efficiency by replacing, upgrading, or maintaining energy - using equipment. Electricity offers superior energy efficiency. It is the most highly organized form of energy available with 100% of its energy convertible into useful work. The advantages of electricity - used in manufacturing sector are:

- Energy Intensity: Electricity can deliver higher temperatures and greater intensity than fossil fuels.
- Speed of production: Electricity's high energy intensity offers industries greater production output in a shorter period of time. This benefit reduces unit costs by spreading the costs of labour, overhead and interest on capital over a larger production volume.
- Precise **Control:** Electricity can be more precisely controlled than conventional thermal processes. It can be applied at defined points, for specific periods of time and in exact amounts.
- Cleanliness: Electricity is clean at the point of use. It involves no fumes or residues which can damage materials being processed.
- Flexible generation base: Electricity can be generated from a variety of fuels as well as by renewable resources. As a result it provides a more flexible generation base than conventional combustion equipment.

2.1.2 The Economics of Energy Efficiency

Economics plays crucial role in energy efficiency policy. Since, energy prices and capital costs both affect the level of energy use. In turn the demand for electricity depends on three economics-based factors - the level of economic activity, the prices of electricity when compared with alternative energy forms, and the availability of high quality and efficient electricity consuming technologies. Each of these inter related factors determines the return on investment of conservation and of investments in new energy efficient technologies. The return on investment in energy efficient technologies is highest, when energy prices are relatively high and capital costs are relatively low. High energy prices provide the financial incentive to use existing energy equipment in a more efficient manner through greater maintenance or increased use. Return on investment is relatively high when both energy prices and capital costs are moderately high. Under these conditions consumers have a substantial incentive to invest in low cost efficiency measures.

They also make new, more energy efficient equipment more economically attractive when both energy prices and capital costs are relatively low, the return on investment drops. Under these conditions, businesses usually have little financial incentive to focus on energy efficiency measures.

There may be some times efficiency drops. This raises concerns about long term competitiveness in electricity supply industry Clark W. Ceilings (1994). Economists cite a number of factors that contribute to this decline:

a) Shifts from a manufacturing dominated to service dominated economy.
b) Inadequate levels of investments in new plant, new equipment, and R & D to support innovation.
c) Deterioration in work effort or a reduction in the traditional work ethic.
d) Government regulations.
e) Management failures.

2.2 ATTRIBUTES OF ELECTICITY

Electricity offers society more than just improved energy efficiency. It has greater value than any other energy source. The inherent value of electricity needs technical innovation. It encompasses 3 dimensions, namely

(a) Technical (b) Economic (c) Resource use.

2.2.1 Technical

Electric powered equipment offers significant advantages when compared with conventional counter parts including reduced energy use, increased productivity and improved product quality, compactness and environmental cleanliness. Electricity's technical attributes included electrical phenomena, input energy density, volumetric energy disposition, controllability and synergistic combinations. Residential appliances, energy systems in buildings, and industrial processes frequently, involve the interaction of energy and matter to modify materials pump refrigerants or fluids or to transform them from one form to another.

Electrical Phenomena: Three types of electrical phenomena can be involved in these transformation. They are electro motive, electro thermal and electrolytic. These phenomena are all unique to electricity as an energy form and contribute to its form value. Electromotive phenomena occur when mechanical motion is produced using electricity in materials processing. It can exert force with out physical contact permitting precise manufacturing of metal parts by rapidly accelerating them against a form. Electro thermal phenomena employs electricity to produce heat which in turn facilitates a physical or chemical change. Both the phenomena bring a change in the processing industries (eg. chemical, primary, metal stone, clay, glass, paper and petroleum etc.).

Input Energy density: In combustion processes using chemical **fuels.** Eg., Oil and gas, the maximum achievable temperature is thermodynamically limited to about 3000°F where as for fossil fuels there is no inherent thermodynamic limit on the temperature.

Volumetric energy deposition: Using Electro thermal phenomena when, fossil fuels are used to heat material heat it imposes surface radiation. This is slow and inefficient with induction heating, electrical energy is deposited directly within the material. The process can be reduced to several minutes or less. This process improves over all productivity, product yield, and product quality.

Controllability: Electricity is often referred to as an orderly form of energy. This reference means that electrical processes can be controlled more precisely than thermal processes. Since, electricity has no inertia, an industry can instantly vary energy input in response to process conditions such as, material temperature, moisture content or chemical composition as well as accurately maintain a desired state.

Synergetic combinations: In some processes electrical, electro thermal, and electro motive effects combine in an advantageous way.

2.2.2 ECONOMIC

Economic attributes include fixed cost, flexibility of raw material base and product quality and yield.

- **Fixed cost:** High energy density and precise control typically result in increased production rates. In most cases these reduce fixed costs per unit of product. For example, components such as labour, overhead, and interest on capital are spread over a larger production volume. Thus even when the cost premium of electricity increases the energy cost per unit, total production cost per unit, may remain lower.
- **Flexibility of raw material base:** Compared to conventional process, the electro technologies have a greater degree of flexibility with regard to raw material resources.

2.2.3 RESOURCE USE

It includes flexibility of fuel supply, domestic resource balance of payments and national security, environmental and energy consumption.

- **Flexibility of fuel supply:** The combustion based process is highly dependent on the availability of specific fuel sources. But the shift to electrically based processes assigns, responsibility for fuel choices to the electric utility.
- **Domestic resources balance of payment and national security:** Total resource requirements and the need for imported fossil fuels, declines with the increased

use of electricity due to the overall efficiency of electrically based **systems.** As these imports decline, the impact on balance of payments declines.

> **Environmental:** Electric processes and systems are the most environmentally benign at the point of end use. The application of electro technologies can mitigate the adverse environmental impacts in applications. Thus, electricity becomes the environmentally preferred energy form due to its efficiency at the point of end use.

> **Primary Energy consumption:** The primary energy consumption is always higher for electrical processes than conventionally fueled system. Historically energy intensity has declined as use of electricity has declined.

Thus restructuring of Electricity Supply Industry (ESI) plays a crucial role in curtailing the drop in economic efficiency. Therefore electricity is a key energy source in the modern economic chain. Electric utilities improve the productive capacity of any economy by improving economic efficiency. With out continuing improvement in ESI, the economic efficiency in the country cannot sustain economic growth.

2.3 SUMMARY

This chapter highlighted electricity as an important input in Indian Economy. The relationship between electricity, energy efficiency, and economics are highlighted. It is clear from the attributes of electricity that, electricity's utility is diverse and it facilitates the achievement of many more needs. One should be aware of the role of electricity in Indian economy, especially with respect to adoption of restructuring in Electricity Supply Industry (ESI) which reflect the dynamic improvements.

CHAPTER HI

ECONOMICS OF ELECTRICITY

3.0 INTRODUCTION

Electric utility is a special type of business organization and its economic characteristics differ from those of other industries. The most important factor which distinguishes electric utility services from the general business is that a competitive market for them is neither desirable nor feasible. However monopolistic production of a commodity is a evil because production under monopoly is usually less than the optimum, because marginal cost is not equal to marginal revenue which is the condition of equilibrium. But in monopoly, marginal revenue is less than price. This fact often comes into conflict with other objectives of the social optimization of resource allocation and a reasonable price structure for the consumers which can be ensured only in the competitive market. Government regulation has been adopted as a substitute for competition in the market for electric utility services.

3.1 ECONOMIC CHARACTERISTICS OF ELECTRICITY

The most important features of electricity market are:

(i) It is not a primary energy source but is derived by transforming a range of sources such as coal, natural gas, wood, petroleum, bio-gas, water pressure, fissile elements, wind and sun.

(ii) It is economically impossible to store electricity in significant quantities, since demand fluctuates sharply over time.

(iii) It can be transmitted over long distances and regional benefit spill over.

(iv) The components of electricity supply industry (ESI); generation, transmission and distribution requires technologically advanced and capital intensive infrastructure International Energy Agency, 1994. This special treatment and protection to ESI which prevailed until 1970s, rested on the fact that markets fail to secure efficient and stable supply due to inherent attributes of electric energy referred to above Atkinson and Stiglitz (1980).

3.1.1 NATURAL MONOPOLY

John Stuart Mill was the first economist to recognize the principle of natural monopoly. The ESI was considered a natural monopoly due to economies of scale in power generation resulting in declining long run average costs. Govinda Rao et al (1998). There are number of utility companies supplying the same service in the same area before electric utilities came to be recognized as natural monopolies. There is a need to achieve monopoly control over prices and economies of lower cost by eliminating costly duplication of overhead investment. For example if more than one electric utility operates then, each organization will have to erect its separates poles, lay under ground circuits and cables and install machinery and equipment in separate sets for each. This gives rise to unnecessary duplication of investment. Competition in electric utility industry imposes a special problem such as price is not equal to marginal cost, marginal revenue is below the marginal cost. Choudhury R K, (1986).

The economic justification for electric utility regulation arose out of the assertion that electric utilities are natural monopolies Penner (1997). According to the original theory, a natural monopoly means that a single firm is the lowest cost means of supplying a single area with a product or service loosely known as electric power. If a market is a natural monopoly, the theory goes that, competition in such market will lead to excessive instability. This follows some what intuitively from the fact that "economies of scale" reduce costs as output increases. In such a competitive race for increased market share, rivarly will result in price wars that leave only a single surviving monopoly. This turmoil can be avoided by granting an exclusive license to sell and ask the monopolist to sell without discrimination or excess profit. Recent developments in economic theory cast doubts on the existence of a natural monopoly in electric utilities and question the rationale for having statutory monopoly and traditional methods of regulation. Baumol et.al, (1977, 1982) argues that the existence of natural monopoly alone does not necessarily warrant statutory monopoly status for an industry. Some economists argued from the beginning that electric utilities were not really natural monopolies. However in the mainstream there was little disagreement that all three segments of the industry and thus the industry as a whole were a natural monopoly during the first few decades. Later by 1970s many argued that economies of scale in power generation had come to an end, while transmission and distribution remained natural monopolies. Now most observers believe that the generation stage of power industry has lost enough of its economies of scale to qualify for deregulation. Finally, economist Walter **Primeax,** noted that the economic literature concerning natural monopoly presents no standard definition of the theory. Various economists specified different conditions for such a monopoly to exist.

Researchers found that a new cost conditions called sub-additive costs rather than declining average costs or economies of scale was the proper condition establishing a natural monopoly. An industry has sub-additive costs if it is cheaper from one **firm** to supply all of one product to open market place. Costs need not be declining as output goes up for any firms in the market, which was the old requirement for natural monopoly. It is suspected that power generation no longer has economies of sale. Interestingly the few researchers who have studied this question have concluded that generation may still be sub additive today even though economies of scale have flattened out. Other evidence concerning the growth of average plant and unit size is also inconclusive. As a result there is a lack of formal economic proof of the fact that the era of natural monopoly is over in the generation portion of the industry. Nonetheless there is a wide spread agreement that in the generation stage of industry, competition is preferable to price regulation.

3.1.2 DECREASING COST INDUSTRY

Electric utilities are decreasing cost firms whose costs are largely fixed with respect to services consumed. They require heavy initial investment in plant and machinery. The cost structure of electric utilities are dominated by elements of constant costs. For a constant plant size, cost relating to depreciation, interest amortization, property taxes, insurance, dividends on capital stock are constant in character. Therefore as out put increases in electric utilities, the average unit cost of production has a tendency to decline. Moreover, the benefit of decreasing cost industry is greater in electric utility as it is a natural monopoly that has the advantage of supplying its services in the entire market. The reason for realizing lower average cost by electric utilities is the diversified demand for services. In the absence of competition, the market size of electric utility service is bigger. It is less possible that the maximum demand of different customer classes will coincide. Diversity of demand means that the maximum level of demand of different consumers or consumer classes occur at different points of time. Due to this diversity, the volume of the supply of services required at a point of time is considerably reduced. Hence, to serve the systems peak demand, smaller plant capacity is required with greater diversity of demand, while a larger plant capacity will be necessary if the diversity is limited. Electric utilities have access to such economies of greater diversity.

In earlier days the power is used in a limited purview the curves are static i.e. timeless. But however real utility systems are a composite of facilities of various vintages. With the increasing needs of power, the utility system planners are continually expanding their stock of equipment. The cost curves are continually shifting in time. Under the following grounds the electric power industry may be said to be one of increasing costs.

a) Change in fuel prices with change in technology and also with each change in the policies of regulatory agencies.

b) Particular plants may exhibit cost characteristics that increase as output increases. But utilities are not mere aggregates of individual plants, they are systems of complex and inter-related. Generating plants are only part of the system. Enormous parts of the system are comprised of distribution facilities, the costs of which, in large part, are not marginal cost at all. In the sense that they do not vary with the load on the system.

In this aspect of utility it is decreasing not increasing marginal costs. There is a second sense in which the electric power industry may be said to be one of increasing costs. In recent years, the costs of generating plants and fuel have increased rapidly.

3.1.3 NON-STORABILITY

A peculiar **characteristic** of electric utility service is that it cannot be stored and hence the question of larger amount of production than what is demanded does not arise. An electric service must be produced and delivered as it is demanded. This means that the capacity of each piece of capital equipment (power stations, transmission lines, transformers etc.) is determined by the highest demand which that particular piece of equipment is expected to have to meet at any given moment.

3.1.4 WIDE FLUCTUATIONS IN DEMAND

One of the most important **characteristics** of the demand for electric utility services is their wide periodic fluctuations. The patterns of fluctuation may be daily, weekly or seasonal. The maximum aggregate demand for services at a particular time period is called the peak demand. In developed countries electric utilities may expect annual peak demand during winter when more energy is used for both heating and lighting for long hours, since the days are shorter and nights longer. Therefore, the plant capacity of electric utility must be sufficiently large in size to able to serve the peak demand expected in any year.

The price elasticity of demand for utility services may be sharply different among different customer classes. It is highly elastic for some uses and relatively inelastic for some other uses. For example, the demand for the same service as an industrial fuel is highly elastic because, fuel constitutes a very important element in the cost structure, and because the industrial user is generally highly equipped to switch over to other substitutes like oil or coal or electric power.

3.1.5 PRACTICE OF DIFFERENTIAL PRICING

The economic distinctions in the areas of inter-group demand characteristics use difference in utility services, diversity factor, timings of demand etc. are reflected in the pricing of electric utilities, which follow a practice of price discrimination between customer classes. Thus, the prices charged for the electric service used for lighting are different from the prices charged when the power is used for industrial purpose. By asking those who create peak demands for services to pay more heavily, electric utilities encourage the consumers to shift their demand to off-peak periods in order to secure the economy of reduced plant capacity and decline in the average cost of production. The policy of differential pricing helps the electric utility to earn higher revenues by increasing sales and to achieve the maximum utilization of plant capacity as well.

3.1.6 PRICE REGULATION

Price determination of electric utilities is distinctly different from that of a monopoly. Therefore, electric utilities are required to submit proposals of rate schedules that are expected to raise the revenue amount approved. The regulatory agency may approve the rate schedules as proposed, if they are justified or it may amend them, if necessary before allowing a electric utility to fix prices for its services. It should be noted that the reasonable approved prices are regulated in such a manner that, the electric utility, with prudent and economic management can earn the required revenues as allowed by the regulatory agency.

3.1.7 LOW CAPITAL TURNOVER RATIO

The electric utilities has the lowest capital turn over ratio because of its limited revenue potential on the one hand and the requirements of exceptionally large capital investment on the other. There are electricity services which require a number of years of operation before they can attain a capital turn over ratio of 10 i.e., before revenue equals capital investment, while the manufacturing group of industries can earn an annual revenue which is more than double the amount of the capital investment.

From the standpoint of economic thinking, because of specific characteristics of ESI, there is an increasing intervention by the state in the ESI Turkson (1998).

3.2 SUMMARY

This chapter dealt with a special type of industry, called electricity with its distinguished economic characteristics, based on the fact that they supply an indispensable service under monopoly conditions, with government regulation of prices, profits and service quality. Some economists questioned the existence or implementation of natural monopoly in ESI and preferred competition to achieve the results in the form of reasonable prices or rates, reasonable profits and adequate service quality.

CHAPTER IV

COST STRUCTURE OF ELECTRICITY

4.0 INTRODUCTION

The availability of adequate energy resources at a reasonable cost is a vital **pre-condition** for continued economic progress and the power sector in particular is acknowledged as an engine of growth. Unlike other forms of energy the power costs and its pricing are closely tied up with several complicated factors. The proper appreciation would enable the power supplies to deliver it with least cost and the users to utilize it economically and efficiently.

H.S. Houthakker (1951) and Jyothi Parikh **et.al** (1994) divided the cost of electricity supply into following categories in order to see how the circumstances affect tariff policy.

- Capacity costs: If there is a need for extra demand during peak time, it requires not only generation of extra energy but also extra capacity. Hence, the total marginal cost of supply during peak time includes marginal generation capacity costs in addition to marginal energy costs. Thus the marginal capacity costs are the investments in capacity addition in generation, transmission and distribution needed to supply additional kilowatts.
- Avoided energy costs: These include fuel costs and the costs of transporting the fuel where as the running costs include energy related costs and operation and maintenance costs. These costs should be adjusted for loss factors during transmission and distribution and also for auxiliary consumption. Since the operation of power plant varies with the time of day and season, it is better to estimate avoided energy costs according to various rating periods.
- Peak avoided energy costs: During this time an increase in demand would be met by increased generation from peaking hydro plants and gas turbine plants. These costs are the opportunity costs of hydro energy output demand not served.
- Consumer costs: They are the function of the number and type of consumer. They include the cost of meter accounts.

> Residual Costs: They are relatively small item in practice comprising some expenses of management etc.

4.1 MARGINAL ANALYSIS OF COST IN ELECTRICITY INDUSTRY

A frame work is developed by MunaSinghe(1982), Mitchell, Manning Acton (1978), Cichetti, Smolensky (1977), Surinder Kumar (1985) and Peter G.Soldatos (1991) for the estimation of electric system marginal cost. Three broad categories of marginal costs may be identified for the long run marginal cost calculations such as: (a) capacity costs (b) energy costs (c) consumer costs.

4.1.1 ESTIMATION OF LONG RUN MARGINAL COST IN THERMAL POWER PLANTS

4.1.1 (A) Marginal Capacity Costs:

Munasinghe(1982) considers a typical system annual Load duration curve for the starting year zero divided in to two rating periods, peak and off peak. Mitchell, Manning Acton (1978) also considers typical daily load curve in which there is a substantial difference between minimum and maximum demand, the optimal system will consist of a mix of base load, cycling and peaking. As demand grows over time, the load duration curve increase in size and the resultant forecast of peak demand given by the curve D, starting from the initial value MWo.

The long run marginal cost curve of capacity (C) - change in system capacity costs associated with a sustained increment K in the long run peak demand. This is shown by a shaded area in Figure 4.1 (a) and broken line D+A D in (b).Then the LRMC of generation

= C / A D. In theory D can be either positive or negative. (i.e. both increments and decrements should be considered symmetrically). If many such values of C/A D are computed, an average of this yield LRMC.

He says that for expanding generation and to meet the new incremental load would normally consist of advancing the commissioning date of a future plant or inserting new units such as gas turbines or peaking hydro units.

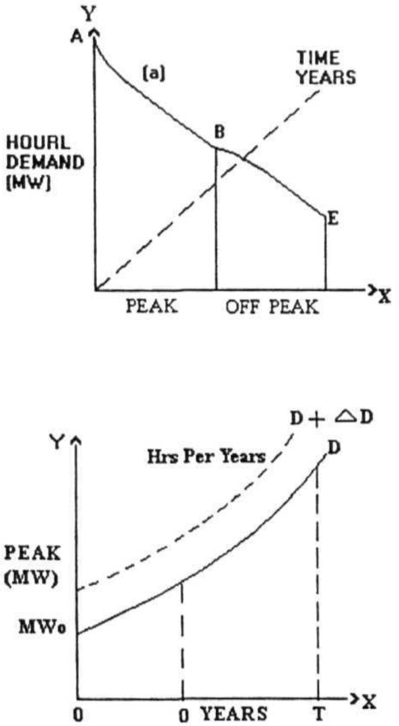


Figure 4.1 GAS TURBINE AND PEAKING LOAD

Suppose gas turbines are used for peaking. Then the required LRMC of generating capacity may be approximated by the cost of saving from delaying 1 **kw** of gas turbine. This may be estimated by the cost of a kilowatt installed, annuitized over the expected life time and adjusted for the reserve margin and appropriate percentage loss typically caused by station use. In this simple model all capacity costs are charged to peak period consumers. Therefore, if the capacity costs of base load generating units are to be included in the calculations, it is important to net out potential fuel savings resulting from the displacement of less efficient plant by these new base load units. From a practical point of view it is clear that if peak period consumers are incorrectly charged the high capacity costs of expensive base load units such as nuclear plants may encourage them to install their own gas turbine plants. Next, the LRMC of transmission and distribution is calculated. According to Surinder kumar (1985) three alternate methods of estimating marginal cost have been advocated. These are (a) long run incremental cost (LRIC) method. (b)Present worth of incremental system cost (PWISC) method. (C) Average incremental cost (AIC). The methods differ primarily in the way marginal capacity cost has been computed. At year k the capacity cost may be redefined in terms of the next capital investment to be made. This method suffers from certain serious defects. For example if the investment takes place every year, marginal capacity cost will vary with new investments. Thus the estimates of marginal cost will fluctuate. The simplest approach is to use the average incremental cost method to estimate the LRMC of T&D (relative to the previous year) and investment cost respectively. In the average incremental cost method the actual additional increments of demand are considered as they occur, rather than the hypothetical increment method which also yield similar results. An alternative method of determining marginal T&D costs at different voltage levels would be to use historical data to fit regression equations. According to Mitchell (1978) in all thermal— the marginal generating cost during

(a) daily variation— extreme

(b) Seasonal---small

(c) peak period- A few hours daily

4.1.1 (B) MARGINAL ENERGY COSTS

The LRMC of energy during the peak period will be the running costs of machines to be used last in the merit order to meet the incremental peak kilowatt hours corresponding to the demand increment D. In this simple model it is fuel and operating costs of gas turbines. These costs have to be adjusted by appropriate peak loss factors at each voltage level in the same way as applied to marginal capacity costs. The LRMC for off peak energy corresponding to a load increment during the off peak period would usually be the running costs of the least efficient base load plant used during this period. This would correspond to the minimization of operating costs over several pricing periods rather than on an hourly basis. The loss factors for adjusting off peak costs will be smaller than the loss factors for the peak period. Thus the LRMC analysis at the generation, transmission and distribution levels helps to establish whether these incremental costs are excessive because of over investment, high losses or both.

4.1.2 ESTIMATION OF LONG RUN MARGINAL COSTS IN HYDRO ELECTRIC PLANTS

Here seasonal variations in LRMC are particularly important. Munasinghe (1982) presents the analysis of all hydro electric system with the following assumptions.

(1) The operation of an entire multi-reservoir, multi-plant system is modeled in terms of equivalent single composite reservoir.

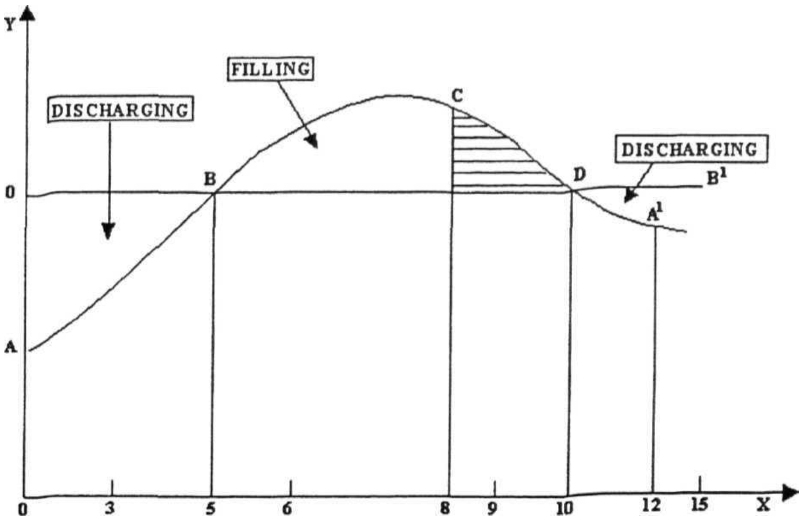
(2)The system is analyzed for one year. For example, long run capacity costs represented by annuitized investment costs.

(3) Expected values of water inflows and out flows are used and the effects of uncertainty are ignored.

According to Mitchell (1978) one important advantage in hydroelectric plants is they can with hold the release of water until a later hour. So it can store electricity costlessly over the course of a day.

(A) MARGINAL CAPACITY COSTS AND ENERGY COSTS

In an hydro system, the LRMC of generating capacity incurred during the peak period would be based on the cost of increasing peaking capability that is additional turbines, penstocks, expansion of the power house and so on. He depicts the typical annual flow of water into and out of the lumped equivalent reservoir.



MONTHS
LUMPED EQUIVALENT RESERUOIR

IFIOURE *AT*

- From month 0 to 5 (dry season)- reservoir is being discharged and the water required for generation exceeds the inflow. Therefore, from the point A to B the reservoir is being constantly depleted, until at point B the reservoir will be at its lowest level.

~ From months 5 to 10 (wet **season)--** water inflow from the catchment area exceeds the desired out flow.

The reservoir fills up, consequently between points Band C.

— In month 8, the reservoir is full and excess water is spilled, since the net flow is still positive even after the daily generation requirements have been fully **satisfied.** i.e., at point C.

~ At point D spilling ceases and the onset of the dry season again requires a steady draw-down of the reservoir between months **10** and **12.** After point A, the annual cycle is again repeated.

Long run marginal costs of power are incurred as in case of all the thermal system when additional generating capacity in peak period is needed to meet a sustained increment in peak period demand. When significant spilling of water occurs for example, during wet season-long run marginal energy costs during this period is essentially zero usually involving operation and maintenance costs only.

If the system is capacity **constrained--During** peak period

Wet season—capacity costs

Dry season— capacity and energy costs.

During off peak period

Wet season — none

Dry **season--** energy

If the system is energy **constrained--** Total incremental costs required to supply additional

According to Mitchell **(1978)** in all **Hydro--the** marginal generating cost

(a) Daily variation- none

(b)Seasonal--pronounced

(c)Peak **period--** All hours of dry season or dry hours.

4.1.3 ESTIMATION OF MARGINAL COSTS IN A MIXED HYDRO-THERMAL SYSTEMS

Muna Singhe (1982) says that its estimation depends critically on the mix of generating plants used at different times. The mixed thermal-hydro electric systems are common in United States and in many parts of Europe. As compared with the patterns of costs in all-thermal systems, in a mixed marginal costs are highest for a longer daily period but the variation in the level of marginal generating costs over the course of the day is more limited. According to Mitchell in all **Thermal-Hydro-the** marginal generating cost

(a) Daily variation— moderate

(b)Seasonal— moderate

(c) Peak period—A long daily period.

The division of generating systems i.e., all- thermal, all hydro electric and mixed thermal-hydro electric cases provides a qualitative indication of the pattern of marginal generating costs in each type of system.

In addition to this Mitchell (1978) is of the view that although capital costs often constitute the greatest portion of the total costs of producing electricity, the cost of labor and the cost of fuel consumed are also important. Moreover, the technology available for producing electricity makes it possible to choose one of several different mixes of capital, labour, and fuel to produce the same quantity of electricity. He supposed that only three basic generating technologies are available- a base load (for example nuclear or coal) plant with an annual capital cost of C_1 per kW of capacity and a constant running cost of r_1 per kw of electricity generated. An intermediate plant (For instance Oil fired) with some what lower capital costs C_2 but higher running costs r_2; and a peaking plant (say a gas turbine)with lowest capital costs C3 and the greatest running cost r_3. In figure 4.3(a) each straight line represents the total annual cost per kilowatt of capacity of constructing and operating a plant of one type for any number of hours during the year. The vertical intercept gives the annual fixed cost per kw of capacity, while the slope is equal to the running cost per kwh. From an examination of the curve it is clear that the three technologies that are available will always have the lowest total cost of supplying electricity for a given number of hours per year. It is supported by Cichetti, Smolensky (1977).

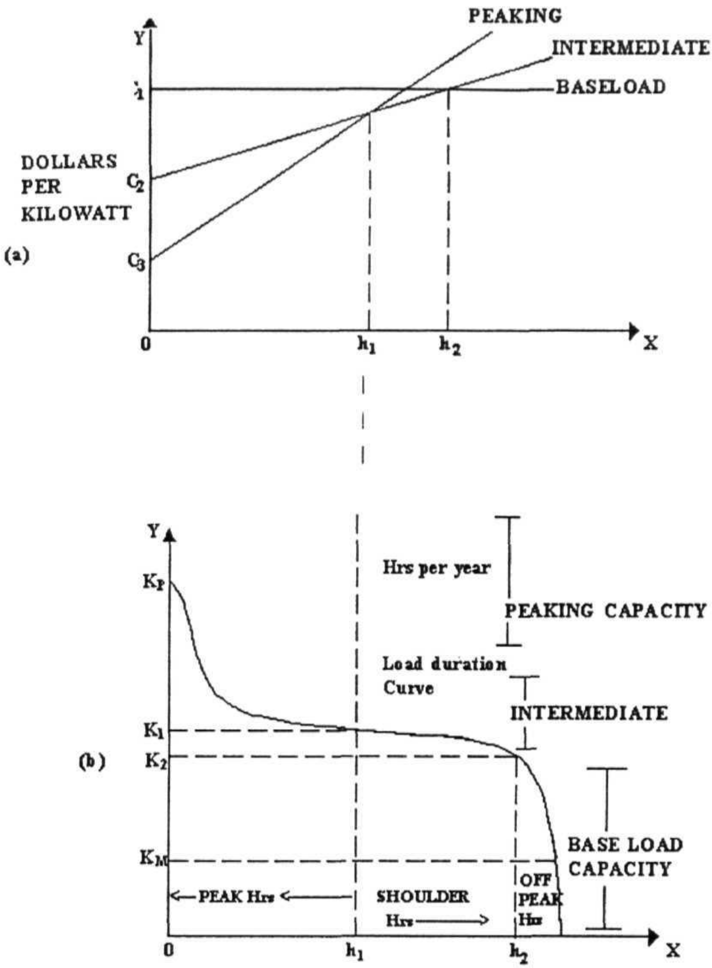


FIGURE 4.3 (a) & (b)

A SIMPLE MODEL WITH THREE TECHNOLOGIES

For example if the consumption of electricity exceeds h_2 hours per year power can be supplied most cheaply by a base load plant. The desirability of employing a combination of different types of generating plants is due to the fact that the amount of electricity demanded is not constant.

Figure 4.3(b) shows the amount of electricity demanded for different lengths of time, measured in number of hours per year. This graph termed as the load duration curve can be derived from each of the daily load curve through out the year. It indicates for example that the annual peak load of k_p kilowatts will occur for only a very few hours and that the minimum load K_m occurs every hour of the year. Combining the information in both the diagrams we can see that the least costly method of satisfying demands of h_2 or more hours per hour is to use a base load plant, with k2 kilowatts that last between h_1 and h_2 hours per year; the intermediate plant is least costly to build and operate. Incremental loads of this duration is total (k_1-k_2) kwh. And the optimal amount of peaking capacity to service loads of less than h_1 hours is (k_p-k_1).

This representation of a power system is highly simplified. Despite its simplicity the model provided a key insight in to economics of electricity supply. In its investment strategy the typical utility will construct a mix of base load, intermediate and peaking generating units to minimize the total costs of meeting its customer loads. And in daily operation of the power system the dispatcher will minimize the short run operating costs of meeting hourly loads by using first the unit (base load) unit with lowest running cost and then adding units in order of their fuel efficiencies.

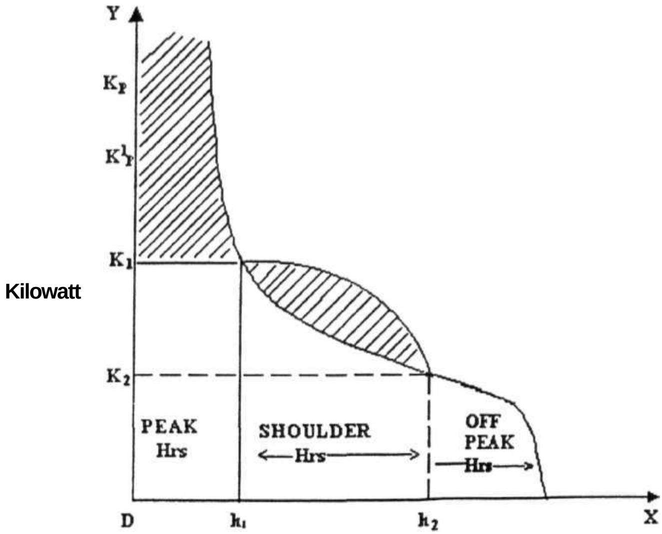


FIGURE 4.4

LOAD SHIFT FROM PEAK TO SHOULDER HOURS

A reduction in the peak load of the system from k_p to k_p' in figure 4.4 accompanied by a shift of some of that load to hours when there is lower demand, will reduce the total costs. As an illustration suppose that the load is shifted to hours of the year when the total load does not exceed k_1 in figure 4.4. This shifted load is represented by the shaded area. Two types of cost savings result.

The first is due to an increase in short run operating efficiency achieved, when the shifted kilowatt hours are generated by more efficient intermediate generating unit that, require less fuel than a peaking plant. The cost savings per kwh is equal to $(r_3\text{-}r_2)$, the difference in the running costs of a peaking plant which is exactly the difference between the short run marginal cost of generating electricity in the two periods.

The second type of cost saving will be realized from modifications of the utility's construction schedule. Over time a permanent shift in the system load will permit the utility to alter its mix of generating units, in this illustration by reducing its peaking unit capacity and enabling it to save on capital costs. The total saving in both running and capital costs represents the reduction in short run marginal cost.

The simple model also makes clear that the marginal cost of supplying additional electricity will generally vary with the level of system demand. In this model; the year can be divided in to a peak **period.** (the h_1 hours when demand exceeds k_1); the shoulder period (the h_2-h_1 hours when demand is greater than k_2 but less than k_1) and the off peak period (hours between demand is less than k_2). The short run marginal cost of generating added power in these periods are r_3, r_2, and r_1 respectively. According to him the distinction between the generating cost and distribution cost cannot always be sharply drawn. In fact the capacity of high voltage transmission lines that interconnect power plants and large areas of consumption, closely related to the capacity requirements for generation. Few customers are served directly from these lines. For this reason the costs of transmission are usually analyzed as a component of the costs of generating it.

The author Peter. G.Soldatos (1991) comments that in the field of energy economics estimating the real costs of fuels is essential for the appraisal of economic viability of the various energy technologies. This can be done by number of ways. Some of the methodologies used are:

(A) Long run average incremental cost

It is the per kwh cost of generation, transmission and distribution of electricity for the planning period (say) T years, all discounted at a discount rate I.

(B) Detailed long term energy models

They are optimization or simulation models in which shadow prices reflect the real cost of fuels. Such models should ideally cover not only the electricity sector but the whole energy sector and they are usually very complex and cumbersome to work with.

(C) **Back of** envelope **calculations:**

Calculations based on marginal plant. They range from simple and rough calculations to more detailed analyses. Here the author seeks the estimation of the real or marginal cost of electricity by identifying and adding up its real cost components (fuel, generation, transmission and distribution). Besides it concentrates on cost of rural electricity. i.e. the cost of electricity delivered to rural region, which are situated away from high concentration areas and where each kwh is more costly to supply.

(D) **Screening curve analysis:**

This kind of analysis gives a good indication of the merit order and load rating periods of the system as well as rough estimation of the marginal cost of electricity at each of the rating period.

For this he assumes a system consisting of three types of stations (peak, cycling and base)with different economic parameters.

Type of plant

	Peaking		Cycling		Base load
Running cost \$/kwh					
	V_1	>	V_2	>	V_3
Annuitized capital cost \$ kw/year	C_1	<	C_2	<	C_3

Where V_1 is the running cost of the peaking plant, V_2 is the running cost of cycling plant, V_3 is the running cost of base load plant and C_1, C_2, C_3 are capital costs.

(E) **Approximately long run marginal costs**

With the help of total cost function it is possible to approximate the Long run marginal cost of peak, intermediate and base load electricity. This marginal cost is by definition equal to the change in total cost ATC due to a small change in electricity demand sustained in to future.

(F) **Peak load electricity cost**

Assume a sustained increase in peak load electricity demand equal to 1 **kw** or h_1 **kwh/year.** The optimal long run system response will be an increase of its peak capacity (k_1) by one kw to reach the level of (k_1+1).

The total system cost will increase by:

$$\Delta TC = c_1 + h_1 v_1 \ \$$$

which is equal to the marginal cost of increasing demand by 1 kw.

The cost of the peak kwh can be found by dividing by the number of hours this piece of capacity operate per year, i.e.

Marginal cost of the peak kwh = $c_1/h_1 + v_1$ \$ /kwh

It shows that the cost of peak load electricity is the sum of running cost plus it share of the capital cost of a peaking plant.

(G) Intermediate load electricity cost:

Now assume a sustained increase of 1 kw in intermediate load demand. The long run system response will be either to operate existing peaking capacity of 1kw for h_2 more hours per year and cover the increased demand or install new cycling capacity 1kw and operate it for (h_1+h_2) hours per year in order to generate the additional electricity demanded and at the same time, displace 1kw of peaking capacity which is not needed any more.

The total cost increase TC in the first case will be equal to the running cost of the peaking plant for another h_2 hours per year. i.e. $h_2 v_1$. In the second case Δ TC = \$$h_2 v_2$

Therefore the optimal system response to a small increase in intermediate load electricity demand is the installation of appropriate cycling capacity and displacement of an equal amount of peaking capacity.

The per kwh marginal cost of intermediate load electricity = $h_2 v_2/h_2 = v_2$ \$ / kwh

This does not include a capacity cost including that the cost of intermediate load electricity is nothing but the running cost of a cycling plant. This is because its capacity cost is exactly offset by the running and capacity cost savings due to the displacement of the peaking plant.

(H) Base load electricity cost:

Suppose it is found that the total system cost change due to a sustained increase of 1 **kw** in base load demand then

A TC = h_3v_3

and Marginal cost of base load electricity = h_3v_3/h_3 = $\$v_3$ /kwh

Here again the marginal cost is no more than the running cost of the introduced base load plant because its capital cost is offset by the running cost savings i.e., from running a more efficient base load station and saving from the displacement of an equal size, less efficient cycling plant.

Thus electricity long run marginal cost is calculated as the sum of generation, transmission and distribution capacity costs.

4.2 SUMMARY

This chapter attempted a systematic approach to the computation of long run marginal costs of electricity in thermal, hydro, and mixed(thermal & hydro) systems. The underlying objective is total cost minimization . Different economists distinguished electricity costs into following categories as:

l)Generation capacity cost 2) Transmission capacity cost 3) Distribution capacity cost

which is expressed by different views regarding cost structure of electricity. The first step in the calculation of long run marginal cost is the identification of the marginal plant in each rating period. With in each block, the marginal plant is the plant that would choose to build in order to meet the next demand increment. For a peak load demand service, combustion turbines (CT) of various types are the marginal choice. For intermediate load the marginal plant is an oil or gas fired station. Finally, for base load electricity the marginal plant in most cases is a thermal (coal) station.

CHAPTER V

CONCEPT OF RESTRUCTURING ELECTRICITY SUPPLY INDUSTRY

5.0 INTRODUCTION

Electricity is enormously capital intensive and most countries are becoming increasingly electric intensive as their economic growth depends on the availability of adequate and reliable generating capacity. For nearly a century, in all countries electricity sector has been viewed as a natural monopoly industry, where efficient production of electricity required reliance on public or private monopoly suppliers subject to government regulation of prices, entry, investment, service quality and other aspects of firm behavior. In both developed and developing countries the era of the monolithic regulated, vertically integrated utility has ended. Policy makers advocated breaking up the utility in to components, keeping the parts that are natural monopolies under regulation and turning loose the others in a competitive market Hyman (1995). Four processes are involved in this regard.

a) Restructuring
b) Privatization
c) Deregulation
d) Unbundling

- **Restructuring:** Re organization of the industry, breaking up existing entities, rewriting the rules of regulation, bringing in new owners, selling assets and encouraging private firms to supply services to government owned utilities.
- **Privatization:** Sale of government owned asset or company to private investors.
- **Deregulation:** To remove government rules and controls.
- **Unbundling:** In case of power sector, to determine the costs and benefits it may be useful to break the sector into its component parts to examine which activities are essentially monopolistic and which are of competitive nature.

Unbundling can be done through vertical separation. It refers to break up in the production chain between up stream and down stream activities or between infrastructure and services. In power sector, such unbundling translates into three or more distinct activities namely generation, transmission and **distribution.** Unbundling also takes the form of horizontal separation. **It** means dividing a single activity of incumbent monopolist.

All these prepare the field for liberalization. That is freedom of generation, choice of supply and opening of the grid. After the market opening and introduction of a certain degree of freedom competition can work. This means that appropriate number of operators can interact, and compete, searching for profits and utility maximization. These process increase efficiency and social welfare.

5.1 ELECTRICITY AS A PRODUCT

Three basic processes are required to produce the commodity electricity that is usable by the consumer. They are generation, transmission and distribution. Generation is the process of converting other forms of energy into electricity. It is usually performed by power stations on a very large scale relative to the use of consumers. They are four major methods of undertaking the generation of electricity. 1) Conventional thermal which include coal, oil and natural gas. 2) Nuclear 3) Hydro electric. The other sources are non-conventional like solar, wind, tides, geo thermal, ocean thermal and many others. Transmission consists of taking the electricity generated at the power stations and sending it through wires at high voltage to sub-stations where it is transformed down to the low voltage, ready for distribution through low voltage lines to individual meters, that is consumers.

5.1.1 PROBLAMATIC AREA IN POWER SECTOR:

Many countries in the world experienced problems during the last decade i.e. inefficient and even wasteful use of energy. But in many countries the problem area in the electricity sector had been the performance of the State Electricity Boards which generate and distribute power, set tariffs and collect revenues. The main reason for losses incurred by state electricity boards are reported to be as follows: Absence of equity component in the capital structure of state electricity board, non capitalization of interest during construction of projects in the past, low agricultural **tariff,** non payment of rural electrification subsidy by the state government, in adequate rate of depreciation for adequate generation of internal resources, payment of state electricity duty, high transmission and distribution losses, over staffing, large arrears in revenue collection, time and cost over run in completion of projects, deficiencies in operation and maintenance practices, short comings in voltage and frequency, poor standards of reliability and poor financial returns from the investment in ESI, uneconomic and distortionary pricing in the sector. So it is imperative that a country has to undertake structural adjustment in the economy, by restructuring the ESI, to minimize inefficiencies and short comings.

5.1.2 REASONS FOR REFORM TREND IN ESI:

Various economists emphasized the reasons for reform trend in ESI. The following developments seem to be of importance for the deregulatory reform trend in the ESI.

- Liberalization and integration of markets: Growing competition especially in industrial markets causes cost pressure on the industries, increasing their sensitivity with respect to prices, for electricity as an important productive input factor.

- Deregulation of capital markets: Growing competition between all institution and companies with capital needs for attracting investments causes efficiency pressures on the ESI, as a capital intensive industry. Reorganization and privatization (if state owned) allow third party financing of capital intensive generation or grid infrastructure projects.

- Deregulation of other network industries: Deregulation in other traditionally monopolistic industries with net work characteristics such as telecommunications, railways, air traffic and gas supply gave their customers more choice and increased pressure to re-organize the ESI.

- **Trend towards decentralized electricity generation:** Environmental concerns increased the public interest in decentralized electricity generation based on renewables and combined heat and power. New technologies especially based on gas made decentralized generation are economically attractive. Both trends pushed decentralized generation and increased problems between their operators and the traditional utility, demanding a competitive re-organization of the ESI.

According to the Bernard Tenenbaum et.al (1992) in many less developed countries and newly industrialized countries two broad rationales drive most electricity privatization. That is planning and operational inefficiencies and national debt. Despite these there are political and institutional barriers to privatization in many countries. They are:

a) Economic nationalism which constitute industry and regulatory structures with government control of the key elements of the power system

b) In many countries subsidization poses a major barrier to efficient privatization. In developing countries subsidization especially of consumer prices and in developed countries or economies cross subsidies between consumer classes and subsidies to other industries delay or prevent privatization from achieving their full potential.

c) Bureaucratic opposition from government owned utility management's or labour unions derail privatization initiatives. These two basic rationales for electricity privatization mentioned above are important for making critical decisions in privatization. The state owned electric companies in most Latin American countries are in a precarious situation, financially, technically and administratively. Rates are below costs and costs are beyond reasonable limits due to political interference in investment decisions, over staffing, poor management and exorbitant demands form politically motivated unions. Lack of adequate maintenance and financial restrictions have originated acute shortage in countries like Argentina, Bolivia, Colombia, the Dominican Republic, Jamaica and Mexico. Mario Zenteno (1995) agree that an effective way to remedy this situation is privatization. Don. D. Jordon (1995) also held the similar view that in many countries state owned enterprises such as electric utilities have been big money losers requiring massive subsidies. Being extremely capital intensive they often have burdened governments with crushing debt. According to US Agency for International Development (AID), the electricity requirements of developing and industrialization nations over the decade will amount to a whooping $100 billion a year.

Michael Weiner et. **al** (1995) lists out the confluence of forces responsible for reform trend in developed countries.

- The end of ever-increasing demand and price inelasticity: Since the first oil well was drilled unit costs of oil declined all the way through 1973.Then the Arab embargo ended the era of cheap energy. Later there was a hope that the nuclear industry could bring lowest cost energy. Together these events dashed the prevalent belief that energy prices were inelastic.

- The end of economies of scale in generation: As eventually happens with every technology the electric utility industry ran up against the curve of scale economies. Power generation which comprises mostly capital assets, is basic technology that has changed little in the past 100 years. To meet the burgeoning demand, electric utilities built bigger and bigger power plants. That drove the cost of power down until the late 1960s when unit cost of power went down until the late 1960s. When unit costs of the incremental kilowatt of electricity began increasing, adding a unit of capacity to a traditional power plant raised the average cost of power.

- Large customers asserted choice: In contrast, independent power producers **(IPPs)** emerged as an anomaly of regulation and exploited the economics of small scale technology. In US, in the late 1970s federal regulation permitted co-generation facilities to sell excess power back to the utilities. These facilities proved the economies of scale for smaller scale generation technology. They also spawned a power generation sector independent from the investor owned utilities. In the 1980s IPPs built the majority of new power capacity. This has created competition in the whole sale market. It also has pushed customers and legislators to seek true competition and thus choice in retail market. In other countries, also small producers entered the market. In the United States, large consumers of electricity gained access to their chosen regional power pools has created the possibility of customer choice. All these pressurized for reform trend in ESI.

According to Pierre Gurslain (1997) many economic, political and technological developments combined with severe constraints on public finances have also generated a dual movement of demonopolization and privatization of power sector. Chitru S. Fernando et.al (1996) also asserted that in recent years there were number of developments in ESI . Competition has become increasingly feasible. These changes were technological, regulatory and legislative. In previous days, there were economies of scale. But nowadays the industry faced increasing cost pressures from stiffer environmental regulation. The hope in future that nuclear power industry will supply the low cost base load power disappeared. In addition to this new smaller scale technologies such as co-generation and combined - cycle plants which were more efficient in their use of energy became alternatives to traditional utility generation. Hyman (1995) was also of the view that the expiry of economies of scale in ESI is a contributory force for reform trend in ESI. According to Lennart Hjalmarsson (1996) the reasons for deregulation in Scandinavian countries are the regulation of state owned enterprises which worked less efficiently, Retail distribution productivity growth was slow and large dispersion in productive efficiency among retail distributors. Ahmad Faruqui (1996) also lists out the reasons for the entry of new comers in a traditionally sheltered electric utility.

Rising utility costs: Several factors have caused the rise in costs. It includes a) over capacity brought on by optimistic demand forecasts b) difficulties with nuclear power plants c) environmental problems with coal d) limits on hydro electric power due to the endangered species act and e) exhaustion of the economies of scale that had existed in 1950s and 1960s.

- Changing capital markets: These changes give an edge to project financing. This is used by non utility generators. They have shorter construction times and financing costs are lower.
- Technological changes: With the exhaustion of economies of scale in power production and the success of small gas fired generation, the natural monopoly of utilities ended, on the supply side. According to Kwoka (1996) the reasons for restructuring are network economies, close interdependence between stages of production, persistent monopoly power, atleast in some portions of the industry. All these factors increase the risk and cost of policy errors. A number of exogenous factors such as oil price escalation, abrupt and radical changes in the exchange rate and inflation following the two oil crisis in Japan's electric utilities encouraged reform trend in ESI. It aimed at establishing decentralized power generating units such as co-generation, which might undermine the economies of scale in power service. In addition to it the electric utilities must refrain from exercising monopoly power and cross-subsidization should be avoided.

According to Govinda Rao et.al (1998) the reforms in most of the advanced countries have been motivated by the need to keep the industry efficient and competitive, whereas in developing countries fiscal constraint, particularly the inability to finance large and growing investment from the budgets has also been a major factor. He lists the following reasons to privatize in the developed countries A) the government needs money. This is the simplest motive. Utilities may be largest, most profitable assets owned by the government that can be easily sold, that will produce more cash upon scale. B) the utility system must expand but the government lack the funds to finance the expansion. Once the government sells the system the new owners have to find the capital for the expansion. Why does not the government owned utility raise prices enough to allow it to finance its expansion? This is due to the fact that sometimes the government does not have the political will to raise the price. Other times the budget rules include utility capital expenditure in the total government budget and overall budget constraints limit those expenditures. In either case selling the utility may be easier than raising prices or changing budget rules. C) the government believes that private management is inherently more efficient than a government bureaucracy D) the government desires to built capitalism by encouraging wide spread share ownership E) the government wants to restructure the industry in order to eliminate monopolies and encourage competition between suppliers. Through those measures the government hopes to force the utilities to run more efficiently and to lower prices. The government decides that introducing competition is a better way to control the utilities than by means of heavy handed regulation. As part of the process, the government has to break up the existing state owned monopoly or to introduce new firms in to the business. But the firms all owned by the government might not compete vigorously. The government must sell some or all the industry's assets to private investors in order to introduce competition.

5.2 HINDRANCES TO PRIVATIZATION

In most third world countries state owned electric power utilities are the sole suppliers or are substantially larger than other suppliers if they exist. In addition the functions of generation, transmission and distribution are most often integrated vertically. Both characteristics are hindrances to privatization. Large size gives rise to two problems. First, the capital market may not have sufficient capacity to undertake to purchase the company. Second, excessive concentration of capacity in a single company thwarts competition. Vertical integration mingles different activities. Electricity supply comprises three functions whose marketing needs to be regulated in different ways. **Hyman** (1995) was of the opinion that the governments have contradictory goals and as a result it does not extract the optional result. In order to obtain highest price the government may have to avoid restructuring and should not introduce competition to the industry and should set up a tariff and regulatory system favourable to the utility. Though restructuring might break up monopolies or introduce competition or create an effective regulatory system, these steps reduce the profits of existing utilities. Society might be better off with a restructured utility industry but government treasury will receive less from selling the utility to investors. The government plans to privatize its utility sector, must set the rules to allow them to achieve and prioritize the goals of regulation. In some instances the electric utility sector no longer exhibits the characteristics of natural monopoly as an example: Generation. If that is so then consumers might benefit from the introduction of competition. Making room for competitors where none existed before may require rules that specifically encourage competition. Therefore before privatization the governments in any country who **write** the rules must understand the conflicts between the goals. His view was supported by Mario Zenteno (1995) who said that some characteristics of ESI like capital intensity, long construction periods, price regulation and long periods of capital recovery have often been used to justify public ownership and may now create obstacles to its privatization.

5.3 IMPORTANCE OF LIBERALIZATION

Liberalization is to induct competitive forces in to the economy more specifically, liberalized policies are targeted to increase competition and reduce tariff levels and to obtain efficient outcomes in industry. In a world with out market imperfections and externalities, liberalized markets would lead to a first best pareto optimal situation. But in a second best world of imperfections, it becomes important to trace the implications of these liberalization policies. These liberalized policies can have competitive out comes only in the absence of entry by new firms and allow capacity expansion of incumbent firms.

Liberalization in its broadest sense, is a shift towards decreasing government intervention in economic activity. Two significant forms of intervention have been a) direct state participation in economic activity and governments regulatory role through industrial and trade policies. (Guha, 1990). Liberalization would then denote deregulation - a decrease in government role in resource allocation, production and distribution. Decisions in **the** economy and privatization decrease government's direct participation in economic activity. According to Kruegar (1978) at on end, the spectrum liberalization stands for minimum government activity and at the other end a liberalized market where there are no quantitative restrictions either on buyers or sellers. Since all restrictions are not quantitative, liberalization in a more general sense could be defined as any policy which reduces the restrictiveness of controls - either their complete removal or the replacement of a more restrictive set of controls with less restrictive ones.

Adeloa Adenikinju **(1994)** deregulation is expected to enhance efficiency in two ways

1) The introduction of actual and potential competition would curtail inefficiency.

2) The rent accruing to special interest groups would be competed away.

Wellenious and Stern quoted in Adeola Adenikinju (1994) identify four levels of intensity of deregulation.

1) commercialization and separating operations from the government.
2) Increasing the participation of private enterprises.
3) Restraining monopolies, diversifying supply of services and developing competition, and
4) Shifting government responsibility from ownership and management to policy and regulations

Most deregulations are a mixture of the above four forms. Commercialization is the first level in the deregulation process. Effective commercialization should involve the organizations with complete control over revenue and **pricing,** management and personnel and investment and finance decisions. Any area of restriction on the above would dilute the commercialization process and mitigate against operational efficiency. Further more, commercialization without competition may not solve the deep faceted problems. Similarly privatization without deregulation is just a transfer of monopoly form the public to the private sector. The social welfare function would not be at the maximum in either case.

An international liberalization process is reshaping the whole international electricity industry. Almost all the countries in the world are involved in such a process. It sets common rules for generation, transmission and distribution of electricity. The main points are freedom of generation for new production capacities, freedom to choose the supplier for eligible customers, right of access to transmission and distribution systems. The result of such changes is more competition and more electricity trade among countries, Vincenzo Di Giulio **et.al, (1998)** Four processes are under way, restructuring liberalization, competition and regulation. These four processes are linked and overlap. Restructuring, privatizing, and breaking monopolistic situations prepare the field for liberalization. That is the freedom of generation, free choice of supply and opening of the grid. After the market opening and the introduction of a certain degree of freedom, competition can work. This means that an appropriate number of operators can interact and compete searching for profits and utility maximization. Due to the peculiarities of the energy. The relevance of elements such as security of supply, environmental protection, conditions of access to the grid, has to be regulated by some authority. This creates conditions for efficiency and equity in defense of the public interest.

These processes increase efficiency and social welfare through a number of channels:

a) The introduction of private ownership which removes the political discretion in the management of the electricity industry. Firms in making strategic choices eg. Location, technology, employment should not be influenced by politicians whose targets are linked to the increase and conservation of personal power and unrelated to social welfare.
b) The removal of protections by the government for example barriers to free international trade, funds covering the firms financial losses and the introduction of right system of incentives.
c) The removal of monopolistic revenues and the introduction of the possibility that firms can be expelled by the market.
d) The firms search for lower costs (eg. use of cheap inputs, rationalisation of the productive processes in order to have low prices, increase profits and extend their market share.
e) The firms search for innovation, new processes and best services for the customers in order to obtain competitive advantages.
f) the exploitation of local advantages, that is transfer of the productive plants in regions where the input's prices (eg. fuels, manpower) are lower.
g) The firms search for new markets abroad and the extension of the area of competition.

He assess the effects of liberalization, Reality does not always coincide with the ideal picture and there are increases in social welfare, (Consumers and producers surplus). He presents an unclear situation which is complicated by the effects that competition could have on environment. Competition could eliminate the distortions arising from monopolies and inefficient management of electricity system. Distortions are caused by externalities. Not only prices do not reflect marginal costs, they do not fully incorporate externalities that only damages public health. This means that the correction of distortions induced by competition could be unable to improve the price structure. There are four possible theoretical situations.price structures expressed in the following A, B, C, D categories

A	B	C	D
Inefficiency Marginal costs	Marginal costs	Social Costs Inefficiency Marginal Costs	Social Costs Marginal costs
No internalisation Market distortions	No Internalisation No market Distortions	Internationalisation Market distortions	**Internalisation** No market distortions.

i) Structure A is one in which both the market mechanism and the environment policy are inefficient. This results in a price that incorporates inefficiency. Example: Monopoly but not externalities.

ii) Structure B is a case in which the market distortions are removed but there is no internationalization.

iii) Structure C is the situation in which market distortions still exist but social costs are internationalized.

iv) Structure D is the case in which internationalization occurs and market distortions are removed.

These four cases are theoretical and are not able to represent the complexity of reality. The electric system is either in A or in C or in between them. The key elements in the determination of the final impact on the ESI are the possible elimination of barriers to the diffusion of clean technologies (eg. small plants, co-generation) and renewables, the search for new opportunities and technologies, the removal of subsidies, the diffusion of combined cycle gas turbines. Privatization and deregulation has been part of a global trend which placed great reliance on market forces and less dependence on government intervention in the resource allocation process. The opening of the electricity markets that is a transition from protected to contestable markets will necessitate the structural changes in ESI. Norbert Wohlgmuth (1998) focus towards electricity market deregulation has brought controversy over whether utilities are entitled to compensation for stranded costs. Costs which utilities will not be able to recover due to unforeseen changes in the regulatory frame work of markets in which they operate. Increased competition should be pursued to achieve benefits for consumers such as greater economic efficiency and reduced prices that are not possible and unlikely through regulation. Pollit MG. (1997) offers a review of studies which gives prudent indications. In some cases liberalization gave rise to large positive effects (eg. UK. Chile, Argentina) in other cases the effects are modest (eg. Scandinavia).

According to Pierre Gurslain (1997) the electricity privatization is relatively new and still evolving field in most countries. The direction of the gains will almost be positive. But it depends on the country situation. The explosion of investment needs in the electricity sector World wide. The poor state of public finances in most countries, the rapid growth of large private power companies operating on an international scale and steady break up of activities traditionally regarded as natural monopolies are fundamentally changing the way in which infrastructure services such as electricity are delivered. The entire picture in five, ten or fifteen years will be very different from the present one and will involve greater private sector participation, sharper competition and increase in public welfare following liberalization.

5.4 SUMMARY

This chapter emphasizes the concept of restructuring electricity supply industry. This chapter defined the four processes involved in Electricity Supply Industry and also about various sources of generating electricity. Along with this some other issues like problematic area in power sector, reasons for reforms in Electricity Supply Industry pointed out by various economists both in developed and developing countries and importance of liberalization was examined.

CHAPTER VI

EXPERIENCES WITH RESTRUCTURING

6.0 INTRODUCTION:

This chapter offers the process of Electricity Supply Industry restructuring and its experiences due to Privatization, in different countries in the world. The electric power industry is on the agenda for reform in many countries. Some countries have begun the process by replacing public ownership with private enterprise, full integration of generation, transmission and distribution with disintegration and traditional monopoly regulation with significant elements of competition. But most countries have approached reform of structure and governance of electric utilities with considerable caution. There is a wide spread belief that electric power represents a more difficult set of circumstances (John E. Kwoka, 1996). Network economies, close interdependence between stages of production, persistent monopoly power, atleast in some portion of the industry, and the essential character of electric power to consumers. All these factors increase the risk and the cost of policy errors. Over the past 20 years, privatization has become a standard prescription for improving the performance of enterprises World wide. The motivation varies in detail but there is a rooted belief that public ownership results in cost efficiency, arbitrary pricing and misuse of the enterprise for political purposes. Publicly owned enterprises are not necessarily inefficient nor is their pricing uniformly above some norm. Public enterprise may have an advantage over private ownership where the latter is subject to regulation. The existence of subsidies to publicly owned utilities, achieves lower costs for reasons that go beyond advantages due to subsidies. Simply shifting an enterprise to private status will not necessarily lead to improvements in its performance. One helpful tool in this task is competition Pierre Gurslain (1997). The merits of competition at the generation stage of electric power are well understood, but the role of competition at other stages are limited by cost disadvantages of reduced scale and facilities duplication. In electric industry, restructuring is well suited as it allows competitive forces to operate in generation stage.

6.1. REFORM AIMS

The electric power industry is on the agenda for reform in many countries. Many countries in the world experienced problems during the last decade. In almost every single country vertically integrated monopolies of the power sector were identified as fundamental causes of these problems. As a result to begin reforming the electricity sector, the public monopoly was ended in most countries and incentives for private sector involvement were created. In most countries in reforming their electricity sector, some common objectives are observed. Almost all the countries undertaking restructuring have similar goals in mind.

- Achieving lower electricity costs for consumers and improve the efficiency of the system through increased competition.
- Raising revenues for the treasure through the sale of public assets and their by reducing public borrowing.
- Obtaining necessary capital and technology from abroad, for electricity infrastructure and expansion. The more general efficiency aim is some times specified or supplemented by additional reform aim.
- To objectify the price to be paid for electricity generation of independent power producers. (USA competitive bidding).
- Privatization (England, Chile, Argentina, Portugal developing countries)
- Optimization of utility sizes (Netherlands, Norway)
- To increase spatial integration of investment and operation decisions. (USA - Wheeling).

  Equalization of regional price differentials (Norway, Netherlands)
- To give customers more choice (Norway, England, California)
- To increase the efficiency in the remaining monopolistic grid business (England, New Zealand, Norway, Netherlands.)

These deregulatory measures in ESI are naturally designed to increase the efficiency of electric utilities irrespective of countries. The statement of reform aims should be the starting point of the reform process.

6.2. CHOICE OF REFORM MODEL

Many countries across the world both advanced and developing have attempted to restructure the ESI to subject them to rigor of competition in feasible activities. In most advanced countries the reforms, restructuring/privatization/deregulation/unbundling have been motivated by the need to keep the industry efficient and competitive but for developing countries fiscal constraints, particularly the inability to finance large and growing investment has been a major factor. The restructuring of the electric utility industry which is now underway, consists of creating a universal whole sale power market place in which vertical integration will be effectively eliminated. Restructuring can be viewed in terms of the economic trade off between vertical and horizontal integration and the more extensive use of contracts awarded on the basis of competition . All the distribution systems, whether integrated or not will have to buy from the market place, all generators, whether integrated or not will have to compete, to sell their power and will get paid only, if their offers are among the winners selected list. Basically the models can be classified into:

- competitive bidding (for new capacity additions)
- wheeling (whole sale / retail)
- pool (mandatory / voluntary, access for all parties / co-operative generators).

In USA whole sale competition or supply refers to competition to sell electricity that will be resold to retail customers. The power that is sold may be firm, non-firm or any intermediate degree of firmness. Outside USA, whole sale competition is described as competition in generation. Retail wheeling is a pre-requisite for retail competition. It is defined as competition to sell electricity to industrial, commercial and residential end use customers. In most countries this is known as Franchise or supply competition. In USA wheeling or the unbundled transportation of electricity over high and low voltage lines is typically categorized by the customer that receives the electricity. Outside USA whole sale wheeling is described as wheeling or transmission for generators. The generators could be independent generators or vertically integrated companies selling outside their service territories. In Europe wheeling is usually referred to as third party access (TPA) Stephen Sayer (1996). It encompasses both whole sale and retail sale competition. Power pool agreements are multiparty agreements to change power. Pooling refers to a formalized agreement between interconnected companies to utilize their power systems so far as to achieve specific common goals. These pooling arrangements are essential pre-condition to buy and sell all surplus power to and from pool members which can be exchanged with benefits to both parties that is the buyer can save money by buying and the seller can earn a profit Alex Henney (1995), John Barker (1995). Electricity pools are now in operation in England and Wales, Norway, Australia, Spain, Alberta (Canada) Chile and Argentina and others. Countries aiming at a further competition in retail supply have understood the need for an organized short - term market for electricity, open to both sellers (generators) and buyers (wholesalers and retail customers) of electricity. England and the State of Victoria in Australia are examples for the toughest form of introducing such a markets. Electricity pools can be mandatory (eg. England and Wales) or non-mandatory (eg. Norway) in which case bilateral trade outside the pool is permitted. Longer term contracts between generators and whole salers or customers exclusively have financial characters (hedging contracts).

Norway and Argentina have already introduced, Sweden and some interest groups in California want to introduce a some what weaker form of short term electricity market. Longer term contracts can have the form of both physical delivery contracts and financial hedging contracts. Chile, Portugal and Netherlands have introduced co-operative generators pools aiming at central dispatch and operation cost minimization with a limited form of competition in retail supply. In these systems distributors and final customers are not allowed to buy directly from the operative pool. The models differ in the authorization procedures for new generation capacity ranging from central planning (Netherlands) via tendering procedures for the "public system" and full liberalization for the "Independent System" (Portugal to full liberalization (Chile).

Other groups are arguing for a pure retail wheeling concept with bilateral physical type contracts. In Finland and California there is a discussion whether a pool is necessary for retail competition. But even proponents of a retail wheeling, agree on the need of a transparent market information and the reduction of transaction cost. Portugal proposes the introduction of spot market substitutes like market indices and brokers and argues that the market development should be based on self-organization by market participation rather than on initiation and design by regulatory authorities. For all countries restricting competition to the selection of capacity additions, the competitive bidding concept is naturally the appropriate solution. In many developed countries like USA, UK, Norway, Sweden, Finland, Columbia, Poland etc. there is a strict separation between transmission and distribution on one hand and supply activities on the other. Transmission and distribution services are provided by regulated monopolies and there is a central system operators for the short term stability of the system. In generation side, the hourly production plants are in effect, determined a spot market where wholesale buyers and sellers trade electricity and hourly prices are determined. On the basis of bids they construct aggregate demand and supply schedules for each hour and compute the market clearing prices. With respect to transmission, point tariffs are used. This means that at each location there is a given price per unit of power fed in to the transmission system and this power is independent of the location of the buyer of that power. United States and Japan opted for competition bidding as a voluntary tool and France put forward an European commission reform proposal.

Single Buyer System is characterized by some modifications to the classical competition bidding concept trying to adapt it to EC competition and Internal market legislation. In its Directive proposal the EU commission defines (negotiated third party access system) the aim of introducing retail supply competition but leaves the choice of a reform model to the individual decision of the member states under the principle of subsidiary. Most of the reforms countries have understood the need for a vertical disintegration of competitive (generation supply) and monopolistic functions (transmission and distribution). Countries only introducing competitive bidding for generation capacity additions did not introduce a vertical disintegration of transmission and distribution. This is not necessary because the entry of competitors does not depend on the use of utilities transmission and distribution of infrastructure. The utility as the monopolistic buyer of electricity could exercise market power via discrimination of competitive bids in the tendering procedure. To protect the competitors against this use of monopolistic power the tendering processes is subject to the supervision of regulatory authorities in all countries introducing competitive bidding on a mandatory basis. In countries introducing competition in electricity supply, the vertical disintegration of the monopolistic transmission function is viewed as very important. Most countries have separated the transmission function into an independent countrywide transmission company. The treatment of the monopolistic distribution function differs between the reform countries depending on the degree of competitive opening of the system. Because all countries aim at a competition in generation, the distribution function is either separated or unbundled from new generation.

Countries which aim only at a limited retail competition do not introduce unbundling of distribution and supply because both functions remain to be bundled services. In countries aiming at further reaching competition in retail supply, the vertical disintegration of those services becomes a necessity. Those countries tend to introduce an unbundling of accounts and management instead of the further reaching separation in to different companies. Because of standard cost and tariff calculation techniques and the indifference of load flows in the distribution grid with respect to the choice of a supplier it is much more difficult for the regional distributor to discriminate competitors in supply. In contrast to models introducing only competitive bidding, the French single buyer system proposal also foresees wheeling transactions (for exports by IPPS (independent power producers)) and special whole sale import trading arrangements (between the network operator as single buyer and eligible customers). This means that some competitive mechanism depend on the monopolistic transmission function and the monopolistic procurement **function** outside the control of a tender procedure (valuation of own and purchased generation). This makes a vertical disintegration more important. The proposal therefore proposes an unbundling between generation, transmission and distribution.

6.2.1 FINANCIAL ASPECT

Different countries follow different models and different strategies in different places. Capital infrastructure problems exist. All countries need more energy and there is not enough money to fund these projects even with international help and direct loan. (David L Haug 1995). In many countries both developing and developed privatization and foreign investments are very popular. Developers need to recognize that there is no fixed model for privatization. The basic models are:

a) all facilities privatized at the same time generation, transmission and distribution.

b) Just generation only, not transmission.

c) Only new generation.

d) Sell electricity on wholesale verses retail level. Argentina adopted a radical privatization and U.K. moderate privatization via share offering. A number of countries are adopting the gradual approach - privatizing new generation only. Guatemala, Philippines and Dominican Republic, south east Asia, central America and Eastern European countries. James T. Doudiet (1995) was also of the view that there is no model to follow or experience to show how to combine the concepts of electric operations with competition. In spite of these he explores the financial significance of the changes occurring in the electric utility industry and suggests strategies that will be appropriate for electric companies to pursue in a competitive market.

In a monopoly the financial goal is to increase the wealth of common shareholders by earning a market return on an increasing book value base. Market share is assured by monopoly franchise. This is a viable financial growth strategy because the monopoly provides assured capital access. With the product (kwhr) priced to recover cost, the investor is confident his return will be earned and he is eager to invest great amounts of capital cash flow as a part of financial strategy. But the movement to competition changes the foundation principle on which the financial structure and strategy of electric industry is built. In a regulated monopoly the product is priced to recover its cost including financial cost. Where as in a competitive market the product price is not related to its cost. The recovery of financial cost is not assured. This demarcation alters everything else. Doudiet (1995) also mentions a list of financial concepts with less capital access selling a commodity product in a competitive market in the way of:

a) Costs must be reduced.
b) Cash flow is important, but it should be used wisely.
c) Fixed costs are not desirable
d) Long term commitments should be avoided.

As capital recovery is not assured in a competitive frame work, the investor has less confidence in financial returns. In a monopoly the debt levels must be replaced with equity because without assured cost recovery lenders will be less willing to invest and because debt service is a fixed cost. A competitive commodity business tries to diminish all fixed costs. With poorer capital access, cash flow must become the central theme of financial strategy. In a competitive electric company there is a greater percentage of common equity. The total amount of cash can be devoted to pay financial costs but it is not used as, cash is used for other uses. Unlike in monopoly, in competitive markets depreciation periods will be shortened and investments in plant were written off. Companies will replace old facilities with new and lower cost technologies. New investments will be determined on a cash pay back basis with appropriate recognition of contribution of an operation to fixed or variable costs. If once costs are diminished, then substituting variable costs for fixed costs will take on strategic importance. Similarly, long terms fixed price contracts will be replaced with a series of short term contracts making fixed costs mimic variable costs. So there is a need for new cost accounting systems, so that costs can be unbundled and matched with pricing strategies.

COMPARISON OF ELECTRICITY MODEL STRUCTURES

Chitru S. Frenando et.al (1996) opts a options based market model to an electric utility. He assumes it operating in a stochastic environment. The utility could either be a conventional vertically integrated utility or a power pool which buys and sells power. The utility is also assumed to be based at a single local region of a power network with the capability to buy and sell power through interconnections. The utility faces demand from various sources.

a) consumers in the local region (it means consumers who have bought call options from the utility to consume power).

b) Wheeling contracts which the utility may have sold to wheel power to consumers through the transmission grid. In similar manner, the utility has two supply-side options.

c) Electricity generated by generator located in the utility's local region.

d) Wheeling contracts which the utility may have purchased for wheeling power into the local region through transmission network. Finally the utility will meet demand by optimally calling off this portfolio of supply and demand side option contracts.

Fernando (1996) illustrates each of these options and the utility's optimal port folio contracts to generate, transmit or interrupt in figure 6.1

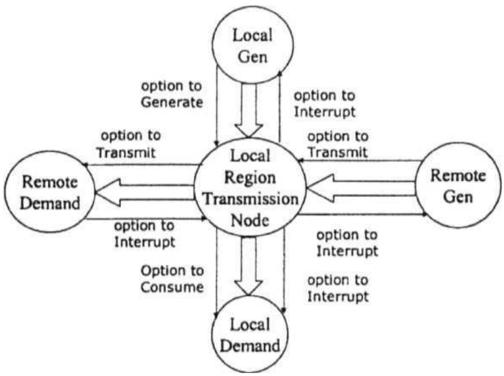


Figure 6.1 Options Utility Optimal Portfolio

First an option is one of the general class of financial instruments known as derivatives options may be either 'calls' or 'puts'. There are "American options" and "European options". In case of a call option on a stock, the option gives the holder of the option the right to purchase a specified quantity at a specified price, "the strike price" during a specified time period. If the owner actually uses this option, then he is said to have exercised this option. European option entitles the owner of the option the right to purchase the underlying asset from the writer of the option for a price equal to the strike price at the instant of maturity. In American option it may be exercised at any time up to the time of its maturity. In the framework proposed, utility is viewed as a writer or purchaser of options. An intemiptible contract is a third kind of option. In this the utility has the right to interrupt the customers actual load at any moment during the duration of the option at rate not to exceed 25% of his actual consumption at that time. In this kind of contract the utility purchases an option with an option price (per row of interrupted energy supply). He brings out the similarities to the market based structure of the England and Wales electric power supply system and of his market structure. EW (England & Wales) electric power system also has supply side and demand side option.

On the supply side the system is comprised of two major publicly owned generating companies which were spun off (break) from the former CEGB (Central Electricity Generating Board). National power and power generation and the government owned nuclear electric, together with several smaller but rapidly growing independent power producers and wheeling connections with France and Scotland. On the demand side, retail distribution is handled by 12 publicly held distribution companies which were the area distribution boards in the system before it was privatized. In EW electric power structure, the generators submit bid prices and available plant capacities for each of their plant units on a day ahead basis and this information together with demand forecasts is used to develop a generation call off merit order. Another important distinction between EW system and the scheme developed here is that EW system generators are paid a uniform but half-hourly varying price, where as he proposes a simpler longer term option contract which fixes the generator's revenue stream and the utility cost stream. In EW system the end users are charged uniform prices and the distribution companies have been encountered with the price risk associated with half-hourly varying prices by entering into bilateral forward contracts with individual generating companies.

(Bernard Tenenbaum et.al, 1992) presents four basic models of electric utility industry structure and examines how these structures interact with different competitive structure. The interactions are analyzed with examples from recent U.S. U.K. and European experience.

Model 1.

It is the traditional industry structure prevailing in USA. It consists of one or more vertically integrated privately owned electricity companies. Each company owned its own generation, transmission and **distribution** facilities. If this model is chosen, a government monopoly will be replaced with one or more private monopolies. This model can be easily implemented because it keeps the existing structure intact.

Model 2.

This model continues the traditional structure with competitive procurement of generation. This structure could be developed if all state owned generating plants that existed at the time of privatization were transferred to new private companies. Each company owners, all of the distribution and transmission facilities in its services territory but only some of the generation plant need to serve its retail or end use customers. This model creates a mixed regulatory system. That is deregulation of new generation with continued regulation (government ownership) of transmission and distribution. USA followed this model in 1978 with the passage of public utilities regulatory policies act (PURPA). This has made independent power producers to enhance efficiency and competition in the generator sector.

Model 3.

This model expands on second model by introducing common or contract carriage. (An entity that is regarded to transmit electricity for buyers and sellers on a non discriminatory basis and if necessary to construct an additional transmission capacity if the existing capacity is inadequate to meet all requests). Model 3 seems to be chosen by government authorities who want to go beyond competitive procurement of new generation. One remarkable change is that there who own transmission must provide its services to possible competitors at reasonable prices and on reasonable terms.

Model 4.

This is the new British (England and Wales) model. It requires complete vertical separation of generation, transmission and distribution. In this model also most or all of the state owned generating plants are conveyed to new privately owned, independent generating companies. Distribution facilities are also owned by separate private companies. They provide unbundled transmission at distribution voltages and sell electricity to wholesale and retail customers within and outside their traditional service areas Colin Robinson (1996). This model will work only if it implemented exactly as British model in their 1990 privatization. In British privatization of electricity sector 3 factors were incorporated. The first feature is retail competition. End users with a demand greater than 1 MW currently have the right to buy electricity from any willing suppliers, that is local distribution company (REC) or licensed non contiguous supplier. The second features of the British version of fourth model is that the distribution companies can own equity interests in generating stations to supply up to 15%of their total sales. Finally the British system has chosen a Market mechanism that employs a spot market for energy and capacity backed up by a variety of financial hedging contracts.

Paul L. Joskow (1997) also presents two basic models for promoting competition in electricity section in US for past several years. The first is portfolio manager model. This framework was envisaged by PURPA (1978) and Energy Policy Act of 1992. In this wholesale competition model, the distributor relies on competitive procurement mechanism to buy electricity from the lowest cost suppliers in competitive structure. Wholesale markets rather than building new generation facilities to serve growing electricity demand in its franchise area. This model promotes both continues growth of the independent power sector and associated competitive wholesale markets and retains the traditional retail monopoly. With regard to price for the electricity received by retail consumers, continues to be regulated since the consumers must buy their electricity from local monopoly distributor.

The second model is customer choice or retail wheeling model. In this model retail customers can access the wholesale market directly by purchasing unbundled distribution and transmission services from their local utility. In this model, generators can sell energy in a competitive spot market as well as arrange for long term financial contracts with electricity supply intermediaries or directly with retail consumers. The role of local distributors is to provide wire services to retail customers for access to the power market as well as metering and billing services. The prices for these distribution and transmission services would be subject to regulation since they continue to be monopoly services. Variations on customers choice model have been adopted in England and Wales, California, Chile, Argentina, New Zealand, Norway, Pennsylvania, New York and Illinois. The major potential benefit of the customer choice model over the port folio manager model is that this approach reduce the ability of regulators to control the generation market including service prices, entry to and exit from generation segment and the forms of the contractual arrangements that support new generation segment with different degree of competition in ESI, (Single buyer, Third Party Access and pool). In Europe these models were introduced as planned by European commission (1977). The real competitive electricity market was analyzed in different western European countries. Some arguments curtail the success of EU guideline (Hans Aver, Reinhard Hass et.al 1998). One argument is that real competition is curtailed by small emerging IPPs as they are not interested to sell very cheap electricity as long as other generators are not similar cheap and there is a high demand for electricity.

In single buyer model eligible customers conclude supply contracts with producers on the basis of a voluntary commercial agreement. The single buyer is obligated to purchase the electricity contract by an eligible customer from a producer at a price which is equal to the sales prices offered by the single buyer minus the price for the use of the network. The single buyer is not informed of the electricity price as it appears in the contract between the producers and the eligible customer. The benefit of the eligible customer is equivalent to the differences between the price of purchase from producer and the price of sale to the single buyer, but including the transmission costs. In the TPA model eligible customers and producer conclude supply contracts directly with each other on the basis of voluntary commercial agreements. The system operator gets only information about the amount of electricity, not about price. The system operator receives wheeling free either from the producer or from the eligible customers.

Hunt and Shuttle Worth as in Augusto (1998) presented some alternatives for restructuring electrical systems. He considers four ways to structure an electrical sector in terms of degree of competition. According to him the possible models are:
Model A. Has no competition at all.
Model B. Allows or requires a single buyer or purchasing agency to choose from a number of different producers to encourage competition in generation.
Model C. It allows distcos (a company which owns both the distribution wires and retails electricity) to choose their supplier, which brings competition into generation and whole sale supply.
Model D. It allows all customers to choose their supplier which implies full retail competition.

The important characteristics of each model are competition among generators, choice for retailers and choice for final consumers. Green (1996) concluded that UK experience showed that competition in generation is possible and that competition in supply to large consumers became a reality bringing benefits to this consumer. Privatization has been associated commonly with greater operating efficiency and it is neither a necessary nor a sufficient condition for it. He proposed fourth model for Brazilian electrical system restructuring by arguing that it generates significant financial and operational efficiency gains.

The Scottish power sector in order to improve the efficiency did the following:

a) They set focused plans and objectives for each business.
b) Reorganized to remove layers of management.
c) Reviewed working practices to match them to the various markets.
d) Reduced manpower and conserved capital.

Initiated movements in services and maximized sales. I.M.H. Preston (1995)

6.3 ROLE OF REGULATION IN RESTRUCTURING ASPECT:

In new structure of ESI the term market is often used Miles O' Bidwell (1996). The objective of restructuring the ESI is to increase production efficiency with corresponding decreases in costs and prices, then the generation market structure must be competitive efficient market. But too little structure or too much regulation can present the new electricity market from being efficient and this lack of efficiency will greatly reduce the potential gains from restructuring. John Vickers (1996) competition is most effective means of protection against monopoly and a vigilance should be there against anti competitive practices. Profit regulations is a merely a stop gap. There are important interactions between competition and regulation. A) There are substitutes in so far as sufficient competition might enable regulation to diminish. b) They are complements in so far as competition can enhance the effectiveness of regulation. c) Regulation can distort competition by its effects on incentive. Roger Rodriquez et.al (1996) was also of the same view that combination of regulation with potentially competitive element may not be efficient in every aspect. David M. Newbery & Richard Green, (1996) In designing a appropriate regulatory frame work there are two alternative models for its structure. In the first production that is generation and the network a) the grid can be retained as a vertically integrated monopoly. The other model is one of vertical separation with the objective of ensuring competition in those stages of industry that do not suffer from natural monopoly, retaining regulation for the natural monopoly elements. Regulation falls into 5 categories.

Rate of return: This procedure has dominated regulation for almost a century. The system focusses attention on the profit that utility needs to attract capital, so an expanding utility that needs new capital can invest money knowing that the new investment will earn a profit Penn (1995). Kenneth P. Linder et.al (1995) cost based rate of return regulation in US was never designed for competitive markets as it results in rigid prices, regulated capital structures, an obligation to serve all customer segments, slow decision making process, high administrative costs limits on the ability of utilities to market their product and services.

Standard Cost: Regulators may like rate of return regulation but they also want to reward utilities that separate more efficiently. To do so, regulators analyze the cost structure of the industry and then set up a cost and investment model for a hypothetical utility. A price is set for electricity that provides an adequate rate of return for the utility.

The price derived from that model is then applied to all the utilities. Utilities whose costs are lower than the standard used in the model earn a higher return than those whose costs are higher than the standard utilities that manage to serve customers with less capital than the standard utility earn a higher return than those who required larger amounts of capital than the standards. In effect the utility that is more efficient in its operations or in its use of capital earns a higher return than that set by the standard model. This method of regulation encourages efficiency, but if may not provide the means for regulators to deal with specific problems at a utility. It may not produce lower prices for customers for long periods of time, either until the period of the formula runs out and a new one is set that brings down prices to reflect efficiencies.

Incentive: If the utility earns less than the designated return, but within the range, it cannot request a price increase. If the utility earns more than the designated return, but within the range, it can keep the extra profit over the designated return. This procedure induces the utility to run efficiently and to spend less time seeking price changes from regulators because the utility loses profits if it cannot earn the designated return and because it collects extra profits if it can exceed that return. The second type of incentive regulation involves profit sharing. The regulator again sets a range of return. If the utility earns above that range it can keep some of the excess profit and in turns the rest of the excess back to customers through a refund. In this way customers immediately gain some of the benefits of the increase in efficiency. The third type of incentive plan requires the regulators to set up an elaborate array performance indices. The utility's level of profit depends on how well it performs against indices. While the idea seems sensible, in principle, devising the right indices is into a simple task and the utility might **find** a way to game the indices with out necessarily producing lower costs over all that benefits customers.

Price **cap:** Regulators tie the annual price increase to the cost of living index for a given period of years. Then in order to encourage more efficient operations they normally subtract a productivity index from the cost of living index to arrive at the price increase for the year. If the utility can increase its real productivity by more than the productivity index it makes an extra profit that it can keep. The procedure has faults too. The **prices** and costs at the utility may be poorly connected to the moves in the cost of living index. The rigid productivity index takes no account of sudden and dramatic change in costs. The formula provides no incentive to add to investment in a major way. Finally although the prices cap formula was designed to avoid the problems caused by rate of return regulation, the results of price cap are often judged on rate of return basis. In other words, if the price cap formula produces too high a return on investment, it may be changed to produce a lower return.

Adhoc: The utility for instance may have to borrow large sums of money in order to meet the demand for service. The regulator would then set prices in such a way to produce enough profit to cover borrowing cost by a given margin or the regulator might want to encourage a merger that would help reduce costs, so the regulator gives the utility special profit incentives to make the merger. A few regulatory agencies have resisted regulatory formulas altogether and set price by bargaining with the utility every year. To the extent that adhoc procedures solve problems they are good. To the extent they create uncertainity because of their impermanent nature, they may discourage investment.

Gordon Mackerron **et.al (1995)** speaks about regulatory issues from both economic and environmental in ESI. It is difficult to separate economic from environmental control. Nowadays environmental control. Nowadays environmental regulation has become increasingly important especially in its implications for the generating side of the industry and environmental regulation gives powerful incentives to the regulated incentives which may either reinforce or contradict the incentives give by economic regulation. The economic regulation in England and wales encompasses the orchestration of competition as well as control of monopoly but at anther level foccusses on the efficiency and competition issues.

Richard J. Gilbert and Edward P **Kahn,** (1996) mentioned about 3 principal alternative regulatory futures.

Option **1:** In the US electricity sector, the competitive segment of generation market is not viewed favourable by participants. The unbundling of ESI involves costs. The critics of deregulation in ESI were of the view that the success of deregulation in ESI were of the view that the success of private producers was due to special regulatory treatment rather than economic superiority.

Option 2: Managed competition. The US electricity system is moving towards a mixed system in which whole sale competition is balanced by the two structural issues. a) Market share in generation for the IOUs and the regulation of distribution segment.

Option 3: "Radical restructuring" British model applied in the piece meal American fashion.

- The privatization of the British electric power system implemented radical changes in regulatory policy. The ESI in Britain is completely vertically de-integrated whole sale generators sell to the grid at prices that are determined in a national spot market. Regional electric distribution companies purchases their power requirements from the grid, at spot prices.

Larry E. Ruff, (1996) explains the unbundled process in ESI for effective and efficient competition diagrammatically. For this he considers an US electricity system usually an electricity system consists of the basic functional building blocks.

Figure 6.2. The Logical Building Blocks

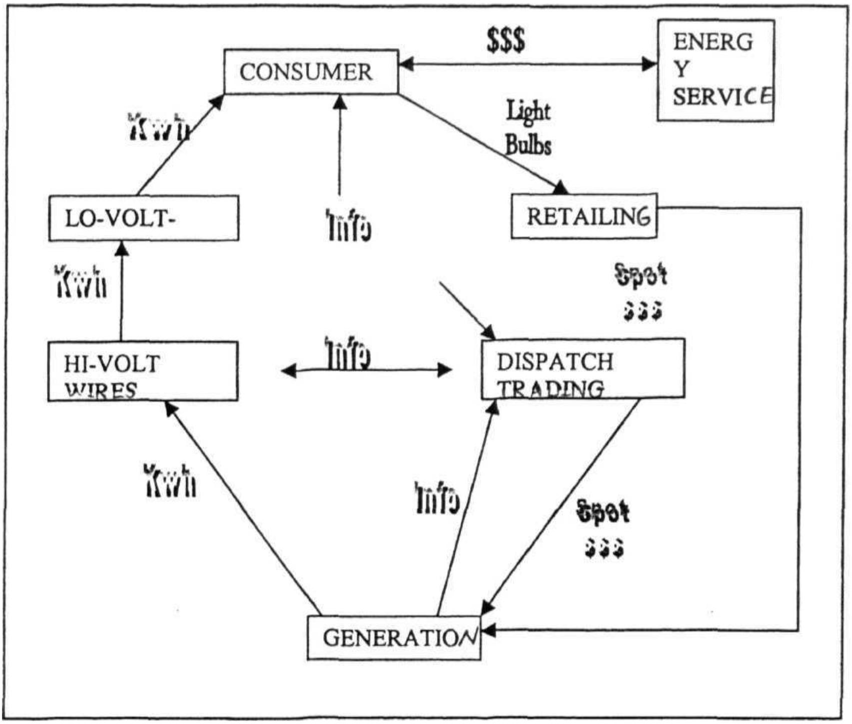
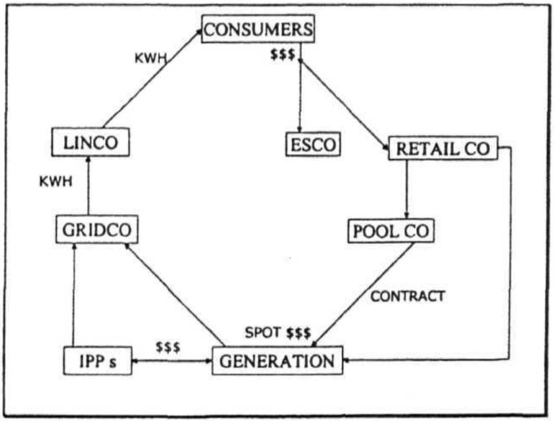


Figure 6.2 clearly separates the functions of owing and operating physical generation and transmission / distribution assets from the commercial function of buying and selling electricity and from the function of co-ordinating (dispatching) the integration system and pricing its short run services. In his view a reasonably efficiency electricity system must perform all the functions. In united states these different functions are performed by identifiable divisions within an integrated utility or even span off into separate organizations. For successful unbundling of ESI there should be internal coherence and logical interactions among these basic functions. In any electricity system consumers pay a retailing function . This can be competitive if retail wheeling is allowed or have a franchise over captive customers. This function provides delivered electricity to consumers by buying

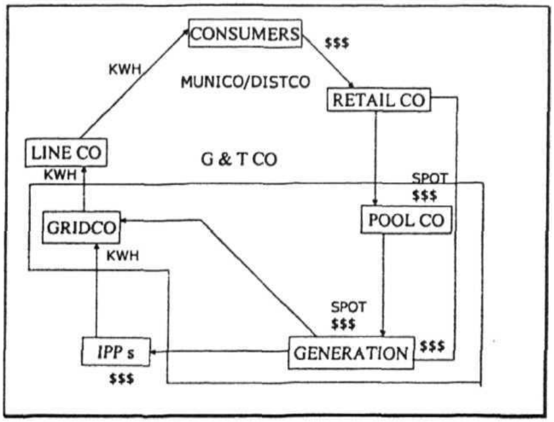
through some combination of spot, contract and ownership arrangements. Three kinds of services are: Actually or potentially competitive generation services, physical delivery services provided by natural monopoly high voltage grid and low voltage distribution system and natural monopoly co-ordination and spot trading functions. He identifies these as institutional infrastructure monopolies that must be available to all competitors if competition is to be both efficient and effective.

Figure 6.3: An Integrated monopoly



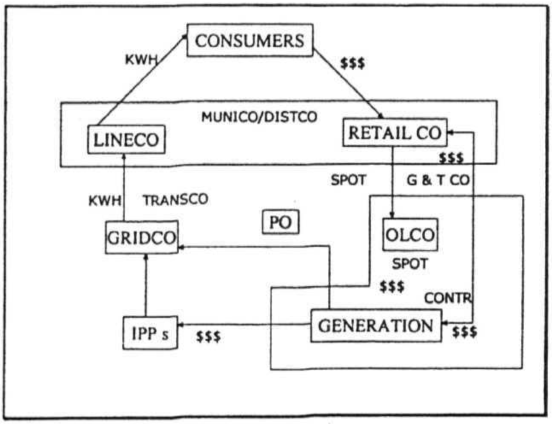
US style utility combines all these functions into a single centrally planned and centrally controlled utility as shown in figure 6.3. Such a utility decides what services consumers should have, rolls these services and all their costs in to a single bundle prices on some average dollar per unit of energy basis and offers the bundle on a take it or leave it basis, if the objective is efficient unbundling and efficient competition. In US the demand side services provided by ESCO are rolled into, take it or leave it energy bundle by adding independent power producers **(IPPs)** to the utility's generation mix, can provide significant benefits but the monopoly and its regulators have not always protected consumers. A light power pool (not illustrated) establishes a GRIDCO consisting of separate grids owned by the member utilities and jointly owned. POOLCO that dispatches the combined **sytem** to meet combined demand, with spot energy trades priced to share the savings. This arrangement provides some efficiencies and competition among the neighboring monopolies but limits competition from anybody not in pool club.

Figure 6.4: A MUN1C0 / DISTCO



Municipal utilities (MUNICOs) have traditionally purchased their full power requirements from the local generation and transmission monopoly **(G&Tco),** a profit seeking distco also did the same. Wholesale wheeling have allowed **munico-distco** to own franchise customers and shop among suppliers. This will not be very effective or efficient even if local G & T co controls either Gridco or Poolco. A UK style competitive market unbundles the industry into all the separate components as shown in Figure 6.2. This allows final consumers or competitive merchants to get their physical electricity through centrally **co-**ordinated system while engaging in commercial translations with competitive generators and other traders. The objective of open transmission access should be to arrange the functional blocks into logical structure. The wheeling model as key to the transmission services has a drawback. There is no functional block in Fig.6.2. that provides this service. This is called transmission provider separate from other functional blocks. There is a GRIDCO but if just provides the physcial interconnections among the players in the market. It is not an essential **co-**ordination and trading functions. If GRIDCO functions are converted into an open access "transmission provider" while leaving POOLCO as the exclusive property of the G & T co as the wheeling model does. But this results in problems such as price all the interactions between independent grid users and the G & T Cos own operations. The problems are opportunity costs, back up energy losses, spill energy, reactive power, reserves etc. In effect the wheeling model tries to unbundle the electricity system as illustrated in figure 6.5.

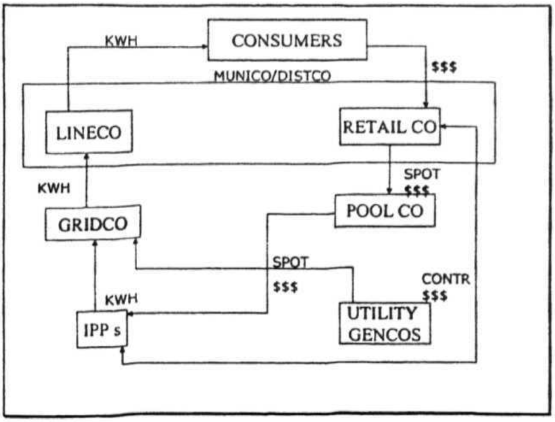
Figure 6.5: The Wheeling Model



Transmission service is assumed to be something that can be unbundled from G & T Co's generation and pooling / dispatch functions and provided to third party users by a transmission entity or 'TRANSCO' usually affiliated with the G & T Co's consisting largely of the grid assets. The third party use of the grid involves generation as well as access to GRIDCO's assets or to incorporate some subset of POOLCO's functions into a TRANSCO function that provides a third party transmission service. Efforts are made to define and separately price the service provided by the G & T Co's generation and pooling function. But POOLCO is a complex natural infrastructure monopoly that cannot realistically unbundle and price each of it services. The policy of trying to force integrated utilities to provide transmission service by unbundling grid assets while leaving the essential co-ordination and market functions with the integrated utility is illogical, cumbersome and inefficient. But this policy of unbundling will either result in competition or will result in frustrated regulators ordering electric utilities to ignore and under price critical interactions in effect subsidizing independent users of the grid. The result **will** be inefficient and distorted competition. This is because the wheeling model does not take into account the importance of other natural monopoly at the core of an electricity system. The POOLCO functions of dispatch, pooling and economy energy trading. Therefore the wheeling model gets unbundling all wrong. So the key to effective and efficient competition in electricity is to recognize that the pool co function is a natural monopoly in the same sense that **GRIDCO's** physical system is a natural monopoly. It cannot be economic to have more than one such system in a region. Any competitor excluded from or over charged for access to that system will be at a serious competitive disadvantage. Unless both **GRIDCO** and POOLCO **functions** are separated from generation, the GENCO with whom they are associated will always have unfair competitive advantage in the competition for customers.

To begin the process of separating POOLCO functions, utility controlled dispacth and regional power pool should be separated from GENCO's and retail Co's and provide their services to all electricity traders on the same **non-discriminatory** terms.

Figure 6.6: Unbundling for Competition



Spot market is essential for competition because it allows all competitors to participate in the central co-ordination and energy trading processes. But neither buyers nor sellers want to be exposed in the spot market for the bulk of their transactions in the electricity markets contracts of varying length, from few days to many years will play a large role in a competitive electricity market. In a well functioning market in any commodity short term operations should depend on actual cost condition at the time, not on contracts directly. Contract prices and quantities are based on estimates of future costs. These contract variables are kept in the with reality by indexing the production, capabilities and market conditions in various ways. The contracts should be such that it should allow contracting parties to make economic adjustments to the conditions as they develop. The financial payments should be settled among the parties by sharing the resulting costs and benefits in a specified ways. Today in electricity system the actual conditions and no contracts should determine operations. The competition for contracts with customers will only wheel money not power. By this, it means to say that the wholesale dispatch pooling and economy trading will result in same plants to meet the same demands at the same (least) cost. Finally in the long run the customers should seek out suppliers offering the most attractive contracts with efficient short term energy market assuring that costs on the day not contracts which determine system operations and short term operation should be based on actual conditions at the time. In sectors such as electricity, technology may be a restrictive factor in creation of an ideal competitive market while the grid could only exist as a monopoly generation and supply activities could be separated that is unbundled and competition encouraged among them (Ganesh Mittal, 1998).

Chile & UK are good examples where prior to privatisation ESI was subjected to such unbundling and subsequently to competition. Breaking up of large enterprises, prior to sale would also be desirable, which promotes competition and is technologically feasible. Another concept mass privatization has been widely used in countries in transition of central and Eastern Europe. Advantage of this type of mass privatization ties in speedy transfer of assets from the state to individual share holders. Disadvantages are it does not result in improved economic efficiency with out competition and proper regulation, public monopoly converts in to private monopoly with attendant exploitation potential. William W.Hogan (1994) An efficient design for an open access whole sale electricity market mostly balance a number of competing objectives. They are reliability, least cost dispatch, open access, revenue adequacy, efficient trading and investment and practicality.

(Richard Abdoo, 1995). Discussed about Wisconsin ESI. The functions in vertically integrated utilities should be split into two major categories. Single providers and competitive entities.

Re-regulated single providers: The regulated single provider are the regional power exchange transmission and distribution function. These providers are regulated to give the appropriate incentives to provide services at reasonable prices.

Competitive Entities: In Wisconsin electric's model the competitive entities are the generation, customer service and energy merchant functions. These entities see that elimination of traditional price regulation in favour of market driven pricing.Re-regulated service providers and competitive entities can provide a best possible solution for restructuring (Steve Thomas, 1995) also looks at the development of competition in generation by examining power pool in theory and practice, reviews the impact of the contracts for differences and finally the introduction of competition to end consumers is assessed.

The pool was the main arena in which competition in generation was expected to take place. It has a two sided market with generators placing bids of the minimum price at which they were prepared to supply power and customers placing bids of the maximum price at which they were prepared to purchase. The CEGB had adapted to operate as a one sided pool with only generators placing bids. All generators that wish to operate their plant must place a bid with the pool that applies to each half hour of the next day. The pool software matches the bids against forecasts of demand choosing the lowest bids necessary to meet demand. The pool purchase price for each half hour is largely set by the price bid by the highest successful bidder, the SMP. But the fact that more than 90% of power bought and sold has not had to place a realistic bid into the pool He noticed that if the new system operates as envisaged by government then competition in supply is not a important direct mechanism for promoting economic efficiency.

The introduction of competition for large and medium sized consumers face problems like high cost of the sophisticated meters which will make customers to switch suppliers. Competition amongst large consumers also requires the use of sophisticated meters which transmit consumption data on a half hourly basis to supplier. This allows the supplier to derive tariffs which accurately reflect the hourly cost of supplying the final consumer and also generate useful data which allow the consumer to modify consumption. A retail free market is the final objective of the deregulation of electricity market in Japan (Hiroyoki Okamoto et. Al 1998) consumers would be able to choose from several suppliers offering different prices and services. Japan should take a leading role among Asian nations in the energy industry by introducing an advanced policy of promoting competition in the energy market and environmental issues. There is a need to introduce public and private co-operation in its sphere of supply and the abolition of legal restrictions on the ability of the private sector to sell excess capacity to other buyers and prices may be used to cover up the cost of inefficiencies. It should ensure greater competition (Adeola Adenikinju, 1998). The main objective of polish government is to ensure power security in decentralized, privatized and competitive power supply industry (Zbigniew Mantorksi, 1998), Turkey has exercised several options to meet its power needs. They include privatization and restructuring of state assets in order to improve productivity and efficiency. It introduced Built operate Transfer model. It covered 3 types of private sector involvement in the power sector.

a) Assignment for the generation, transmission and distribution: In this arrangement private companies are allowed to carry all activities and sell electricity directly to consumers in certain "assignment regions". The assigned companies in those regions are obliged to meet the energy needs in its region.

b) Construction and operation of power plants including co-generation plants: Companies operating under this option are not allowed to sell electricity directly to consumers. Instead they have to sell their power to assigned companies with aright to T & D operations in that particular region.

c) Transfer of operational rights of already existing power plants:

T & D facilities owned by the state. In all the 3 options at the end of the assignment period (usually 20 years) all facilities and immovable assets related to the subject of the assignment need to be banded over to the state at no cost.

In UK on the supply side competition has been introduced in 3 stages. 5000 customers who had maximum demand of over 1 mw were able to choose their own supplier and transmission and distribution sectors are considered natural monopolies. In UK, Norway, Sweden Finland the reforms implied a transformation of the traditionally regulated electricity market to a market with competition and prices determined by the interplay of demand and supply. In both Nordic and UK electricity market there is a strict separation between transmission and distribution functions on one hand and supply activities (generation) on the other. The hourly production plans are in effect determined a spot market where whole sale buyers and sellers trade electricity and hourly prices are determined. In Norway and Sweden point tariffs are used. This means that at each location there is a given price per unit of power fed into the transmission system and this power is independent of the location of the buyer of that power. (Daniel Freed, 1998) John Turkson, 1998).

In a competitive electricity market, the issues of risk sharing and risk management are central and vertical separation is to occur together with horizontal separation to create competition. In Brazil though TRANSCO's are created some transmission assets remain ownership of generation or distribution utilities.

In ESI restructuring (Norbert Wohlgemuth, 1998) covers the broad aspect of consumer choice, market structure, and transition to a more liberalized industrial organization.

a) Consumer choice: It is the guarantor of efficient and fully competitive markets. Ultimately customers served by ESI should be able to choose among a range of service providers, services, pricing options.

a) Market Structure: Economic Efficiency and Industrial Competitiveness: To ensure competition any electricity market system must limit the market power of energy providers.Separation of generation, transmission and distribution services: Generation, transmission and distribution services within the ESI should be functionally separated in order to move to a fully competitive generation market based on customer choice. Vertical integration should not be allowed to interfere within the operation of efficient markets for electricity. He represented the transmission of ESI in table form.

From	To
1. vertically integrated monopoly	Unbundled competitive systems
2. public investment	Private investment
3.central control	Decentralized market
4. least cost	Least risk
5. controlled prices	Market prices
6. economies of scale	Modular technologies
7. hands on supervision	Arms length regulation

Irwin M. Stelzer, (1996) regarding competition is ESI lists out four principal barriers.

a) Strandard assets: UK ESI industry is characterized by vertically integrated suppliers (monopoly) and all the utilities have an obligation to meet the demand of all customers by building expensive plants. But this does not materialize all times. Under monopoly, the ESI charges prices high enough to recoup (cover) its investments and a reasonable return. But as the ESI is open to competition competitors are offering prices based on low cost, gas burning generating equipment (stranded assets). As a result they are burdened with more unrecoverable costs which results in stranded investment. This delays competition in retail market in US.

b) Vertical integration: New entrants in power generation must move their electricity over transmission and distribution wires and the terms and conditions of access might be so stringent as it makes them impossible to compete. Even though they are more efficient in generating electricity.

c) The Greens: the third barrier to emerging competition in America's ESI is the political clout of the environment movement. An electric utility in monopoly agrees in the demand of environmentalists for a host of economically inefficient conservation arrangements. For environmental purpose there is a need for high cost power supply technologies and the costs could be passed on to captive customers. But times have changed when competition from new, low cost producers makes continuation of anti consumer, utility / environmentalist alliance impossible. So the environmentalist are demanding that a 'green surcharge' be a added to prices imposed on new power producers for the use of transmission and distribution. Similar pressures may also develop in Britain.

d) State Regulators: The fourth barrier is the regulators are of the view that competition will benefit only large, industrial customers, who threaten to move or expand their plant in some other state and lower rates to these customers. But the utilities will try to recoup the lost revenues from small householder who does not have much bargaining power. So many regulators have rejected the idea of subjecting utilities they regulate to competition from outside suppliers.

Despite these hindrances competition is breaking out all over the world. All generators are forced to sell into and all customers to buy from a pool and also allow bilateral deals between consumers, producers, brokers and aggregators.

6.4. REFORM DESIGN:

Deregulatory reforms differ significantly in the reform design. The reform design comprises.

- reform model selection
- reform implementation schedules
- transitional and supplementing regulations.

6.4.1. REFORM MODEL SELECTION:

The decisions on reform model selection and reform elements vary with the following conditions of the reform states.

a) problem analysis and reform aims
b) legal conditions
c) organizational structure (degree of integration)
d) ownership structure (private state)

a) Problem analysis and reform aims: As described above the reform countries differ in their individual reforms aim which are derived from the individual problems analysis and the expectations of potential chances from introducing deregulatory reforms. Because of the differing characteristics of the reform models, the reform aims can predetermine the reform model selection. If the introduction of more customer choices is an explicit reform aim, a pure competitive bidding system will not be an appropriate solution. If central planning shall continue to be used as the tool to reach a long term optimization of generation capacity, only the competitive bidding system will offer the opportunity to combine planning with some competition on the generation level.

b) Legal Conditions: The legal framework can heavily influence the selection of a reform model. New laws or the enforcement of existing laws especially in the fields of competition law and free trade law can initiate and accelerate reform movements and can pose certain requirements to be fulfilled by the reform design. Eg. A pure competitive bidding system would not confirm with general EU Internal market law. When developing its single buyer proposal, the French government therefore supplement it by additional liberalizations with respect to cross -border trade. Deregulatory reforms are often implemented by abolishing old laws rather than by creating new laws. Depending on the designing of the interrelation between the general industry laws and the special legal and regulatory framework of the electricity industry such as abolishment of existing regulations can have quite different effects. In Germany such a deregulatory reform by abolishment of existing regulations would directly lead to a wheeling type system with the possibility of third parties to apply for the use of utilities grids. An important legal condition to be considered in deregulatory reforms is the relative importance of the legal protection of property rights and competition law. The implementation of a far reaching deregulatory reform (eg. Introduction of pool model) can make it necessary to restructure the industry (certical disintegration, market organization) such measures infringe on the property rights of the utilities and their owners, resulting in a conflict between efficient competition and private property rights. While such restructurings are possible in some countries (US eg. Bell Companies, AT & T) they prove to be extremely difficult in other countries giving more weight to private property than to competition (Eg. Germany).

c) Organizational structure: Roughly seven types of organizational structures of national ESIs can be differentiated.

Type 1. One fully integrated national utility. (IGTD)

Type 2. One Integrated National Generation Transmission Utility (IGT(D)) and several regional distributors (XD)

(IGT(D) + XD)

Type 3. One utility as national transmission owner integrated in both generation and distribution (UGTD) and several generators(XG) and regional distributors(YD)

(UGTD + XG + YD)

Type 4. One integrated national transmission distribution utility 1(G) TD and several generators (XG)

(XG + 1 (G) TD)

Type 5. One national transmission utility and several generators and distributors.

Type 6. Several regionally integrated generation transmission utilities(XGT(D) and several distributors. (Y (G) D)

(XGT(D) +Y(G) D)

Type 7. Several regional fully integrated utilities

(XGTD)

The pre-reform organizational structure of the ESI is an important factor to be considered in reform model selection, because the different reform models pose different requirements with respect to the post reform organizational structure. (Compatibility of reform models with types of industry structure)

- competitive bidding All Types
- wheeling Types of 6,7
- a generators pool Types 3,4,5
- pool Type 5

6.4.2. REFORM IMPLEMENTATION SCHEDULE:

Countries reforms differ significantly with respect to reform implementation . Based on a legislation introduced in 1989 (Electricity Act) the general system change was realized in one single step, supplemented by a detailed and binding schedule for additional reform elements like privatization and transitional regulations. The whole reform was based on a blue print for the future functioning of the ESI and the reform implementation. The other extreme is marked by the reform developments in the **US.** As a result of years of controversial discussion a **de-regulatory** reform legislation was introduced (PURPA **1978,** EP Act 1992) such a legislation only has the character of a framework defining (deregulatory) policy aims and some details to be considered as restrictions in implementation. **It** leaves almost all practical implementation aspects to the federal regulatory authority and state legislation or regulators. To complicate the reform process even more such framework laws are far from being clear, leaving a wide range of interpretations and sometimes formulating conflicting aims. The reform process is therefore to large extent unpredictable and time consuming, **arriving** at functioning systems 5 to **10** years after introduction of the legislation. In countries with strong central government (Chile, Argentina, Portugal) reforms tend to follow the English example, while in cases of conflicting legislative powers, reforms rather tend to follow the US. Example. Conflicting legislative powers are especially given in federally constituted countries (US Germany, Australia and in the European union).

6.4.3. TRANSITIONAL AND SUPPLEMENTING REGULATION:

In most countries a deregulatory reform is accompanied by transitional and supplemental regulations. Transitional regulations are designed to handle problems which arise from changing from monopoly to competition. Such **regulator's** refer to

- the termination of existing long term contracts
- transfer regimes for compensation of stranded investments
- the designing of **tariff** structure
- the use of domestic fuels in electricity generation.

Supplemental regulations are needed to **find** solutions for public policy obligations to be fulfilled by the ESI such as

- subsidization of environmentally desirable electrical' generation
- financing of energy saving programs
- financing in social programs and tariffs
- financing of R & D programs

6.5 RESULTS OF RESTRUCTURING:

General Performance of reform models:

a) **Competitive bidding:** (Primarily based on US experiences) Intensive competition in capacity additions. Solicitations in the US are frequently 10 times over subscribed. No direct consumer affects. Because of the restriction of competition to capacity additions and the longevity of generation projects, downward effects on consumer prices were limited so far. No inter regional integration (eg. Price equalization) effect, no improvement effects on service quality and consumer choice.

b) **Wheeling:** U.K. energy act- wheeling had no competitive effects. The energy Act was introduced in the UK opening the public grid for private generations to wheel power to retail customers. High wheeling charges based on contract path methodologies and the unpredictability of the behaviour of the mighty state owned utility (CEGB) caused the total failure of this wheeling system. This was one reason for the more fundamental deregulatory reform (separate for England, Scotland and Northern Ireland). EU transit directive had no competitive effects. A limited form of whole sale wheeling was introduced on the EU level. It granted transmission grid owning companies access to the transmission grids of other companies under certain circumstances. This very limited form of competitive opening was not able to change the traditional co-operative transactions occurred. US EP act - whole sale wheeling not yet implemented. The wholesale wheeling system giving all generators access to the grids in order to complete transactions with any vertically integrated or distributing utility had no visible practice results, so far, because many details of implementation are not yet decided. In the mean time several states started a debate on the introduction of retail supply competition, its possible forms ranging from retail wheeling to pools. In Scotland there is limited competition. A retail wheeling system was introduced. Although access is given in a generalized way based on non-discriminative postage stamp grid tariffs and grid cost are controlled by an unbundling of the transmission function of the two vertically integrated Scottish utilities, only very limited competition in supply and generation has developed. The reason is not a failure of system design, but a result of market conditions in Scotland a) only two competitors (Duopoly) b) very low cost and price levels and over capacity in Scotland making competitive entry unattractive c) only limited connection with

England effectively separating these markets and limiting exports into the Scottish market.

c) Pool: Pools instantaneously stimulate competition generation and supply. Both in England and Norway the pool system initiated an intensive competition. In England market shares of the competitors changed significantly during the first years in supply where as competitors played only a limited role in generation because of the defacto duopoly in the generation market.

Price reductions: Customers with competitive supply opportunities have profited from significant price reductions in Norway or moderate price reductions in England. Integration effect: The pool system reduced interregional price differentials to the extent of cost differences. This was especially evident in Norway where the large regional price difference were strongly reduced. Customers choice and product innovation and competition in retail supply increased customers choice as regards load management possibilities and the distribution of risks.

Result in Generation: a) Looses for owners of expensive over capacity (Norway)
b) market entry by new "independent" generators (England, USA) such as gas suppliers manufacturers, eternal and foreign utilities, industrial self generators - single or jointly in groups c) earlier replacement of old and inefficient plants (England) forced by competitive entrants d) strong pressure to build cheap plants (England, USA) e) reduced construction times of plants f) professionalization and internationalization globally engaged companies.
Result in Supply: a) competition supply for customers down to 50,000 KWHR (Norway) b)sharply decreasing prices for non-franchise customers (Norway) c) inter regional equalization of prices (Norway) d) increased customer orientation (England, Norway, New Zealand) e) better consideration of customer specifies such as load profile, load management possibilities, risk preference in contracts (England, Norway, New Zealand).

6.6. LESSONS FROM RESTRUCTURING:

The impetus to **privatization** came not only from public pressure for improved performance but also from government committed to move nationalized industries from the public to private sector and to replacing monopoly with competition. Mike Parker, (1995) and **Mc** Gowan (1992).

Henney Alex, 1995, Colin Robinson, (1996) lists out the benefits and flaws of privatization.

The benefits of privatization can be grouped into

a) political gains
b) cost reductions
c) greater commercialization in the industry
d) modest customer gains.

Flaws with the privatization are: The attempt to privatize nuclear power was responsible for two of the worst mistaken in the privatization namely

a) the creation of a duopoly of major generators. It has stimulated over building of CCGTs and premature closure of plant maintained higher prices, distorted the pool and contract market. Another mistake was that customers did not get a good deal because the government wanted to raise a substantial sum from the floatation of the RECs

b) Continuing forcing of tariff customers to subsidize British coal

c) Ensure the nuclear electric imposed no burden on tax payers fund. These were political choices, not economic necessities. They highlight the governments conflict of interest which is present in monopoly under taking. Many problems emerged because the economic characteristics of an electric system are very complex. In a traditional integrated utility they are internalized and ignored but in an unbundled and competitive system, the difficulties are exposed at contractual interfaces as a nexus of inter related issues.

The study suggested some future course of action

a) Be clear that effective competition means competition that is efficiency enhancing as well as real. It is not to be equated with the interest of competitors though positive externalities they bring. For eg. By lessening the need for monopoly regulation should not be ignored.

b) Maintain a presumption in favour of structural separation of natural monopoly elements - if not by divestiture then atleast by merger control.

c) In the absence of structural separation, seek to decouple regulation of monopolized and competitive activities so that behaviour in the latter is distorted by incentives arising from the former.

d) In particular separate subsidy policy, which should be explicit in any event, from competition policy.

6.7 SUMMARY

In recent years, through out the world electric utilities face strict regulation to the encouragement of competition and change in ownership from subsidized government controlled organizations to more economically viable private owned entities. This chapter demonstrated the basic models of electric utility industry presented by different economists with diagrammatic explanations and role of regulation in restructuring. The major consideration by economists in implementing their models in various countries like USA, UK, Norway, Australia, Spain, Chile, Argentina, Portugal, Finland, Poland, Colombia, Germany, and many other counties is restructuring power sector. A successful privatization requires a well-balanced regulatory structure. That is regulators take into account the needs of electric utilities to earn sufficient income to attract investors as well as the requirement that the utilities provide reliable services in adequate quantities at the lowest possible price. It also examines the drawbacks and results of restructuring. By unbundling the integrated national utility into several generators, several distributors can be provided by multiple parties - By this all classes of customers have reasonable opportunities or benefits from restructuring.

CHAPTER VII

THEORITICAL ASPECTS OF ELECTRICITY PRICING

7.0 INTRODUCTION

In all utility systems the necessity of study of pricing policy has been widely accepted and the case of electricity pricing is no exception. The capital, foreign exchange and primary energy requirements of electric power are appreciable and costly and they are growing at a very fast rate. Therefore there is an urgent necessity to evolve a price policy for electricity undertaking which encourages efficient use of scarce resources.

7.1 IMPORTANCE OF PRICING AS A CORNER STONE IN RESTRUCTURING

The economic principles of determining prices of electricity are not unique, the special characteristics of the ESI call for the consideration of additional factors. The electric markets unlike usual markets are characterized by a significant degree of monopoly power and even when unbundling of various components and creation of more competitive environment has progressed in recent years - government regulation of pricing has become necessary to ensure a proper market. Three alternative pricing policies can be adopted for pricing electric utilities. These are:

a) Monopoly pricing

b) Full-cost pricing

c) Marginal- cost pricing.

These three pricing policies are illustrated with the help of a figure, which depicts a decreasing cost industry.

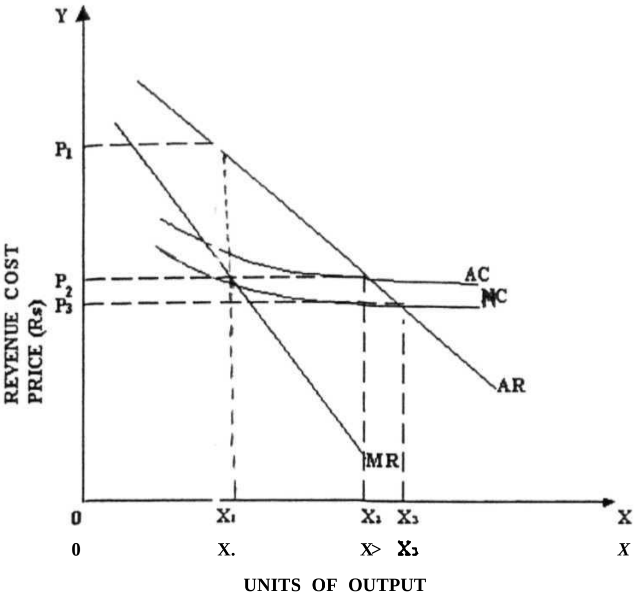


FIGURE 7.1

ELETCR1C UTILITY PRICING

The use of monopoly pricing shows that the product price would be op_1 and output ox_1. It would provide monopoly profits to the firm and there fore would be intolerable to the public . On the other hand if the electric utility is following full cost pricing (in this method the price is determined by adding a fixed mark-up to the cost of acquiring or producing the product) it would produce ox_2 output and price its product at op_2 . This is said to provide a fair return on the investment in the utility. This pricing method is the most popular method have shown that welfare of the society cannot be maximized by using full cost pricing as the value of the added services exceeds the marginal cost of the added output of these services. These economists favour the use of marginal cost for pricing electric utilities. If the utility is priced on the basis of MC the recommended price would be op_3. The welfare of the society is maximum, because at op_3 the value of the product to the marginal user equals the value of the resources used up in the production of the last unit (measured by MC) It may be noted that in case of decreasing cost firm, the price op_3 would not cover total costs. On the other hand, in case of increasing cost firm, the MC pricing may result in a price which exceeds total cost. In case of the increasing cost industry such pricing policy fails to maximize social welfare, while in the electric utility(decreasing cost firm) this pricing cannot cover total cost and consequently has to depend on subsidy which results in political interference.

According to R.K. Choudary (1986); Govinda Rao M et.al (1998) economists have considered marginal cost pricing principles as the most efficient pricing theory so far as theoretical economic analysis is concerned. Under this theory marginal cost of production that is incremental variable cost would be equal to the average revenue. (demand price of the product). The product will expand up to OQ and will be sold at price PQ.

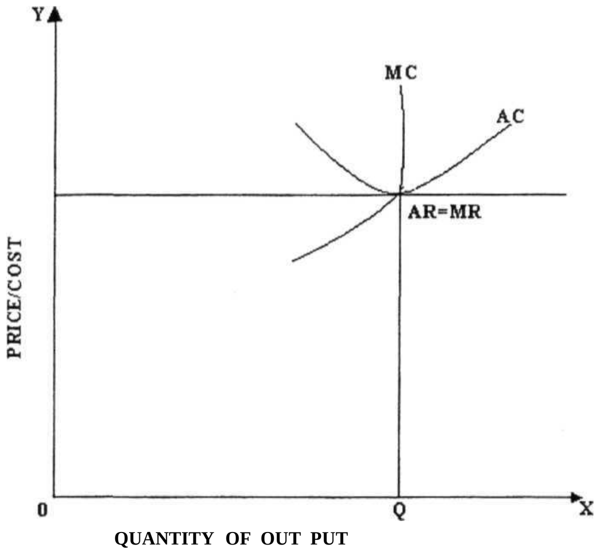


Figure 7.2 Cost and Revenue Curves under Perfect Competition

In Figure7.2: The output indicates p=MC, p=MR and this equality takes place at the minimum point of average cost. Since AC=AR, no excess profit is left and economic resources are utilised at their highest point of efficiency. Thus MC pricing brings about optimum allocation of resources conditioned by the operation of perfectly competitive market. We have noted that an important economic characteristic of electric utility is relatively low capital turnover ratio because of their comparatively large investment in fixed capital. They are in general decreasing cost industries and the application of marginal cost industries and the application of marginal cost pricing under this brings out a different price-output-cost relation than the one under competitive conditions.

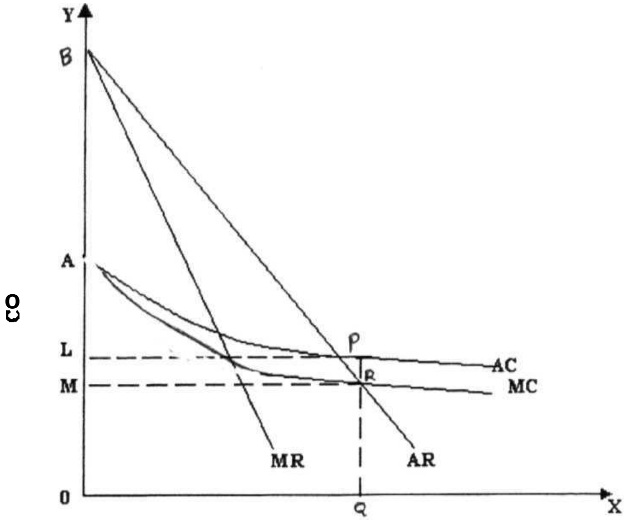


Figure 7.3 Cost and Revenue Curves under imperfect Competition

In the figure 7.3: the electric utility industry has declining average cost and marginal cost. The consumer demand curve or producer's AR curve as well as MR curve are declining, usually assumed under conditions of monopoly (here natural monopoly) . Under the MC pricing principle, the output of the electric utility would be expanded up to OQ, at which price=MC and this is shown by PQ. But at this price the average cost per unit of output is more than average revenue and total deficit-PRLM has resulted. The electric utility will suffer a loss of PR amount per unit of output sold, unless an equivalent subsidy is granted to it. A tax would therefore have to be used to finance the subsidy in order that the deficit of the industry is covered. Advocates of marginal cost pricing justify on the ground that social benefit from large scale output which this pricing policy brings about would exceed the social cost involved in taxation to meet the subsidy requirement. This line of reasoning was put forward by Hotelling. Since then many economists have discussion on marginal cost pricing controversy .The marginal cost pricing determines the efficient scale of output in electric utility can be analyzed in terms of surplus analysis of par to **optimality.** Consider the utility industry. Assume that any increase of decrease in the consumption of utility services does not make any significant difference in real income of consumers. The most efficient scale of output is determined at a point where the net aggregate benefit that is the total benefit, less total cost is maximum. This will in turn **bring** about consumer surplus and producer surplus . In figure 7.1 consumer benefit from output consumption - BPQO that is area under demand curve and the total cost is represented by the area under **Mc** curve. That is APQO. Therefore under these demand -cost conditions, the difference between the total benefit and total cost that is when the aggregate amount of consumer surplus and producer surplus becomes maximum indicated by the area BPA.. The optimal output is at point Q, since surplus here is maximum which is brought about by the equality between marginal benefit and marginal cost. There is a scope for most proper utilization of economic resources, for marginal benefit is still at a higher level than the level of marginal cost and the net benefit has yet to be maximized. Though optimum resource allocation is theoretically achievable under marginal cost pricing in electric utility rates without a greater amount of information on what norms society has and what form and shape the consumption and production functions take. Although in utility economics of India as in the USA and **UK,** no serious study of application of marginal cost pricing principles for rate structure determination has yet been found. It is important to note that utilities in France have made some successful advance in applying this principle. What other principle is followed in practice in determining utility rates and price structure. Three principles as to how price structure for electric utility be designed. Cost of service principle says that the prices should be of such magnitude as to collect revenues which are sufficient to cover the cost of providing service to consumers that is it should cover average cost of production. In this principle pricing in electric utility according to cost of service principle closely resembles pricing in competitive economy under average cost pricing theory, which makes available to the producer only normal profit. In the determination of price under cost of service principle the rates are supposed to be set at level that would provide a fair return. This means **price=AC.** As electric utilities generally have heavy investment in fixed capital, the AC curve which has a continuous declining tendency, though at a diminishing rate points to a decreasing cost industry.

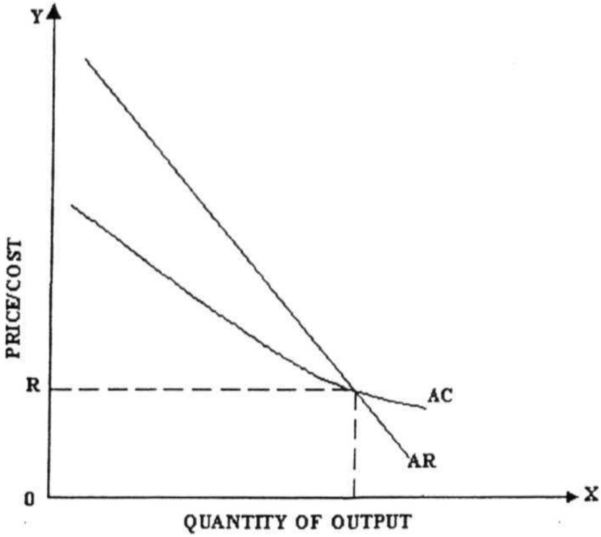


FIGURE 7.4

COST OF SERVICE PRICING

But electric utilities operate under conditions of joint cost. For Eg: electric utility provides different types of services such as residential, lighting, street lighting, industrial power, electricity for heating , cooking, refrigeration. Pricing for these different uses of electric service must be differently calculated so that prices structure may be reasonable. Since the measure of average cost attributable to each of the different joint products is not possible. Average cost pricing principle or what may properly called cost of service pricing for electric utilities cannot provide the basis for rate making purposes. During decades of experience and practice, however the least controversial design of the rate structure for electric utility services has been found to be based on what has been called differential pricing. There are certain essential conditions for the application of differential pricing policy.

7.2 MARGINAL COSTS AND TARIFFS

Regarding marginal cost pricing principle for public utilities, Hotellings's (1939) contribution to the subject is considered to be one of the pioneering works. But the problem of peak load pricing has been treated by Harberger and Andreatta (1963) and also by Montogomery, R.F Harrod and E.A.G. Robinson (1951) advocated the marginal cost pricing on government owned and operated railroads and electric utilities. He recommended further that the electricity industry should charge only incremental costs i.e. price at marginal cost with out attempting to maximize profits. The basic marginal cost theory for the determination of electricity tariff has been analyzed in the frame work of 'Social welfare Function' by many writers like Boiteux (1964), Houthakker (1951), steiner (1957) and others. As explained by Turvey and Anderson (1977) accounting costs generates tariffs which relate to average rather than to marginal cost. But prices based on accounting costs are inadequate as signalling devices. According to Mohan Munasinghe and Jeremy .J.Warford (1982) for efficient resource allocation the prices must equal to the marginal cost of supply. Munasinghe presents a pricing frame work based on long run marginal cost that meets these requirements. The modern approach to power pricing recognizes the existence of several objectives.

(A) The national economic resources must be allowed efficiently not only among different sectors of the economy, but also within the components of the electric power sector itself.

(C) The power prices should raise sufficient revenues to meet the financial requirements of the sector.

(D) The power tariff structure must be simple.

(E) Some exogenous requirements (example political, geographical and other requirements) must also be considered.

Finally the author Muna Singhe comes to the conclusion that LRMC based tariff is a compromise between different objectives. Therefore no ideal tariff exists. By using this it is possible to revise and improve the tariff on a consistent and continual basis. Gradually optimal price is reached over years for electricity with out subjecting the consumer to unfair shocks because of large abrupt price changes. Spot or spontaneous prices are suggested as an alternative for this problem. According to G.P. Keshava (1990) marginal cost pricing in electricity involves a tariff structure so framed that the cost to any consumer of changes in the pattern and level of his consumption equals the cost to the electricity industry as consequence of his action. Such pricing will cause individual consumption decisions to conform to the national interest if consumers are well in formed and rational, the distribution of income is taken as given, the cost to the industry responding to consumption charges coincides with costs (absence of external economies or diseconomies) N.S.S Arokiaswamy (1982) says that the marginal cost pricing study will give an indication of what it is going to cost to provide additional power supply to new consumers at the time needed by taking in to consideration all the capital investments to be made , fuel to be burnt, administrative charges to be incurred in the ensuring years.

There to is an argument that marginal cost pricing does not help efficient allocation of resources in its application to one industry unless it is applied to all others. The relevant situation to marginal cost pricing is substitutes and complementary goods. Where as substitute is priced lower than marginal cost, marginal cost pricing for electricity cannot lead to efficient resource allocation. Peter G. Soldatos (1991) uses the terms real cost, true cost and marginal cost synonymously. The rationale is based on the fact that economic theory defines the true cost of a commodity as the increase in total welfare or inversely the decrease in total welfare as a result of consuming one unit less. This extra unit is called the marginal unit and the change in total welfare is the marginal cost. The use of marginal cost in economic appraisal is distinguished from the use of average cost. But it is incorrect for economic planning. Average costs express historical data while marginal costs are forward looking and marginal cost pricing is achieving maximum efficiency and optimal resource allocation.

Most economists agree that price should be set equal to marginal cost. But here the dilemma is whether the marginal cost should be the short run marginal cost (SMRC) or the long marginal cost (LRMC). Anderson R and Bohman.M(l985), Turvey Ralphfl969) and William Vickrey (1985). According to David M.G. Newbery (1985) the efficient price of electricity is the short run marginal (social cost) of producing electricity. In general this is not equal to the long run marginal cost and that when the two differ the long run marginal cost is not the efficient price. From this it follows that if investment decisions are on average correct then pricing at SRMC will cover interest costs and assuming constant returns to scale in investment, will cover total costs and earn the efficient rate of return on investment. large developed countries like United states of America or United Kingdom of Great Britain and Northern Ireland, electricity were produced in a large number of independent competitive generating stations, selling to consumers through a common carrier national grid then prices would naturally be equal to SRMC and competition would ensure cost minimization in the production and optimal investment decisions. This is impractical in developing countries where individual units are typically large relative to market served grids are often small and poorly integrated and hence competition unrealistic. The danger with SRMC pricing is that, if under written by subsidies, when SRMC is below average cost it provides an incentive to over invest and under price. Anna P.Della Vella(1988) argues that given the economic and technological conditions in the United States electric utility industry to day, pricing based on SRMC is more efficient than pricing based on LRMC. According to Gunter Schramm (1985) the appropriate base for determining efficiency prices are LRMC . While this view is widely held it is challenged by some economists who argued that SRMC should be used instead. For long term planning applications LRMC is more appropriate than SRMC.

Newbery (1985) argues that the difficulties of SRMC pricing can be dealt with by offering contracts of varying length during which an agreed stable price. Variations in consumption above or below this contracted amount would be priced at the spot price or the SRMC. But he did not say how this "stable price" for long term contracts is to be calculated. However having defined SRMC at the spot price, on the long run marginal(rather than average costs) the contract price is to be based. Selling the remaining surpluses in a spot market at SRMC makes eminently good sense and does not violate the principle of LRMC pricing. Such "spot markets" for electricity supplies are well known and widely used.

Ashraf and Sabih (1993) lists out certain limitations for marginal cost price.

a) First it assumed that cost curves are continuous and the marginal cost of each additional unit of out put can be easily calculated.

b) Second marginal cost pricing leads to profits for the firm only when average costs are rising in the range of output where the firm is operating. But if the firm is experiencing economies of scale and prices are set equal to marginal cost, then the firm will suffer losses. But they were also of the view that, from society point of, it is advisable to set prices equal to marginal cost if the cost of raising the government funds for subsidizing the utility is less than the cost of non-optional pricing.

c) It is also difficult to use uniform marginal cost pricing when a firm faces different classes of consumers within the same consumption group. For example an electricity utility faces consumers with different income in the residential sector. If prices are set equal to marginal cost, it may eliminate low income consumers, since these prices are higher than the limit price of such customers.

d) Another limitation is variations in demand also make it difficult to implement uniform MC pricing. Because during peak demand there is a pressure for additional capacity. As a result the marginal cost of satisfying this demand is higher than the marginal cost of meeting off-peak demand. Suppose if prices are set to reflect only peak demand, excess capacity may exist during peak hours and if prices are set to reflect only off-peak demand, shortages may exist in peak hours. The application of marginal cost pricing in one sector would imply that efficient or first best prices prevail in other sectors. This may not be real as taxes, subsidies, monopolies and many other distortions may exist in other markets. Therefore MC pricing in one sector may not necessarily lead to optimal allocation of resources. Though MC pricing is praised theoretically it is correct only for a very idealized economy A. Abraham Ravid, (1987) . As far as real world concerns, this type of pricing seems to be impartial and incorrect. An economy where the government has authority to tax, marginal cost pricing is not optimal and second best solutions are called for. When consumers own small production facilities and base their investment divisions on the utility's pricing strategy, the welfare maximization prices deviate from utility's marginal cost. This is because they provide economic incentives for potential co-generators and instruct the electric utilities to self and purchase power from consumers at a just and reasonable rate.

Economists suggests that those who can afford the necessary additional consumer cost the time of day tariff is the right long term solution . The purpose of structuring tariffs by TOU, voltage level, geographical areas and so on is to convey the LRMC of supply to consumers as accurately as possible. Although peak load or TOU tariffs may be determined on the basis of accounting costs, the allocation of capacity costs to different pricing periods is arbitrary. TOU is the best way to apply pricing structures based on LRMC. Peak load pricing or TOU tariffs have been applied in varying degrees for many years in Europe and more recently in developing countries. In general HV and MV industrial and commercial customers have been faced with separate capacity and energy charges varying by time of day or season. Greater deviations are allowed for LV consumers because of simplicity of metering .

Many state regulatory commissions implemented TOD/time-of-day) electricity tariffs by offering them on an optional basis. TOD implementation can be analyzed from the stand point of economic welfare. John.T. Wenders, (1981), Seeto, Woo and Horowitz, (1997) explores whether time-of-use pricing (TOU) or a Hopkinson tariff would be suitable for a regulated Disco in North America. Hawsman and Neufield (1983, 1984) Suggested that for theorists TOU pricing is favoured as they reflect utility's marginal cost and the user's time of consumption. There is a change towards the two rates due to exhaustion of technological economies of scale that stem from the electricity generation process. Christen sen and Greene, (1978). The emergence of competitive whole sale per markets in North America has brought real time pricing (RTP), limiting the TOU pricing in power pools with many active buyers and sellers. This type of tariff also enables the utility implicate to price discriminate among its customers in accordance with there price sensitivities. Bohn et.al, (1984) Chao, (1983)

In theory TOU pricing is economically efficient but its implementation entails the installation of expensive metering devices than is required by non-TOU pricing Spuiber

(1992), panzar and Sibley (1978), Schwartz and Taylor (1987), Chao and Wilson (1987), Woo (1985, 1991), Seeto, et.al (1997) T Jean, Jacques Laffont, (1996) TOU pricing can be economically efficient and marginal costs vary hourly and the TOU pricing will not necessarily be economically efficient.

Noel D.Uri (1984) develops a suitable model to enhance that economic efficiency will be obtained in the pricing and allocation of electrical energy.The general principles of optimal pricing from the model developed by the author are as follows:

(a) Set prices by time of day (or seasons of the year) in accordance with the pattern of demand. This means that any consumer or class of consumers in a particular hour is treated the same regardless of how much he consumes.

(b) Charge high prices when the quantity demanded rises above the level of capacity. Thus a utility can obtain a quasi rent in the short run by charging a price in excess of the operating, capital, environmental and transmission costs. But this ignores the long run consideration of imposing a penalty on the utility due to inadequate capacity to meet future requirements.

(c) Vary prices spatially depending on how far the consumer is from the generating plant.

(d) Capital costs are imputed to consumers only to the extent their demand presses on the capacity of a generating plant. Thus any increase in demand during a peak period requiring a utility to expand its generating capacity will result in a charge for electrical energy just sufficient to compensate for the increased cost associated with satisfying demand.

(E) Requires consumers to bear the implicit and explicit costs of implementing environmental quality standards.

A new electricity pricing is described by H.R. outhred, c.h. bannister, R.J. Kaye et.al.(1988), Brown and Johnson (1969), Bernstein (1988), Serra (1997) incorporates future uncertainty and intemporal linkages between decisions. It indicates that electricity prices should contain two terms- short run marginal cost plus a term that reflects how each particular decision is likely to affect future global welfare.

Ashok V.Desai (1990) identifies that the theory of electricity pricing has three approaches. The first of these is the recovery of costs through tariffs. The second deals with marginal costs (long run and short run). The third looks at spot pricing which is based on the real time cost of generation of electricity.

A firm that uses the same facility to supply many markets at different points of time can increase its profits by the use of peak load pricing Peter.O.Steiner (1957). Peak load pricing in electricity essentially involves charging higher price from consumers wanting to consume the service during the peak demand period and lower price from those who consume during off peak period. For Eg: demand for electric services is quite intense during the day time and very low during the night .Chao and Wilson (1987) by proposing innovations in pricing employing a simple options - based theory. This particular approach has advantages compared to existing approaches. This is particularly in reference to ESI facing increasing competition. time. Edward F. Renshaw (1980) estimates the benefits of peak-load electricity pricing by considering the demand curves of different types of consumer within each sub-period . the zero price line for capital. When all consumers have identical demands for electricity in the various sub-periods or where the demands in the various periods differ by about the same proportion, a separate charge for capacity will be as efficient at maximizing consumer and producer surplus as the more peak load pricing structure. In real world, where energy can be substituted for capital, the separate charge for capacity should be refined by allowing for differences in production techniques. Kleindorfer and Fernando (1993) and crew Fernando and Kleindorfer (1995) have combined in their theoretical frame work, principles of peak load pricing under stochastic conditions. Market based pricing, retail wheeling, competitive sourcing and direct access all relate more to electric competition. Regarding the price of electricity in future it will reflect the customers willingness to pay and not the cost of the product. Many utility information systems have to be revised to support the new pricing needs under competition according to James T. Doudiet. et.al (1995), David H. Spencer, (1995)

7.3 APPLICATION OF PRICING PRINCIPLES IN DIFFERENT COUNTRIES

The price of electric power is the most important criterion by which utility performance is judged. John E. Kwoka, (1996). It depends upon the objectives of regulated, competitive or publicly owned utilities. Models which portray the relationship of price to underlying costs are reviewed. To maximize economic efficiency electric utilities should be priced at marginal cost and it is assumed to be constant and labels the resulting price Pc. With high fixed costs, Mc pricing results in the failure of utilities to cover their full costs of operation.

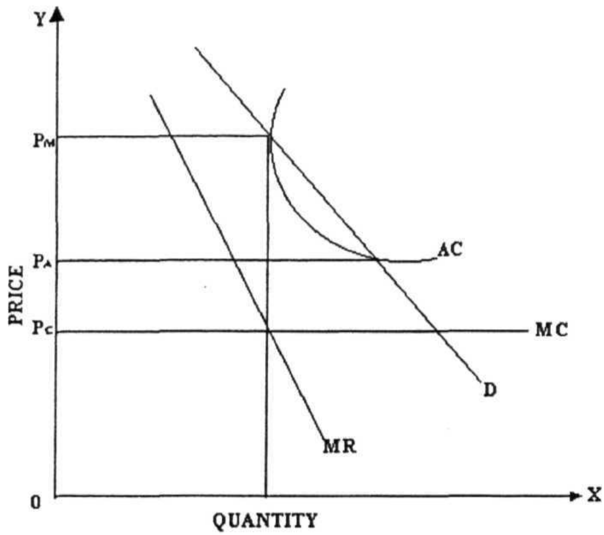


FIGURE 7.5

ALTERNATIVE PRICES FOR ELECTRIC UTILITIES

In the figure 7.5 note that AC is above MC by the amount of average fixed cost. The only remedy for revenue shortfall would be direct subsidization. Therefore MC pricing is not governing utility pricing. Some studies have concluded that prices under rate of return regulation differ from profit maximizing levels. Public systems are also managed in order to maximize profit and therefore pricing under both regimes must be modeled as profit maximization. Such pricing would require marginal cost equated to marginal revenue, resulting in price Pm. Another model is utilities do mark up price over marginal cost, but not to full profit, maximizing level. The full cost of operation can be recovered, if price is equal to the sum of marginal cost plus per unit fixed costs that is average total costs Pa in the figure. First the average cost pricing is taken as a good first approximation to electric utility pricing as it focuses on meeting the utilitiy's revenue requirement. The average cost pricing model can be written as.

PRICE = f (AVG COST, TAX RATE, PUBLIC, COMP, X)

The first two right hand side variables are cost terms, where AVG cost denoting average total costs of the utility, while TAX RATE is its per unit rate of tax, They are the major determinants of the price level both under regulation and public ownership. The variable PUBLIC is included to determine given costs, price is set differently under public versus private ownership. COMP is a variable defined as unity for dupoly or a border competition, intended to capture the impact on price from a utility's operation in a competitive environment.

Tensions between subsidy policy and competition policy have been important in ESI. Uniform nation wide pricing constrains liberalization (John vickers, 1996). But in UK as competition developed in ESI implicit subsidies to coal disappeared. Bawmol and Willing argue for the efficient component pricing rule (ECPR) which is cost based. Armstrong, Doyle and Vikers, (1995) claim that the ECPR and Ramsey approaches are fundamentally very similar . The pricing policies in Argentina, Brazil and Uruguay are similar . pricing policies in three countries are (Pablot Spiller et.al, 1996).

a) First average tariffs are below longrun average costs
b) Second tariffs discriminate by enclose
c) There is an attempt to have uniform pricing across regions.

Navorro (1996) was of the view that Ramsey pricing has been gaining attention in recent years and proposals have been gaining attention in recent years and proposals have been made to introduce such a pricing system into the rate structure in an attempt to balance revenues and expenditures. This kind of Ramsey pricing was encouraged from the techniques such an increase in self generation and co-generation in recent years, resulting in more intense competition in ESI. Jurgen Muller and Konrad Stahl, (1996). The customer must be supplied electricity at a cost -oriented price. The pricing policy of Electricity Defrance must achieve budget balance, equity among consumers and economic efficiency Jean Jacques Laffont, (1996). Increased attention has been received by transmission pricing reform. Michael Einhorn **et.al (1996)** focuses his study on the work of Fred Schweppe, Roger Bohn and Michael **Caramanis** on spot pricing.

Finally whatever criterion is selected what is really important is that the rate system should be based on technical concepts in order to make it impervious to political manipulation. It is extremely important that the government pledge to maintain the tariff systems stability by passing a law rejecting any pressure to distort it no matter where the pressure comes from.

7.3 SUMMARY

This chapter dealt with theoretical aspects of electricity pricing where in different economists expressed different views regarding marginal cost and average cost pricing principles. Their contribution to the subject is considered to be one of the pioneering nature. But no ideal tariff actually exists in ESI (during restructuring). For large developed countries like USA, UK, Northern Ireland the prices would naturally be equal to short run marginal cost and competition would ensure cost minimization in the production and optimal investment decisions. This is impractical in developing countries as individual units here are typically large relative to market serviced grids which are small and poorly integrated and hence competition is a unreality. However, efforts are made to apply marginal cost pricing to electricity tariff practically in India. In Andhra Pradesh long run marginal cost pricing method is used in ESI during restructuring. One important point is that too much emphasis on low price which has been an harm from past several years could frighten away potential investors there by hindering a successful privatization.

CHAPTER VIII
RESTRUCTURING OF ELECTICITY SUPPLY INDUSTRY -INDIAN EXPERIENCE

8.0 INTRODUCTION

Significant structural, institutional and regulatory changes in the ESI are required and for this there is a need for rapid transformation of the ESI from a natural monopoly to that of a business supplying a multitude of electricity services to satisfy consumer requirements. This was further aided by a change towards consideration of generation, transmission and distribution as different activities rather than a single integrated bundled industry. Imparting dynamism to the ESI and its transformation from an industry under government ownership and control to a more decentralized, unbundled industry subject to competitive forces and market disciplines are presenting and upcoming new challenges to policy makers in most countries.

This chapter provides the ESI in India , its characteristics and a historical background related to power sector outlay and actual expenditure for selected years and all the states. This chapter also deals with electricity consumption sector wise, plant load factors, transmission and distribution losses and cost structure of SEB's. Finally cost recovery calculated from unit cost and tariff are included for selected years in all states.

The objective of this chapter is to analyze the over all power scenario of Indian Economy. The present study undertakes a comprehensive and detailed analysis of the power sector in India for identifying the problem areas to remedy the situation. For this the study aims to review plan outlay and expenditure in power sector, the power generation from different sources such as Hydro, Thermal, Coal based thermal electricity, oil based thermal electricity, Gas based thermal electricity, nuclear electricity at the All India level. Generally the database is annual time series data on various variables stated above and the comparison is based on the growth rates and the proportion or the share as the relevant measure of comparison.

With the help of this data this chapter reviews evolution and growth of power sector in India, performance of SEB's i.e., financial performance, pricing policies of SEB's in India. This chapter indicates the directions for reforms in pricing policy to promote private sector participation in the Electricity supply Industry (ESI). It also examined the case studies of power sector reforms in India and abroad.

8.1 THE ECONOMY AND ELECTRICITY LINKAGE IN INDIA

The appendix table A.8.1 provides the GDP at factor cost (1980-81=100 as a base year) measured in Crores of rupees covering the period 1970-71 to 2001-02. The industries under considerations are agriculture, manufacturing, electricity, transportation and others to totalling to the GDP at factor cost in real terms.

Traditionally India being an agriculture based country the over all average growth rate has only 2.5%, for 32 years put together. The date suggests that electricity sector has an average growth rate of 7.0% which is due to expansion of its generation through private sector participation. It is expected that this sector will play an important role in the future economic development. The appendix table A.8.2 provides the share of each sector out of the GDP. The share of agricultural sector has drastically reduced from 1970-71 to 2001-02, where as the share of manufacturing sector has increased from 17.4% to 27.3% in the same comparable period. The share of electricity sector varied from 1.2% to 2.7% in the 32 year period, which is not significant.

8.1.1 PLAN OUTLAY AND EXPENDITURE IN POWER SECTOR

The percentage of power outlay in total out lay of all sectors is highest at 19.28% in Annual Plan (1990-91) and power expenditure percentage in total expenditure is highest at 21.41% in annual plan (1990-91). An earnest attempt has to be taken by the central and state governments to further increase outlays on the power sector to keep pace with the growing demand for electricity and provide adequate, regular, high quality and low cost power supply.

TABLE 8.1

POWER GENERATION BY SOURCE (MKWH)

YEAR	HYDRO ELECTRICITY (1)	COAL BASED THERMAL ELECTRICITY (2)	OIL BASED THERMAL ELECTRICITY (3)	GAS BASED THERMAL ELECTRICITY (4)	THERMAL ELECTRICITY [TOTAL (5) = (2)+ (3)+(4)]
1980-81	46542 (-)	60714(-)	65(-)	522 (-)	61301(-)
1981-82	49565 (6.5)	68747(13.2)	69(6.2)	699(33.9)	69516(13.4)
1982-83	48373(-2.4)	77914(13.3)	44(-36.2)	1910(15.1)	79868(12.9)
1983-84	49954(3.2)	844345(8.4)	43(-2.3)	2199(-16.6)	86677(8.5)
1984-85	53948(7.9)	96957(14.8)	45(4.6)	1834(-4.2)	98836(14.0)
1985-86	51021(-5.4)	112540(16.1)	51(13.3)	1757(90.1)	114347(15.6)
1986-87	53841(5.5)	125452(11.5)	59(15.7)	3340(11.7)	12885112.7)
1987-88	47444(-11.9)	145814(16.2)	69(16.9)	3731(-26.6)	149614(16.1)
1988-89	57868(21.9)	154895(6.2)	76(10.1)	2740(26.6)	157711(5.4)
1989-90	62116(7.3)	172643(11.5)	91(19.7)	5962(117.6)	178696(13.3)
1990-91	71641(15.3)	178322(3.3)	111(21.9)	8113(66.11	186546(4.4)
1991-92	72757(1.6)	197163(7.1)	134(20.47)	11450(41.1)	208747(11.9)
1992-93	69869(-32.9)	211124(10.4)	162(20.9)	13480(17.7)	224766(7.71
1993-94	70463(0.85)	233151(4.3)	311(91.9)	14728(9.3)	248189(10.4)
1994-95	82712(17.4)	243110(12.6)	545(75.2)	18475(25.41	262130(5.6)
1995-96	72579(-12.3)	273744(5.7)	714(31.0)	24858(34.5)	299316(6.2)
1996-97	68901(-5.1)	289378(5.7)	1554(117.6)	26985(8.6)	317918(5.9)
1997-98	74571(8.2)	304834(5.3)	2820(81.5)	29000(7.41	336654(5.9)
1998-99	82619(10.8)	321300(5.4)	3000(6.3)	29500(1.7)	353800(5.1)
1999-00	93421(13.1)	353009(9.9)	3215(7.1)	29534(0.11)	385758(9.0)
2000-01	99000(5.9)	384547(8.9)	3410(6.1)	30124(1.9)	418081(0.37)
2001-02	99457(0.46)	402345(4.6)	3524(3.3)	32698(8.5)	438567(4.9)
Average	2.5	8.8	30.6	17.3	8.6

SOURCE : CENTRE FOR MONITORING INDIAN ECONOMY, ENERGY, MARCH 2000

Note: The numbers in the parenthesis are growth rates

TABLE 8.1 (contd..)

POWER GENERATION BY SOURCE (MKWH) INDIA

YEARS	NUCLEAR ELECTRICITY (6)	ELECTRICAL ENERGY(UTILITIES) (7)	ELECTRICAL ENERGY(NON-UTILITIES) (8)
1980-81	3001 (-)	110844(0	8416(-)
1981-82	3021 (0.67)	122101(10.2)	9024(7..2)
1982-83	2022 (-33.1)	130264(6.7)	10036(11..2)
1983-84	3546 (75.4)	140177(7.6)	10817(7.8)
1984-85	4075(14.9)	156859(11.9)	12346(14.1)
1985-86	4982(22.3)	170350(8.6)	13040(5.6)
1986-87	5022(0.80)	187714(10.2)	13565(40..3)
1987-88	5035(0.26)	202093(7.7)	16891(24..5)
1988-89	5817(15.5)	221896(9.8)	19911(17..9)
1989-90	4625(-20.5)	245438(10.6)	23226(16.6)
1990-91	6141(32.8)	264329(7.7)	25111(8.1)
1991-92	5524(-10.0)	287029(8.6)	28602(13.9)
1992-93	6726(21.7)	301862(5.2)	31352(9.6)
1993-94	5398(19.7)	324050(7.4)	32285(2.9)
1994-95	5648(4.6)	350490(8.2)	35067(8.6)
1995-96	7982(41.3)	379877(8.4)	38166(8.8)
1996-97	907(13.6)	395889(8.4)	40840(7.0)
1997-98	10095(11..3)	421320(6.4)	42784(4.8)
1998-99	11987(18.7)	448406(6.4)	43000(0.56)
1999-00	13487(12.5)	489274(9.1)	49578(15.3)
2000-01	15280(13.2)	526683(8.3)	49951(0.75)
2001-02	18245(19.4)	547945(4.0)	52412(4.9)
Average	12.9	7.4	10.5

REFERENCE: CENTRE FOR MONITORING INDIAN ECONOMY, ENERGY, MARCH 2000

8.1.2 ELECTRICITY GENERATION FROM VARIOUS SOURCES

The power generation by various sources (both electrical energy utilities and non-utilities) and its consumption in various sectors in the economy in MKWH was shown in the table 8.1 and appendix A.8.3. The analysis here is based on the trends in electricity generation by utilities classified under hydro electricity, thermal electricity i.e (coal based thermal electricity, oil based thermal electricity, Gas based thermal electricity) and nuclear electricity. The over all electricity generation in 1980-81 was 110844 MKWH and it has increased to 99457 MKWH by 2001-02 in the 32 time year period with an average growth rate of 2.5%.

The power generation by thermal electricity has increased 438567 MKWH by 2001-02, an average growth rate of 8.6%, compared with oil based and gas based thermal electricity by 3524 MKWH and 32698 MKWH. The comparison of average growth rates of coal based, oil based and gas based thermal electricity i.e. 8.8%, 30.6% and 17.3% shows that natural gas is increasingly used as feed stock in electricity production.

The Hydropower generation as shown in the table indicates an increase from 46542 MKWH in 1980-81 to 99457 MKWH by 2001-02. The data shows that there are many fluctuations in power generation based on Hydro sources, mainly due to monsoon and natural water resources. For example, in 1995-96 there was 12.3% drop of electricity generated from hydro sources. From the table it is in ferried that in India the contribution of nuclear electricity is very much negligible. It was 3001 MKWH in 1980-81 and increased to 18245 MKWH in 2001-02, an average growth rate or 12.7%. The highest negative growth rate has been recorded in case of nuclear electricity in 1982-83 i.e -33.1%. The electrical energy in case of non-utilities indicates that their production has increased from 8416 MKWH in 1980-81 to 40840 MKWH to 52412 MKWH in 2001-02, with an average annual growth rate of 10.5%. With the announcement of private policy (October 1991) there is a need to open an alternate route i.e., to increase electricity generation from non-utilities also. India in their recent restructuring process of electricity sector have brought important changes like private power promotion, captive power and co-generation route which would quickly add to generation capacity in the country.

The appendix A.8.3 shows the consumption of electricity in various sectors of the economy. Compared to the domestic sector, the industrial sector is the major consumer of electricity. Within industrial sector, high-tension industries consume more electricity i.e., 83215 **MKWH.** The agricultural sector is also major consumer of electricity because of the rural electrification programmes and electricity was provided to the fanners at subsidized rates by most of SEB's in India i.e., **14489MKWH** in 1980-81 to **90214MKWH** in 2001-02.

8.1.3 DEMAND - SUPPLY BALANCE

Though the actual power generation increase at an annual average rate of over 10 percent during the last four decades supply has not been able to keep up with increasing demand as shown in table 8.2. The balance in electric power has changed dramatically **from** a surplus in the **1960s** and early **1970s** to one of increasing shortages since the **1980s.** the demand for electricity in 1980-81 was 120100 MKWH and it increased to 741200 MKWH in 2001-02 with an average annual growth rate of 8.7%. Compared with demand, the supply of electricity was only 104900 MKWH in 1980-81 and 550001 MKWH in 2001-02 average annual growth rate of 7.8%. The energy deficit has showed a steady increase from **15200** MKWH in **1980-81** to **131199** MKWH in 2001-02, with an average annual growth rate of 0.06%. The highest growth rate was recorded at 42.8% in 1995-96 and negative growth rate at 33.3% in 1984-85. The reasons for this are T & D losses, Low PLF, subsidy, pilferage, technical inefficiencies in generation, short comings in voltage and frequency, poor standards of reliability, poor financial returns from the investments in the ESI and uneconomic and distortionary pricing policy in the sector. **The** broad strategy of the government has been both supply side and demand side management to meet these shortages. On the supply side, however, the emphasis has primarily been on addition of generation capacity. There is a need to successfully implement private sector participation in Renovation and Modernization of power plants, which offers a quick remedy to power shortages to a considerable extent.

TABLE 8.2

DEMAND-SUPPLY BALANCE FOR ELECTRICITY(MKWHR), INDIA

YEAR	DEMAND	SUPPLY	DEFI1CIT	DEFICIT AS A PERCENTAGE OF DEMAND
1980-81	120100(-)	104900(-)	15200(-)	12.6
1981-82	129200(7.6)	115300(9.9)	13900(-8.6)	108
1982-83	136800(5.9)	124200(7.7)	12600(-9.4)	9.2
1983-84	145300(6.2)	129700(4.4)	15600(23.8)	10.7
1984-85	155400(6.9)	145000(11.8)	10400(-33.3)	6.7
1985-86	170700(9.8)	157300(8.5)	13500(29.8)	7.9
1986-87	192400(12.7)	174300(10.8)	18100(34.1)	9.4
1987-88	211000(9.7)	188000(7.9)	23000(27.1)	10.9
1988-89	223200(5.8)	205900(9.5)	17300(-24.8)	7.7
1989-90	247800(11.0)	228200(10.8)	19600(13.3)	7.9
1990-91	267600(7.9)	246600(8.1)	21100(7.7)	7.9
1991-92	289000(7.9)	266400(8.0)	22500(6.6)	7.8
1992-93	305300(5.6)	279800(5.0)	25400(12.9)	8.3
1993-94	323300(5.9)	299500(7.0)	23800(-6.3)	7.3
1994-95	352300(8.9)	327300(9.3)	25000(5.0)	7.1
1995-96	389700(10.6)	354000(8.2)	35700(42.8)	9.2
1996-97	429700(10.3)	380700(7.5)	49000(37.3)	11.4
1997-98	471700(9.8)	410700(7.9)	61000(24.5)	12.9
1998-99	515700(9.3)	442300(7.7)	73400(20.3)	14.2
1999-00	624702(21.1)	520412(17.7)	104290(42.1)	16.7
2000-01	654898(4.8)	530145(1.9)	124753(19.6)	19.0
2001-02	741200(13.2)	550001(3.7)	131199(5.2)	17.0
AVERAGE	8.7	7.8	0.06	

SOURCE: CMIE, INDIA'S POWER SECTOR, CENTRE FOR MONITORING INDIAN ECONOMY, MUMBAI (VARIOUS ISSUES)

Note: The numbers in the parenthesis are growth rates

8.1.4 CONSUMERS OF ELECTRICITY AND ELECTRICITY CONSUMPTION IN STATES

Appendix A.8.4 and A.8.5 provides the number of consumers of electricity and per capita consumption of electricity in states. In India there are 19 SEB's and 8 ED's (electricity Departments). Among SEBs Maharashtra State has increased number of consumers of electricity from 1992-93 to 1996-97 compared to other states. i.e., 9.27 million to 11.42 million.

Interstate distribution of power consumption shows wide variation and is significantly higher in more developed states. The average consumption of electricity per head is high in western region i.e., 443.3 MKWH as compared to other regions i.e 285.1 KWH, 330.6 KWH, 145.6 KWH, 94.9 KWH. The per capita consumption of electricity at all India level increased from 253 KWH in 1990-91 to 338 KWH in 1996-97.

8.1.5 ELECTRICITY, TRANSMISSION AND DISTRIBUTION

Appendix A.8.6 provides the distance of transmission and distribution lines covering the period from 1970-71 to 2001-02. The highest growth rates for T&D was recorded in 1972-73 and 1979-80 at 3.5.7% and 14.9%. This is due to massive expansion of transmission and distribution network through rural electrification and also to remote areas.

8.1.6 TECHNICAL EFFICIENCY - STATE LEVEL PERFORMANCE

Appendix A.8.7 shows that the PLF(plant load factor) and Auxiliary consumption of thermal stations in four regions (Northern, Western, Southern, Eastern, North Eastern, Central sector and private sector). The PLF's of thermal units in the southern region is more i.e., 77.10% compared to other regions. Assam and Orissa has PLF's of less than 30%. An important reason for low PLF is the poor quality of coal which results forced outages. Private sector showed a steady increase in percentage of PLF i.e., 71.10 in 1997-98. Andhra Pradesh and Rajasthan logged more than 80% PLF's. However major improvements in the PLF's would require large investments in long term rehabilitation and re-powering through private sector participation.

8.1.7 TRANSMISSION AND DISTRIBUTION LOSSES

Appendix A.8.8 shows T & D losses in SEB's. Internationally a T & D loss of 10% of total power generation is considered satisfactory. In most developed countries T & D losses are less than 10%. Even among developing countries, mostly the losses are less than 15%. In India the losses vary state wise. There are non-technical losses in several SEB's due to pilferage and unmetered supplier which made the estimated figures of T & D losses in correct to actual T & D losses.

8.1.8 COST STRUCTURE OF SEB's

Appendix A.8.9 shows cost components of SEB's which include fuel, power purchase, operation and maintenance (O & M), establishment and administration, depreciation and interest for the years 1993-94 to 1999-2000. On an average the total cost of supplying electricity varied from 200.40 Paise per KWH in 1993-94 to 280.88 Paise per KWH in 1999-2000.

8.1.9 PRICING OF ELECTRICITY

Sections 49 and 59 of the Act empower the SEB's an advisory role to directly influence tariffs in accordance with their socio-political interest. This has neglected the economic considerations in policies. Low technical efficiency, high supply cost and inability of the SEB's to charge economic prices for the electricity sold to different categories of customers are the principal reasons for the heavy losses incurred by them during the years. According to section 63 of the Act, the Board should adjust its tariff so as to ensure that the total revenue in any year of account shall, after meeting all expenses properly chargeable to revenues, including operating, maintenance and management expenses, taxes or income and profits, depreciation, and interest payable on debentures, bounds and loans, leave such surplus, the state government ma y from time to time specify. An amendment to act in 1978 stipulates that SEB's should earn at least 3% return (after interest and depreciation) on a historic cost-asset base. In reality, the SEB's have little control over their own tariff policy and were never required to generate any rate of return.

The table 8.3 shows the net calculation of **tariff** and unit cost which includes fuel cost. A comparison of average tariffs levied by SEB's with their average costs shows that through out the years from 1974-75 to **1998-99** the average tariffs were consistently below the average costs of supplying electricity and low at 4.4% in **1991-92.**

8.1.10 COMMERCIAL LOSS

Appendix **A.8.10** shows the level of commercial loss of SEB's which is due to effective subsidies provided to agriculture and domestic sectors are shown in Appendix **A.8.11** and **A.8.12.**

8.1.11 EFFECTIVE SUBSIDY AND CROSS SUBSIDIZATION

Table 8.4 provides estimates of subsidy for agricultural, domestic sectors and state government. **"Effective subsidy"** (defined as average unit cost of supply minim average unit revenue realization times that total sales for agricultural and domestic sector). The "Net Subsidy" on account of sale of electricity to agricultural and domestic consumers was Rs. 5404 Crore in 1991-92 which works out 4.6% of central plan assistance Rs. **11749** Crore to state in that year. The effective subsidy is likely to increase to Rs. 26982 Crore in 1999-2000 (Annual Plan AP) which works out to 85% of Central plan assistance (Rs. 31918) to State. Introduction of the national minimum agricultural tariff of 50 paise /kwhr would still leave a substantial gap uncovered. For example, in 1997-98 this gap was of the order of nearly Rs. **17156.8** Crore taking in to consideration Rs. 4450.2. Cross subsidy is received from state governments while some state governments partly compensate the SEBs for the subsidized sales of electricity to agricultural and domestic sectors, others do not provide any compensation at all. In 1998-99 (RE) the state governments had proposed to give subvention to their SEBs, totaling a sum of Rs. 2214 Crore, which works out to 8.3% of the effective subsidy that the SEBs had to bear at the estimated tariffs. Some of the state governments also write off the interest payable to them in lieu of subsidized sales to agricultural and domestic sectors.

Table 8.5 provides estimates of cross subsidy from others. A part of the subsidy provided to the agricultural and domestic consumers is recovered by the SEBs through cross-subsidization of tariff on the users of other sectors (Mainly industrial and commercial) as indicated in the above table, The cross subsidy from commercial and industrial sectors (as a percentage of effective subsidy to domestic and agricultural consumers was 41.7% in 1992-93 declined to 37.6% in 1995 and increased to about 41% in 1997-98. It is expected to be 40.4 in 1999-2000. It is worth-noting that the cross subsidy form other sectors was only 22.9% There is however, a limit to such cross subsidization as greater burden on industry and commercial sectors can affect the competitiveness of these sectors and also encourage them to set up their own captive generation.

8.1.12 RATE OF RETURN

Table 8.6 provides ROR with subsidy, with out subsidy and with 50 Paise/KWHR for agricultural sales. In terms section 59 of the Electricity (supply) Act, 1948, the SEB's are required to earn a minimum rate of return (ROR) of 3% on their net fixed assets in service after providing for depreciation and charge. The state governments could prescribe a higher return if considered necessary. However most of the SEB's are yet to comply with this statutory stipulation. Revenue realization from the sale of electricity in some cases does not even cover their revenue expenditure requirements. There has been in general deterioration in the ROR of the SEB from -12.7% in 1992-93 to - 20.7% in 1998-99 (RE). Though subvention from the state governments has improved the ROR it still remains negative. If the suggested national minimum agricultural tariff of 50 Paise/KWHR has been implemented by all SEB's, the ROR would still have been - 13.5% in 1998-99 (RE). If the SEB's are required to financially break, they would have to mobilize substantial revenue. The table 8.7 brings out the additional revenue of SEB's in case they achieve break-even ROR 3% or adopt the all-India minimum agricultural tariff of 50 Paise per KWHR for the agricultural sector. If all the utilities are able to adopt a tariff of 50 Paise /KWHR for agricultural sales they would be able to mobilize additional revenues to the tune of Rs. 2651 Crore in 1999-2000 and (AP) their resource could improve to over Rs. 13817 Crore at 0% ROR and over Rs. 1600 Crore at 3% ROR the additional revenues would provide them with much needed funds for capacity expansion and improving the performance of the existing assets. These would also reduce the subvention. It is evident from the tables that on an average at the all India level, the SEB's would have to raise the tariff by about 66 Paise /KWHR for achieving 0% ROR and by about 73 Paise/KWHR for achieving 3% ROR in 1991-2000 and above the average tariff proposed for 1991-200 the increase required for achieving 0% ROR is as high as 163 Paise for Assam, 162 for Haryana and 110 Paise/KWHR for Jammu and Kashmir. As against this tariff increase required for Himachal Pradesh is only 7 Paise per unit only.

ELECTRICTY TARIFF MINUS UNIT COST (PAISE PER KWH), INDIA

YEAR	1990-1991			1991-1992		
SEB	TARIFF	UNIT COST	% OF COST RECOVERY	TARIFF	UNIT COST	% OF COST RECOVERY
ANDHRA PRADESH	74.5 (-)	78.72 (-)	0.95	83.3 (11.8)	89.23 (13.4)	0.93
ASSAM	94.8 (-)	249.59 (-)	0.38	92.1 (-2.8)	281.24 (12.7)	0.33
BIHAR	88.6 (-)	168.97 (-)	0.52	97.8 (10.4)	176.53 (4.5)	0.55
DELHI VB	99.1 (-)	137.89 (-)	0.72	124.7 (25.8)	144.06 (4.5)	0.87
GUJARAT	78.0 (-)	110.11 (-)	0.71	93.0 (19.2)	132.28 (20.1)	0.70
HARYANA	66.6 (-)	103.66 (-)	0.64	66.3 (-0.5)	115.47 (11.4)	0.57
HIMACHAL PRADESH	79.1 (-)	94.77 (-)	0.83	86.0 (8.7)	118.19 (24.7)	0.72
JAMMU& KASHMIR	35.9 (-)	125.59 (-)	0.29	35.9 (0)	172.34 (37.2)	0.21
KARNATAKA &KPC	81.3 (-)	113.9 (-)	0.71	82.4 (1.4)	122.99 (7.9)	0.67
KERALA	52.6 (-)	68.17 (-)	0.77	60.0 (14.1)	81.30 (19.3)	0.74
MADHYA PRADESH	84.9 (-)	116.44 (-)	0.73	94.9 (11.8)	121.53 (4.4)	0.78
MAHARASHTRA	103.1 (-)	107.44 (-)	0.96	107.8 (4.6)	124.51 (15.9)	0.87
MEGHALAYA	59.2 (-)	137.28 (-)	0.43	64.6 (9.1)	107.06 (-22.0)	0.60
ORISSA	67.9 (-)	71.43 (-)	0.95	65.1 (-4.1)	71.77 (0.47)	0.91
PUNJAB	54.9 (-)	106.79 (-)	0.51	59.9 (9.1)	98.77 (-7.5)	0.61
RAJASTHAN	92.9 (-)	114.59 (-)	0.81	93.1 (0.22)	113.31 (-1.1)	0.82
TAMIL NADU	86.5 (-)	114.32 (-)	0.76	96.1 (11.1)	103.33 (-9.6)	0.93
UTTAR PRADESH	73.1 (-)	110.04 (-)	0.66	79.7 (9.0)	119.51 (8.6)	0.67
WEST BENGAL &WBPDC	104.2 (-)	226.74 (-)	0.46	111.9 (7.4)	236.81 (4.4)	0.47
AVERAGE	77.74(-)	124.02		83.9(7.9)	133.17(7.4)	

SOURCE: ANNUAL REPORT ON WORKING OF SEB's, ELECTRICITY DEPARTMENTS, ENERGY AND POWER DIVISION, PLANNING COMMISSION, (1999), NEW DELHI

ELECTRICTY TARIFF MINUS UNIT COST (PAISE PER KWH), INDIA

YEAR	1992-1993			1993-1994		
SEB	TARIFF	UNIT COST	% OF COST RECOVERY	TARIFF	UNIT COST	% OF COST RECOVERY
ANDHRA PRADESH	94.3 (13.2)	100.07 (12.1)	0.94	98.6 (4.5)	109.00 (8.9)	0.90
ASSAM	121.0 (31.4)	255.22 (10.2)	0.47	121.3 (0.25)	252.65 (-1.0)	0.48
BIHAR	118.4 (21.1)	185.67 (-9.3)	0.64	147.4 (24.5)	200.05 (7.7)	0.74
DELHI DVB	134.0 (7.5)	164.12 (13.9)	0.82	—	—	—
GUJARAT	100.3 (7.8)	146.59 (10.8)	0.68	121.0 (20.6)	158.40 (8.1)	0.76
HARYANA	72.5 (9.3)	134.40 (16.4)	0.54	83.3 (14.9)	165.40 (23.1)	0.50
HIMACHAL PRADESH	101.1 (17.6)	114.31 (-3.3)	0.88	106.8 (5.6)	142.80 (24.9)	0.75
JAMMU & KASHMIR	35.3 (-1.7)	165.46 (-3.9)	0.21	35.1 (-0.57)	209.13 (26.4)	0.17
KARNATAKA &KPC	93.4 (13.3)	139.41 (13.4)	0.67	106.8 (14.3)	155.68 (11.7)	0.69
KERALA	74.0 (23.3)	87.30 (7.4)	0.85	82.1 (10.9)	98.32 (12.6)	0.84
MADHYA PRADESH	118.9 (25.3)	141.44 (16.4)	0.84	118.9 (0)	157.80 (11.6)	0.75
MAHARASHTRA	136.9 (26.9)	138.95 (11.6)	0.99	150.5 (9.9)	152.24 (9.6)	0.99
MEGHALAYA	89.5 (38.5)	110.09 (28.3)	0.81	91.4 (2.1)	97.75 (-11.2)	0.94
ORISSA	77.2 (18.6)	98.80 (37.6)	0.78	95.1 (23.2)	133.46 (35.1)	0.71
PUNJAB	70.3 (17.4)	122.00 (23.5)	0.58	89.3 (27.0)	145.16 (18.9)	0.62
RAJASTHAN	105.1 (12.9)	138.24 (22.0)	0.76	115.3 (9.7)	163.80 (20.5)	0.70
TAMIL NADU	107.1 (11.4)	124.52 (20.5)	0.86	128.3 (19.8)	144.72 (16.2)	0.89
UTTARPRADESH	108.4 (36.0)	153.42 (28.4)	0.71	111.8 (3.1)	169.44 (10.4)	0.66
WEST BENGAL	115.7(3.4)	244.8(3.4)	0.47	135.4(17.0	260.45(6.4)	0.52
AVERAGE	98.6(17.5)	145.52(9.3)	0.68	102.02(3.5	153.48(5.5)	0.66

SOURCE: ANNUAL REPORT ON WORKING OF SEB's, ELECTRICITY DEPARTMENTS, ENERGY AND POWER DIVISION. PLANNING COMMISSION, (1999), NEW DELHI

ELECTRICTY TARIFF MINUS UNIT COST (PAISE PER KWH), INDIA

YEAR	1994-1995			1995-1996		
SEB	TARIFF	UNIT COST	% OF COST RECOVERY	TARIFF	UNIT COST	% OF COST RECOVERY
ANDHRA PRADESH	92.9 (-5.7%)	128.93 (18.3%)	0.72	97.1	156.12	0.62
ASSAM	121.5 (0.16)	299.30 (18.5%)	0.41	214.7 (76.7%)	356.07 (18.9%)	0.60
BIHAR	155.0 (5.2%)	232.84 (16.4%)	0.67	179.1 (15.5%)	252.40 (8.4%)	0.71
DELHI VB	-	-		-	329.76	
GUJARAT	128.0 (5.8%)	171.63 (8.4%)	0.75	132.0 (3.1%)	181.53 (5.8%)	0.73
HARYANA	110 (33.0%)	179.53 (8.5%)	0.75	132.0 (3.1%)	181.53 (5.8%)	0.73
HIMACHAL PRADESH	116.3 (8.9%)	126.60 **(-11.3%)**	0.92	122.1	111.45 **(-11.9%)**	1.1
JAMMU& KASHMIR	36.7 (4.6%)	230.80 (10.4%)	0.16	35.6 (-2.9%)	242.48 5.1%	0.15
KARNATAKA &KPC	105.1 (-1.6%)	163.03 (4.7%)	0.64	114.1 (8.6%)	222.09 (36.2%)	0.51
KERALA	86.7 (4.6%)	108.84 (10.7%)	0.79	92.8 (7.0%)	134.46 (23.5%)	0.69
MADHYA PRADESH	129.6 (4.6%)	167.18 (5.9%)	0.77	139.3 (7.5%)	181.64 (8.6%)	0.76
MAHARASHTRA	161.1 (7.0%)	162.02 (6.4%)	0.99	169.0 (4.9%)	185.25 (14.3%)	0.91
MEGHALAYA	98.9 (8.2%)	139.01 (42.2%)	0.71	107.2 (8.3%)	147.35 (5.9%)	0.73
ORISSA	149.8 (57.5%)	185.70 (39.1%)	0.81	170.3 (13.7%)	227.46 (22.5%)	0.75
PUNJAB	108.3 (21.3%)	165.06 (13.7%)	0.66	124.9 (15.3%)	179.69 (8.9%)	0.69
RAJASTHAN	133.3 (15.0%)	196.52 (20.5%)	0.68	142.3 (6.8%)	213.17 (8.5%)	0.67
TAMILNADU	150.2 (17.1%)	152.02 (40.2%)	0.99	165.9 (10.5%)	170.91 (4.8%)	0.67
UTTAR PRADESH	122.4 (9.5%)	177.53 (4.8%)	0.69	140.8 (15.0%)	191.98 (8.1%)	0.73
WEST BENGAL	143.0 (5.6%)	295.55 (-13.4%)	0.48	147.9	298.42	0.49
AVERAGE	199.42 (17.0%)	182.33 (18.8%)	0.65	134.88 (12.9%)	210.04 (12.2%)	0.64

SOURCE: ANNUAL REPORT ON WORKING OF SEB's, ELECTRICITY DEPARTMENTS, ENERGY AND POWER DIVISION, PLANNING COMMISSION, (1999), NEW DELHI

ELECTRICTY TARIFF MINUS UNIT COST (PAISE PER KWH), INDIA

YEAR	1996-1997			1997-1998		
SEB's AGENCY	TARIFF	UNIT COST	% OF COST RECOVERY	TARIFF	UNIT COST	% OF COST RECOVERY
ANDHRA PRADESH	150.0 (54.5%)	205.12 (31.4%)	0.73	188.5 (25.6%)	217.44 (6.0%)	0.87
ASSAM	214.9 (0.09%)	402.17 (12.9%)	0.53	216.6 (0.79%)	423.17 (5.2%)	0.51
BIHAR	185.2 (3.4%)	290.55 (1.6%)	0.63	210.7 (13.8%)	295.28 (1.6%)	0.71
DELHI VB	248.6	332.73	0.75	265.1 (6.6%)	365.02 (9.7%)	0.73
GUJARAT	162.0 (22.7%)	199.66 (9.9%)	0.81	193.0 (19.1%)	235.37 (17.9%)	0.82
HARYANA	155.3 (16.9%)	230.51 (10.5%)	0.67	178.8 (15.1%)	244.09 (5.9%)	0.73
HIMACHAL PRADESH	143.5 (17.5%)	129.36 (16.1%)	1.1	162.3 (13.1%)	160.17 (23.8%)	1.0
JAMMU& KASHMIR	34.2 (-3.9%)	282.38 (16.5%)	0.12	39.3 (14.9%)	290.47 (2.9%)	0.14
KARNATAKA &KPC	140.6 (23.2%)	294.15 (32.4%)	0.48	163.7 (16.4%)	272.51 (7.4%)	0.60
KERALA	95.6 (3.0%)	169.92 (26.4%)	0.56	126.9 (32.7%)	199.04 (17.1%)	0.64
MADHYA PRADESH	177.2 (27.2%)	208.71 (14.9%)	0.84	176.2 (-0.56%)	218.12 (4.5%)	0.81
MAHARASHTRA	189.0 (11.8%)	206.85 (11.6%)	0.91	213.8 (13.1%)	218.24 (5.5%)	0.97
MEGHALAYA	127.7 (19.1%)	158.59 (7.6%)	0.81	130.0 (1.8%)	168.19 (6.1%)	0.77
ORISSA	202.0 (18.6%)	263.80 (15.9%)	0.76	218.0 (7.9%)	272.03 (3.1%)	0.80
PUNJAB	136.3 (9.6%)	187.44 (4.3%)`	0.73	139.7 (2.5%)	226.64 (20.9%)	0.62
RAJASTHAN	166.6 (57.4%)	239.49 (12.3%)	0.69	194.9 (16.9%)	259.57 (8.4%)	0.75
TAMILNADU	172.9 (4.2%)	185.00 (8.2%)	0.93	197.1 (13.9%)	217.06 (17.3%)	0.91
UTTAR PRADESH	143.0 (1.6%)	222.33 (15.8%)	0.64	171.5 (19.9%)	239.59 (7.8%)	0.72
WEST BENGAL	151.6 (2.5%)	340.63 (14.1%)	0.45	194.0 (27.9%)	418.1 (22.7%)	0.46
AVERAGE	157.69 (16.9%)	239.44 (13.9%)	0.66	177.9 (12.8%)	260.0 (8.6%)	0.68

SOURCE: ANNUAL REPORT ON WORKING OF SEB's, ELECTRICITY DEPARTMENTS, ENERGY AND POWER DIVISION, PLANNING COMMISSION, (1999), NEW DELHI

TABLE 8.3
ELECTRICTY TARIFF MINUS UNIT COST (PAISE PER KWH), INDIA

YEAR	1998-1999		
SEB	TARIFF	UNIT COST	% Of Cost Recovery
ANDHRA PRADESH	188.1 (-0.2%)	234.0 (7.6%)	0.80
ASSAM	216.8 (0.09%)	420.28 (-0.68%)	0.52
BIHAR	210.8 (0.05%)	268.71 (-8.9%)	0.78
DELHI VB	270.7 (2.1%)	380.85 (4.3%)	0.71
GUJARAT	325.0 (68.4%)	261.74	12
HARYANA	180.5 (0.95%)	278.68 (14.2%)	0.98
HIMACHAL PRADESH	172.7 (6.4%)	175.99 (9.9%)	0.98
JAMMU& KASHMIR	50.0 (27.2%)	277.0 (-4.6%)	0.18
KARNATAKA &KPC	188.7 (15.3%)	309.52 (13.6%)	0.61
KERALA	173.2 (36.5%)	230.52 (15.8%)	0.75
MADHYA PRADESH	168.5 (-4.3%)	231.38 (6.1%)	0.73
MAHARASHTRA	214.1 (0.14%)	236.68 (8.4%)	0.90
MEGHALAYA	156.9 (20.7%)	405.04 (140.8%)	0.39
ORISSA	240.0 (10.1%)	280.77 (302%)	0.85
PUNJAB	146.7 (5.6%)	238.95 (5.4%)	0.67
RAJASTHAN	198.5 (1.8%)	264.67 (1.9%)	0.75
TAMILNADU	224.7 (14.0%)	244.18 (12.5%)	0.92
UTTAR PRADESH	171.9 (0.23%)	246.26 12.8%)	0.69
WEST BENGAL	218.0 (12.3%)	439.28 (5.1%)	0.49
AVERAGE	195.56 (9.9%)	459.47 (76.7%)	0.43

SOURCE: ANNUAL REPORT ON WORKING OF SEB's, ELECTRICITY DEPARTMENTS. ENERGY AND POWER DIVISION, PLANNING COMMISSION, (1999), NEW DELHI

TABLE 8.4

SUBSIDY FOR AGRICULTURE AND DOMESTIC SECTORS(RS CRORE)

YEAR	EFFECTIVE SUBSIDY FOR AGRICULTURE	SUBSIDY FOR AGRICULTURE WITH 50 PAISE PER UNIT TARIFF	EFFECTIVE SUBSIDY FOR DOMESTIC SECTOR	SUBSIDY GIVEN TO STATE GOVERNMENT
1992-93	7335.0	5143.4	2034.9	3182.0
1993-94	8965.6	6744.2	2130.8	2364.3
1994-95	108941.0	8536.3	2436.8	5127.1
1995-96	13606.0	10984.9	3224.4	7592.0
1996-97	15487.3	13061.1	4509.5	5179.8
1997-98	19063.5	16340.4	5266.6	4450.2
1998-99	20232.4	19122.4	6994.9	2214.1
1999-2000	22703.4	21608.8	8082.6	2135.0

TABLE 8.5

CROSS SUBSIDY FROM OTHER SECTORS ALL INDIA LEVEL

YEARS	CROSS SUBSIDY(RS CRORES)	CROSS SUBSIDY AS % OF SUBSIDY FOR AGRICULTURE AND DOMESTIC SECTORS
1992-93	3911.0	41.7
1993-94	4522.5	40.8
1994-95	5379.2	39.9
1995-96	6333.7	37.6
1996-97	8260.1	41.3
1997-98	10176.3	41.8
1998-99	10119.9	37.2
1999-2000	12434.3	40.4

TABLE 8.6

RATE OF RETURN ON CAPITAL % ALL INDIA LEVEL

YEAR	WITH SUBSIDY	WITHOUT SUBSIDY	WITH 50 PAISE PER UNIT AGRICULTIRE TARIFF
1992-93	-7.6	-12.7	-6.6
1993-94	-6.6	-12.3	-6.9
1994-95	-5.7	-13.1	**-8.1**
1995-96	-2.2	**-16.4**	-8.5
1996-97	-5.7	-14.7	-7.4
1997-98	-9.5	-16.8	-9.4
1998-99	-17.3	-20.7	-13.5
1999-2000	**-16.0**	-19.0	-12.2

8.1.13 **NET INTERNAL** RESOURCES

The net internal resource (R) refers to the surplus left with SEB's after meeting the revenue expenditure and loan repayment obligations. It includes depreciation and the subvention provided by the state government. If the SEB's function on commercial lines as statutorily required, the IR would have been position in the normal course. However, in practice IR have been negative in all the years except in 1995-96. the net IR was Rs. 1615 Crore in 1992-93 and Rs. 7057 Crore in 1998-99 (RE). The position varies from one SEB to another.

TABLE 8.7
ADDITIONAL REVENUE MOBILIZATION (RS CRORE)

YEAR	WITH 0% **OF ROR**	WITH 3% **OF ROR**	WITH 50 PAISE PER UNIT AGRICULTURE TARIFF
1992-93	4723.0	5642.5	2191.5
1993-94	6011.9	7863.2	2412.2
1995-96	8277.8	9822.9	2621.1
1996-97	8473.8	10206.7	2426.2
1997-98	10253.1	12085.6	2723.1
1998-99	13430.6	15381.5	2652.2
1999-2000	13816.6	16000.8	2651.2

8.2 REVIEW OF EVOLUTION, GROWTH AND PERFORMANCE OF POWER SECTOR IN INDIA

Before independence the power supply industry in India was developed mainly by a few private developers on a limited scale and concentrated near the major urban centres (India, 1987). Supply of electricity commenced in India in the 1880s. The power supply system was developed as virtually a statutory, public monopoly owned and operated by central and state governments, their agencies such as CEA, REBs SEBs, and the corporations set up by them.

For planning of power generation in India, the entire country has been divided in to five regions i.e., the Northern Region, the Western region, the Southern region, the Eastern Region, and North-Eastern region. The total installed capacity increased from 2,300 MW in 1950-51 to over 93251 MW, in 1999-2000, registering an annual growth rate of about 10.5%. The generating capacity in electric utilities run by the public sector during this period increased from 1713 MW to 83,000 MW. Inspite of this phenomenal growth, the per capita consumption of electricity (World Development Report, 1993) averaged only about 370 KWHR , which was one of the lowest among the developing Asian countries. It was very lower than South Korea (2,996 KWHR) and Singapore (6,353 KWHR), Thailand (1,000 KWHR), Malaysia (1612 KWHR) and compared with countries like Pakistan (435 KWHR) Philippines (510 KWHR) Chile (1,567 KWHR) and China (647 KWHR). International comparison of electricity consumption shows that India's position was far below that of developed countries. Based on the 14^{th} EPS (Electric Power Survey) findings CEA had prepared a National Power Development Plan in 1991, covering the period up to the end of the tenth plan (2006-2007). According to this plan, the requirement of the additional generating capacity to provide target levels of reliability in power supply (2 percent loss of load probability and 0.15 percent Energy Not Served) was about 142,000 MW over the 15 year covered by the Eighth, ninth and tenth plans. The 15 year power development plan identifies projects totaling 56,783 MW for implementation in the ninth plan. This would include 18,778 MW in hydro, 37563 MW in thermal and 440 MW of nuclear. With these additions, it is projected that the share of installed hydro capacity would still be much less than optimum - only 28.6% - by the end of the Ninth plan. During the Tenth plan, the required capacity additions for ensuring the target levels of reliability by the end of that plan period would be 60,000 MW.

The total investment of public and private sectors of Rs. 6,244 billion over the next decade, reckoned with reference to the power development plan will be public sector Rs. 2,338 billion, private sector - Rs.3,906 billion. Raising of the required funding by public sector undertakings, both central and state will be contingent on the minimum of structural and price reform measures being undertaken. With regard to private financing, the amount projected above (equaling US $ 111.6 billion) is massive, the feasibility of attracting this volume of finance and the costs this would entail to the sector as well as the economy need to be considered. Based on the power development plan, the capacity addition needed over the next 10 years is calculated at 111,500 MW. In rough proportion to the projected growth in demand, the capacity addition would need to escalate form around 7,500 MW in 1996-97 to 15,500 MW in the year 2005-06. Investment in capacity addition will need to be supplemented by that in transmission and distribution. There are several measures through which investment in capacity addition could be reduced or staggered. These involve basically, the maximizing of output from existing sources and promoting energy savings through demand management and end-use efficiencies. Captive generation and industrial co-generation, while not contributing to significant investment saving are two means by which the addition to capacity can be produced in the shortest period of time.

During the last few years, the plant availability as well as the PLF have shown a marginal improvement. But they are still below the norm. The average size of state-sector units is smaller, for which plant availability tend to be lower. The reason for this is poor quality of coal which results in forced outages and hence low PLF. But it has raised capacity construction costs as well as environmental concerns. (Gotierrez, Luise, 1993).

Inefficiency in generation is compounded by very high losses in transmission and distribution (T &D) of electrical energy. Internationally, a T&D loss of 10 percent of total power generation is considered satisfactory. In most developed countries T&D losses are less than 10 percent. Even among the developing economies, mostly the losses are less than 15 percent. However in India the average T&D losses for the period 1985-84 were about 22 percent and in every year these exceeded 20 percent.

8.3 FINANCIAL PERFORMANCE OF STATE ELECTRICITY BOARD'S:

The Electricity supply Act 1948 stipulates that SEB's, should generate a net rate of return of 3 percent on capital invested. From time to time this has been reviewed and almost all the committees that have investigated the performance of SEB's have reiterated the need to generate adequate return. The Venkataraman Committee recommended that SEB's should earn a rate of return of 11 percent and earn a net return of 3 percent within a period of 10 years. The Rajadhyaksha committee recommended a higher rate of return on investments to sustain the growth of the utility without excessive dependence on external finance. It recommended that SEB's should generate an annual rate of return of 15 percent or 6 percent net return. The finance commissions that examined the financial performance of SEB's have reviewed the rates of return from time to time keeping in view the ground realities. But these recommendations remained only in paper and the SEB's have been continuously incurring heavy losses in the range of 10 to 15% on capital invested and in the last 4 years the situation has worsened with losses increasing. Another factor which was responsible for is the low level of tariffs and their failure to keep up the cost increases. A principal reason for uneconomic pricing is the excessive interference of state governments in the functioning of SEB's particularly in setting tariffs. Although state governments are supposed to play only an advisory role, in actual practices they often directly influence the tariff structure. Consequently tariffs are determined more by social and political considerations of state governments influenced by special interest groups rather than by economic and efficiency objection.

8.4 PRICING POLICIES OF STATE ELECTRICITY BOARDS IN INDIA

Even though economic reforms were initiated, the average price increased marginally and met only 83% of the cost in 1998. There were also wide variations across states in this coverage. The cost recovery was less than 65% in special - category states except Himachal Pradesh. Maharashtra recovered the entire cost from consumers, where as in Bihar and Punjab were 60% and in Haryana and Uttar Pradesh less than 70% Electricity prices are lowest for agricultural consumption and the difference between the average cost and the price charged has widened considerably. All the states except Assam charged less than 50 Paise / KWHR for agricultural consumption at all and in Andhra Pradesh and Madhya Pradesh it is less than 10 Paise / KWHR. Haryana, Himachal Pradesh and Meghalaya have been able to implement a consensus decision taken by the chief minister to fix a floor price of 50 Paise / KWHR. But other states have not been able to do so. Most states also provide unmetered supplies of electricity to the farmers, charging them not on the basis of electricity consumed but levying a lump sum charge. This makes the marginal cost of electricity to the farmers zero, leading to uneconomic use of electricity and change in the cropping pattern. For domestic consumers the average price charged is about 70% of the average cost. In all states the tariffs on domestic consumption were significantly below the average costs, varying from 20 Paise / KWHR in Jammu & Kashmir to Rs. 1.23 in Maharashtra, In contrast industrial and commercial sources were charged at rates higher than the average cost in almost all major states (except Jammu and Kashmir) for making up partially for the huge losses from the subsidized supply of electricity to agriculture and domestic consumers. A part of this was offset by cross subsidies of higher than average cost of pricing of commercial and industrial consumption (Rs. 64.62 billion) The SEBs were left with a net commercial loss of Rs. 71.30 billion. The low tariffs on agricultural consumption contributed to significant losses in Andhra Pradesh, Gujarat, Haryana, Punjab, Uttar Pradesh, Tamil Nadu and Maharashtra.

8.5 REFORM IN PRICING POLICY

One of the essential element of the power sector restructuring programmes is reforming the present practice of uneconomic consumer pricing. It has to be implemented at the state level. Price reform must aim at

a) reaching cost-based pricing for each consumer segment in a phased manner through a gradual increase in average tariff per annum net of inflation.
b) Replacing unmettered supply by providing metering at the consumer end or at an intermediate distribution point
c) Identifying institutional means to administer subsidies to target consumer groups

d) **Independent** regulation of prices with provision for price reforms to be balanced by improvement in a quality of service technical as well as commercial and

e) Reform of pricing for agricultural consumers. Pricing reforms can be made even politically popular by providing adequate and uninterrupted power supply to farmers **(Parikh,** 1996). The move to market based prices exerts a downward pressure on demand as consumers adapt to conserve energy (Sanjeev S. Ahluwalia, 1997). To facilitate the price-reform process, there is an urgent need to create a tariff commission at state level. The commission should function as an independent and transparent body reflecting the interests of both producers and consumers. It should carryout a thorough costing exercise and review the tariff every 5 years. Price may be revised every year to allow for increase in input costs on the basis of an appropriate **(Kendreik** - type) productivity linked escalation formula subsidy. The to any consumer category should be transparent and should be borne by the general budget rather than complicating the tariff structure by cross-subsidization. (M. Govinda rao, KP **Kali raj** an et. **Al 1998).** It is also important to ensure autonomy and flexibility in the SEB's and to insulate them from political exigencies of the state movements. Providing autonomy in pricing and managerial decisions to SEB's and hardening their budget constraints would go a long way towards restoring the health of the ESI in the country. The shift from the existing price regime to one based on long run marginal social costs (LRMSCs) in a phased manner will not only augment the resources of the SEB's of their future expansion plans, but can also encourage private entry in power generation at a lower cost (Sankar and **Hema,** 1985) adopted a methodology for determining the LRMC. These price reforms can also induce energy conservation.

8.6 POWER SECTOR RESTRUCTURING AND LESSONS FOR INDIA

The Government of India have notified the Electricity Regulatory Commissions Act, 1998 for setting up CERC (Central Electricity Regulatory Commission) and SERCs (State Electricity Regulatory Commission) policy initiatives have also been taken in the form of amendment of specific sections of ES Act, 1948 required for regulatory sale of power by the Generating Companies to Boards, etc. As a follow up of the major policy initiative, GOI has decided to work closely with state governments for time bound corporatisation of the State Electricity Boards. Generation, transmission and distribution of electricity will be unbundled as separate activities.

Tariff reform, privatization of transmission and distribution of power and setting up of SERCs will be accelerated. Some of the states eg. Orissa, Haryana, Andhra Pradesh and Uttar Pradesh are being assisted by the World Bank in the reform process. The ADB is assisting the states of Gujarat and Madhya Pradesh. The PFC has been interacting with states of Assam, West Bengal, Meghalaya, Tripura, Jammu & Kashmir, Punjab, Tamil Nadu, Karnataka, Maharashtra, Himachal Pradesh, and Goa in the reform and restructuring process. The Maharashtra SEB also was asked by World Bank to initiate measures to reach a rate of return of at least 45% to improve its current commercial and financial operations to decrease cross-subsidization and bring about licenses in tariffs.

In order to set in to motion the reform programmes the Government of Orissa established two committees to direct the restructuring programme These were steering committee and the Task Force Committee. To further facilitate reforms and to abolish the unpractical and unworkable provisons of existing legislation, the government of Orissa passed the Orissa State Electricity Reforms Act 1995. The legislation aims to

a) break the monopoly of the Orissa SEB
b) promote competition and private capital by encouraging competition procurement in the generation sector
c) protect consumer interests
d) rescue the powers of the Orissa SEB in not only setting tariffs and issuing related notifications but also in its role as planner and operator of the State's Electricity supply system and
e) enable the reforms to be carried out. For example, sanctioning the dissolution of the Orissa SEB, achieving the transfer of assets contemplated by the reform plan and removing all potential for legal challenges to provisions set out in earlier legislation if the reforms envisage issues that may conflict with the provisions of the Electricity Supply Act.

The SEB responsibilities for generation were taken over by Orissa Hydro Power Corporation (OHPC) and Orissa Power Generating Corporation (OPGC). The existing transmission and distribution assets and duties of Orissa SEB have been taken over by GRIDCO which would procure power competitively and supply it further. Distribution was given particular attention under the states reform programme. Distribution areas were established subject to appropriate criteria and competitive tendering processes.

The regulatory authority is expected to play an important role in so far as distribution of electricity in the area is concerned. The aim of the regulatory authority is to balance the interest of the state, the consumers and GRIDCO, to issue and enforce licenses and to monitor the quality of service. The OERC (Orissa Electricity Regulatory Commission) highlights first order tariff –

a) Determined retail tariff for 1997 - 98 with over all increase of 10.5% over existing rate against 17.5% suggested by GRIDCO
b) GRIDCO to limit the overall T & D loss to 35% as against 42%.
c) Uncovered gap more than Rs. 400 Crores (1997-98) not approved
d) Scaled down the revenue requirements of GRIDCO by Rs. 395 Crores
e) GRIDCO was directed to effect economy in purchase of power through a merit order.

Basic principles in this regard are cost based tariff - some incentive for future investment, efficiency based rate making - only reasonable cost as pass through, subsidy, elimination of cross subsidy - formulated and implement programme for elimination of cross subsidy.

Highlights of the Second tariff order

a) Uniform tariff approved for all distribution licensees. Additional revenue mobilization estimated at 9.8% over previous year
b) Tariff calculated at T & D loss level of 35% Incentives proposed for licensees if they reduce losses below 35%
c) Slab system of tariff for domestic consumers rationalized
d) Minimum energy charge contract demand less than 110 KVA now pay monthly minimum fixed charge
e) Tariff for domestic consumers, small scale industries, street lighting and public institutions kept well below normative level

f) Replacement of defective meters given high priority, licenses to report progress to OERC. The electricity boards of Bihar, **Haryana,** Rajasthan, UP, West Bengal, Gujarat are expected to follow Orissa model for reform.

Orissa represents a single buyer model where all generating companies (GENCOS) are required to sell their produce to a state owned transmission company (Transco). This implies that even if GENCOS are willing to offer spot sales, or enter in to short term contracts there cannot be a credible market in the absence of multiple buyers. Therefore GENCOS cannot bear the market risk and rely on long term power purchase agreements with the Transco on a cost plus basis leading to comparatively high tariffs. According to (Gajendra Haldea, 2001) continued adherence to the so-called Orissa model of electricity reforms which seven reforming states have adopted is likely to promote monopolies, raise tariffs, deny consumer choice and constrain investment in the power sector.

8.7 LESSONS FOR POWER SECTOR REFORM IN INDIA FROM ABROAD

According to M. Govinda Rao **et.al** (1998) the reforms in most of the advanced countries have been motivated by the need to keep the industry efficient and competitive, though in developing countries fiscal constraint, particularly the inability to finance large and growing investment from the budgets has also been a major factor - considerable success have been achieved by different countries in restructuring their ESI' s and though it is wrong to utilize their policies and implementation strategies, as they suit the features and needs of a particular country situation. These experiences offer useful lessons that can form the back ground. It will also be **useful** to review the experiences of some of the countries that have been successful in reforming the power sector, before evolving appropriate policy measures and strategies for restructuring Indian **ESI.**. The inefficiency of ESI in India has long been realised and the reforms in the sector have been relatively slow. If we want to manage transition in the Indian electricity sector from the present monopolistic public sector to a competitive industry then we have to adopt an integrated approach towards reforms. This approach will help in achieving efficiency in the electricity sector and in reducing the cost of electricity to end consumers. (V. Ranganathan et. **al.** 1998) The author has recorded in detail the experience of restructuring the power sector in Australia and this can be useful to reforming the Indian power sector for a number of reasons. Australia can provide useful lessons for India's power sector reforms prior to reforms like India Australia also has been plagued by the problems like lack of transparency, uneconomic pricing and cross subsidization. The reforms in ESI in Australia are recent that is they have been undertaken in **1990s** and are still in progress. In an attempt to achieve efficiency gains and cost reductions the Australian government shifted the focus to restructuring the industry by unbundling the function of generation, transmission and distribution, corporatising or privatizing the industry and introducing commercial accounting practices. The significant gains in **efficiency** achieved by restructuring **ESIs** in countries like USA, New Zealand Norway, & UK have also been a motivating factor for Australian initiative. In 1991 following the recommendation on Industry Commission, the council of **Australia,** governments (COAG) agreed to separate the function of generation, transmission and distribution and form a interstate transmission network. The National competition policy Review (the Hlimer Report) submitted in 1993, set the framework for promoting competition. In Australia the states of Victoria and New South Wales have made significant progress in reforming their ESIs.

Reforms in Victoria: The reforms were to be implemented in 3 stages. In the first stage 3 new businesses were created. Generation Victoria (Gen Vic) was made responsible for generation. In the second stage ESI reform Unit (ES1RU) was established. Based on its recommendations, the government created 8 government owned entities in 1994 namely Victorian power exchange **(VPX),** to monitor and control the whole sale electricity market and to ensure the security of supply system, 'Power Net Victoria' (PNV), a high transmission company to own and manage the high voltage grid, (Gen Vic) Company comprising **five** independent generating corporations and privatize the **five** DBs (Distribution businesses) to improve competition and efficiency in retail distribution of electricity. The third stage of reforms in intended to develop whole sale market in

Victoria, link it with developments in the neighboring state of New South Wales. The development of whole sale market is at the core of reform programme that involves buyers and sellers. Second they may trade power in the spot whole sale market - VPX - where each day sellers bid into the pool for the price of electricity for each half hour in the following day and the generators are designated to supply electricity to buyers in order of their bids that is lowest price bid gets the first claim, over which is the pool price. Finally the generators may decide to place power on the grid for retail sale. An important component of restructuring ESI is the introduce of an independent regulatory body ORG (Office of regulatory General) 1994 to protect the interests of consumer and to promote competition, regulated prices and price setting mechanism.

Reforms in New South Wales: Reforms in NSW are along the lines in Victoria. The process started in 1991 with the restructuring of electricity commission of NSW into internal 6 business units renaming it as pacific power. In 1995 25 distribution companies were amalgamated into 6 regional companies each with distribution (wires) business and retail supply business.

Thus the reforms of ESI in Australia have been to improve efficiency by promoting competition. They promote competition in generation as well as whole sale and retail distribution. Reform has also evolved extensive regulation to ensure healthy competition, develop complex electricity market and protect the interest of consumer and retaining the advantages of economies of scale and scope by having transmission publicly owned and regulated.

India also draws lessons from California energy crisis particularly with regard to power sector reform in market.

Hence it is important to draw crucial lessons from the California energy crisis to safe guard the Indian power sector.

1) A careful comparison of the costs and benefits of the old regulated system and the new deregulated system is essential before dismantling the old and ushering in the new.
2) If it is decided to replace a cost-plus price regime with market driven prices then it must be realized that a market alone is not sufficient. It must be demonstrated

that the market does not permit the exercise of market power, price gouging and gaming. In addition the extent of competition must be monitored and it must be shown that there is indeed effective competition.

3) The case for unbundling the power sector must not be made merely on economic grounds, the restructuring must also be justified convincing on technical grounds. Thus apart **from** economists and bureaucrats power system engineers must also be involved.
4) The affordability of retail electricity prices to consumers is a necessary condition for the success of restructuring but it is not a sufficient condition. Whether the consumer prices are frozen or not if whole sale prices are frozen or not if wholesale electricity prices rise above the retail prices and the difference is borne by the utilities then the utilities go increasingly in to debt- a process that is not financially sustainable. Hence the impact of restructuring on prices must be anticipated before rushing in to restructuring particularly unbundling and privatization.
5) The market alone cannot take care of the integrated functioning of the electricity system and therefore the requisite regulatory arrangements must be in place. For example it is important to have mechanisms in place to ensure that there are adequate reserve margins to cope with sudden peaks of demand and short falls of supply.
6) Compared to increasing capacity by building new power plants, energy conservation measures provide the quickest way out of crisis.

It is unwise to go ahead with **restructuring/** reform with out specifying the criteria by which the **success/failure** of the **restructuring/reform** process will be judged.

8.8 SUMMARY

A number of countries driven by the desire to improve efficiency have been reforming and restructuring their Electricity Supply Industry to reap advantages of more efficient and competitive market. This chapter dealt with Indian experience in restructuring ESI. In order to provide stable, environmentally safe and efficient energy, the Indian government have been re-examining the nature of their own involvement in the ESI. This chapter examined data analysis of SEB's (all over India), evolution, growth and performance of SEB's in India. The whole idea of pricing electricity in India has revolved around appropriate provisions for subsidies. The weak financial and operational health of SEB's and the fact that tariff were not set commercially, hampered self sufficiency in the sector.Some states like Orissa, Haryana, Andhra Pradesh, Uttar Pradesh, Karnataka, Maharastra, Himachal Pradesh and Goa were on the verge of restructuring process and tariff reforms. Therefore reforms in pricing policy are of urgent necessity. There is a need to shift from existing price regime to one based on long run marginal costs. Such kind of pricing policy enables purchase of electricity at an appropriate price, fair return on the investment and encourages the purchase, supply and consumption of electricity in a reasonable and commercially viable manner. This chapter also dealt with the lessons, India drew from Australia and California.

CHAPTER IX

REFORM TREND IN ANDHRA PRADESH

9.0 INTRODUCTION

The previous chapter deals with the global context of electricity sector reform. The restructuring of the ESI in most cases began with the unbundling of the vertically integrated industry into its three activity components, namely generation transmission and distribution and identification of the components of the industry where competition is desirable and feasible. These changes were followed up with transparent accounting methods, rational pricing and investment policies, development of a competitive distribution network as well as whole sale and retail market for electricity, the introduction of an independent regulatory system to protect the interest of consumers. This chapter will analyze the demand and supply position, generation by source, sale of power category wise, fuel consumption in thermal plant i.e. coal and gas, consumer category wise tariff structure, financial investment in power sector, cost of fuel per unit of electricity generation i.e. coal and oil for the last 10 years and more. With the help of this data this chapter reviews the power sector prices in Andhra Pradesh and implementation of reform and restructuring programme.

9.1 POWER DEVELOPMENT IN ANDHRA PRADESH

The plan wise outlay in power sector i.e., generation, transmission and distribution, rural electrification and others has varied for every five year plan. The outlay in generation in all five year plans i.e. from 1951-56 to 1999-2k is more 5265.04 crores, For the three annual plans during 1997-98,1998-99,1999-2k an amount of Rs.3071.5 Crores with respect to total Board expendilure and Rs. 13104.69 Crores has been sanctioned as the first phase of Andhra Pradesh power sector restructuring project for reinforcement of overloaded transmission lines, creation of new sub-stations, increase of capacity of associated sub stations installation of shunt capacitors to reduce losses and improve service in order to maintain, reliable quality and security of power supply besides meeting the present and future load demands.

9.2 SOURCE OF POWER—INSTALLED CAPACITY

The total installed capacity in the state that was 6245.88 MKWH in 1971-72 increased to 65717.52 MKWH in 1999-2000, with an annual average growth rate of 8.3%. It has also a share in private and central sector generation up to 5790.36 MKWH and 8251.92 MKWH with growth rates at 21.9% and 14.0%. The installed capacity of the private sector with respect to its growth rate is more compared to others. In line with the recommendations of High Level Committee constituted by government of Andhra Pradesh (Hiten Bhayya Committee) APSEB decided that it is necessary to add more generation capacity in private sector in Andhra Pradesh. The projects are 1040MW Visakhapatnam coal based thermal power station 2x520 MW, Krishnapatnam A and B Thermal power project (2x500 MW) and Ramagundam TPP (2x260MW), projects with a total capacity of 253 MW has been allocated to private developers under private sector for implementation of mini hydel schemes, wind farms of total capacity is 54.74 MW. Government of A.P. is encouraging private investment in Baggasse based co-generation projects with 46.75 MW capacity. APSEB has selected eight proposals to set up liquid fuel based short gestation power projects aggregating to 1750 MW capacity. Even if these capacities are materialized the requirement may go up between 11000 MW and 15000MW by the beginning of the 10^{th} plan and beyond i.e. 2007 and beyond depending on the rate of growth.

9.3 GENERATION OF POWER

The power generation by thermal sources has increased from 1824.28 MKWH in 1971-72 to 21499.10 MKWH in 1999-2000 with an average annual growth rate of 11.4%. The comparison of growth rates of three sources (i.e. thermal, hydel and gas), natural gas has a high average annual growth rate at 19.1%. The oil and natural gas potential at the Krishna Godavari basin is said to be 890 million tones oil equivalent. In order to avoid perennial shortage in the state and also to avoid grid disturbances the natural gas fuel has been mobilized as it also an environmental free pollutant. The highest growth rate was recorded in 1992-93 i.e. at 333.1%. However diesel and fuel oil are atleast favoured nationally as power fuels because we are net importers of petroleum products. The central and private sectors also contributed in generating power. Private sector contribution is very negligible with an negative average growth rate of –63.9% and central sector with its growth rate 42.5%. The total generation of power in Andhra pradesh increased from 3045.74 MKWHR in 1971-72 to 42752.44 kWh in 1999-2k.

TABLE 9.1

ANDHRA PRADESH POWER - INSTALLED **CAPACITY (MKWH)**

YEAR	HYDEL	THERMAL	PRIVATE	CENTRAL	TOTAL
1971-72	2347.68	3898.20			6245.88
1972-73	2347.68	4774.20			7121.88
1973-74	2347.68	5256.00			7603.68
1974-75	2347.70	5431.20			7778.90
1975-76	3456.40	6321.40			9777.80
1976-77	4521.30	6321.40			10842.70
1977-78	6353.80	7210.50			13564.30
1978-79	7340.88	7358.40			14699.30
1979-80	7340.88	7358.40			14699.30
1980-81	7340.88	7358.40			14699.30
1981-82	9992.88	11037.60			21030.50
1982-83	13034.80	10932.48			23967.30
1983-84	14480.28	10932.48		473.04	25885.80
1984-85	17195.88	10450.68		1419.12	29065.70
1985-86	19035.48	10450.68		1769.52	31255.70
1986-87	21041.52	10450.68		2049.84	33542.00
1987-88	21216.72	10450.68		2619.24	34286.60
1988-89	21216.72	10450.68		5054.52	36721.90
1989-90	21216.72	12290.28		6280.92	39787.90
1990-91	21216.72	14708.04		6675.12	42599.90
1991-92	21547.15	15005.88		7069.32	43622.40
1992-93	22031.40	15005.88		7463.52	44500.80
1993-94	22740.96	25544.16		7857.72	56142.80
1994-95	23310.36	22364.28		7857.72	53532.40
1995-96	23292.84	22364.28	402.96	7752.60	53812.70
1996-97	23548.10	25544.16	2566.68	7752.60	59411.50
1997-98	23548.10	28251.00	4336.20	7752.60	63887.90
1998-99	23548.10	28251.00	4940.64	7752.60	64492.30
1999-2K	23424.24	28251.00	5790.36	8251.92	65717.50

SOURCE: POWER DEVELOPMENT IN ANDHRA PRADESH (Statistics) 1999-2000

TABLE 9.2

GENERATION OF POWER (MKWH)

YEAR	THERMAL	HYDEL	GAS	PRIVATE	CENTRAL	TOTAL
1971-72	1824.28	1221.46				3045.74
1972-73	2053.56	974.39				3027.95
1973-74	2196.10	910.08				3106.18
1974-75	2709.15	532.61		....	....	3241.76
1975-76	2728.91	941.50		....		3670.41
1976-77	3144.87	1680.04				4824.91
1977-78	3145.63	2001.96				5147.59
1978-79	2875.29	3180.28				6055.57
1979-80	3267.55	3065.54				6333.09
1980-81	3595.89	3535.10				7130.99
1981-82	5092.44	3984.25				9077.19
1982-83	5562.40	4683.86				10246.26
1983-84	5909.33	5092.15			173(-)	11174.48
1984-85	5835.19	6715.99			834(382.1)	13385.18
1985-86	6771.77	5453.29			2095(151.2)	14320.06
1986-87	7281.97	6517.47			1979(-5.5)	15778.44
1987-88	7985.34	5864.34			1605(-18.9)	15454.68
1988-89	7263.37	6877.80			2376(48.0)	16517.17
1989-90	7221.77	7802.65			35.5(49.4)	18574.42
1990-91	8101.62	10017.08	81.90		2725(-23.2)	20925.60
1991-92	8726.17	9515.63	354.73		4595(68.6)	23191.53
1992-93	9114.18	8757.71	416.17		6748(46.8)	25036.06
1993-94	9639.42	9632.42	524.74	....	7612(12.8)	27408.58
1994-95	10842.34	9687.22	431.26		8449(10.9)	29409.82
1995-96	15102.86	6661.75	540.33		7814(-7.5)	30118.94
1996-97	16719.76	7970.01	626.04	0.505(-)	7308(-6.4)	33128.81
1997-98	19019.49	7245.13	1248.98	2055(-306.9	7321(0.17)	36889.60
1998-99	19833.62	7189.24	1798.82	2820(37.2)	6921 (-5.5)	38562.65
1999-2K	21499.10	8133.00	2006.34	3217(-63.9)	7897(14.1)	42752.44

SOURCE: POWER DEVELOPMENT IN ANDHRA PRADESH (Statistics) 1999-2000

9.4 DEMAND AND SUPPLY OF POWER

Table 9.3 shows acute power shortage from 1970-71 to 1999-2000. Compared with demand, the supply of electricity was only 4923.12 MKWH in 1970-71 and 26212 MKWH in 1999-2000 with an average annual growth rate of 9.0%. The energy deficit has showed a steady increase from 2737.12 MKWH in 1970-71 to 32339.84 MKWH in 1999-2000 with an average annual growth rate of 10.2%. Therefore the strategy for matching demand and supply has to be considered for the power system as a whole that is generation, transmission and distribution.

9.5 TRANSMISSION AND DISTRIBUTION LOSSES:

Lack of efficiency in generation is compounded by very high losses in transmission and distribution of power. In Andhra Pradesh there is a continuous increase in line losses from 1971-72 tol999-2k i.e. 845.03 MKWH to 16142.65 MKWH. Compared to previous years the percentage of line loss are high in 1998-99 i.e. 38% as shown in table 9.4.

9.6 CONSUMERS OF ELECTRICITY

In 8th and 9th plans with the increasing needs of the consumers the per capita consumption has substantially increased to more than 400 KWH serving more than 100 lakhs of consumers.

TABLE 9.3
DEMAND AND SUPPLY OF POWER

YEAR	DEMAND	SUPPLY	DEFICIT	DEFICIT AS A % OF DEMAND
1970-71	4923.12(--)	2186(--)	2737.12(--)	55.6
1971-72	4923.12(0)	2330(6.6)	2593.12(-5.3)	52.7
1972-73	4935.30(0.25)	2173(-6.7)	2762.3(6.5)	55.9
1973-74	5068.52(2.7)	2479(13.9)	2589.52(-6.3)	51.1
1974-75	6184.56(22.0)	2575(4.1)	3609.56(39.4)	58.4
1975-76	6920.34(11.9)	2794(8.5)	4126.34(14.3)	59.6
1976-77	7534.50(8.9)	3433(22.9)	4101.5(-0.6)	54.4
1977-78	8241.61(9.4)	3782(10.1)	4459.61(8.7)	54.1
1978-79	9285.60(12.7)	4336(14.6)	4949.6(10.9)	53.3
1979-80	13753.20(48.1)	4552(4.9)	9201.2(85.9)	66.9
1980-81	13753.20(0)	5104(12.1)	8649.2(-5.9)	62.9
1981-82	13753.20(0)	(6093(19.4)	7660.2(-11.4)	55.7
1982-83	15181.08(10.3)	7099(16.5)	8082.08(5.5)	53.2
1983-84	15268.68(0.58)	7717(8.7)	7551.68(-6.5)	49.5
1984-85	18904.08(23.8)	9230(19.6)	9674.08(28.1)	51.2
1985-86	21059.04(10.9)	10312(11.7)	10747.04(11.1)	51
1986-87	23345.40(10.9)	11761(14.1)	11584.4(7.8)	49.6
1987-88	24107.52(3.3)	11669(-0.78)	12438.52(7.4)	51.6
1988-89	26507.76(9.9)	13050(11.8)	13457.76(50.8)	50.8
1989-90	26893.20(1.5)	14435(10.6)	12458.2(-7.4)	46.3
1990-91	30353.40(12.9)	16093(11.5)	14260.4(14.5)	46.9
1991-92	32438.28(6.8)	17750(10.3)	14688.28(3.0)	45.3
1992-93	34304.16(5.8)	19227(8.3)	15077.16(2.7)	43.9
1993-94	36529.20(6.5)	21186(10.2)	15343.2(1.8)	42
1994-95	38841.84(3.2)	22935(8.3)	15906.84(3.7)	40.9
1995-96	40085.76	23400(2.02)	16685.76(4.9)	41.6
1996-97	43992.72(14.3)	20923(-10.6)	23069.72(38.3)	52.4
1997-98	50299.92(14.3)	23770(13.6)	26529.92(14.9)	52.7
1998-99	56764.80(12.8)	23246(-2.2)	33518.8(56.3)	59
1999-2K	58551.84(3.2)	26212(12.8)	32339.84(-3.5)	55
	AVERAGE	9.1	16.3	10.2

SOURCE : **POWER DEVELOPMENT IN ANDHRA PRADESH (STATISTICS) 1999-2000**

TABLE 9.4
TRANSMISSION AND DISTRIBUTION LOSSES (MKWH)

YEAR	LINE LOSSES	% OF LINE LOSS
1971-72	845.03	26.53
1972-73	771.43	25.56
1973-74	849.65	24.73
1974-75	894.21	24.63
1975-76	936.41	24.37
1976-77	1171.77	24.39
1977-78	1138.47	22.59
1978-79	1211.04	20.79
1979-80	1325.79	21.40
1980-81	1523.76	22.03
1981-82	1973.57	23.08
1982-83	2228.28	23.09
1983-84	2247.65	21.36
1984-85	2604.79	20.48
1985-86	2871.09	20.91
1986-87	3146.74	20.68
1987-88	2978.52	20.03
1988-89	3099.76	19.01
1989-90	3714.35	20.25
1990-91	3978.98	19.67
1991-92	4351.16	19.30
1992-93	4678.32	19.16
1993-94	5117.33	19.05
1994-95	5464.23	18.94
1995-96	5551.95	18.85
1996-97	10281.93	32.04
1997-98	12020.79	33.06
1998-99	14713.62	38.00
1999-2K	16142.65	36.90

SOURCE: POWER DEVELOPMENT IN ANDHRA PRADESH (STATISTICS) 1999-2000

9.7 CONSUMPTION AND COST OF FUEL PER UNIT OF ELECTRICITY GENERATION

The table 9.5 shows the consumption of coal per unit of electricity is far more compared to oil per unit of electricity generation. And table 9.6 presents the cost components in APSEB from 1993-94 to 1999-2k..The cost components in APSEB include fuel, power purchase, O & M, Establishment, miscellaneous, depreciation, Interest. The cost composition shows that purchase costs are high for the period of 1993-94 to 1999-2k i.e. 408.4 Paise per kwh of sale compared to other cost components. Next comes fuel cost. Average cost composition shows that fuel and power purchase costs constitute about 25% of the total, interest adds almost 16.2% and the administration costs constituted 13.4% of total cost. Over all the reasons for high unit cost of electricity are poor technical efficiency in generation, high T & D losses and excessive employment resulting in low productivity.

9.8 CONSUMER CATEGORY WISE AVERAGE TARIFF

Table 9.7 provides consumer category wise average tariffs for the APSEB for the years 1993-94 to 1999-2000 shows considerable variations among different user categories. Compared to other categories industrial users are subjected to higher tariffs i.e. 214.70 paise per kwh of sale in 1993-94 to 370 paise per kwh of sale in 1999-2000 with an annual average growth rate of 36.5%. The reason is industrial users partly cross subsidize agricultural and domestic consumers. Thus industrial consumers, in addition to facing frequent power cuts and outages have also to pay a much higher price. Therefore many of them have found it economical to insulate themselves from an unstable supply of electricity by investing in captive generation capacity. The average tariff for the agriculture/ irrigation have been 6.4 paise per kwh in 1993-94 to 16.46 paise per kwh of sale in 1999-2000 with an annual average growth rate of 43.4%.Further APSEB do not meter agricultural consumption. The average tariffs for the commercial category for the years 1996-97 to 1999-2000 pay a much higher price than industrial category.

TABLE 9.5

CONSUMPTION AND COST OF FUEL PER **UNIT OF ELECTRICITY GENERATION**

YEAR	CONSUMPTION PER KWHR		COST PAISE PER KWHR	
	COAL(KG)	OIL(ML)	COAL	OIL
1990-91	3.34(-)	15.74(-)	34.57(-)	1.13(--)
1991-92	3.71(11.1)	21.51(36.7)	41.61(20.1)	1 40(23.9)
1992-93	**3.73(0.54)**	**31.22(45.1)**	51.56(23.9)	1.50(7.1)
1993-94	3.73(0)	27.43(-12.1)	61.38(19.0)	1.77(18.00)
1994-95	3.57(-4.31	24.91 (-9.2)	64.46(5.0)	1.86(5.1)
1995-96	4.445(2.5)	26.74(7.3)	69.17(7.3)	1.76(-5.4)
1996-97	4.5(1.1)	36.46(36.4)	77.36(11.8)	1.57(-10.8)
1997-98	4.16(-7.6)	28.58(-21.6)	83.68(8.1)	2.62(66.9)
1998-99	5.08(22.1)	28.00(-2.01)	85.52(2.2)	2.92(13.7)
1999-2K	4.84(-4.7)	5.88(-79)	87.31(2.1)	3.00(0.67)
AVERAGE	2.1	0.6	9.9	11.9

SOURCE : POWER DEVELOPMENT IN ANDHRA PRADESH (STATISTICS) 1999-2000

TABLE 9.6
COST STRUCTURE OF ANDHRA PRADESH STATE ELECTRICITY BOARD (PAISE PER KWHR OF SALE)

YEAR	FUEL	POWER PURCHASE	OPERATION AND MAINTENANCE	ESTABLISHMENT AND ADMINISTRATION	MISCELLANEOUS EXPENSES	DEPRECIATION	INTEREST	TOTAL
1993-94	28.52(-)	34.80(~)	5.73(-)	11.55(--)	1.01(--)	8.07(-)	19.29(-)	108.97(-)
1994-95	31.14(9.2)	40.71(16.9)	5.73(0)	17.89(54.9)	0.58(-42.5)	12.42(53.9)	28.59(48.2)	141.06(29.4)
1995-96	45.47(45.6)	41.71(2.5)	5.81(1.4)	17.63(-1.5)	4.49(674.1)	12.17(-2.0)	34.01(18.9)	161.28(14.3)
1996-97	60.19(32.4)	47.84(14.7)	8.53(46.8)	24.92(41.3)	4.70(4.7)	19.11(57.0)	39.79(16.9)	205.08(27.1)
1997-98	59.33(-1.4)	68.00(42.1)	7.65(-10.3)	20.71 (-16.9)	3.08(-34.5)	16.62(-13.0)	42.02(5.6)	217.42(6.0)
1998-99	58.3(-1.7)	78.43(15.3)	8.03(4.9)	22.84(10.3)	3.11(0.97)	18.38(10.5)	44.92(6.9)	234.00(7.1)
1999-2K	68.18(16.9)	96.91(23.6)	9.51(18.9)	30.25(32.4)	4.25(3.67)	20.11(9.4)	65.51(45.8)	294.71(25.9)
AVERAGE	14.4	16.4	16.4	17.2	4.6	16.5	20.3	15.7

SOURCE : POWER DEVELOPMENT IN ANDHRA PRADESH (STATISCTICS) VARIOUS ISSUES

TABLE 9.7
CONSUMER CATEGORY WISE AVERAGE TARIFF (PAISE PER KWHR OF SALE

YEAR	DOMESTIC	COMMERCIAL	AGRICULTURE/ IRRIGATION	INDUSTRIAL	RAILWAY/ TRACTION	OUTSIDE STATE	OVERALL AVERAGE
1993-94	89.30(-)	190.04(--)	6.4(-)	214.70(--)	207.30(-)	26.K-)	122.4(-)
1994-95	91.8(2.8)	195.7(2.9)	5.3(-17.2)	221.8(3.3)	212.5(2.5)	35.9(37.5)	127.2(3.9)
1995-96	107.5(17.1)	231.7(18.4)	2.8(-47.2)	236.0(6.4)	250.1(17.7)	41.8(16.4)	144.9(13.9)
1996-97	142.5(32.5)	327.71(41.4)	12.0(328.5)	287.9(21.9)	329.2(31.6)	76.6(83.2)	195.98(35.3)
1997-98	167.0(17.1)	367.8(12.5)	17.4(45.00)	333.3(14.7)	374.3(13.7)	80.0(4.4)	222.8(13.5)
1998-99	167.0(0)	367.8(0)	16.1(-17.5)	333.3(0)	374.3(0)	80.0(0)	222.5(-0.13)
1999-2K	165.60(-0.85	389.04(5.8)	16.46(2.2)	370.00(12.0)	378.00(12.0)	36.71 (-54.1)	222.6(0.04)
AVERAGE	9.8	11.5	43.4	36.5	36.5	12.9	9.5

SOURCE : POWER DEVELOPMENT IN ANDHRA PRADESH (STATISTICS) VARIOUS ISSUES

9.9 EMERGING POWER CRISIS IN ANDHRA PRADESH:

The power sector in AP is going through two acute crisis, a power shortage of about 16 percent of demand and heavy financial losses by APSEB. Eliminating the power shortage by the end of this decade would take an annual investment of about $2.5 billion. Average investment has been slightly over one-tenth of this amount in recent years, Therefore extensive private sector participation will be necessary to achieve this target. Until 1986/87 AP was in a position to meet its power demand. Since then the gap between demand and availability of power has gradually increased, reaching about 16 percent in 1995-96 (High Level Committee Report, 1995). This has deterred private investment and depressed capacity utilization, contributing to the recent slow down of growth. This power shortage is primarily due to inadequate investment in the sector. (Rao & Sen, 1993). In the Past decade, AP's budgetary allocations for the power sector fell sharply compared to the decade before and stood at about half of what the 14 major states allocated for their power sectors. Deterioration of APSEB's financial position can be traced to the heavily subsidized agricultural tariffs. Since the early 1980s tariff policy has bee increasingly politicized. The agricultural tariff rate was reduced from ps. 20 per KWH in 1981/82 (about half of the average cost of production) to ps.6 (About 11 percent of the average cost) in 1984/85. It has been further reduced to 3-4 Paise since then. These rates were cross-subsidized by very high tariffs for industrial and commercial consumption. APSEBs losses on account of supply to agriculture increased from Rs. 1.6 billion in 1985/86 to RS. 16 billion in 1994/ 95. In 1993/94, agriculture consumer 43 percent of available power and contributed 3 percent to APSEB's revenue. In the same year, industry consumed 33 percent of the available power but contributed 70 percent to revenue - AP is one of the four Indian states with the highest industrial power rates. It appears that potential for cross-subsidizing agriculture by taxing industry has been largely exhausted - under fiscal pressure, tariffs for all consumer categories were raised in 1996. In ten of the fourteen major states, the tariff rate for agriculture is ps. 50 per KWH or higher, which covers about one-quarter of the average cost of production. It fully collected, APSEB expect to raise additional revenue of RS. 9.3 billion with the new measures, about one-third of its expected total revenue in this fiscal year. This is a step in the right direction but it will not be sufficient to restore the credit worthiness of APSEB.

9.10 IMPLEMENTATION OF REFORM AND RESTRUCTURING PROGRAMME

Government of Andhra Pradesh (GOAP) has decided to restructure its power sector with the objective of creating environment for sustainable development of the sector through promoting competition and efficiency, ensuring transparency, autonomy and accountability in the state. The ultimate goal of the reform process is to ensure that the power sector ceases to be a burden on the state's budget and eventually becomes a net generator of the financial resources. The government plans to restructure the ESI on the basis of recommendations made by the committee of experts chaired by Mr. Hiten Bhaya (Andhra Pradesh, 1995). The reform and restructuring program broadly involves.

i) Unbundling of the vertically integrated monopoly power utility, APSEB, and functional separation of generation, transmission and distribution business

ii) Establishment of statutorily created independent and autonomous regulatory agency and

iii) Increasing competition in all segments of the power industry through private sector participation. In parallel, GOAP proposes to implement an investment program of the order of about US $5.5 billion during the period FY 1999 - FY 2009, to rehabilitate and expand the power transmission and distribution system, to renovate and modernize the existing generation stations, to promote end-use energy efficiency and demand side management and for capacity building in the new power sector entities. Several multi-lateral and bi-lateral funding organizations, including World Bank, DFID, CIDA and OECF have expressed interest to support Andhra Pradesh's power sector reform and restructuring program.

Implementation Strategy:

The implementation strategy of GOAP is to

i) undertake the reform program in a phased manner over about 10 year time period, with the objective to demonstrate the benefits of the reforms of every step and thereby ensure sustainability of the process.

ii) undertake all possible measures to ensure that the transition period to the new restructured power sector entities is minimized with adequate preparatory work and preparation of well defined implementation plan for various aspects of the reform and restructuring program.

Phased Approach: The initial phase of the reform program (FY 1999-FY 2001) will set the legal, regulatory and structural state for the reform. The important first step will be the enactment of the Reform Bill, which will facilitate establishment of regulatory commission and new power corporations for generation, transmission and distribution business. Distribution privatization process and implementation of financial restructuring plan will also be initiated during the first phase. The second phase (FY 2001 - FY 2003), will focus on the privatization of the distribution business, achievement of financial sustainability in the sector, institutional development of the new entities, and improvement in system efficiency and quality of power supply. In the third phase (FY2003-2005), the efforts will be made towards consolidation of the functioning and financial position of power supply. During this phase, the entire distribution business will be privatized. In the fourth Phase (FY 2005-FY 2007), the focus will be an achievement of higher consumer satisfaction through progressively ensuring adequate supply of power to meet the demand, attainment of higher quality and efficiency in electricity supply and services to the consumers and deepening of the reforms to increase competiton and private sector participation.

Management, Review and Monitoring of the Reform Program

GOAP and APSEB are closely guiding and monitoring the reform program, at various levels. For the preparation and successful implementation of the reform program, Reform project Management Group (RPMG) was established in June 1997. RPMG, comprises ten specific working groups, to provide dedicated support in the preparation and implementation of important elements of the reform program. The specific areas include

i) corporatization, commercialization and PPAs,

ii) financial restructuring

iii) HRD

iv) Planning and investment program

v) Regulatory and legal frame work

vi) **Distribution** reconfiguration

vii) Technical interface and metering

viii) Tariffs

ix) Communications and

x) Identification and asset valuation.

Reform Legislation: The Andhra Pradesh Electricity Reform Bill (Reform Bill) was approved by the state legislative assembly and has received the presidential assent. The Reform Act provides **inter-alia** for

i) the establishment of Andhra Pradesh Electricity Regulatory Commission (APERC) within 3 months of the enactment of the reform bill, proceedings, powers and functions of the commission and the selection procedures for the members of the **commission.**

ii) Powers of the state government

iii) Unbundling of APSEB and establishment of separate corporate entities for power generation, transmission and distribution **business.**

iv) Licensing of transmission and distribution of power and

v) Tariff and financial matters relating to the licenses.

9.10.1. ESTABLISHMENT OF **REGULATORY COMMISSION**

i) GOAP and APSEB have initiated several important steps for the establishment of the new regulatory frame work and restructuring of the power sector. GOAP recognizes that the credibility and acceptance of the reform program will depend on the establishment of independent and autonomous regulator and the proper **functioning** of the new entities. The government is therefore committed to ensure that the members and staff of the commission are selected based on their professional capabilities and commission functions in an independent and autonomous manner. To assist in the process of establishment of APERC, which is on the critical path for the reform and restructuring of the power sector, regulatory and legal working group.

9.11 UNBUNDLING, CORPORATION AND COMMERCIALIZATION

Following the effectiveness of the Reform Act, APSEB was unbundled into two separate companies - APGENCO will own and operate the existing power **generating** Stations of APSEB and APTRANSCO will be responsible for power transmission and **distribution** business in A.P. The share of APSEB in central generating projects, joint sector generating projects and the effective power purchase agreements with the independent private power developers will also be transferred to APTRANSCO. Subsequently power distribution business will be separated and a number of distribution companies will be established as subsidiary companies of APTRANSCO. Initially APGENCO and APTRANSCO will be established as government owned corporate entities, and may invite private sector participation at a later stage. All the distribution companies will finally be privatized as joint venture companies with majority shareholding of the private sector. In the long run the power sector in AP is envisaged to evolve towards multi-buyer model with competition in generation and distribution and where the distribution companies could purchase power directly from the generating companies and the role of the transmission company would be that of providing transmission and service wheeling of power.

9.11.1. PRIVATIZATION OF DISTRIBUTION

GOAP plans to privatize the entire power distribution business in A.P. in a phased manner in the next 5 to 6 years. The distribution companies initially established as subsidiary companies of the state government owned TRANSCO, would be privatized as joint venture companies with majority share holding and management control of the private sector. At least 30% of the distribution business is proposed to be privatized in 2000, about two third of the distribution business by 2002 and the entire distribution business is planned to be privatized by end of 2004. The precise schedule of the privatization process will be finalized as the implementation of the reform and restructuring of the power sector progress. The privatization process - selection of joint venture partner will be carried out through a transparent competitive bidding process. Government plans to appoint a consultant to assist them in designing the privatization process and implementation schedule and provide the support required to form the joint venture companies.

9.12 FINANCIAL RESTUCTURING

a) The past financial performance depicts that increased dependence of the Board on the state government subsidy, for earning the statutory 3% Return on net fixed Assets, has not only strained the resources of the state government beyond manageable levels, but has also led APSEB into a liquidity crisis. The main features of APSEB financial restructuring plan are:

i) providing for unfunded staff related liabilities estimated at Rs. 14 billion (of which Rs. 2.3. billion is recognized by AP and is reflected in the balance sheet while the balance has not been recognized as liabilities into the past and were met from revenues as and when (due) by the issue of bonds guaranteed by GOAP to independent pension and provident fund trusts to be managed jointly by the employees and the companies

ii) adjustment of cross debts between GOAP and APSEB

iii) writing off or provisioning for unusable and obsolete stores and uncorrectable receivables amounting to Rs. 5.2 billion.

iv) write off GOAP debt and equity to the extent of Rs. 20 billion against all the above and

vi) conversion of over dues to tenders and suppliers into long term obligations through the issue of bonds to the extent of Rs. 15 billion and cash settlement of about Rs. 2 billion projections of the financial performance of APSEB and its successor companies, for the period Financial Year 1999-Financial Year 2007, have been estimated based on realistic assumptions of growth in demand and sales mix, tariffs, efficiency improvements, working capital management and the investment and financing plan. Successful implementation of the financial restructuring plan would make the sector commercially viable and eliminate the support required from the state government. However, in the transition period (Financail Year 1999-Financial Year 2003), until the sector turn around and becomes a net generator of resources from the state, the state government will be required to provide a support of about Rs. 65 billion. The sector is expected to reverse the budgetary flows within four years and between Financial Year 2003 to Financial Year 2007 is estimated to contribute Rs. 27 billion to the state.

9.12.1 POWER SECTOR INVESTMENT PROGRAM

Demand Forecast: The aggregate energy requirement in AP is estimated to grow at 7.5% per annum (at consumer end) from about 39 billion KWH in Financial Year 1999 to 72 billion KWH in Financial Year 2007. The peak demand is estimated to reach about 14,000 MW by the end of Financial Year 2007.

i) **Power sector expansion program: Need Based Assessment:** The main objective of AP's long term power sector plan is to meet electricity requirements of all categories of consumers by Financial Year 2007 and to provide reliable and good quality power supply. During the period Financial Year 1999-Financial Year 2007 about 10,766 MW of new capacity addition will be required in A.P. to meet the peak demand of 14000 MW in Financial Year 2007. The generation expansion plan would include new capacity additions through completion of all the ongoing schemes, renovation and modernization of existing generating stations, capacity addition in joint, central and private sector and development of non conventional energy resources, captive generation and inter regional imports to provide energy. A.P. has taken a policy decision that most of the new generating capacity will be promoted in the private sector and power purchased from central generating stations and other states and regions to the extent feasible. Total investments required in A.P. s power sector during Financial Year 1999 to Financial Year 2007 (on need based assessment) is estimated to be Rs. 650 billion, including Rs. 438 billion in generation, Rs. 76 billion in transmission and Rs. 135 billion in distribution. The main focus of investment program of the state government will be to

   i) rehabilitate and expand the transmission and distribution system to meet the growing demand for power.

   ii) Improve operational efficiency of the existing assets.

iii) Reduce system losses and improve enduse efficiency

iv) Improve the quality of power supply to consumers and

v) Support power sector reform program.

APSEBs investment plan in the long term (excluding investments in generation by IPPs and central sector projects) is estimated to be Rs. 146 billion (excluding IDS) during the period Financial Year 1999-Financial Year 2007.

TABLE 9.8 POWER SECTOR REFORM AND INVESTMENT PROGRAM PERFORMANCE INDICATORS.

Key Program Performance Indicators	FY 1999	FY 2002	FY 2007
Energy (deficit) /surplus (%)	8	11	4
Per Capita consumption (KWH)	410	640	890
Access rate (% population connected)	50	55	>62
Transmission and distribution losses (%)			
Technical	18.2	16.9	14.7
Non- Technical	14.5	9.5	3.0
Private Sector Participation (%) in			
Generation	6	12	35
Distribution	0	>30	90-100
Return Equity (%)			
APGENCO	64	16%	16%
APTRANSCO	64	16%	16%
Contribution to Capital Investments (%)			
APGENCO	9%	20%	35%
APTRANSCO	9%	20%	32%
Subsidies as % of revenue from sale of electricity	35%	11%	0%
Contribution of the power sector to the state's budget (USS Million)	236	192	204

Table 9.8 provides summary of some of the important performance targets expected due to implementation of the reform and investment program. It is expected to bring in significant improvement in the over all operations and efficiency of the power sector in meeting the demand for power in the state. It is expected that by FY2007, power demand in the state will be met, consumers will be provided with reliable high quality, and cost effective electricity by credit worthy and commercially operated power utilities functioning in a competitive and appropriately regulated power market, with significant private sector ownership and participation. It is however, important to note that the present situation of performance of the power sector may in fact indicate a decline in the initial 1-2 years of the initiation of the reform program primarily due to reflection of more precise performance indicators of the prevailing situation and also on account of some time lag before the benefits of the new investments in rehabilitation and expansion of the T & D system can be realized.

9.13 SUMMARY

This chapter covers data analysis in Andhra Pradesh and further explains how government of Andhra Pradesh have successfully implemented the reform and restructuring programme, by taking into account implementation strategy, establishment electricity regulatory commission, financial restructuring and evaluation of restructuring programme. This chapter revealed some important performance indicators which will make the whole electricity reform process successful in Andhra Pradesh.

CHAPTER X

ESTIMATED POWER TARIFF MODEL

10.0 INTRODUCTION

It has been observed from the previous chapters that the SEBs are cash strapped. While the cost of supply of electricity has shown an increasing trend the tariff has not been commensurate with this, thus widening the gap between the average cost of supply and realization. In this regard restructuring of SEBs are preferred to stem this deteriorating situation by observing the restructuring models both in developed and developing countries. However, one must realize that in any economy SEBs must strive to bring in commercial viability in the Electricity Supply Industry so as to ensure power supply on demand to all consumers at reasonable prices.

Micro economic reform became a key aspect of economic policy in Andhra Pradesh. According to the provisions of the Andhra Pradesh Electricity Reform Act 1998,the GOAP under took the reform and restructuring of the erstwhile Andhra Pradesh State Electricity Board (APSEB) which was implemented through two statutory transfer schemes notified under the provisions of the Act. Through the first statutory transfer scheme the Government of Andhra Pradesh, on February 1999, Generation business undertaken from APSEB was separated from Transmission and Distribution businesses.

The under takings of APSEB include-

a) The Generation business was transferred to and vested in Andhra Pradesh Power Generation Corporation Limited (AP GENCO) while Transmission and Distribution businesses were transferred to and vested in Transmission Corporation of Andhra Pradesh Limited (APTRANSCO).

b) By licensing order of January 31, 2000 granted a Transmission and Bulk supply license permitting APTRANSCO to carry out the Transmission and Bulk supply business in Andhra Pradesh. By the same licensing order of January 31, 2000 also granted for Distribution and Retail supply of Electricity to APTRANSCO.

c) The second statutory transfer scheme, notified in the official Gazette of the Government of Andhra Pradesh on March 31, 2000 to inter-alia separate the then existing

Transmission and Bulk Supply Undertaking and business of APTRANSCO from the then existing Distribution and Retail Supply undertaking and business of APTRANSCO.

10.1 REVIEW OF THE LEGISLATIVE PROVISIONS AND TRENDS IN TARIFF SETTING:

The reform of the power sector should constitute a very major part of the general economic reform process. Within the power sector the attention should be focused on tariff reform. For the first time in the Electricity Law a tariff has been defined. It defines tariff as " tariff means the price, rate or charge that may be demanded by a license with respect to supply, transmission, distribution or wheeling of electricity." In addition it includes "Any charge demanded by the electricity utility arising out of conditions of supply of Electricity and the agreement concluded with the customer of electricity. But the conditions of supply of electricity and agreement with consumer will be enforced only after receiving approval from Electricity Regulatory Commission.

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. At **the** time there were two types of entities in the power sector.

Licensees under the Indian Electricity Act, 1910 (IE Act):

A licensee is one who has been granted a license by the state government, in consultation with the State Electricity Board, to supply energy in any specified area under section 3 of the IE Act, 1910 and Electricity (supply) Act, 1948.

State Electricity Board under Electricity (supply) Act, 1948:

The Boards are constituted by the state governments under the Electricity (supply) Act, 1948. The broad functions of the Board are to generate, transmit and distribute electricity in coordination with the generating companies, if any, operating in the state and with the central government or any other Board or agency having control over a power system; transmission and distribution of electricity within the state; and exercise of control in relation to generation, distribution and utilization of electricity within the state.

Till the establishment of central generating stations, the industry was dominated by private Licensees and vertically integrated SEB's. SEB's 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 SEB's . The absence of mandatory norms for tariff setting are said to have led to delays in settlement of commercial terms. This was perceived to be inefficient.

Under the chairmanship of Shri K.P.Rao, the central government constituted a committee. The recommendations of the K.P.Rao committee can be regarded as landmark in the history of bulk tariff regulation in India.

In exercise of the powers conferred by sub-section (2) of section 43 A of the Electricity (supply) Act, 1948, the central government determines the factors in accordance with which the tariff for sale of electricity by Generating companies to the Board and other persons shall be determined as follows:

The two-part tariff sale of electricity from Thermal Power Generating Stations including gas and Naphtha based stations shall comprise the recovery of annual fixed charges consisting of interest on loan capital, depreciation, operation and maintenance expenses (excluding fuel), taxes on income reckoned as expenses, return on equity and interest on working capital at a normative level generation, and energy (variable) charges covering fuel cost recoverable for each unit (kilowatt hours) of energy supplied and shall be based on the following norms:

I **Plant Load Factor:**

During stabilisation period	4500 hours/Kw/year
Subsequent period	6000 hours/Kw/year

II **Station Heat Rate for coal based stations:**

During stabilization period	2600 K.Cal/Kwh
Subsequent period	2500 K.Cal/ Kwh

(In respect of 500 MW units where the boiler feed pumps are electrically operated the heat rate of 40 K.Cal/Kwh shall be reduced from station heat rate)

III Station Heat Rate for gas and Naphtha based stations:

For open cycle	2900 K.Cal/Kwh
For combined cycle	2000 K.Cal/Kwh

IV **Secondary fuel oil consumption for coal based stations:**

During Stabilization period	5 ml/Kwh
Subsequent period	3.5 ml/Kwh

V Auxiliary Consumption:

	With cooling tower	without cooling tower
(a) Coal based stations		
200 MW series	9.5 percent	9.0 percent
200 MW series		
Steam driven pumps	8.0 percent	7.5 percent
Electrically driven pumps	9.5 percent	9.0 percent
(b) Gas and Naphtha based stations		
Combined cycle		3.0 percent
Open cycle		1.0 percent

VI Stabilisation period:

Stabilisation period commencing from the date of commercial operation shall be reckoned as follows:

(a) Thermal	180 days
(b) Open cycle and Naphtha based station	90 days
(c) Combined cycle gas and Naphtha based station	90 days

VII Date of commercial Operation:

(a) Thermal Units: Not exceeding 180 days from the date of synchronization

(b) Gas and Naphtha based Units: From the date of synchronization

It is clarified that the norms laid down by the authority are the ceiling norms only and this shall not preclude the Boards and Generating Companies from agreeing to accept improved norms. For the purpose of calculating the tariff the operating parameters i.e. Station Heat Rate, Secondary Fuel Oil Consumption and Auxiliary Consumption shall be determined on the basis of actuals or norms, whichever is lower. The capital expenditure of the project shall be financed as per the approved financial package set out in the techno-economic clearance of the authority. The actual capital expenditure incurred on completion of the project shall be the criterion for the fixation of tariff. Where the actual expenditure exceeds the approved project cost the excesses as approved by the Authority shall be deemed to be the actual capital expenditure for the purpose of determining the tariff. Further if the capital cost of the project increases in comparison to the cost approved in Techno-economic Clearance on account of foreign exchange variation or change of law or any other reason not attributable to the generating company or its suppliers or contractors and approved by the competent Government. The project developer may approach the Authority with the recommendations of the competent Government, not more than once in a financial year, for the mid-term review of the capital cost.

10.1.1 COMPUTATION OF ANNUAL FIXED CHARGES:

Interest on loan capital shall be computed on the outstanding loans, including the schedule of repayment as per the financial package approved by the authority.

a) The rates of depreciation shall be applicable as notified by the Central Government, from time to time.

b) Operation and Maintenance expenses including insurance for the first full year after commissioning of the plant shall be calculated as a percentage on the actual capital expenditure as provided on the basis of one of the following alternatives

(i) At the rate of 2.5 percent of the actual capital expenditure of ceiling on capital expenditure provided in the power purchase agreement.

(ii) At 2 percent of the actual capital expenditure on ceiling on capital expenditure provided in the power purchase agreement together with actual expenditure on insurance.

In case of multi-unit project the operation and maintenance expenses in respect of each unit for the purpose of tariff shall be allowed on the above percentage of the capital expenditure calculated in proportion to the capacity of each unit and not on the basis of allocation of capital expenditure in Techno-economic clearance. The escalation shall be allowed after one year from the date of the commissioning of the **units.**

c) Tax on the following income streams of the Generating Company to be computed as an expense at actuals.

a. Sixteen percent. Return on equity
b. The extra rupee liability on account of foreign exchange rate variation in computing the return on equity not exceeding 16 percent in the currency of the subscribed capital
c. The amount of grossed up tax that is payable and actually paid by the generating company under income streams mentioned at items (i) and (ii)

(e) Return on equity shall be computed on the paid up and subscribed capital relatable to the generating unit and shall be **16** percent of such capital.

(0 Interest on working capital shall cover:

(i) Fuel cost for one month and reasonable fuel stocks as actually maintained but limited to fifteen days for pit head stations and thirty days for non-pit head stations, calculated on normative plant load factor **basis.**

(ii) Sixty days stock of secondary fuel oil calculated on normative plant load factor basis

(iii) Operation and maintenance expenses (cash) for one month

(iv) Maintenance spares at actuals subject to a maximum of one percent of the capital cost but not exceeding one year's requirements less value of one fifth of initial spares already capitalized and

(v) Receivables equivalent to two months average billing for sale of electricity calculated on normative plant load factor basis.

Full fixed charges shall be recoverable at generation level of 6000 hours/kw/year (4500 hours/kw/year during stabilization period). Payment of fixed charges below the level of 6000 hours/kw/year shall be on prorate basis. There shall not be any payment for fixed charges for generation level above 6000 hours/kw/year. For generation of above 6000 hours/kw/year the additional incentive payable shall not exceed 0.7 percent of paid up and subscribed capital for each percentage point increase of plant load factor above the normative level of 6000 hours/kw/year. While computing the level of generation the extent of backing down as ordered by the Regional Electricity Boards or State Load Despatch Centre shall be reckoned as generation achieved. The payment of fixed charges shall be on monthly basis proportionate to the electricity drawn by the respective Boards and other person.

10.1.2 COMPUTATION OF VARIABLE CHARGE:

It covers fuel costs and shall be computed as follows:

(a) Primary fuel namely Coal or Gas or Naphtha

Quantity shall be computed on the basis of Station Heat Rate (less contributed by secondary fuel oil as below for coal based stations) and gross calorific value of coal or gas or Naphtha actually fired.

(b) Secondary fuel oil only for coal based station

At normative consumption

During stabilization period	5 ml/kw
Subsequent period	3.5 ml/kwh

(c) Adjustment on account of variation in price or heat value of fuels

Initially Gross Calorific value of coal or gas or Naphtha may be taken as per actual in the preceding three months. Any variation shall be adjusted on a month to month basis on the basis of Gross Calorific Value of coal or gas or Naphtha actually received and burnt and actual landed cost incurred by the Generating Company for procurement of coal, oil or gas or Naphtha as the Gross Calorific Value of coal or gas or Naphtha actually received and burnt and actual landed cost incurred by the Generating Company for procurement of coal, oil or gas or Naphtha.

Thus the two-part tariff for sale of electricity from thermal power generating stations awarded through competitive bidding shall comprise the recovery of annual fixed charge and variable charge.

10.1.3 GUIDELINES FOR INVITING TARIFF BASED BIDS:

The existing cost plus tariff mechanism is not ideally suited for competitive bidding as this would require bidding on every element of cost of generation which becomes difficult to verify and monitor over the life of the PPA. In addition the nature of costs for IPPs is very different from the public sector power project costs and in the absence of complete knowledge of the cost profile it is almost impossible to design a competitive bidding process based on cost plus approach that is fair to both sides and can elicit good investor response. In realization of this the Alternative Tariff Structure aims at obtaining competitive offers for cost of supply to the utility. Since the utility is primarily interested in low cost service they should evaluate offers on the basis of this aspect allowing the project sponsors the flexibility to structure the project costs in a manner that he is comfortable with so as to offer the most competitive price for electricity generated. However the SEB's must ensure that a reasonably good field of participants are brought in the fray as this will enable lowest tariffs to be obtained through competition.

As the IPP sells all its output to the SEB and not to the market the IPP cannot take market risk. This necessitates the revenue to be broken up in to two streams. The fixed or capacity charge covering the payment received by the IPP for making generating capacity available to the SEB. This is essential because the capital investment is dedicated to the SEB and the IPP can in no way market underutilized capacity at a short notice. The second part is the variable or energy charge which is basically compensation of fuel cost for electricity actually purchased by the SEB. In keeping with this philosophy in view it is proposed that for a specific project SEBs can invite bids covering the fixed expenses and the variable expenses. This has been elaborated below:

10.1.4 FIXED/ CAPACITY CHARGE (Rs/ MW):

As lenders and sponsors are unwilling to accept exchange rate variation risks and inflation risks, SEBs may ask bidders to specify the percentage of the fixed charge they would like to denominate in foreign currency for purposes of exchange rate protection and the percentage of fixed charge they would like to earmark for adjustments linked to a weighted price index. The SEB may also indicate the nature of tariff preferred from a private power project i.e. whether the tariff is to be front loaded, back loaded or an equated tariff stream that reflects the actual generation costs. The significant aspect in this design is that return on equity, incentive etc. are built in to the bid and the market will determine the optimum rates. Even the tax at the prevailing rates would be required to be covered in the quoted tariff. The change in tax level due to future changes in tax structure would need to be addressed in the Power Purchase Agreement. It is important that the tariff structure fulfills the needs and aspirations of both the SEB as well as the project promoter/ lenders. It needs to be pointed out here that the ideal tariff stream for an IPP would be a higher tariff during the period when loan needs to be repaid and during the period the promoter gets the benefit of income tax exemption or concession and a lower tariff thereafter. Even from the SEBs view point a tariff stream with higher initial tariff works out to be more advantageous as the IPP gets the benefits of tax exemption and the concessions and the SEB and the ultimate consumers stand to benefit in terms of lower tariff. Additionally in the beginning the absorption of electricity at a tariff level reflecting the actual cost of power generation would be relatively easier considering the fact that the private power will form only a small component of the power generated and supplied by the SEB. However in order to ensure that the tariff proposals based on a front loaded tariff structure are not absurd as has been observed in some of the cases and are within the acceptable range. The SEBs may define the boundary conditions before hand. It would be desirable to indicate the maximum first/second year fixed cost component (FCC) and the rate at which tariff reduction is desired by the SEB during debt repayment period. If the tariff is back loaded i.e. initially it is kept low and is allowed to increase with time the supplied electricity in the later stages of operation becomes much more expensive for two reasons. Firstly the debt servicing is planned in such a way so as to get the back loading effect. This results in substantial debt mostly in foreign exchange to be carried forward and hence the impact of FE variation on the Fixed cost Component of tariff is much more pronounced. Secondly as the tariff increases with time it increases substantially increasing his profit as well and making the IPP liable to pay heavier taxes.

Even though the taxes are not a pass through in the proposed revised tariff structure the IFF is likely to load the increased tax burden on the tariff only- which would ultimately be borne by the SEB. An equated tariff for the entire PPA period leads to a low or negative return during the period of tax holiday and a much higher return thereafter leading to higher tax liability thus increasing the payment liability for the SEB.

10.1.5 VARIABLE EXPENSES

Variable charge would depend on heat rate over the life of the project and the cost of fuel. The IPP is in no position to take a risk on the fuel price and this needs to be left to adjustment linked to the relevant fuel price index or to the price of fuel at which procurement is actually made by the IPP. In such cases the procurement would have to be made on transparent procedures with the concurrence of SEB to ensure a minimum price. In case of indigenous fuel the current administered price would have to be referred. The bidders can in their bid indicate a heat rate and proposed annual duration. This will enable the bidder who is offering the lowest heat rate which will translate in to lowest variable charge to get suitable weightage.

Since the project promotion would be through competitive bidding for bringing in transparency and effectiveness in the bidding process the State Governments/SEBs would be required to prepare documents for Request for Qualification and Request for Proposal. Through "Request for Qualification", the state Government/SEB would seek information from the bidder about

- Managerial capability of the bidder
- Financial standing of the company/promoters
- Past experience of the bidder/promoters in the field
- Technology and type of plant proposed

After short listing of the bidders on the basis of pre-qualification evaluation in the RFQ stage, the State Government/SEB would invite detailed proposal from the bidders for project implementation through "Request for proposal" document. These would form the basic response evaluation parameter. The components of fixed cost and variable cost would also vary from state to state and depending on the type of the project.

10.2 METHODOLOGY

Electric utility is a special type of business organization and its economic **characteristics** differ from those of other industries. A separate category of industries like electricity is based on the fact that they supply an indispensable service under monopoly conditions with government regulating prices, profits and service quality. The Electricity Supply Industry was considered a natural monopoly due to economies of scale in power generation resulting in declining long run average costs. Electric utilities are decreasing cost firms whose costs are largely fixed with respect to services consumed. They require heavy initial investment in plant and machinery. The cost structure of electric utilities are dominated by elements of constants costs. For a constant plant size, costs relating to depreciation, interest amortization, property taxes, insurance, dividends on capital stock are constant in character. Therefore, as the output increases in electric utilities, the average unit cost of production has a tendency to decline.

10.2.1 TARIFF PROJECTIONS WITHOUT COST ESCALATION

As an important exercise four case studies linking the cost and expected tariffs are discussed in this dissertation. The power tariff is calculated in four case studies i.e. **Rayalaseema** Thermal power **station—Stage** II **(2x210MW)—A** coal based project (privatization Period), Spectrum power generation Limited Stage I (208 **MW)—A** natural gas based project (Privatization Period), Spectrum power generation Limited Stage II (208 **MW)—A** natural gas based project (Privatization **Period),GVK** Gas power plant **stageII** (216 **MW)—A** natural gas based project (Privatization period) with constant economics and power tariff projections are made in each power project over a life period of each plant.

10.2.2 TARIFF PROJECTIONS WITH COST ESCALATION

The Electricity as a commodity previously was regarded as natural monopoly. But with privatization or unbundling of Electricity Supply Industry the micro economic reform claimed that the natural monopoly hypothesis was invalid and it had rendered obsolete by technological advances. Many argued that economies of scale in power generation had come to an end, while transmission and distribution remained natural monopolies. The Electric power industry may be said to be one of increased costs due to change in fuel prices, with each change in technology.In recent years the costs of generating plants and fuel have increased rapidly. The Central Electricity Authority constituted by the central Government under Section 3 of the Electricity (Supply) Act, 1948. **It** conducts the techno-economic appraisal of the project reports in respect of setting up of generating stations in the country and issues techno-economic clearances for projects. The CEA lays down certain norms regarding operation of Thermal power generating stations (i.e. Coal, Natural gas), subject to subsequent modifications, if any, in accordance with which the tariff for sale of Electricity by Generating companies to the Board are determined. Based on the above concept the power tariff in four generating companies i.e. Rayalaseema Thermal power **station—Stage** II **(2x210MW)—A** coal based project (privatization Period), Spectrum power generation Limited Stage I (208 **MW)—A** natural gas based project (Privatization Period), Spectrum power generation Limited Stage II (208 MW)—A natural gas based project (Privatization Period),GVK Gas power plant **stageII** (216 **MW)—A** natural gas based project (Privatization period) have been computed with 6 % fuel price escalation, 6 % Operation and maintenance escalation and 6.68 % Total loan Interest with foreign exchange escalation and 6.68% Loan Repayment with foreign exchange inflation escalation have been computed and power tariff projections are made over the life period of each plant.

By this it is clear that free market economists and other reformers hoped that the power sector reform in Andhra Pradesh should be accompanied by rapid emergence of competitive markets.

10.3 CASE STUDIES

10.3.1 CASE STUDY **I :** PRO-PRIVATIZATION PERIOD

In the SO years since the time of independence, India has come a long way in coal fired power station technology. Unit sizes at that time were of the order of **10-15** MW. With the time the unit sizes increased and with it the technology. By 1960 the unit size had grown to **75** MW. By **1970** several units having a capacity of 140 / 150 MW had been installed and by **1980** there were about **15** numbers of 200 / 210 MW units in the country.

Today the largest unit made in the country is 500 MW and technical know-how and capability exists to manufacture sets with ratings up to 1000 MW.

Andhra Pradesh State Electricity Board being a vertically integrated organization, having total responsibility for Generation, Transmission and Distribution. There are 24 Generating stations in the state out of which 10 are thermal and 13 are hydro and 1 wind station.

The growth in generation from the thermal, hydel and wind has not kept pace with the growing system demand leading to shortage situation.

CASE STUDY - I

<u>Computation of Tariff in case of Coal Based Project - Rayalaseema Thermal Power</u> Station Stage-I (2x210 MW) - (Pro-privatisation Period)

1.Capacity of the project:	420 MW
2.Project cost as per TEC : (Nov. 1987)	Rs.503.71 Crores
3.Final cost of the project : (April 1997)	Rs.860.30 Crores
4. Installed cost : (Item 3 / 1)	Rs.2.048 Crores per MW
5. Interest on capital during : Construction	Rs. 198.00 Crores
6. Total sum at charge : (Item 3 + 5)	Rs. 1058.30 Crores
7. Cost / MW including Interest during Construction (Item 6/1)	Rs.2.52 Crores
8.Annual Generation assuming 6500 Kwh/Kw installed	2730 M.U.
9. Auxiliary Consumption at 9 %	245.7 MU

10. Units Sent Out (Item 8-9)	2484.3 MU
11. Weighted heat rate (Assumed) : ©Boiler of 88%	2300 K.cal/Kwh
12. Coal consumption assuming net calorific : value of coal of 3275 K.cal/ kg (Item 11/3275)	0.702 kg / kwh
13. Coal consumption / year/ kw installed : (Item 12x8 / Item 1)	4.563 M.T
14. Annual coal cost @ Rs.440/MT/kw : installed (Item 13x14)	Rs.2007.72
15. Fixed Charges @ 6.25 % on item (4) : and 11.5 % on item 7	Rs.4178.0
16. Total fixed and running charges/year/kw : installed (Item 14+15)	Rs.6185.72
17. Adding the cost of fuel oil in the running cost @ 10 ml/ kwh falling fuel oil cost at : Rs.3000 / kl Total fuel cost (Item 14 + Rs.180)	Rs.2187.72
18. Total fixed plus running charges including : fuel oil cost (Item 16 + Rs.180)	Rs.6365.72
19. Cost per kw at 220 kv busbar (Item 18/ 5460) :	Rs.116.58 paise per kwhr
20. Return on capital @ 3.5 % of cost /kw on Item 7	Rs.882.0
21. Profit per unit sent out (Assumed)	12.31 paise per kwhr
22. Price/ kwh generated for sale including cost of fuel oil (Item 19 + 21)	128.89 paise per kwhr

(a) The fixed charges have been taken as 16.25% the break-up of which is as follows:

> Interest @ 10%

> Depreciation @ 3.5%

> Operation & Maintenance Charges @ 2.5%

> Insurance @ 0.25%

(b) A return on capital of 3 and half per annum of he cost/MW installed has been taken.

10.3.2 CASE STUDY II: SCENARIO OF PRIVATIZATION PERIOD

To keep pace with the growing demand Andhra Pradesh is a pioneer in facilitating private sector project in generation. After the proposed restructuring of the APSEB and privatization of generation as well as distribution the sector that will be under the control of the State Electricity Board or the state government would require additional investment for proper functioning of the power sector. When private generating stations would be coming up with out any contract with APSEB to purchase power or any guarantees by the state government create a situation in which the generating companies will be competing among themselves and negotiating agreements with the distribution companies in regard to quantity of energy to be supplied and the tariff for sale and other matters incidental thereto. At this stage electricity would be sold and purchased as a commodity in a competitive market.

CASE STUDY- II

Computation of Tariff in case of Coal Based Power Project- Rayalaseema Thermal Power Station Stage-II (2x210 MW):

Recently M/s ZMEC a Chinese government company have come forward to construct RTPP- II project at a very economic price of Rs.3.6 crore/ MW with a unique 100 % debt finance, on build and transfer basis. The project work has commenced on April 2001 and the first unit will be commissioned by November 2003 and the second unit by February

2004. The annual coal requirement for the two additional units is expected to around 1.5 million tones.

The cost of generating one KWH of electrical energy by the RTPP stage-II with a capacity of 2x210 MW has been calculated as per CEA guidelines.

COST AND ANALYSIS OF COAL BASED PROJECT

CALCULATION OF TARIFF FOR RAYALASEEMA THERMAL POWER PROJECT—STAGE-II

Capacity of the project	: 420 MW
Cost of project as per TEC	: Rs.1577.63 Crores
Cost of the project (Total capital cost)	:Rs.1563.61 Crores
Years of service life	: 30 years
Net Generation (MU)	
Unit –1 (MU)	: 1224.93
Unit _ 2 (MU)	:1103.27
Total Net Generation at PLF 80%	:2328.19
Notional equity	
(20 % on total capital cost for tariff)	:Rs. 312.72 Crores

FIXED EXPENSES:

Return on equity	
(at 16 % of notional equity)	: Rs.50.04 Crores
Operation and maintenance	
Expenses at 2.5 %	: Rs. 39.09 Crores
Depreciation at 7.84 %	
(as per project cost TEC)	: Rs. 123.69 Crores
Interest on loans	Rs. 94.54 Crores
Interest on working capital	: Rs. 20.48 Crores
Capacity cost	

(Summation of Return on equity + Operation and maintenance
+ Depreciation + Interest on loans
+ Interest on working capital) : Rs. 327.83 Crores

Capacity cost per kwh : 327.83/2328.19
= 140.81 paise/kwhr

VARIABLE CHARGES:

Total coal requirement	: 1578396 metric ton
Price of coal	: Rs.1667.52/metric ton
Cost of coal	:263.2 Crores
Total oil requirement	:6159.83 Kilo litres
Price of oil	:Rs.7960/Kilo litre
Cost of oil	: Rs. 4.9 Crores
Total cost of fuel	:263.2 + 4.9 = Rs. 268.1 Crores
Fuel cost per kwh	:268.1/2328.19 = 115.16 Paise per kwh
Fixed Expenses + Variable Charges	= 140.81 + 115.16
	= 255.97 paise per kwh (or) Rs.2.56

It is proposed that for simplification of the evaluation process and for making it more market driven only the parameters having an impact on the tariff in the succeeding years and plant efficiency be evaluated. The power tariff of Rayalaseema thermal power project Stage-II for the succeeding years that is for 30 years have been projected with constant economics based on Techno-Economic Clearance. The parameters used in variable expenses that is Total coal requirement, Total cost of coal, Total oil requirement, Total cost of oil are assumed to be constant. The two parameters in fixed expenses that is interest on loans and interest on working capital are computed as follows:

Loan Repayment Schedule and Interest on loans computation:

Total loan granted for RTPP stage-II - Rs. 1264.91 Crores

Out of this Rs. 1264.91 Crores - 96.78 % is Foreign Loan
- 3.22 % is Home Loan

Therefore Foreign Loan - Rs. 1224.13Crores

Home Loan -- Rs.40.78Crores

Interest on Foreign Loan -- 7.36% PA

Interest on Rupee Term Loan - 14% PA

Interest on Foreign Loan :

Interest for first 6 months:

Foreign loan - Rs. 1224.13Crores

Interest rate 7.36/2 = 3.68%

Therefore interest amount for 6 months is 45.05.The amount 1224.13Crores have to repaid in 11.5 years. No repayment in first 6 months.

Interest for second 6 months:

Foreign Loan—1224.13

Repayment in 23 instalments = 1224.13/23 = Rs53.22Crores.

As the time of loan instalment repayment is not correctly known average of loan repayment is taken as 53.22/2 = Rs.26.61 Crores.

Here Loan - 1224.13 less 26.61 = Rs.1197.52Crores.

Interest amount = 1197.52 x 3.68% = Rs.44.07Crores.

(a) Therefore total interest on Foreign loan for first instalment =

45.05+44.07= Rs.89.12Crores.

Interest on RTL Loan:

Interest for first 6 months

RTL Loan : 40.78

Interest rate : 14/2 = 7%

The amount Rs.40.78Crores have to be repaid in 10 years in 20 instalments.

Loan Repayment 40.78/2 = 2.04crores.

In this case also as the correct date of loan instalment repayment is not correctly known average of loan instalment is taken for interest calculation.

i.e. 2.04/2=1.02

Hence loan = 40.78 less 1.02 = Rs.39.76Crores

Interest amount = 39.76x7% = Rs.2.78Crores

Interest for second 6 months

RTL 40.78 less 2.04 = Rs.38.74Crores

Instalment amount = Rs.2.04Crores

But for interest calculation it should be taken as **1.02** as mentioned earlier.

Hence RTL for Interest purpose = 38.74 **less1.02** = Rs.37.72Crores.

Interest amount = 37.72x7% = Rs.2.64Crores.

(b) Total Interest on RTL Loan for second instalment =2.78+2.64 = Rs.5.42Crores.

Therefore the total loan interest yearly is (a)+(b) = 89.12+5.42 = Rs.94.54Crores.

For the remaining years it is calculated in the similar manner and the results are:

Loan interest for Stabilisation **period,**	47.83+46.71=	Rs.94.54Crores
Year Loan interest for 2002-2003,	44.61+42.51 =	Rs.87.12Crores
Year Loan interest for 2003-2004,	40.41+38.30=	**Rs.78.71** Crores
Year Loan interest for 2004-2005,	36.2+34.1=	Rs.70.3Crores
Year Loan Interest for 2005-2006,	32+29.9 =	**Rs.61.9Crores**

<u>Computation of Interest on Working Capital:</u>

The working capital norms are:

Coal **costs – 18.779**

Coal **stock – 18.779**

Fuel oil cost - 0.700

Spares- 10.79

Operation and Maintenance - 4.34

Expenses

Receivables - 92.90

For the year total working capital requirement - Rs.l46.20Crores.

For the Stabilisation Period

Coal costs—21.47

Coal stock – 21.47

Fuel oil cost—0.67

Spares – 10.79

O & M—3.26

Receivables - 96.01

(excluding incentives & Income tax)

Total working capital - Rs153.68Crores.

For the remaining years also the total working capital is calculated. The total working capital requirement is decreasing as the receivables are reducing from the year 2002-2003 to the remaining years. The working capital interest rate is 14%. Therefore for the Stabilization period the total working capital requirement is 146.29x14% = Rs.20.48Crores.

For the remaining years also the interest on working capital is calculated in the similar manner.

Yearly interest

Stabilization period -Rs.20.48Crores

2002-2003—Rs.21.68Crores

2003-2004 - Rs.21.48Crores

Therefore based on the above two parameters that is Interest on loans and Interest on working capital requirement in the fixed charges and constant economics of variable expenses, power tariff projections are made for 30 years.

10.3.3 CASE STUDY III : PRIVATIZATION PERIOD

The cost and analysis of two fast track natural gas based projects (private sector) have been made. One is Spectrum Power Generation Limited (Godavari CCGBTPS—Kakinada, 1997) with a capacity of 208MW and other is GVK Jegurupadu CCGBTPS ,Stage-II, 2002-2003 with a capacity of 216MW and power tariff projections for 18 years in case of Spectrum power generation limited and 15 years in case of GVK are done.

CASE **STUDY-HI**

COST AND ANALYSIS OF NATURAL GAS BASED PROJECT-(SPECTRUM POWER GENERATION LIMITED AT 68.5% PLF

Capacity of the project:	208MW
Capital cost :	Rs.748.43Crores provisional cost as approved by CEA
Years of service life :	18 Years
Net Generation (MU) at : PLF 68.5%	1210.7 MU
Gas turbine 1(MU)-	46.1 MW
Gas turbine 2 (MU) -	46.1 MW
Gas turbine 3 (MU) -	46.8 MW
Steam turbine (MU) -	69.0 MW
Total	208 MW
Notional Equity (20% on total capital cost for tariff):	Rs.l49.69Crores

FIXED EXPENSES:

Interest on Term Loans	
At 19.51% on Rupee Term Loans:	Rs.55.05 Crores
At 7.82 % on Foreign Currency Loans:	Rs. 16.73 Crores
Interest on Debt	
On Rupee Loans	Rs.298.75 Crores
Opening balance	Rs.33.19 Crores
Repayments during the year	Rs.265.56 Crores
Interest for the Year @ 19.51 % PA	Rs.55.05 Crores
<u>Foreign Currency Loan:</u>	
Opening balance	Rs.225.15 Crores
Repayments during the year	Rs.22.52 Crores

Closing balance		Rs.202.64 Crores
Interest for the Year @ 7.80 % PA		Rs. 16.73 Crores
Total Interest for the year		Rs.71.77 Crores
Return on Equity	:	Rs.35.92Crores
(at 16% of notional equity)		
Depreciation	:	Rs.57.72Crores
(7.84% as per project cost TEC)		
Operation and Maintenance	:	Rs. 18.71Crores
(at 2.5%)		
Interest on loans:		Rs.71.77 crores
Interest on working capital	:	Rs.l0.8Crores
Norms of working capital		
1/12 of O & M Expenses		1.56
Inventory of spares		7.48
Initial spares to be written off		4.49
Spares inventory		2.29
Cost of fuel		1.34
Fuel stock- Alternate Fuel		0.00
Bills receivable		42.1
Working Capital		60.27
Interest© 18%		10.8
Insurance:		Rs.3.74 crores
Total Fixed assets	:	198.67
Per unit cost of fixed cost	:	198.67/1210.7 = Rs. 1.64Paiseperkwh

VARIABLE EXPENSES:

Natural gas calorific value :	9600 k.cal/cubic meter
Station heat rate :	1900k.cal/kwh
Quantity of natural gas per kwh (unit) :9600/1900 :	5.05
Quantity of Gas Per day in Spectrum gas plant =	208x1000x24/5.05 = 988514 cu.m

Price of Natural Gas per 1000 cu.m =	3873
Cost of Natural gas =	3873x988514/1000
	= 3828514722/208x1000x24
	=0.767x0.65= 0.49
Unit Variable cost =	0.49 paise per kwh
Fixed cost + Variable Cost = 1.64+ 0.49 :	Rs.2.12 Paise per kwh

10.3.4 CASE STUDY IV : PRIVATIZATION PERIOD

COST AND ANALYSIS OF NATURAL GAS BASED PROJECT- SPECTRUM POWER GENERATION LIMITED STAGE-II AT 95.00% PLF

Capacity of the project:	208MW
Capital cost :	Rs.748.43Crores provisional cost as approved by CEA
Years of service life :	18 years
Net Generation (MU) at PLF 95.00% :	430.7MU
Notional Equity (20% on total capital cost for tariff)	

FIXED **EXPENSES:**

Interest on Rupee Term Loans:	Rs.55.05 Crores
Interest on Foreign Currency Loans:	Rs. 16.73 Crores
Total Interest	Rs.71.77 Crores
Return on Equity (at 16% of notional equity) :	Rs.35.92Crorcs
Depreciation (7.84% as per project cost TEC) :	Rs.57.72Crores
O & M expenses :	Rs. 18.71 Crores

(at 2.5%)

Interest on Loans: Rs.71.77 Crores

Interest on working capital: Rs. 10.8 Crores

Incentives : Rs.35.70Crores

Insurance : Rs.3.74Crores

Total Fixed Assets : Rs.234.36Crores

Per unit cost of fixed **cost :** 234.36/1430.7 = Rs.l.63Paiseperkwh

VARIABLE EXPENSES:

Quantity of Gas **Per** day in Spectrum gas plant - **208x1000x24/5.05** = **988514 cu.m**

Price of Natural Gas per **1000** cu.m =3873

Cost of Natural gas **=3873x988514/1000**

= 3873x988514\1000

= 3828514.722\208xl000x24

= 3828514.722/4992000

= 0.767 **x0.95** = 0.72

Unit Variable cost = 0.72 paise per kwh

Fixed cost + Variable Cost = **1.63+** 0.72 = Rs.2.35 Paise per kwh

10.3.5 CASE STUDY V: PRIVATIZATION PERIOD

COST AND ANALYSIS OF NATURAL GAS BASED PROJECT-GVK GAS POWER PLANT STAGE-II (216MW) AT 80% PLF

Capacity **of** the project: 216Mw

Cost of the project: Rs.700Crores provisional cost as approved by CEA

Years of service life: **15years**

Net **Generation(MU)** at PLF 80%: **1541.76MU**

Notional Equity Rs. **140Crores**

(20% on total capital cost or tariff)

FIXED EXPENSES:

Interest on Term Loans:	Rs.55.05 Crores
Interest on Foreign Currency Loans:	Rs.16.73 Crores
Return on Equity (at 16% of notional equity)	Rs.22.4 Crores
Depreciation (7.84% as per project cost TEC):	Rs.54.88Crores
0 & M Expenses:	Rs.17.5 Crores
Insurance : (at 0.5%)	Rs.3.5 Crores
Interest on Loans:	Rs.71.77 Crores
Interest on Working Capital:	Rs.10.8 Crores
Total Fixed Assets:	Rs.180.85 Crores
Per unit Cost of Fixed Cost:	180.85/1541.76= Rs.1.17 paiseper kwh

VARIABLE EXPENSES:

Cost of Natural gas -

3873x988514/1000

= 3828514.722/208x1000x24

= 3828514.722/4992000

= 0.767x0.8 = 0.61

Fixed cost+ variable cost = 1.17+0.61 - 1.78 paise per kwh

10.3.6 POWER TARIFF PROJECTIONS

The tariff projections for each case study are shown in appendix

10.3.7 POWER TARIFF BASED ON DISTRIBUTION OF ELECTRICITY SUPPLY INDUSTRY

Four distribution companies were contributed to under take distribution and Retail supply businesses. For this purpose the state of Andhra Pradesh was carved in to four geographical contiguous distribution zones (East, South, Central and North and Distribution and Retail supply undertaking and business was segregated in to and vested respectively in to four distribution companies.

(i) Eastern Power Distribution Company of Andhra Pradesh Limited (APEPDCL)

(ii) Southern Power Distribution Company of Andhra Pradesh Limited (APSPDCL)

(iii) Central power Distribution Company of Andhra Pradesh Limited (APCPDCL)

(iv) Northern power Distribution Company of Andhra Pradesh Limited (APNPDCL)

They are collectively referred to as Discoms.

The commission for ERC (Electricity Regulatory Commission) and tariff filings require the License to file the costs of servicing the various consumer classes based on embedded cost and marginal costs methods. The estimates of emdedded costs of service reflect the average costs associated with servicing that category. Both average costs and marginal costs are important bench marks in determining whether the tariffs reflect the economic costs of servicing its customers. The guidelines require these costs to be determined by customer classes and voltage levels and compares the tariffs with thaes estimates of costs by category and voltage.

10.3.7.1 METHODOLOGY FOR DETERMINATION OF FUTURE TARIFFS

The costs of retail supply and distribution of energy can be calculated by two alternative methods, one is embedded cost method and the marginal cost method.

The embedded or average cost method does not consider the demand that is to be placed on the system by the future users of the system. This method uses the projections of costs based on historical accounting costs that have been incurred for servicing the category. Thus the revenues derived from tariffs can be closely matched with the costs of service derived from this method.

For determination of future tariffs it is appropriate that the economic costs reflect those associated with future use of the system and not just those for past use. The cost of distribution and retail supply not only vary with the quantum of energy used or transmitted but also with the time of day during which the energy is transmitted and the season of the year. These variations in costs are dependent on the marginal demand placed on the distribution system on account of the distribution of energy and also on account of the cost of additional generation capacity that has to be contracted to meet this demand. In the transmission and distribution system , not only does additional capacity need to be built in for any incremental load that occurs when the system operates as its peak capacity, but also for the costs associated with additional losses. The incremental losses at peak capacity increase exponentially with the additional demand placed on the system. Similarly for supply of energy at the peak load, additional capacity has to be contracted and the cost related to contracting of this capacity reflect the costs associated with servicing these loads. The extra costs depend on the nature of the generating capacity contracted for meeting the additional load.

A scarce resource like electricity needs to be priced based on the economic costs of generating and supplying the resource. A higher price than the economic costs will lead to building capacities that are not optimal in size and thus will not allow for realization of economies of scale. In addition this will drive away the load from the grid to other sources of supply that may not reflect the optimal use of such resources. Conversely, charges that are lower than costs will lead to excessive consumption of a scarce resource in an uneconomic manner.

There are many controversial views regarding the average cost based pricing and marginal cost based pricing by economists which have been discussed in the review of literature. It has been believed that marginal cost based pricing methods reflect the economic costs of servicing much more closely than embedded cost based pricing.

However for the purpose of present subsidy and cross subsidy allocation as well as the required directional movement of the tariffs, the estimates of embedded cost may be adequate. The present tariff distortions are extremely large and hence movement towards cost reflective tariffs will take substantial time. In addition the embedded cost base cos estimates have the advantages of capturing accounting costs accurately. Once the gap between tariffs and costs is substantially bridged it would be worth while to emphasise upon marginal cost based cos estimates for tariff and subsidy determination.

The imbalance in tariff rates for various categories of consumers does not allow proper economic signals being send to the consumers and results in inefficient consumption and subsequent stress both financial and operational on the system. For example let us examine the APNPDCL Tariff Rates.

10.3.7.2 The Design of Retail Tariff Rates

The proposed schedule charges has been determined with the objective of unbundling costs and reflecting them appropriately in the tariff structure.

The current schedule of charges has the following components:

- Energy charges in paise per kwhr for all categories (including optional metered tariff for agricultural and irrigation)
- Demand charges (for a few categories in Rs/KVA/month.
- Fixed charges in Rs/HP/month for consumer categories.
- Monthly minimum charges.
- Over drawal charges or tariffs for agricultural and irrigation consumers in Rs/HP/annum.

Energy Charges:

These charges are per kwh of energy consumed. The energy charges at present include recovery of both variable and a large proportion of fixed costs, but generally do not reflect the true marginal costs of production. Most of the fixed costs are also covered in this charge, the extent of which varies between categories.

Demand Charges:

Demand charges are designed to enable AP distribution companies to meet atleast a part of its fixed cost obligation. At present demand charges requires meters capable of measuring maximum demand. A part from the HT categories having demand meters only some the LT industrial category consumers have such meters at this time. Hence AP distribution company is proposing an optional tariff with a demand charge component based on contracted demand in place of the fixed charges based on connected load.

Fixed Charges:

The AP distribution company recognizes the need for collection of fixed charges from those categories consumers who are not subjected to demand charges. Presentlyonly the LT Industrial category have a fixed charges based on HP(Horse Power). It believes that the fixed charges incident on a category should be linked to the variability in revenue from the category and not to the cost structure of the licensee alone. In future if better information is available on the variability in consumption profiles of the categories across time of day and months of the year, the distribution companies will consider the introduction of fixed charges for these categories to address the variability in revenues and costs.

Monthly Minimum Charges:

These charges are currently made applicable in respect of certain tariff categories, to ensure certain minimum amount from the consumer, when the consumer does not consume a minimum level of energy. The AP distribution company have a minimum charge for demand for categories having a two part tariff.

Demand over drawal charges:

These are currently applicable for categories with two part tariffs. These charges are essential as they protect AP distribution company from under contracting of load by consumers. In addition APTRANSCO pays capacity charges to generators, a substantial part of which are on account of fixed costs, which can be expected to be passed on to distribution company.

Flat rate tariffs:

These are applicable to the unmetered agricultural and irrigation consumers. These charges are based on pump capacity and location of the consumer and not the actual level of energy offtake. This is an inefficient method of tariff design. The absenceof any metering infrastructure is the primary impediment in introducing metered tariffs on a universal basis for the consumers of this category. Agricultural tariffs in Andhra Pradesh are among the lowest in the country with the exception of free supply. This has proved to be heavy drain on the finances of APTRANSCO and its subsidiaries. The resultant cross subsidies have severe impact on the tariffs of other categories (especially the industrial categories), pushing the rates substantially above the cost of service and to levels which are among the highest in the country, affecting the competitiveness of these industries and driving them towards captive generation.

Customer Charges:

In addition to the tariff charges, the distribution company has customer charges for various categories.

10.4 SUMMARY

In this chapter power tariff is computed on generation segment of electricity supply industry and also in distribution segment of electricity supply industry. For computation of power tariff in generation segment of ESI, the study examined five case studies namely, Rayalaseema Thermal Power Station—Stage I (2x210MW)—A coal based project (pro privatization Period), Rayalaseema Thermal Power Station—Stage II (2x210MW)—A coal based project (privatization Period), Spectrum Power Generation Limited Stage I (208 MW)—A natural gas based project (Privatisation Period), Spectrum Power Generation Limited Stage II (208 MW)—A natural gas based project (Privatization Period),GVK Gas power plant stage II (216 MW)—A natural gas based project (Privatization period).

In each case study a cost and analysis have been undertaken for the calculation of power tariff. For this the parameters used are Capacity of the project(MW), Cost of the Project as per TEC(Techno-Economic Clearance) (Rs. Crores), Years of service life, Net Generation (MU), Notional Equity, Fixed Expenses (Rs.Crores) which include Return On

Equity, Operation and Maintenance Expenses, Depreciation, Interest on loans, Interest on working capital, Incentives, Taxation, Capacity Cost, Variable Charges which include Cost of fuel (i.e., Coal, Natural gas) (Rs.Crores), Fuel Requirement (i.e., Coal, Natural gas) (Metric tonne, Kilo Litres, Cubic metre) and Price of fuel. For making the power sector in Andhra Pradesh more competitive only the parameters having impact on tariff in the succeeding years have been evaluated. The Power tariff projections have been made in each case study at five year intervals by assuming constant economics based on TEC.

Similarly power tariff projections are made in each case study by assuming Cost Escalation based on TEC at five year time intervals.

CHAPTER XI

EQUILIBRIUM IN ELECTRICITY SUPPLY INDUSTRY

11.0 INTRODUCTION

In general economic analysis, for any industry equilibrium is attained when it is earning maximum profits. It will go on increasing its output at a level where it is making maximum money profits. Profits is the difference between total revenue (TR) and total cost (TC). Thus the industry will be in equilibrium at the level of output where the difference between total revenue and total cost is greatest. Atleast the industry has to reach a break even point, where total revenue just equals total cost and therefore the industry is making profits nor losses.

After discussing general economic analysis, one should make such kind of analysis and see to it whether it suits in case of specialized commodity like electricity. (i.e. ESI)

To draw out such kind of analysis , the following computation work is done.

11.1 CONSUMPTION OF ELECTRICITY

Today consumption of electricity is considered one of the key yardsticks to measure development. A detailed statement showing consumption of power by different categories during the period 1995-96 to 1999-2000 is furnished in Table 11.1. A survey of growth of electricity consumption by the three major consumer categories namely industry, agriculture and domestic shows that while agricultural consumption has gone up steeply, the industrial consumption has declined. Domestic consumption has gone up steadily. Details are shown in Table 11.1 (a). The data has also been presented in the form of graphs. By this the consumption pattern of power in Andhra Pradesh state is clear. It showed that more power is consumed by agricultural sector.

TABLE 11.1 CONSUMPTION OF ELECTRICITY - CATEGORY WISE(MU), ANDHRA PRADESH

CATEGORY	1995-96	1996-97	1997-98	1998-99	1999-2000
DOMESTIC	3276	3801	4535	5090	5486
NON-DOMESTIC	704	795	927	1060	1142
INDUSTRIAL	1172	1270	1358	1492	1576
COTTAGE INDUSTRIES	22	23	25	27	27
AGRICULTURE	11399	7835	9336	7969	10632
PUBLIC LIGHTING	159	212	286	367	403
GENERAL PURPOSE	62	70	86	100	115
TEMPORARY	2	3	2	5	7
TOTAL CONSUMPTION	16796	14009	16555	16110	19388

TABLE 11.1 (a) PERCENTAGE OF TOTAL CONSUMPTION, ANDHRA PRADESH

CATEGORY	1995-96	1996-97	1997-98	1998-99	1999-2000
DOMESTIC	19.5	27.1	27.4	31.6	28.3
AGRICULTURE	67.8	55.9	56.4	49.5	54.8
INDUSTRY	6.9	9.1	8.2	9.3	8.1

TABLE 11.2 TARIFF RATES OF ELECTRICITY (Rs.), ANDHRA PRADESH

CATEGORY	1995-96	1996-97	1997-98	1998-99	1999-2000
DOMESTIC	1.47	1.8	1.8	1.8	2
NON-DOMESTIC	2.37	3.25	3.25	3.25	4.6
L.T. INDUSTRIAL	2.3	2.75	2.75	2.75	3.4
H.T. INDUSTRIAL	2.34	2.82	2.82	2.82	3.55
COTTAGE INDUSTRIES	0.9	1.2	1.2	1.2	1.2
L.T. AGRICULTURAL	0.4	0.7	0.7	0.7	0.9
H.T. AGRICULTURAL	1.3	1.3	1.3	1.3	1
PUBLIC LIGHTING	0.92	1.2	1.2	1.2	1.2
GENERAL PURPOSE	1.55	2	2	2	2.5
TEMPORARY	3	3	3	3	5

The data in Table 11.2 shows that the agricultural tariff in 1995-96 is Rs.1.7 and increased to Rs.1.9 in 1999-2000. While domestic tariff is Rs.1.47 in 1995-96 and Rs.2 in 1999-2000. Compared with industrial tariff that is Rs.4.64 in 1995-96 and Rs.6.95 in 1999-2000, the agricultural tariff is less. Heavily subsidized supply of power to domestic and agricultural sectors, constituted over half the total consumption. High industrial tariff had always compensated for subsidies on agriculture and domestic tariff. With steadily increasing demand from the agricultural sector, this disparity between agricultural and industrial tariff was steeply increasing over the years. This was causing pressure on the industrial sector, leading to stagnation in industrial consumption as industry moved towards cheaper captive generation. This resulted in a significant loss of industrial load, which had an adverse financial impact on APSEB (Andhra Pradesh State Electricity Board's) capacity to cross subsidizes other sectors.

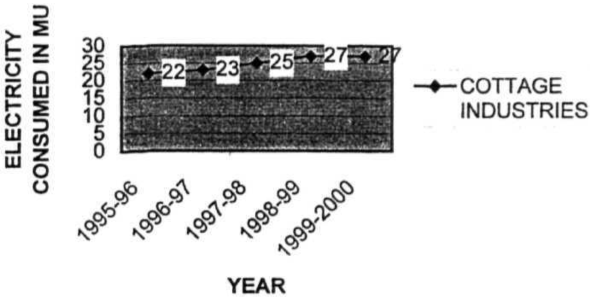
TABLE **11.3** CALCULATION OF REVENUE IN APSEB BEFORE RESTRUCTURING (i.e., Vertically Integrated Monopoly) (Rs.Crores), ANDHRA PRADESH

CATEGORY	1995-96	1996-97	1997-98	1998-99	1999-2000
DOMESTIC	481.6	684.2	816.3	916.2	1097.2
NON-DOMESTIC	166.8	258.4	301.3	344.5	525.3
L.T. INDUSTRIAL	269.6	349.3	373.4	484.9	535.8
H.T. INDUSTRIAL	274.3	358.1	382.9	420.7	559.5
COTTAGE INDUSTRIES	19.8	27.6	30	32.4	32.4
L.T. AGRICULTURAL	455.9	548.5	653.5	557.8	956.8
H.T. AGRICULTURAL	148.2	101.8	121.4	1035.9	10632
PUBLIC LIGHTING	14.6	25.4	34.3	44.1	403
GENERAL PURPOSE	96.1	14	17.2	1	1.76
TEMPORAY	1.8	0.9	0.6	1.5	3.5

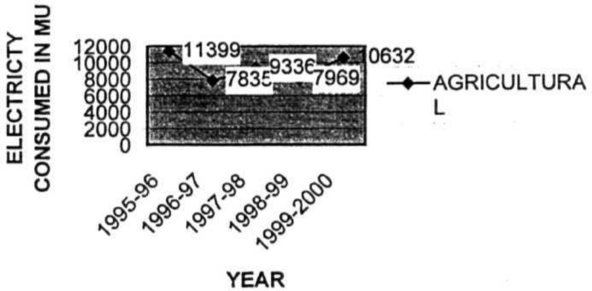
TABLE **11.4** COMPUTATION OF REVENUE GAP, ANDHRA PRADESH

YEAR	TOTAL REVENUE	TOTAL COST	REVENUE GAP
1995-96	1928.7	3550.9	-1622.2
1996-97	2368.2	3894.7	-1526.5
1997-98	2730.9	4000.8	-1269.9
1998-99	3839	5345.5	-1506.5
1999-2000	14747.3	16045.9	-1298.6

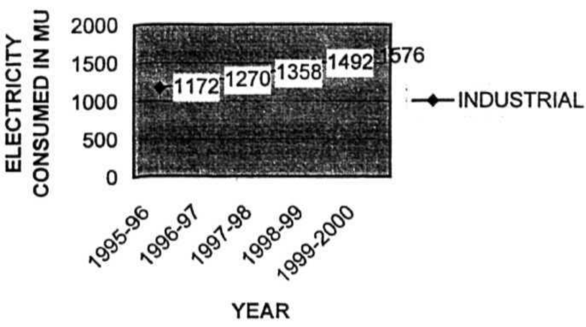
CONSUMPTION OF ELECTRICITY - COTTAGE INDUSTRIES



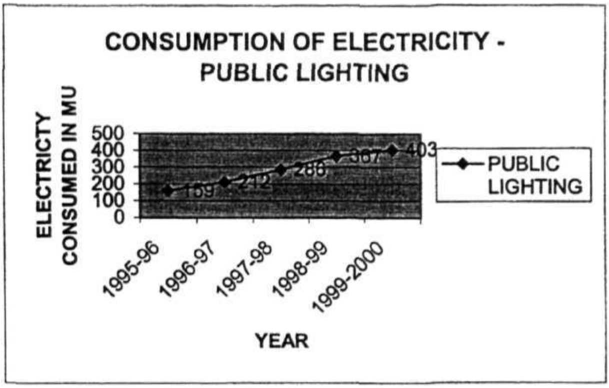
CONSUMPTION OF ELCTRICITY - AGRICULTURAL

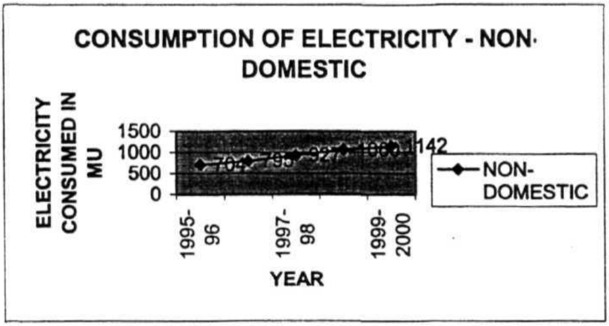


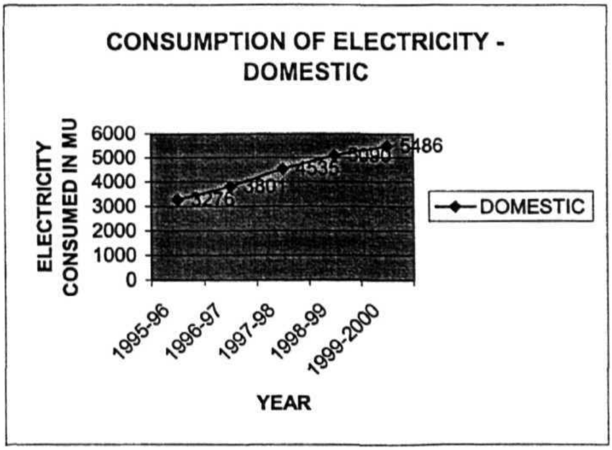
CONSUMPTION OF ELECTRICITY - INDUSTRIAL



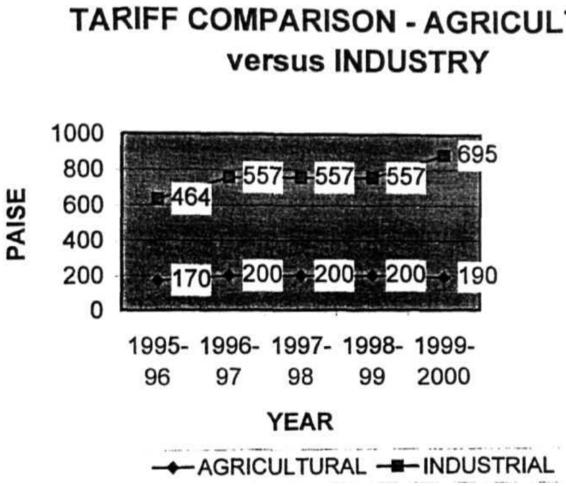
GRAPH11.2


CONSUMPTION OF ELECTRICITY - PUBLIC LIGHTING
ELECTRICTY CONSUMED IN MU
500
400
300
200
100
0
159
212
286
367
403
PUBLIC LIGHTING
1995-96
1996-97
1997-98
1998-99
1999-2000
YEAR


CONSUMPTION OF ELECTRICITY - NON-DOMESTIC
ELECTRICITY CONSUMED IN MU
1500
1000
500
0
704
1142
NON-DOMESTIC
1995-96
1997-98
1999-2000
YEAR


CONSUMPTION OF ELECTRICITY - DOMESTIC
ELECTRICITY CONSUMED IN MU
6000
5000
4000
3000
2000
1000
0
3276
3801
4535
5486
DOMESTIC
1995-96
1996-97
1997-98
1998-99
1999-2000
YEAR

GRAPH 11.3



TARIFF COMPARISON - AGRICULTURE
versus INDUSTRY
PAISE
1000
800
600
400
200
0
464
557
557
557
695
170
200
200
200
190
1995-96
1996-97
1997-98
1998-99
1999-2000
YEAR
AGRICULTURAL
INDUSTRIAL

TABLE 11.5 CONSUMPTION OF ELECTRICITY IN CPDL, NPDL, SPDL and EPDL (DISCOMS) - CATEGORY WISE (MU), ANDHRA PRADESH

YEARS	2000-2001	2001-2002	2002-2003
LOW TENSION			
DOMESTIC (CATEGORY-I)	6117	6880	7496
NON-DOMESTIC (CATEGORY-II)	1233	1429	1822
INDUSTRIAL (CATEGORY-III)	1681	1883	2020
COTTAGE INDUSTRIES (CATEGORY-IV)	27	28	31
IRRIGATION AND AGRICULTURE	11541	10271	10594
PUBLIC LIGHTING (CATEGORY-VI)	459	517	551
GENERAL PURPOSE (CATEGORY-VII)	103	83	91
TEMPORARY SUPPLY(CATEGORY-VIII)	7	8	11
HIGH TENSION			
INDUSTRIAL SEGGREGATED (CTG -I)	3646	3772	3866
INDUSTRIAL SEGGREGATED(CTG-I)(NTPC)	0	0	0
INDUSTRIAL NON SEGGREGATED (CTG-II)	602	658	712
IRRIGATION AND AGRICULTURE (CTG-IV)	38	58	177
RAILWAY TRACTION (CATEGORY-V)	923	940	987
ELECTRIC CO-OPERATIVE SOCIETIES	1132	1219	1291
POWER INTENSIVE CONSUMER (CTG-III)	0	0	0
INTER STATE SUPPLIES	0	0	0
TEMPORARY	0	0	0
COLONY LIGHTING	145	168	183
TOTAL CONSUMPTION	27654	27914	29832

NOTE:
CTG - CATEGORY
CPDL - Central Power Distribution of Andhra Pradesh Limited
SPDL - Southern Power Distribution of Andhra Pradesh Limited
NCPDL - Northern Power Distribution of Andhra Pradesh Limited
ECPDL - Eastern Power Distribution of Andhra Pradesh Limited

TABLE 11.5 (a) PERCENTAGE OF TOTAL CONSUMPTION, ANDHRA PRADESH

CATEGORY	2000-2001	2001-2002	2002-2003
DOMESTIC	22%	24.6%	25%
H.T. INDUSTRY	15%	15%	15%
H.T. AGRICULTURE	0.13%	0.20%	0.59%

Consumption of electricity category wise (Table 11.1) and Tariff rates of electricity category wise (11.2) are key inputs in determining or computing total revenue from 1995-

96 to 1999-2000. By multiplying consumption of electricity category wise with corresponding tariff rates category wise, we arrive at annual total revenue. It has been found that Electricity Supply Industry in a integrated structure could not attain a break even point i.e. Total revenue equal to Total Cost. If e look at the figures in Table 11.4, it has been found that the total cost is greater than total revenue and there is a revenue gap. The revenue gap or annual deficit of APSEB has increased. The reasons for huge deficits or losses incurred are high subsidized tariff for supply of power to farm sector, subsidized domestic sector, limitation to further cross subsidization and tariff not being revised regularly or adequately in a vertically integrated monopolistic structure. (APSEB).

A detailed statement showing consumption of power by different categories during the period 2000-2001 to 2002-2003 is furnished in Table 11.5. There are essentially three key categories that significantly influence the sales forecast after unbundling of APSEB in to Northern Power Distribution of Andhra Pradesh Limited, Southern Power Distribution of Andhra Pradesh Limited, Eastern Power Distribution of Andhra Pradesh Limited and Central Power Distribution of Andhra Pradesh Limited. These are the Domestic, HT industrial and the HT Agricultural categories.

Domestic Supply:

In recent periods the domestic category has witnessed very significant growth and the sales to this category increased very significantly from 6117 MU in 2000-2001 to 7496 MU in 2002-2003 on account of the regularization measures initiated in the past one and half years.

HT Industrial:

Sales in the HT industrial category has been stagnating in the sate compared to domestic supply. The consumption levels were low that is 4248 MU in 2000-2001 and 4578 MU in 2002-2003. This trend is expected to continue unless there is an improvement in the over all macro- economic scenario and there are significant tariff interventions that make grid consumption attractive.

HT **Agriculture:**

Compared to APSPDCL, APEPDCL, APCPDCL, the APNPDCL has one of the highest densities of agricultural load in the sate and the economy in the areas served by APNPDCL is primarily agrarian. For the years 2000-2001 to 2002-2003 the agricultural consumption has intended to grow sharply, that is 38 MU to 177 MU.

The above factors are evident from the percentage of total consumption shown in Table 11.5 (a).

11.2 TARIFFS RATES OF ELECTRICITY

The classification of tariff rates by consumer categories in Table 11.6 covers the following:

TABLE 11.6 TARIFF RATES OF ELECTRICITY - CATEGORY WISE (Approved Electricity Regulatory Commission), ANDHRA PRADESH

YEARS	2000-2001	2001-2002	2002-2003
LOW TENSION			
DOMESTIC (CTG – I)	3.65	3.68	2.93
NON - DOMESTIC (CTG-II)	5.85	5.84	5.48
INDUSTRIAL (CTG-III)	4.15	4.8	3.85
COTTAGE INDUSTRIES (CTG-IV)	1.75	1.74	1.8
IRRIGATION & AGRICULTURE(CTG-V)	1.0	1.1	1.1
PUBLIC LIGHTING(CTG-VI)	2.7	2.68	2.82
GENERAL PURPOSE (CTG-VII)	4.3	4.3	1.5
TEMPORARY SUPPLY (CTG-VIII)	6.2	6.2	6.2
HIGH TENSION			
INDUSTRIAL SEGGREGATED(CTG-I)	3.87	3.87	3.71
INDUSTRIAL SEGGREGATED(CTG-I)(NTPC)	0	0	0
INDUSTRIAL NON-SEGGREGATED(CTG-II)	4.5	4.5	4.5
IRRIGATION & AGRICULTURE (CTG-IV)	1.2	1.3	1.78
RAILWAY TRACTION (CTG-V)	4.6	4.6	4.6
ELECTRIC CO-OPERATIVE SOCIETIES	3.2	3.2	3.2
POWER INTENSIVE CONSUMER(CTG-III)	0	0	0
INTER STATE SUPPLIES	0	0	0
TEMPORARY	0	0	0
COLONY LIGHTING	3.2	3.2	3.2

NOTE: CTG - CATEGORY

HT TARIFFS:

The tariffs are applicable for supply of electricity to HT consumers having loads with a contracted demand of 70 KVA and above and having a connected load exceeding 75 HP/ 56 KW excepting the optional category under LT III.

HT CATEGORY I:

This tariff is applicable for supply to all HT industrial consumers. Industrial purpose shall mean manufacturing, processing and preserving goods for sale. The water works of municipalities and corporations and any other organization comes under this category.

(1) Consumption of energy for lights and fans in factory premises in excess of 10% of total consumption shall be billed at the energy charges applicable for HT II category provided lights and fans consumption in the unit is separately metered.

(2) In case of lights and fans loads has not been done 15% of the total energy consumption shall be billed at the energy charges applicable for HT II category and the balance at HT category I rates.

COLONY CONSUMPTION:

The consumption of energy exclusively for the residential colony/ township in a month separately metered with meters installed by the consumer and tested and sealed by the licensee shall be billed at HT category VI rates.

SEASONAL INDUSTRIES:

Consumer avails supply of energy for manufacture of sugar or ice or salt, ginning and pressing, tobacco processing and re-drying and for such other industries or processes as may be specified by the licensee from time to time principally during certain seasons or limited periods in the year. He may be charged for months during which the plant is shutdown i.e. off-season period under HT category II rates.

HT CATEGORY II:

This tariff is applicable to all HT consumers other than those covered under other HT Categories. In respect of Government controlled auditorium and theaters devoted for the purpose of propagation of art and cultural activities are not let out with a profit motive and in respect of charitable institutions to the general public the over all unit rate may be limited to the tariff rates under LT category VII.

HT CATEGORY IV:

IRRIGATION AND AGRICULTURAL

This tariff is applicable for consumers availing HT supply for irrigation and agricultural purposes only.

HT CATEGORY V:

RAILWAY TRACTION

This tariff is applicable to all HT railway traction loads.

HT CATEGORY VI:

TOWNSHIPS AND RESIDENTIAL COLONIES

This tariff is applicable to HT supply exclusively for townships, residential colonies of consumers under HT categories I to V and bulk supplies for domestic purpose such as lighting, fans, heating etc provided that the connected load for common facilities such as non-domestic supply in residential, street lighting and water supply shall be within the limits.

Water supply & Sewerage & Street lighting 10% of total load connected

Non-domestic, Commercial & General purpose 10% of total load connected

LT TARIFFS:

System of Supply	Low Tension A.C. 50 Cycles
	Three Phase Supply at 415 volts
	Single Phase Supply at 240 volts.

The tariffs are applicable for supply of electricity to LT consumers with a connected load of 56 KW/ 75 HP and below except the optional category under LT III

LT CATEGORY I DOMESTIC:

1) Three phase supply for domestic purpose will not normally be given. However three phase supply can be considered if three phase supply of the licensee is available at that point. For loads less than 3 KW single phase supply only will be given.

2) If electricity supplied in domestic premises is used for non-domestic and commercial purposes the entire supply shall be charged under LT category II tariff.

3) Single point LT services released to residential complexes of state government / Central government department under specific orders of licensee with contracted load/ connected load in excess of 56 KW / 75 HP shall continue to be billed under LT I. Domestic tariff slab rate applicable based on the average monthly energy consumption per each authorized dwelling that is total energy consumption in the month divided by the number of such dwelling units in the respective residential complex.

MODE OF BILLING AND PAYMENT:

The licensee may introduce monthly billing for all consumers instead of bimonthly (once in two months) presently in vogue.

LT CATEGORY II NON DOMESTIC AND COMMERCIAL:

This will be applicable up to 56 KW. Applicable for supply of energy for lights and fans for non-domestic and commercial purposes excluding loads falling under LT Categories I. III to VII. The educational institutions run by individuals, non-governmental organizations are also classified under this category. Exclusions for this would be those that qualify to be under LT VII.

LT CATEGORY III (A) INDUSTRIAL:

NORMAL CATEGORY

The tariffs are applicable for supply of electricity to low tension industrial consumers with a contracted load up to 75 HP/ 56 KW and below including incidental lighting load not exceeding 5% of the total contracted load. This tariff is applicable to water works and sewerage pumping stations operated by government departments or co-operative societies and pumpsets of railways, pumping of water by industries as subsidiary function and sewerage pumping stations, poultry farming units other than those coming under LT Category IV.

CATEGORY III (B) OPTIONAL:

This optional tariffs is applicable to all industrial with connected load 50 HP and up to 150 HP and who wish to avail supply to low tension. The existing LT Category III consumers who come under SSI (Small scale industries) category and who were sanctioned LT supply for connected loads above 75 HP and up to 125 HP.

LT CATEGORY IV:

(a) Cottage Industries

Applicable for supply of energy to bonofide small cottage industries like power looms having connected load not exceeding 5 HP including incidental lighting in the premises.

LT CATEGORY V:

AGRICULTURAL

Applicable for supply of electricity for irrigation and agricultural purposes up to a connected load of 75 HP.

LT CATEGORY VI:

Applicable for supply of energy for lighting on public roads, streets through fares including bridges and for traffic signaling and also for PWS scheme in the local bodies namely panchayats, municipalities, municipal corporations.

LT CATEGORY VII:

GENERAL PURPOSE

Applicable for supply of energy to places of worship like churches, temples, mosques, Governmental educational institutions, charitable institutions and recognized service institutions.

LT CATEGORY VIII:

LT TEMPORARY SUPPLY

For temporary supply of energy to all categories other than irrigation and agriculture.

After unbundling of APSEB, the tariff rates have been revised significantly for industrial and agricultural sector. The agricultural tariff increased significantly from Rs.3.9 in 2000-2001 to Rs.4.6 in 2002-2003. Compared to last five year tariff rates, agricultural and industrial tariff were very high. The industrial sector tariff rate is Rs.1 1.00.

TABLE 11.7 CALCULATION OF REVENUE DURING RESTRUCTURING (i.e., Unbundled APSEB(DISCOMS)) Rs. Crores, ANDHRA PRADESH

YEARS	2000-2001	2001-2002	2002-2003
LOW **TENSION**			
DOMESTIC (CTG – I)	2232.7	2531.8	2196.3
NON - DOMESTIC (CTG-II)	721.3	834.5	998.4
INDUSTRIAL (CTG-III)	697.6	903.8	777.7
COTTAGE INDUSTRIES (CTG-IV)	4.7	4.8	5.58
IRRIGATION & AGRICULTURE(CTG-V)	1154.1	1129.8	1165.3
PUBLIC LIGHTING(CTG-VI)	123.9	138.5	155.3
GENERAL PURPOSE (CTG-VII)	44.2	35.6	13.65
TEMPORARY SUPPLY (CTG-VIII)	4.34	4.96	6.82
HIGH TENSION			
INDUSTRIAL SEGGREGATED(CTG-I)	1411.0	1411.0	1434.2
INDUSTRIAL SEGGREGATED(CTG-)(NTPC)	0	0	0
INDUSTRIAL NON-SEGGREGATED(CTG-II)	270.9	296.1	320.4
IRRIGATION & AGRICULTURE (CTG-IV)	4.5	7.54	7.54
RAILWAY TRACTION (CTG-V)	362.2	362.2	362.2
ELECTRIC CO-OPERATIVE SOCIETIES	295.3	432.4	454.0
POWER INTENSIVE CONSUMER(CTG-III)	0	0	0
INTER STATE SUPPLIES	0	0	0
TEMPORARY	0	0	0
COLONY LIGHTING	46.4	46.4	46.4

NOTE: CTG - CATEGORY

TABLE 11.8 COMPUTATION OF REVENUE GAP (Rs. Crores), ANDHRA PRADESH

YEARS	TOTAL REVENUE	TOTAL COST	REVENUE GAP
2000-2001	7102.2	8090.2	-988
2001-2002	8139.3	9200.3	-1061
20002-2003	7943.9	8835.94	-892.04

From Table: 11. 5 and Table: 11.6 i.e. consumption of electricity category wise in all 4 Discoms **that** is Northern Power Distribution of Andhra Pradesh Limited, Southern Power Distribution of Andhra Pradesh Limited, Eastern Power Distribution of Andhra Pradesh Limited and Central Power Distribution of Andhra Pradesh Limited and their respective tariff rates as fixed by Electricity Regulatory Commission category wise total revenue is computed from 1999-2000 to 2002-2003. Still there is arevenue gap and even through unbundling process (which is a part of restructuring) which can be seen in Table: 11.8 and the companies are not able to reach a break even point. The reasons for this are the cost of supply of power has been rising over the years. In the initial years there was considerable hydel capacity providing cheap hydel power costing 7 to 10 paise per unit. Even as recently as in 1991, hydel power costing about 9.41 paise per unit accounted for about 50% of the total energy supplied. Since then no major irrigation /hydel projects have come up in the state & all the subsequent capacity additions have been found. Over the years the cost of inputs for generation have been going up i.e., cost of coal to APGenco have been increasing . Considerably from Rs. 690 per metric tonne in 1993-94 to Rs. 569 per metric tonne. Added to this the increasing cost of purchases is leading to an ever increasing cost of supply of energy.

TABLE 11.9 PROJECTION OF ELECTRICITY CONSUMPTION - CATEGORY WISE (MU), ANDHRA PRADESH

YEARS	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008
LOW TENSION					
DOMESTIC (CTG – I)	8245.6	9152.7	10251.02	11583.7	13205.4
NON - DOMESTIC (CTG-II)	1967.76	2144.9	2359.4	2618.9	2933.2
INDUSTRIAL (CTG-1II)	2262.4	2556.5	2914.4	3351.56	3887.8
COTTAGE INDUSTRIES (CTG-IV)	32.6	34.6	37.02	39.98	43.6
IRRIGATION & AGRICULTURE (CTG-V)	12289.0	14378.13	16966.2	20189.8	24227.8
PUBLIC LIGHTING (CTG-VI)	584.1	624.9	674.9	803.13	883.4
GENERAL PURPOSE (CTG-VII)	94.6	99.33	105.3	114.8	123.9
TEMPORARY SUPPLY (CTG-VIII)	11.6	12.3	13.16	14.08	15.3
HIGH TENSION					
INDUSTRIAL SEGGREGATED (CTG-I)	4213.94	4635.3	5145.2	5162.6	6511.7
INDUSTRIAL SEGGREGATED (CTG-)(NTPC)	0	0	0	0	0
INDUSTRIAL NON-SEGGREGATED (CTG-II)	761.84	822.8	896.8	1004.4	1114.9
IRRIGATION & AGRICULTURE (CTG-IV)	198.24	224.0	255.36	293.6	340.6
RAILWAY TRACTION (CTG-V)	1046.22	1119.4	1208.9	1317.7	1449.5
ELECTRIC CO-OPERATIVE SOCIETIES	1381.37	1491.9	1626.2	1788.8	1985.6
POWER INTENSIVE CONSUMER (CTG-III)	0	0	0	0	0
INTER STATE SUPPLIES	0	0	0	0	0
TEMPORARY	0	0	0	0	0
COLONY LIGHTING	192.15	203.7	217.95	235.4	256.6

NOTE: CTG - CATEGORY

TABLE 11.10 PROJECTION OF REVENUE (Rs. Crores), ANDHRA PRADESH

YEARS	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008
LOW TENSION					
DOMESTIC (CTG – I)	2415.9	2681.7	3003.5	3394.8	3869.2
NON - DOMESTIC (CTG-II)	1078.3	1175.4	1292.9	1435.2	1607.4
INDUSTRIAL (CTG-III)	871.02	1400.9	1122.0	1290.4	1496.8
COTTAGE INDUSTRIES (CTG-IV)	5.9	38.06	6.7	7.2	7.8
IRRIGATION & AGRICULTURE (CTG-V)	1351.8	4054.6	1866.3	2220.1	2665.1
PUBLIC LIGHTING (CTG-VI)	164.7	176.2	190.3	226.5	249.1
GENERAL PURPOSE (CTG-VII)	14.2	14.8	15.8	17.2	34.9
TEMPORARY SUPPLY (CTG-VIII)	7.2	7.6	8.2	8.7	9.5
HIGH TENSION					
INDUSTRIAL SEGGREGATED (CTG-I)	1563.4	1719.7	1908.8	2137.9	2415.8
INDUSTRIAL SEGGREGATED (CTG-)(NTPC)	0	0	0	0	0
INDUSTRIAL NON-SEGGREGATED (CTG-II)	342.8	370.3	403.6	451.9	501.7
IRRIGATION & AGRICULTURE (CTG-IV)	91.2	39.8	45.5	52.3	60.5
RAILWAY TRACTION (CTG-V)	334.8	514.9	556.1	606.1	666.7
ELECTRIC CO-OPERATIVE SOCIETIES	442.0	477.4	520.4	572.4	635.4
POWER INTENSIVE CONSUMER (CTG-III)	0	0	0	0	0
INTER STATE SUPPLIES	0	0	0	0	0
TEMPORARY	0	0	0	0	0
COLONY LIGHTING	61.5	65.1	69.7	75.3	82.1

NOTE : CTG - CATEGORY

TABLE 11.11 COMPARISON OF TOTAL REVENUE AND TOTAL COST UNDER NEW SCENARIO, ANDHRA PRADESH

YEARS	TOTAL REVENUE	TOTAL COST	PROFITS
2003-2004	8744.72	8381.86	362.86
2004-2005	12736.47	8381.86	4354.61
2005-2006	11009.8	8381.86	2627.94
2006-2007	12496.0	8381.86	4114.14
2007-2008	14302.1	8381.86	5920.24

11.3 REVENUE OF ELECTRICITY SUPPLY INDUSTRY

In order to bridge gap between its revenues and costs, the following avenues are available which are a part of restructuring process.

1) Increased revenues from wheeling tariff charges and grid support charges.
2) Revenues from sale of power outside the state/
3) Increased revenues from Bulk Supply Tariffs (BST) charged to Discoms.
4) Increase the consumption levels category wise considerably.

By increasing the consumption levels category wise 2002-2003. by some assumed percentages the consumption of electricity category wise from 2003 to 2008 has been calculated (Table: 11.9) and the tariff rates fixed by Electricity Regulatory Commission(Table 11.7) remaining same, the total revenue is calculated for the future years. For future years the Electricity Supply Industry can attain a break even point and it can also earn maximum profits as the revenue gap is filled up. For example by raising the consumption levels Electricity Supply Industry earns a profit of Rs.362.86 Crores for the year 2003-2004 as total revenue is greater than total cost and for the subsequent years its revenue has increased considerably. (Table: 11.11).

11.4 SUMMARY

Despite losses in Andhra Pradesh Electricity Supply Industry, a break even point is reached where total revenue equals total cost. The total revenue and total cost of APSEB before and after restructuring is taken into account and revenue gap is calculated. The projections of Electricity Consumption and revenue for future years i.e., (2003-2004 to 2007-2008) are made. The picture of Total Revenue and Total Cost for future years (2003-2004 to 2007-2008) revealed that profits of SEB's can combat losses successfully. This is an indication of recovery of losses in Andhra Pradesh Electricity Supply Industry.

CHAPTER XII
SUMMARY AND CONCLUSIONS

12.0 INTRODUCTION

This chapter deals with the summary and conclusions. It also covers policy recommendations and Financial viability of future Power Projects in Andhra Pradesh.

12.1 SUMMARY

Sustained Power Availability is the essential pre-requisite of the development **in India.** Currently around 65% of the total installed capacity is owned and operated by the State Electricity Boards and 29% by Corporations setup under the central government. Instead of earning a Minimum Rate of Return (RoR) of 3 percentage on their net fixed assets as statutorily required under Section 59 of the Electricity Supply Act, 1948 almost all the State Electricity Boards are showing negative returns. Major factors responsible for the losses of SEB's include high Transmission and Distribution (T&D) losses including wide spread theft and pilferage of power, unsustainable cross subsidy. The combined estimated losses of revenue of the Electricity Boards are Rs. 14913 crore. The past five decades had witnessed a considerable growth in electricity generation. The generation capacity has increased by more than 60 times; that is from a meagre 1,362 MW in 1947 to over **448.4** billion KWH during 1998.Presently the country faces energy shortage of about 6% and peak shortage of 11%. The total installed generating capacity in the country is 1,00,077.35 MW out of which thermal generating capacity is 71,245.36 MW and Hydel generating capacity 24,712.26 MW. 28 thermal units aggregating to a capacity of 5952 MW have completed their useful economic life. Government has taken a renovation and Modernization programme, comprising 34 thermal power stations covering 163 units in the country which resulted in an additional generation of about 10,000 MWs per annum. The phase 2 of the R&M covering 44 stations with 198 units has been taken up for implementation. Since the entry of private sector in the power generation, the government has given techno economic clearance (TEC) to 56 private sector power projects amounting to around 28,849 MW. Reforms and restructuring of Power sector has gained momentum since the enactment of ERC Act, 1996. Orissa was the first state in the country to unleash the reforms through enactment of the Orissa Electricity Act, 1995.Several State governments have also initiated reforms in their power sectors. Haryana, Andhra Pradesh, UP, Karnataka have enacted their State Reforms Act, which provide inter alia for unbundling/corporatisation of SEB's.

The studies conducted by different economists like Pierre Gurslain(1997), Stephen Sayer(1996), Alex Henney(1995), John Barker(1995), Chitru S Frenando et al (1996). Bernard Tenenbaum et al(1992), Paul L Joskow(1997) etc found that there was a fundamental shift in the structure of Electricity Supply Industry from the era of monolithic regulated, vertically integrated utility to a competitive market. Though a wide research is carried out in this area, one needs to look at its wide application.

Regarding tariff structure, the pricing policies followed by India often lead to inefficient allocation of resources, under utilization of energy and incur a heavy burden on the economy. According to economists like Mohan Munasinghe and Jeremy Warford, David M.G. Newbery, Cicchetti, Gillen and Smolensky, H.R. Outhred et. al, Surinder Kumar, Caramanis, Bohn and Schewepe and N.S.S.Arokiaswamy the price should be related to the marginal cost of supply. But according to Turvey and Anderson, G.P.Keshava and Peter G.Soldatos the price should be related to the real cost of fuels. Therefore there are lot of controversies regarding the pricing of electricity. For the development of energy sector the market forces must be allowed to play their part effectively. Pricing of energy products should be such that they reflect the true opportunity cost of their use. There should be more emphasis on the application of the principles of economic efficiency and a great deal of attention should be paid to marginal cost pricing policies inorder to recover Electricity Supply Industry from losses.

12.2 CONCLUSIONS

The GDP at factor cost in Electricity Sector at All India level suggests that the average growth rate of 7% is due to expansion of its generation through private sector participation. Among various sectors i.e., Agriculture, Industrial, Domestic the consumption of electricity in Agricultural sector was more and provided to the farmers at subsidized rates. The supply of Electricity was only 550001 MKWH in 2001-2002 as compared with demand i.e., 741200 MKWH. In order to mobilize additional resources for the Electricity sector, to help bridge the gap in demand and supply, government formulated a policy in 1991 to encourage greater investment by private enterprise in the electricity sector. The government recently reviewed the existing guidelines for automatic approval for foreign equity for electricity generation, transmission and distribution projects and has decided to enlarge the provisions for automatic approval for such projects. Accordingly projects for electricity generation, transmission and distribution will be permitted foreign equity participation upto 100% on the automatic approval route. The categories which would qualify for such automatic approval are:

Hydroelectric power plants

Coal/lignite based thermal power plants

Oil/gas based thermal power plant.

The power sector reforms may well be underway in many Indian states. This is due to the fact that average tariffs were consistently below the average cost of supplying electricity. The overall average tariff and the unit cost in Indian SEB's was 77.74 paise per KWH and 124.02 paise per KWH in 1990-91 and 195.56 paise per KWH and 459.47 paise per KWH in 1998-99. Added to this the cost components of SEB's includes rising fuel costs, power purchase, operation and maintenance, establishment and administration, depreciation and interest. The reasons are poor technical efficiency in generation, high T & D losses and pilferage. Because of this the state Electricity Boards are not able to recover costs through tariffs. So power tariff restructuring of SEB's is an urgent necessity at this critical juncture. The effective subsidy and cross subsidization of tariff affected the competitiveness of Electricity Supply Industry.

The reforms in power sector were being effectively implemented in the state. The reforms aided economic development of which percapita consumption was an indicator. The percapita consumption which stood at 510 kilo watt hours against pre-reform periods (i.e.410 kilowatt hrs). This was made possible by strengthening T & D network adding new generation capacity and intensive drive to reduce losses. The demand for power increased by 30% in the last 2 years and it had also overcome the low voltage problem successfully and achieved an addition of 10% in voltage profile. After post reforms the investment increased to 925 crores against 371 crores in pre reform period. This led to substantial improvement in power supply position and total satisfaction of the consumer. As the government is providing Rs.130 crore each month as subsidy the monthly revenue collection improved to Rs.560 crores against Rs.350 crore earlier. The percapita consumption in A.P. was much better compared to Haryana (508 units) Tamil Nadu (469 units) Orissa (447 units) Madhya Pradesh (368 units) Karnataka (338 Units) and Rajasthan (295 units). The network expansion is highest in A.P. among all electricity utilities in the country with the T & D network development being 26.4% against an All India average of 15.4%.

With regard to tariff structure the industrial sector continues to pay heavy tariffs there by enabling AP Transco to subsidize the two other crucial sector. With each unit costing up to Rs.4.50 the industrial power tariff in Andhra Pradesh is one of the highest in the country. In fact there was much opposition when the first post reform tariff was announced last year from the industrial sector. The steep tariff hike would act as a discentive for new industries from coming to state. The LT & HT industrial users in the state were paying between Rs.3.40 and Rs.3.70 per unit prior to the first tariff revision under the reformed regime. Though the industrial sector suffered badly due to the hiked tariffs there was a improvement in the quality of power. Power sector reforms has not translated in to cheaper power for the people according to an official document. The rising fuel cost combined with the increase in establishment and other expenditures including interest payments has seen a sharp hike in power price. Restructuring of State Electricity Board's in A.P., Haryana, Orissa, Karnataka and Uttar Pradesh and the establishment of separate generation, transmission and distribution companies have helped to bring down the expenditure on fuel in the total cost of power supply from 25.8% in 1992-93 to 17.2% in 1999-2000. This is because the financial performance of unbundled utilities has improved to a certain extent.

After experimenting with various reform models aimed at wooing the private sector, there seems to be the conclusion that the focus on the reform effort was at the wrong end (generation)! Unless the distribution system is strengthened and results in improved cash flows, there can be little private sector interest. Major instruments of reform, such as tariff rationalization, efficiency improvements, and the creation of competition, were largely ineffective due to lack of good data and monitoring systems and an incomplete political distancing, despite introducing independent' regulatory commissions (RCs). The reform is, therefore, now being re-focused on this end of the electricity system (distribution). The options for improving the performance of distribution entities can be classified broadly into technical/management and regulatory options. In the first category would fall the areas of 100 per cent metering of consumers, reducing transmission and distribution losses and improving collection efficiency, apart from strengthening the network itself.

Restructuring State electricity boards into corporate entities with a possible view to privatization has unfortunately, not proceeded at the desired pace. Hence, regulatory commissions often find their efforts to introduce competition, even in small measures. Frustrated by seeing the various stakeholders in the tariff process going around in circles year after year, the financial institutions and the donor community have started advocating multi-year tariffs (MYTs). On the other hand, to improve their own competitiveness and financial viability, investors and large sensitive consumers have stepped up their demand for allowing third-party sales.

In a recent workshop on multi-year tariffs (MYTs) at TERI, there was a consensus among the participants that the RCs should be looking at the broader concept of multi-year framework (MYF). There was considerable debate and no consensus on whether the MYTs/MYFs would reduce the challenges posed by inadequate and poor quality data and metering systems.

ADVANTAGES AFTER REFORM AND RESTRUCTURING OF APSEB

Since announcement of government policy to take up Reform and Restructuring of AP

Power sector and steps initiated thereafter.

1) National, international funding agencies that were extremely reluctant to assist APSEB have expressed their willingness to support the reform programme and to extend financial support for development of power sector in A.P.

2) Numerous International Funding agencies have expressed their interest to extend financial support for development of power sector in the state.

3) Some domestic agencies like ICICI & 1DBI have expressed liberal loan assistance.

4) System improvement programme for 5 districts funded by OECF, Japan to the extent of Rs.280 crores.

5) System improvement programme for 3 districts funded by DFID, UK to the extent of Rs. 63 crores.

6) Energy conservation programme with the assistance from the Govt. of Norway to the extent of Rs. 19 crores.

7) Technical assistance for formulating Reform & Restructuring plan provided by DFID (USA) & CIDA (Canada) by way of bilateral grants.

8) World Bank has sanctioned $1 Billion loan in five tranches under Adoptable Programme Lending(APL).

9) DFID have committed an additional assistance of Rs. 200 crores for providing Consultancy services for Institutional Strengthening Package for the new entities.

10) Proposals finalized for setting up of RTPP Stage-II (420 MW) project unit the assistance of a Chinese company.

11) KFW have a agreed to finance the 500 MW power station at VTPS.

12.3 METHODOLOGY

The power tariff in four case studies i.e., Rayalaseema Thermal Power Station - Stage II (2x210 MW) - A coal based project (Privatization Period), Spectrum Power Generation Limited I (208 MW) - A Natural Gas Based Project (Privatization Period), Spectrum Power Generation Limited Stage II (208 MW) - A Natural Gas Based Project (Privatization Period), GVK Gas Power Plant Stage II (216 MW) - A Natural Gas Based Project (Privatization Period) was estimated by making a cost analysis in each project with constant economics i.e., without cost escalation and varying economic parameters i.e., with cost escalation as per Central Electricity Authority (CEA) . The power tariff projections are made in each power project over a life period of each plant.

12.4 POLICY RECOMMENDATIONS

The power sector will have to accept the fact of financial and operational inefficiency of the SEB's and their incapacity to put their house in order. The powerful agricultural lobbying resists any steps to raise the power tariff. Added to this the cost per 1 MW generation of the project is high . Therefore restoration of financial position of the SEB's and improvement in their operational performance are the most crucial issues in the power sector.

One method of reducing the cost of supplying electricity is through better energy management. The main areas of potential supply improvements are in plant load factors and reductions in auxiliary consumption and line losses. Every percent reductions in the line losses will save new generation capacity. Similarly, a one percent improvement in the PLF of thermal stations will mean an additional availability new generation capacity. The increasing demand for power can be met by supply side options. There is a need for Demand Side Management (DSM) By this

a) corresponding T & D losses are avoided
b) gestation periods can be reduced from 5 years to 1 -2 years.
c) Requirements for land, manpower and water are necessary for extra generation, whereas DSM takes place in the consumer's territory.
d) Fuel is saved and hence future requirements for coal mining to produce that fuel and railway linkages to transport that fuel was reduced and
e) Environmental impacts are reduced, therefore associated health impacts and green house gas emissions are reduced.

One should look for other alternatives such as demand reduction instead of increase in supply. Nowadays as restructuring of SEB's plays a key role in order to bridge the gap between demand - supply of electricity and also brings efficiency in ESI, along with this demand side or customer side management options should also be taken into account.

This is because DSM also be taken into account. This is because DSM also in a way bridges the gap between demand and supply of electricity and also brings efficiency in ESI. Maharashtra state Electricity system have implemented the scheme of DSM. It consists licenses (Tata Power Companies), Bombay sub-urban electricity supply company (BSES) and Bombay Electricity Supply and Transport. The electricity consumption in various sectors is as follows 12.7% of total, commercial (6.7%) agriculture (27%) high tension (HT) industries (33 .4%) low tension industries (7.5) street lighting, public water works, electric traction etc. In the total consumption, the share of HT industries is highest with 33.4%. Therefore the energy and demand management in HT industries is very crucial for overall energy conservation and demand management strategies. In this regard different DSM options have been identified.

i) Energy efficient motors (EEM)

ii) Variable speed drives (VSD)

iii) Good house keeping measures (GHK)

iv) Waste heat driven vapor absorption refrigeration systems (VARS)

v) Improvements in electric are furnaces (EAF)

vi) Time-of-day tariff (TOD)

vii) High efficiency sodium vapour lamps (HDSV)

viii) Compact fluorescent lamps (CFL)

ix) Electronic ballasts (ELB)

x) Power Factor improvement (PF)

xi) Efficient pumps and fans (PUMPEAN)

xii) Industrial cogeneration (COGEN)

a) **Energy Efficient Motors:** Electric motors are used in industries to drive pump, fans, compressors, machine tools, and a wide variety of other process equipment. They account for 60-70% of the industrial electricity consumption. Improved design and materials result in improved motors known as energy efficient motors. These motors known as energy efficient motors. These motors save the peak demand and also saves the total cost.

b) **Variable speed drives:** Fluids driven by pumps, fans and blowers are usually regulated by throttling. This is an inefficient method of control and results in significant energy losses. A more efficient control method is to control the speed of the motor using a variable speed drive. They permit continuous regulation of motor speeds which can lead to substantial electricity savings, VSD have a significant scope in paper, chemical, fertilizers, pharmaceutical and cement industries.

c) **Goodhouse keeping practices:** These include measures like reducing leakage of compressed air, proper sizing of motors, improved day lighting, reducing chilled water usage, improved monitoring and control.

d) **Waste heat driven vapour absorption refrigeration systems:** Conventional vapour compression refrigeration systems account for almost the entire air conditioning and cooling load. Instead VARS driven by waste heat or surplus steam would be effective.

e) **Improved electric arc furnaces:** EAF can be retrofitted with technologies like crap preheating, oxyfuel burners, bottom tapping, comprised control and automation. Improved EAFs result in energy savings.

f) **Time-of-day Tariffs:** Among all the DSM programmes TOD is the major contributor with 761 mw accounting to 34.1% of total saving. Saving from other important programmes include GHK 381 MW (17%) PF 278 mw (12.4) USD 258 mw (11.5%) EEM 187 mw (8.4%) EAF 126 MW (5.6%) Pumpmen 111 MW (5.0) and VARS 78 mw (3.5%). By the year 2012 AD VSD programme will save 23,294 GWH. Thus through the adoption of DSM programmes the customer reduces his energy bills. These energy bill savings are determined by a rate module that computes the customer's bill using the base programme before and after implementation of DSM programme. The difference between the two is the savings for the customer. The total savings by the year 2012 AD will be Rs. 89,315 million. Of this amount the savings through VSD will be highest Rs. 27,162 million, GHK (Rs. 19,704 million). TOD (Rs. 8855 million), EEM (Rs. 8345 million)(EAF (Rs. 7227 million), PUMPFAN (Rs. 6966 million) and VARs (Rs. 67,66 million). If the DSM programmes are implemented successfully the utility saves money in terms of operating costs for fuel for power generation and the investments are saved through reduced new capacity requirements. The total amount of utility savings works out of Rs. 252,508 million. Out of all these programmes, the contribution of TOD is the highest with 42.6% of the total, followed by PF with 15.5% ,VSD with 14.6%, EEM 7.4%, PUMPFAN 6.2, VARS 4.4 and ELB 1.8%.

The tariffs could be expected to move over a time-frame of 3-5 years, possibly linked to economic developments free of political considerations; It is important to introduce time of day pricing, because there are certain applications of electricity use, where shifting consumption to off-peak periods may be feasible. In such cases, charging a higher tariff during periods of peak demand can result in significant shifts in consumption. This is typically the case with several industrial processes, say, for instance, a heat treatment furnace functioning at night during off peak hours using electricity at lower prices +rather than during peak hours when prices should be set higher. This would also be the case with domestic applications. For instance, if there was a higher tariff during periods of peak demand, most consumers would be quite happy to switch on electric geysers at 6:00 a.m. rather than 9:00 a.m. and in the afternoon rather than in the evening.

The issue of third-party sales (TPS) is, prima facie, one that would provide greater comfort to investors in generation activities and would result in the utility losing its high-tariff customers to such investors. The latter is a phenomenon often referred to as "cherry-picking". The generation activities seeking TPS could include, independent power producers, captive generators or even those that produce electricity based on renewable energy sources. The objective of such generators would be to get into contractual arrangements with those consumers in the industry and commercial sectors that are cross-subsidising the domestic and/or the agricultural consumers and that have high demands. Such consumers would limit the exposure of private investors to a small number and would also reduce the associated transaction costs. The consumers of such TPS would look forward to lowering tariffs. However, to be assured of higher reliability of supply, for which purpose they continue to be dependent on grid conditions, such consumers would like to see the distribution utilities as a stakeholder in such third-party sales beyond the mere levying of wheeling charges. In other words, TPS would possibly require stringent tri-partite agreements involving the utility and making the issue of transaction costs more relevant. The challenges arising from TPS for the regulatory commissions would be to ensure the financial viability of the existing utilities. The pressures of TPS would manifest themselves in the form of reducing cross-subsidies. As such, the RCs would also have to increase the pressure on utilities to improve efficiencies and reduce costs of supply so as to minimise the upward pressure on tariffs. The Government too may need to increase its subsidy budget depending on the extent to which the demand for TPS increases and the efficiency improvements of distribution entities. Options available to the RC/government to minimise the short-term pressures of TPS include a phasing-in of TPS and the application of a surcharge on TPS - the level of which can be determined by the RC.

There is a need for cost sharing by consumers rather than free hand outs by the utilities. We foresee a consortium approach and increased role for consumers. There is also a need for the DSM to be integrated in to the power planning and management process of the country. It would be very desirable if every state Electricity Board (SEB) formulates an energy efficiency and DSM plan when requesting allocation for new power plants.

There should be some general principles to reinvent electric utilities.

A) The first and foremost is that the goals of restructuring should be specific. Later the utilities, consumers, large industrial customers, independent power producers and environmentalists can seek to find a common ground.
B) The issue of stranded costs should be dealt. Utilities will argue that they should be given a reasonable opportunity to recover costs and it is expected that steps should be taken to lessen these costs and also corresponding burden on rate payers. Otherwise those costs will delay competitive market and create barriers for new market entrants.
C) Unbundle generation, transmission and distribution costs so that competitive functions can be provided by multiple parties.
D) Assure that all classes of customers have reasonable opportunities of benefit from restructuring.
E) Advanced and renewable energy technologies like solar, wind and fuel cell power generation play a valuable role and also promotes resource diversity in a competitive power generation market.

F) The retail competition will provide incentives for the continued operation of old, inefficient and dirty power plants and will deter investments in newer and cleaner technologies. This can be avoided by making the older power plants to meet the same environmental standards as new power plants.

G) Encourage the development of distributed power generation. It offers multiple benefits to electricity consumers.

H) Local distribution utility profits should not be tied to the amount of electricity sales that takes place over the retail system. This is important because the investments in DSM resources are given the same consideration as new supply resources.

The reforms processes in the power sector will necessarily take time to show results and cannot be restored to a healthy status in a short period of time. It is not economical to wait for too long as the investors are looking for returns and would probably take their capital elsewhere to invest. It is, therefore, of utmost importance that RCs and the Government work in concert towards developing the sector, while clearly recognizing and respecting each other's roles and functions.

12.5 THE STATUS OF ANDHRA PRADESH POWER SECTOR BEFORE AND AFTER REFORMS

In this section a comparative statement has been made based on the new power project initiated and completed in the past eight years and the proposed new projects, at different stage upto year 2020. As discussed earlier there are 3 power projects for which a financial analysis has been undertaken in the chapter X. Therefore this section provides a summary of the new power projects anticipated in the next two decades based on Coal, Natural gas and other non-conventional sources.The installed capacity in 1994 was 5626MWs Thermal 2033 MW + Gas 100MWs + Hydro 2596MWs totaling to 4729MWs in the state and 897MWs central). The projections for demand for power in 2020 range from 19000MWs to 35000MWs. According to High Power Committee Recommendations these peg the demand at 30000 MW. According to a thumb rule of doubling of demand every 10 years the peak load of 6750 MW during the year 2020 and the installed capacity required works out to 39000MWs for the year 2020 and it is adopted as an ideal figure.

As a result of reforms implemented in power sector in Andhra Pradesh a number of projects are coming up. Accordingly a programme for the new projects coming up before 2002 AD from the year 1994 was made. From this it may be seen that the additions programmed are on going schemes 1463MWs and new projects 5688MWs totaling to 7151MWs in the state and 253MWs in the central sector with a grand total 7404MWs.

NEW PROJECTS BEFORE 2002 AD

PROJECT	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-2001	2001-2002	TOTAL
I On Going Projects									
a) Thermal									
1 Rayalaseema stage unit- 2	210								210
2. Vijayawada- unit 6	210								210
b) Hydel									
3. Upper Sileru - unit 4	60								60
4. A.P. Power House-Balimela				60					60
5. Srisailam -Left Bank			150	300	300	150			900
6.Mini/Small Hydel schemes	2		4						6
7. Bingur		15							15
c) Wind	2								2
TOTAL I	484	15	154	360	300	150			1463
II New Projects									
a) Thermal									
1. Kothagudem- stageV			500						500
2 Rayalaseema-stage II					210	210			420
3. Visakhapatnam- stage I (private Sector)					500	500			1000
4. Krishnapatnam						500	500		1000

5.Ramagudam Extension (Private Sector)				250	250				500
6.Simhadri-TPS (Vizag Stage- II) (private sector)								500	500
7. Hyderabad Metro P.S. (Private sector)				200		200	200	200	800
8. Renigunta Diesel P.S.(private sector)				100					100
b)Gas									
1. Jcgurupadu (private sector)		92	124						216
2. Kakinada		93	115						208
c) Hydel									
1.Mini Hydel Schemes (private sector)			27						27
2.Tailpond Dam at Nagarjunasagar				25	25				50
3.Jurala - A.P. Share							55	55	no
4. Jalaput - A.P. Share						9			9
5.Somasila				10					10
6. Nelakota							30	30	60
d) Wind (private Sector)			178						
Total II		185	944	585	985	1419	785	785	5688
III Central Sector (AP's Share)									
2.Neyveli 2nd Extension			45						45
3.Kaiga Nuclear Power Station Units I & II			90				59	59	208
Total III			135				59	59	253
Grand Total (I + II + III)	484	200	1233	945	1285	1569	844	844	7404

After the introduction of liberalization in power sector in the country during early Nineties Andhra Pradesh is a pioneer in facilitating private sector projects in generation. In order to implement the massive programme and also to encourage competition between state, center and private sector the power stations were distributed as follows:

PRIVATE SECTOR:

a) Thermal:

1.Visakhapatnam Stage- 1	1000MWs	——Hindujas MOU route
2. Ramagundam Extension	500MWs	——BPL Global competitive bid
3. Krishnapatnam - A	500MWs	——GVK Global competitive bid
4. Krishnapatnam - B	500MWs	——Brooklyne Global Bidding
	2500MWs	

b) Gas:

1.Jegurupadu	216MWs	——GVK
2.Kakinada	208MWs	——Spectrum MOU
	424MWs	

c) **Central Sector - N.T.P.C**

1.Simhadri (Vizag State- II)	1OOOMWs	——NTP
2.Hyderabad Metro P.S	650MWs	——NTPC
	1650MWs	

To meet the growing needs of demand for power and fill the gap between demand for and supply of power a number of power projects are coming in vogue. The table below is

Hydro (N.E.)	20000	1000
	33540	7091

WEAKNESS (or) PROBLEMS FACED DURING RESTRUCTURING

- a When the tariff structure is changed to reflect the economic cost of production, higher prices for the electricity in the residential and agricultural sectors will dampen demand.
- • There is a chance of both advantage & disadvantage form of market mechanism. The whole sale buyers and sellers of electricity participate in auction rounds. At the beginning of each round the buyers and sellers simultaneously submit price and quantity offers received during the round in accordance with publicly known protocols.
- • The difficulty for wholesale electricity markets is that these markets generally compromise small numbers of buyers and sellers with differentiated costs and capacities who repeatedly interact with each other over time. The buyers and sellers may thus have an incentive to "game" an auction mechanism, i.e., to behave opportunistically within the limits set by the auction protocols in an attempt to increase their individual gains to trade In particular, buyers and sellers may have an incentive to submit price offers that misinterpret their true willingness to pay or their true marginal costs and to submit quantity offers that misinterpret their true capacities.
- a Overcoming resistance from employee's unions and associations.
- a Apprehensions in the minds of consumers of possible tariff hikes.

Efficiency enhancement in power sector may be accomplished by technology upgradation, fuel choice & augumentations of labour productivity. Liberalization of economy, privatization & competition are important factors which create conducive atmosphere for advancement of efficiency . The APSEB is still in the first phase of reforms with focus being on corporatization of service **sectors.** k Hence it may take some time to divert the power sector from the path of dead end to the high way of progress and prosperity.

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APPENDIX A.8.1

GROSS DOMESTIC PRODUCT AT FACTOR COST,SECTOR WISE AT 1980-81 PRICES, INDIA

YEAR	AGRICULTURE	MANUFACTURING	ELECTRICITY	TRANSPORT	OTHERS	GDP
1970-71	40214 (-)	15769 (-)	1073 (-)	3155 (-)	30215 (-)	90426 (-)
1971-72	39459 (-1.9)	16277 (3.2)	1160(8.1)	3256 (3.2)	31187(3.2)	91339(1.0)
1972-73	37479 (-5.0)	16939 (4.0)	1214(4.6)	3493 (7.3)	31923(2.4)	91048 (-0.3)
1973-74	40178(7.2)	17653 (4.2)	1241(2.2)	3637(4.1)	32483(1.7)	95192(4.6)
1974-75	39566 (-1.5)	181198(3.1)	1298(4.6)	3992 (9.8)	33248(2.4)	96297(1.2)
1975-76	44666(12.9)	18712(2.9)	1487 (14.6)	4324 (8.3)	35779 (7.6)	104968 (9.0)
1976-77	42085 (-5.8)	20274 (8.4)	1658(11.5)	4633(7.1)	37630 (5.2)	106280(1.3)
1977-78	46309(10.0)	214887 (5.9)	1737(4.8)	4751 (2.6)	39935 (6.1)	114219 (7.5)
1978-79	47375 (2.3)	23985(11.6)	1935(11.4)	5077 (6.9)	42132(5.5)	120504 (5.5)
1979-80	41323(-12.8	23284 (-2.9)	1959(1.2)	5364 (5.7)	42306 (0.4)	114236 (-5.2)
1980-81	46479(12.5)	23531 (2.0)	1989(1.5)	5724 (6.7)	44503 (5.2)	122226 (7.0)
1981-82	49139(5.7)	25523 (8.5)	2172(9.2)	6013 (5.0)	46753 (5.1)	129600(6.0)
1982-83	48358 (-1.6)	27295 (6.9)	2313 (6.5)	6280 (4.4)	49223 (5.3)	133469(2.9)
1983-84	53525(10.6)	29828 (9.3)	2588(11.9)	6692 (6.6)	51677(4.9)	144310(8.1)
1984-85	53544(0.03)	31639(6.1)	2863 (10.6)	7302(9.1)	54618(5.7)	149966(3.9)
1985-86	53698 (0.3)	34042 (7.6)	3099 (8.2)	7951 (8.9)	58558 (7.2)	157348(4.9)
1986-87	52782 (-1.7)	36797(8.1)	3419(10.3)	8493 (6.8)	62433 (6.6)	163924(4.2)
1987-88	53053 (0.5)	38968 (5.9)	3739 (9.4)	9232 (8.7)	65724 (5.3)	170716(4.1)
1988-89	62214(17.3)	41407(6.3)	4080(9.1)	9804(6.1)	70974 (7.9)	188479(10.4)
1989-90	63263 (1.7)	46086 (11.3)	4505 (10.4)	10663 (8.8)	76936 (8.4)	201423(6.9)
1990-91	65653 (3.8)	49070 (6.5)	4797 (6.5)	11164 (4.7)	81592(6.1)	212276(5.4)
1991-92	64174(-2.3)	47850 (-2.5)	5251 (9.5)	11804 (5.7)	85087 (4.3)	214156(0.9)
1992-93	67425 (5.1)	49269 (2.9)	5647 (7.5)	12453 (5.5)	88644 (4.2)	223438(4.3)
1993-94	69412 (2.9)	51098(3.7)	5982 (5.9)	13202(6.0)	93348 (5.3)	233042(4.3)
1994-95	69206(-0.3)	54570 (6.8)	6554 (9.6)	13954(5.7.0)	98052 (5.0)	242336(3.9)
1995-96	66863(-3.4)	62207(13.9)	7033 (7.3)	15127(5.7)	102756(4.8)	253986(4.8)
1996-97	72362 (8.2)	66785 (7.4)	7384 (4.9)	16527(8.4)	107460(4.6)	270518(6.5)
1997-98	74421(2.8)	72481(8.5)	7621(3.2)	16928(2.4)	108470(9.3)	285251(5.4)
1998-99	76534(5.8)	76341(5.3)	7931(4.1)	17241(1.8)	112421(3.6)	289582(1.5)
1999-00	79214(3.5)	79214(3.8)	8241(3.9)	17452(1.2)	113898(1.3)	291453(6.4)
2000-01	81241(2.5)	82412(4.0)	8421(2.2)	18248(4.5)	124131(8.9)	300012(2.9)
2001-02	83920(3.3)	85316(3.5)	8502(9.6)	19241(5.4)	132481(6.7)	312455(4.1)
Average	2.5	0.68	7.0	5.1	5.0	4.2

SOURCE : VARIOUS ISSUES OF NATIONAL ACCOUNTING STATISTICS(NAS)

Note: The numbers in the parenthesis are growth rates

APPENDIX A.8.2

GROSS DOMESTIC PRODUCT AT FACTOR COST, SECTORWISE SHARES

YEARS	AGRICULTURE	MANUFACTURING	ELECTRICITY	TRANSPORT	OTHERS
1970-71	44.4	17.4	1.2	3.4	33.4
1971-72	43.2	18.0	1.3	3.4	34.1
1972-73	41.1	19.0	1.3	4.0	35.0
1973-74	42.2	18.5	1.3	4.0	34.1
1974-75	41.0	19.0	1.3	4.1	34.5
1975-76	42.5	18.0	1.4	4.1	34.0
1976-77	40.0	19.1	1.6	4.3	35.4
1977-78	40.5	19.0	1.5	4.1	35.0
1978-79	39.3	20.0	1.6	4.2	35.0
1979-80	36.1	20.4	1.7	5.0	37.0
1980-81	38.0	19.2	1.6	5.0	36.4
1981-82	38.0	19.7	1.7	5.0	36.0
1982-83	36.2	20.4	1.7	5.0	37.0
1983-84	37.0	20.8	1.8	5.0	36.0
1984-85	36.0	21.1	1.9	5.0	36.4
1985-86	34.1	21.6	2.0	5.0	37.2
1986-87	32.2	22.4	2.1	5.1	38.0
1987-88	31.0	23.0	2.2	5.4	39.0
1988-89	33.0	22.0	2.2	5.2	38.0
1989-90	31.4	23.0	2.2	5.2	38.2
1990-91	31.0	23.1	2.3	5.2	38.4
1991-92	30.0	22.3	2.5	5.5	40.0
1992-93	30.1	22.0	2.5	5.5	40.0
1993-94	30.0	22.0	2.6	5.6	40.1
1994-95	28.5	22.5	2.7	5.7	40.4
1995-96	26.3	24.5	2.7	5.9	40.5
1996-97	27.7	24.7	2.7	6.1	39.7
1997-98	26.1	25.4	2.7	5.9	38.0
1998-99	26.4	26.4	2.7	5.9	38.8
1999-00	27.2	27.2	2.8	5.9	39.1
2000-01	27.1	28.3	2.8	6.1	41.4
2001-02	26.9	27.3	2.7	6.2	42.4

SOURCE : CALCULATED FROM APPENDIX TABLE A.8.1

APPENDIX A.8.3
CONSUMER WISE ELECTRICITY SALES (MKWH) INDIA

YEARS	DOMESTIC	COMMERCIAL	LOW AND MEDIUM TENSION	HIGH TENSION	RAILWAYS
1980-81	9246(-)	4682(-)	**7415(-)**	**40654(-)**	**2266(-)**
1981-82	10440(12.9)	5194(10.9)	9405(26.8)	43659(7.4)	2505(10.5)
1982-83	12092(15.8)	5846(12.5)	**915(-2.7)**	43817(0.4)	2633(5.1)
1983-84	13235(9.4)	6561(12.2)	**11189(22..3)**	45906(4.8)	2710(2.9)
1984-85	15506(17.1)	6937(3.7)	**11228(0.35)**	51791(12.8)	2880(6.3)
1985-86	17258(11.3)	7290(5.1)	**12517(11..5)**	54463(5.2)	3082(7.0)
1986-87	**19323(11..9)**	7772(6.6)	17680(41.2)	52617(-3.4)	3229(4.8)
1987-88	22120(4.5)	8841(13.7)	13665(22.7)	55515(5.5)	3616(11.9)
1988-89	24768(11.9)	9915(12.1)	15016(9.9)	60396(8.8)	3772(4.3)
1989-90	29577(19.4)	9548(-3.7)	**17410(15.9)**	63285(4.8)	4070(7.9)
1990-91	31982(8.1)	11181(17.1)	**17458(3.4)**	66751(5.5)	4112(1.03)
1991-92	**35854(12. 1)**	12032(7.6)	18916(8.4)	68372(2.4)	4520(9.9)
1992-93	39717(10.7)	12653(5.2)	19474(2.9)	70695(3.4)	5068(12.1)
1993-94	43344(9.1)	14144(11.8)	19986(2.6)	74518(5.4)	5620(10.9)
1994-95	47916(10.5)	15973(12.9)	21110(5.6)	79016(6.0)	5886(4.7)
1995-96	51733(7.9)	16996(6.4)	21549(2.1)	83144(5.2)	6823(15.9)
1996-97	55267(6.8)	17519(3.1)	21590(0.19)	**82575(-0.7)**	6994(2.7)
1997-98	56321(1.9)	17928(2.3)	21700(0.51)	81275(-1.6)	**7002(0.4)**
1998-99	58001(2.9)	18321(2.2)	21900(0.92)	83100(2.2)	7952(13.6)
1999-00	60210(3.8)	18958(3.5)	22400(2.3)	83525(0.51)	7982(0.38)
2000-01	61310(1.8)	19248(1.5)	22958(2.5)	84100(0.69)	8021(0.49)
2001-02	62410(1.8)	19592(1.8)	23412(1.9)	83215(-1.1)	8036(0.18)
Average	8.7	6.75	8.2	3.4	**6.0**

SOURCE : CENTRE FOR MONITORING INDIAN ECONOMY, ENERGY, MARCH 2000

Note: The numbers in the paranthesis are growth rates

Appendix A.8.3 (Contd..)

YEARS	AGRICULTURE	PUBLIC SERVICES	ALL OTHER CONSUMERS	TOTAL
1980-81	14489(-)	2282(-)	1332(-)	82366(-)
1981-82	15201(4.9)	2487(8.9)	1355(1.7)	90246(9.6)
1982-83	17817(17.2)	2593(4.3)	1641(21.1)	95590(5.9)
1983-84	18234(2.3)	2762(6.5)	1749(6.6)	102346(7.1)
1984-85	20960(14.9)	3117(12.9)	1648(-5.8)	114067(11.5)
1985-86	23422(11.7)	3202(2.7)	1765(7.1)	122999(7.8)
1986-87	29444(25.7)	3771(17.8)	2116(19.9)	135952(10.5)
1987-88	35267(19.8)	4290(13.8)	2299(8.6)	145613(7.8)
1988-89	38878(10.2)	4709(9.8)	2743(19.3)	160194(10.0)
1989-90	44056(13.3)	5051(7.3)	2423(11.7)	175420(9.5)
1990-91	50321(14.2)	5291(4.8)	3261(34.6)	190357(8.5)
1991-92	58557(16.4)	6215(17.5)	3179(-2.5)	207645(9.1)
1992-93	63308(8.1)	6278(1.01)	3461(8.9)	22054(6.3)
1993-94	70699(11.7)	6777(7.9)	3481(0.57)	238569(8.1)
1994-95	79301(12.2)	7108(4.9)	3321(-4.6)	259631(8.8)
1995-96	85700(8.1)	7501(5.5)	4150(24.9)	277596(6.9)
1996-97	84019(-1.9)	8042(7.2)	4600(10.8)	280606(1.1)
1997-98	83021(-1.2)	8521(5.9)	4658(1.3)	280426(-0.06)
1998-99	85000(2.3)	8613(1.1)	4692(0.73)	287579(2.6)
1999-00	87241(2.6)	8724(1.3)	4718(0.55)	285776(-0.63)
2000-01	89215(2.3)	8784(0.68)	4798(1.7)	298434(4.4)
2001-02	90214(1.1)	8941(1.8)	4825(0.56)	300645(0.74)
AVERAGE	8.9	10.2	7.6	6.2

Reference: CMIE (Center for Monitoring Indian Economy, energy March 2000)

APPENDIX A.8.4

NUMBER OF CONSUMERS OF ELECTRICIITY(MILLION , INDIA

STATE ELECTRICITY BOARDS	1992-93	1993-94	1994-95	1995-96	1996-97
ANDHRA PRADESH	7.70	8.07	8.41	8.91	9.48
ASSAM	0.50	0.63	0.66	0.68	0.71
BIHAR	1.52	1.72	1.72	1.78	1.96
DELHI(DVB)	1.83	2.12	2.15	2.19	NA
GUJARAT	5.54	5.67	5.84	6.01	6.13
HARYANA	2.84	2.97	3.07	3.17	3.29
HIMACHAL PRADESH	1.05	1.09	1.13	1.18	1.23
JAMMU&KASHMIR	0.63	0.64	0.65	0.67	0.69
KARNATAKA	6.07	6.42	6.78	7.12	7.44
KERALA	3.93	4.15	4.42	4.69	4.92
MADHYA PRADESH	6.01	6.19	6.59	7.06	7.42
MAHARASHTRA	9.27	9.74	10.27	10.87	11.42
MEGHALAYA	0.09	0.10	0.10	0.10	0.11
ORISSA	1.11	1.16	1.23	1.27	1.28
PUNJAB	3.99	4.18	4.24	4.51	4.67
RAJASTHAN	3.68	3.92	4.13	4.38	4.57
TAMIIL NADU	9.16	9.22	9.75	10.28	11.04
UTTAR PRADESH	5.27	5.59	5.89	6.14	6.45
WESTBENGAL	1.79	1.98	2.11	2.34	2.58
SUB-TOTAL(a)	72.18	75.56	79.14	83.35	85.39
ELECTRICITY DEPARTMENTS					
ARUNACHAL PRADESH	0.07	0.07	0.07	0.08	0.09
GOA	0.31	0.32	0.34	0.36	0.37
MANIPUR	0.11	0.12	0.13	0.13	0.13
MIZORAM	0.05	0.06	0.07	0.07	0.07
NAGALAND	0.08	0.09	0.09	0.10	0.11
PONDICHERRY	0.14	0.15	0.16	0.17	0.18
SIKKIM	0.03	0.04	0.04	0.04	0.05
TRIPURA	0.11	0.12	0.13	0.13	0.14
SUB-TOTAL(b)	0.90	0.97	1.03	1.08	1.14
GRAND-TOTAL(a+b)	73.08	76.53	80.17	84.43	86.53

SOURCE:ANNUAL REPORT ON WORKING OF SEB's AND ED's , APRIL 1999, PLANNING COMMISSION, GOVERNMENT OF INDIA

APPENDIX A.8.5
PERCAPITA CONSUMPTION OF ELECTRICITY (KWH), INDIA

REGION/STATE/UT	1990-91	1991-92	1992-93	1993-94
HARYANA	400	455	507	491
HIMACHAL PRADESH	209	210	208	219
JAMMU&KASMIR	193	189	188	195
PUNJAB	606	616	684	703
RAJASTHAN	201	231	246	256
UTTAR PRADESH	166	174	179	186
CHANDIGARH	708	755	715	626
DELHI	704	758	823	733
NORTHERN REGION	249	265	282	286
GUJARAT	469	504	538	587
MADHYAPRADESH	247	267	281	311
MAHARASHTRA	411	434	439	459
GOA	452	495	541	588
DAMAN&DIU	-	~	1015	1182
D&N HAVELI	905	980	1175	1392
WESTERN REGION	367	391	406	437
ANDHRA PRADESH	245	191	312	345
KARNATAKA	296	296	303	328
KERALA	188	196	200	215
TAMIL NADU	323	335	369	386
PONDICHERRY	720	782	856	843
LAKSHADWEEP	154	172	183	207
SOUTHERN REGION	272	288	312	335
BIHAR	110	108	117	126
ORISSA	271	295	297	313
WESTBENGAL	148	151	158	171
A&N ISLAND	117	118	162	168
SIKKIM	119	120	114	123
EASTERN REGION	150	156	162	174
ASSAM	94	90	97	95
MANIPUR	97	107	104	111
MEGHALAYA	115	125	129	110
NAGALAND	75	78	73	68
TRIIPURA	47	53	59	60
ARUNACHALPRADESH	68	58	54	67
MIIZORAM	69	69	91	101
NORTH EASTERNREGION	89	88	93	92
ALL INDIA	253	268	283	299

APPENDIX A.8.5 (Contd..)

PERCAPITA CONSUMPTION OF ELECTRICITY (KWH), INDIA

REGION/STATE/UT	1994-95	1995-96	1996-97
HARYANA	467	503	508
HIMACHALPRADESH	254	288	279
JAMMU&KASHMIR	196	201	224
PUNJAB	759	760	790
RAJASTHAN	270	297	295
UTTAR PRADESH	204	207	194
CHANDIGARGH	676	717	794
DELHI	747	608	590
NORTHERN REGION	302	308	304
GUJARAT	608	6711	686
MADHYA PRADESH	335	367	368
MAHARASHTRA	500	545	557
GOA	602	707	719
DAMAN &DIU	1548	2016	2347
D&N HAVELI	1574	1811	2299
WESTERN REGION	468	513	521
ANDHRA PRADESH	374	368	332
KAARNATAKA	364	363	338
KERALA	237	249	236
TAMIL NADU	430	459	469
PONDICHERRY	969	958	1035
LAKSHADWEEP	185	209	234
SOUTHERN REGION	369	377	3611
BIHAR	134	138	145
ORISSA	333	370	447
WESTBENGAL	175	186	197
A&N ISLAND	178	202	210
SIKKIM	143	173	182
EASTERN REGION	182	195	215
ASSAM	98	98	108
MANIPUR	107	118	127
MEGHALAYA	140	143	135
NAGALAND	59	79	88
TRIPURA	66	73	80
ARUNACHAL PRADESH	66	78	81
MIZORAM	112	123	128
NORTH EASTERN REGION	96	99	107
ALL INDIA	320	336	338

SOURCE:ANNUAL REPORT ON WORKING OF SEB's AND ED's , APRIL 1999, PLANNING COMMISSION, GOVERNMENT OF INDIA

APPENDIX A.8.6

ELECTRICITY TRANSMISSION AND DISTRIBUTION LINES(UTILITIES) (KM), INDIA

YEAR	ALL LINES	TRANSMISSI-ONLINES	DISTRIBUTI-ON LINES	% CHANGE IN ALL LINES	%CHANGE IN TRANSMIS-SION LINES	%CHANGEIN DISTRIBU-TION LINES
1970-71	1117163	79887	1034024	0.0	0.0	0.0
1971-72	1304169	59898	11163271	16.7	-25.0	12.5
1972-73	1418364	81273	1333624	8.8	35.7	14.6
1973-74	1518884	83225	1432116	7.1	2.4	7.4
1974-75	1621848	92452	1529396	6.8	11.1	6.8
1975-76	1718942	93763	1622273	6.0	1.4	6.1
1976-77	1850273	99312	1750961	7.6	5.9	7.9
1977-78	1999080	105214	1893866	8.0	5.9	8.2
1978-79	2145919	108694	1947225	7.3	3.3	2.8
1979-80	2351609	115031	2236578	9.6	5.8	14.9
1980-81	2522461	120664	2417979	7.3	4.9	7.4
1981-82	2693086	129033	2564053	6.8	6.9	6.8
1982-83	2865312	135012	2730300	6.4	4.6	6.5
1983-84	3002095	143246	2858849	4.8	6.1	4.7
1984-85	3211956	155921	3056035	7.0	8.8	6.9
1985-86	3371216	162940	3208276	5.0	4.5	5.0
1986-87	3572460	169984	3402476	6.0	4.3	6.1
1987-88	3792107	176561	3615546	6.1	3.9	6.3
1988-89	4042022	184060	3857962	6.6	4.2	6.7
1989-90	4407501	192288	4215213	9.0	4.5	9.3
1990-91	4533414	206891	4326523	2.9	7.6	2.6
1991-92	4574200	215903	4358247	0.9	4.4	0.7
1992-93	4725694	218447	4507247	3.3	1.2	3.4
1993-94	4878028	232254	4645774	3.2	6.3	3.1
1994-95	5018408	239490	4778918	2.9	3.1	2.9
1995-96	5089696	240707	4848989	1.4	0.5	1.5
1996-97	5140993	254223	4886770	1.0	5.6	0.8
1997-98	5161152	264312	4896840	0.39	3.9	0.21
1998-99	5781720	283415	5214890	12.0	7.2	6.5
1999-00	5699121	274132	5424989	-1.4	-3.3	4.0
2000-01	5925590	2914456	5634134	3.9	6.3	3.9 '
2001-02	6126237	302105	5824132	3.4	3.6	3.4
AVERAGE				5.5	4.5	5.6

SOURCE: CENTRE FOR MONITORING INDIAN ECONOMY, ENERGY, 2000

APPENDIX A.8.7

THERMAL STATIONS-PLANT LOAD FACTOR AND AUXILLARY CONSUMPTION%, INDIA

AGENCY	1992-93		1993-94		1994-95	
SEBs	PLF	AC	PLF	AC	PLF	AC
NORTHERN REGION	62.00		64.00		59.10	
HARYANA	49.90	10.50	40.50	10.50	44.70	5.26
PUNJAB	58.30	8.66	63.50	8.64	56.70	4.49
RAJASTHAN	77.00	10.09	81.00	9.90	75.60	**7.10**
UTTAR PRADESH	50.50	10.27	50.30	9.74	43.90	**7.58**
WESTERN REGION	59.70		63.40		63.80	
GUJARAT	61.60	9.20	60.40	9.30	60.50	9.66
MAHARASHTRA	59.70	9.20	64.10	9.10	61.20	7.53
MADHYA PRADESH	52.50	10.30	56.10	10.00	58.20	9.09
SOUTHERN REGION	62.60		68.30		69.10	
ANDHRA PRADESH	65.00	10.00	68.70	10.00	70.20	5.66
TAMIL NADU	65.20	65.20	69.00	9.00	68.10	6.41
KARNATAKA	49.40	49.40	66.90	5.90	64.90	1.60
EASTERN REGION	39.80	39.80	44.80		43.70	
BIHAR	25.20	25.20	24.40	14.00	20.00	12.80
ORISSA	34.50	34.50	35.50	9.50	29.00	9.60
WESTBENGAL	31.10	31.10	40.50	10.10	41.20	10.90
NORTH EASTERN REGION	24.30	24.30	19.90		26.80	
ASSAM	24.30	24.30	19.90	6.85	26.70	8.02
ALL SEBS	54.10	54.10	56.60		55.00	
CENTRAL SECTOR	62.70	62.70	69.80		69.20	
NTPC	68.80	68.80	76.90		76.20	
NLC	56.40	56.40	55.50		60.40	
DVC	32.30	32.30	42.30		38.20	
DPL	28.70	28.70	26.30		26.60	
DELHI(Desu)	54.00	54.00	49.00	NA	53.90	8.84
WBPCD	58.10	58.10	68.20	9.99	60.40	8.86
PRIVATE SECTOR	54.10		56.60		65.90	
AE.CO	62.50		67.00		69.10	
TROMBAY	54.30		48.80		60.60	
C.E.S.C.	67.50		71.30		75.60	
BSES	--					
ALL INDIA	57.10	6.91	61.00	6.96	60.00	7.44

SOURCE: POWER DEVELOPMENT IN ANDHRA PRADESH (STATISTICS), 1998-99, (TRANSCO LTD)

APPENDIX A.8.7 (Contd..)

THERMAL STATIONS-PLANT LOAD FACTOR AND AUXILLARY CONSUMPTION%, INDIA

AGENCY	1995-96		1996-97		1997-98	
SEBS	PLF	AC	PLF	AC	PLF	AC
NORTHERN REGION	62.00		64.70		**66.70**	
HARYANA	42.90	5.57	47.70	6.11	49.40	**6.00**
PUNJAB	55.00	4.46	65.70	4.63	69.10	**4.97**
RAJASTHAN	73.70	7.48	75.60	7.31	80.50	7.47
UTTAR PRADESH	47.30	7.59	49.10	7.67	**48.80**	7.18
WESTERN REGION	68.10		70.20		70.30	
GUJARAT	65.30	9.25	**64.80**	9.77	65.60	**9.47**
MAHARASHTRA	**64.90**	7.64	68.70	7.49	68.30	7.38
MADHYA PRADESH	58.70	8.75	62.30	8.64	66.00	8.63
SOUTHERN REGION	74.70		75.80		77.10	
ANDHRA PRADESH	77.40	6.71	78.30	**6.44**	82.00	6.53
TAMIL NADU	76.10	6.71	72.30	7.30	68.10	**7.24**
KARNATAKA	67.70	2.02	70.20	2.59	75.20	1.82
EASTERN REGION	42.70		42.20		43.00	
BIHAR	17.40	13.53	15.30	14.03	16.10	14.00
ORISSA	67.00	12.84	69.40	**11.36**	65.30	10.52
WEST BENGAL	34.60	12.03	39.20	10.91	40.30	10.80
NORTH EASTERN REGION	28.60	8.88	27.10	8.75	21.30	**7.84**
ASSAM	28.60		27.10		60.90	
ALL SEBS	58.00		60.30		70.40	
CENTRAL SECTOR	70.90		71.00		74.40	
NTPC	76.70		76.40		72.50	
NLC	67.60		70.30		38.40	
DVC	37.80		35.60		38.40	
DPL	26.50		29.50		25.30	
DELHI(Desu)	51.70	9.09	41.70	8.94	47.20	8.26
WBPCD	57.60	9.75	56.50	9.66	52.80	**9.77**
PRIVATE SECTOR	72.30		71.20		71.10	
AE.CO	69.30		71.40		71.30	
TROMBAY	72.80		68.80		63.50	
C.E.S.C.	78.90		74.90		76.90	
BSES	55.30		73.20		82.40	
ALL INDIA	63.00	7.11	64.40	7.22	64.70	**7.06**

SOURCE: POWER DEVELOPMENT IN ANDHRA PRADESH (STATISTICS), 1998-99, (TRANSCO LTD)

APPENDIX A.8.8

TRANSMISSION AND DISTRIIBUTION LOSSES AS A PERCENTAGE OF AVAILABILITY IN SEBS, INDIA

STATE	1990-91	1991-92	1992-93	1993-94	1994-95
ANDHRA PRADESH	22.9	20.3	19.2	119.1	18.9
ARUNACHAL PRADESH	20.0	28.2	34.9	31.6	31.0
ASSAM	24.1	22.7	21.0	20.8	24.9
BIHAR	16.5	18.3	20.5	19.0	24.0
DAMAN & DIU	16.9	15.9	0	0	0
GOA	25.0	23.8	20.8	21.8	26.2
GUJARAT	23.4	23.6	21.1	21.3	20.0
HARYANA	27.5	26.8	25.4	25.5	28.5
HIMACHAL PRADESH	21.0	19.2	18.5	17.3	**17.4**
JAMMU& KASMIR	43.0	50.1	45.3	47.7	46.9
KARNATAKA	20.2	19.3	18.7	18.6	18.9
KERALA	22.4	22.5	21.0	20.2	20.1
LAKSHADWEEP	18.6	17.4	0	0	0
MADHYA PRADESH	18.0	25.8	22.2	15.8	20.1
MAHARASHTRA	18.3	18.6	16.4	22.5	15.3
MANIPUR	28.0	24.4	22.5	10.7	22.0
MEGHALAYA	11.5	11.7	12.2	28.0	18.7
MIZORAM	29.6	34.9	28.1	31.6	28.0
NAGALAND	26.1	23.1	32.4	23.4	23.8
ORISSA	25.8	25.3	23.5	18.5	18.3
PUNJAB	119.3	21.8	18.7	25.2	25.0
RAJASTHAN	25.8	23.1	24.5	21.5	21.2
SIKKIM	24.5	25.9	21.8	17.3	16.9
TAMIL NADU	18.0	18.4	17.5	30.0	30.0
TRIPURA	29.6	32.0	30.5	23.2	22.6
UTTAR PRADESH	27.1	26.1	24.1	22.4	**21.1**
WEST BENGAL	17.7	19.7	23.7	22.0	24.0
ALL INDIA	22.9	22.8	19.8	20.2	20.3

SOURCE: Annual Report on the **working of** SEBs **and EDs,Power and Energy Division, Government of India, New Delhi, 1999**

APPENDIX A.8.8 (Contd..)

TRANSMISSION AND DISTRIIBUTION LOSSES AS A PERCENTAGE OF AVAILABILITY IN SEBS, INDIA

STATE	1995-96	1996-97	1997-98	1998-99
ANDHRA PRADESH	18.9	30.5	25.0	23.0
ARUNACHAL PRADESH	36.0	32.0	30.0	32.0
ASSAM	26.2	24.9	24.0	23.0
BIHAR	25.9	25.3	23.0	23.0
DAMAN & DIU	0	0	0	0
GOA	28.5	26.7	26.0	17.0
GUJARAT	18.3	18.2	18.0	31.1
HARYANA	31.4	31.7	32.2	16.7
HIMACHAL PRADESH	17.5	17.9	17.4	47.0
JAMMU & KASHMIR	48.6	48.0	47.5	17.4
KARNATAKA	18.5	18.5	18.4	18.0
KERALA	20.1	20.0	19.0	0
LAKSHADWEEP	0	0	0	18.5
MADHYA PRADESH	19.5	19.3	19.0	15.2
MAHARASHTRA	15.4	15.3	15.2	21.0
MANIPUR	21.5	21.5	21.5	16.0
MEGHALAYA	17.8	19.3	16.9	25.0
MIZORAM	27.0	26.0	26.0	28.5
NAGALAND	30.0	29.7	29.0	35.0
ORISSA	46.9	45.1	39.0	**17.8**
PUNJAB	18.2	18.0	18.0	22.5
RAJASTHAN	28.5	25.3	23.0	20.0
SIKKIM	21.0	20.2	20.0	17.0
TAAMIL NADU	17.0	17.0	17.0	29.0
TR1PURA	30.0	30.0	29.8	**21.0**
UTTAR PRADESH	22.8	24.6	23.0	**20.0**
WEST BENGAL	20.7	20.1	19.7	18.9
ALL INDIA	22.2	23.0	21.8	20.8

SOURCE: Annual Report on the working of SEBs **and** EDs,Power and Energy Division, Government of India, New Delhi, 1999

APPENDIX A.8.9

COST STRUCTURE OF STATE ELECTRICITY BOARDS, 1993-94 (PAISE/KWH OF SALE), INDIA

STATE ELECTRICITY BOARDS	FUEL	POWER PURCHASE	OPERATION AND MAINTENA-NCE	ESTABLISHMENT / ADMINISTRATION
ANDHRA PRADESH	28.52(-)	34.80(-)	5.73(-)	11.55(0
ASSAM	40.65(-)	51.87(-)	10.74(-)	50.06(-)
BIIHAR	26.91(-)	81.21(-)	11.79(-)	41.91(-)
DELHI	--	—	—	—
GUJARAT	79.69(-)	27.60(-)	5.72(-)	18.66(-)
HARYANA	35.57(-)	60.43(-)	6.97(-)	26.09(-)
HIMACHAL PRADESH	0.00{-)	27.30{-)	15.12(-)	40.86(-)
JAMMU&KASHMIIR	10.00(-)	115.31(-)	6.69(-)	21.75(-)
KARNATAKA SEB	1.30(-)	68.14(-)	4.59(-)	23.39(-)
KPC	19.85(-)	0.00(-)	1.51(-)	4.10(0
KERALA	0.00(-)	29.36(-)	5.65(-)	33.77(0
MADHYA PRADESH	28.34(-)	48.72(0	6.73(-)	24.63(-)
MAHARASHTRA	52.27(-)	29.95(-)	8.89(-)	19.83(-)
MEGHALAYA	0.00(-)	1.34(-)	10.91(-)	39.58(-)
ORISSA	8.14(0	41.33(0	30.63(-)	26.17(-)
PUNJAB	49.90(-)	22.95(-)	4.16(-)	23.43(0
RAJASTHAN	31.09(-)	63.89(-)	6.64(-)	17.90(-)
TAMIL NADU	60.58(-)	32.56(-)	4.04(-)	25.44(-)
UTTAR PRADESH	33.06(-)	54.86(-)	8.17(0	18.19(-)
WEST BENGAL	27.89(-)	80.27(-)	6.78(0	22.31(-)
WBPDC	62.00(-)	0.00(-)	6.80{-)	0.00(-)
AVERAGE	38.87	43.71	7.35	22.00

SOURCE: Annual Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi, 1999

APPENDIX A.8.9 (Contd..)

COST STRUCTURE OF STATE ELECTRICITY BOARDS, 1993-94 (PAISE/KWH OF SALE), INDIA

STATE ELECTRICITY BOARDS	MISCELLANEOUS EXPENSES	DEPRECIATION	INTEREST	TOTAL
ANDHRA PRADESH	1.01 (-)	8.07 (-)	19.29 (-)	108.97 (-)
ASSAM	2.83 (-)	31.24 (-)	65.26(-)	252.65 (-)
BIHAR	4.24 (-)	12.25 (-)	21.74(-)	200.05 (-)
DELHI(DVB)	--	—	—	
GUJARAT	5.71 (-)	9.28 (-)	17.44 (-)	158.39 (-)
HARYANA	0.66 (-)	9.57 (-)	21.05 (-)	165.39 (-)
HIMACHAL PRADESH	0.00 (-)	5.88 (-)	52.98 (-)	152.80 (-)
JAMMU& KASHMIR	-1.46 (-)	12.94 (-)	42.44 (-)	209.13(-)
KARNATAKA SEB	2.94 (-)	5.43 (-)	10.74 (-)	112.13 (-)
KPC	2.84 (-)	4.85 (-)	10.33 (-)	43.58 (-)
KERLA	2.14 (-)	6.27 (-)	20.43 (-)	98.32 (-)
MADHYA PRADESH	6.49 (-)	14.73 (-)	32.52 (-)	157.81 (-)
MAHARASHTRA	0.00 (-)	12.62 (-)	22.19 (-)	152.24 (-)
MEGHALAYA	0.00 (-)	10.56 (-)	35.36(-)	97.75 (-)
ORISSA	23.40 (-)	8.66 (-)	18.33(-)	133.26 (-)
PUNJAB	1.22 (-)	11.43 (-)	32.07 (-)	145.16 (-)
RAJASTHAN	6.13 (-)	13.16 (-)	24.98 (-)	163.79 (-)
TAMIL NADU	0.62 (-)	6.68 (-)	14.80 (-)	144.72 (-)
UTTAR PRADESH	0.10 (-)	15.12 (-)	43.20 (-)	169.44 (-)
WESTBENGAL SEB	3.69 (-)	11.86 (-)	21.62 (-)	170.05 (-)
WBPDC	0.00 (-)	5.37 (-)	23.74 (-)	110.0 (-)
AVERAGE	2.25	8.50	13.10	200.4

SOURCE: Annual Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi, 1999

APPENDIX A.8.9 (Contd..)

COST STRUCTURE OF STATE ELECTRICITY BOARDS,1994-95 (PAISE PER KWHR), ANDHRA PRADESH

STATE ELECTRICITY BOARDS	FUEL	POWER PURCHASE	OPERATION AND MAINTENANCE	ESTABLISHMENT/ ADMINISTRATION
ANDHRA PRADESH	31.14(9.2)	40.71 (16.9)	5.73 (0)	17.89 (54.9)
ASSAM	47.35 (16.5)	70.59 (36.1)	11.75 (9.4)	54.95 (9.8)
BIHAR	22.12 (-17.8)	93.37 (14.9)	14.87 (26.1)	41.99(0.19)
DELHI(DVB)	35.93 (-)	185.10(0)	11.55 (0)	28.56 (0)
GUJARAT	79.69 (0)	27.60 (0)	5.72 (0)	18.66(0)
HARYANA	35.57(0)	60.42 (0.02)	6.98 (0.14)	28.09 (7.7)
HIMACHAL PRADESH	0.00 --	27.72 (15.4)	112.48 (-17.5)	33.56(-17.9)
JAMMU&KASHMIR	13.83 (38.3)	130.21 (12.9)	7.19(7.5)	28.64 (31.7)
KARNATAKA SEB	3.20 (14.6)	67.56 (-0.85)	5.31 (15.7)	22.55 (-3.6)
KPC	20.45 (3.0)	0.00 (0)	0.97 (-35.8)	3.30 (-19.5)
KERALA	0.00--	30.97 (5.5)	39.78 (60.4)	0.00 (-100)
MADHYA PRADESH	25.11 (-11.4)	43.17(-11.4)	5.96 (5.5)	21.82 (-11.4)
MAHARASHTRA	52.27 (0)	29.96 (0.03)	8.89 (0)	19.83(0)
MEGHALAYA	0.00 --	7.65 (470.9)	20.55 (88.4)	64.03(61.8)
ORISSA	7.55 (-7.2)	47.30 (14.4)	7.34 (-7.6)	25.38 (-3.0)
PUNJAB	50.64 (1.5)	29.21 (27.3)	4.37 (5.0)	25.10 (-4.1)
RAJASTHAN	32.96 (6.0)	72.55 (13.6)	7.11 (7.1)	19.05 (4.7)
TAMIL NADU	59.26 (-2.2)	35.64 (9.5)	4.33 (7.2)	23.69 (-6.9)
UTTAR PRADESH	31.81 (-3.8)	55.12 (0.47)	8.16 (-0.12)	18.15 (0.22)
WEST BENGAL SEB	28.87 (3.5)	88.99 (10.9)	6.72 (-0.88)	22.43 (0.54)
WBPDC	66.79 (7.7)	0.00 (0)	7.08 (16.4)	0.00 (0)
AVERAGE	37.68 (-3.1)	46.43 (6.3)	7.52 (2.3)	20.14 (-8.5)

APPENDIX A.8.9 (Contd..)
COST STRUCTURE OF SEBS, 1994 - 1995, (PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	MISCELLANEOUS EXPENSES	DEPRECIATION	INTEREST	TOTAL
ANDHRA PRADESH	4.58 (353.5)	12.42 (53.9)	28.59 (48.2)	141.06(29.4)
ASSAM	3.04 (7.4)	31.91 (2.1)	106.95 (63.9)	326.55 (29.2)
BIHAR	0.00 (-100)	18.67(52.4)	21.44 (-1.4)	212.47 (6.2)
DELHI (DVB)	0.00 (0)	10.46 (0)	18.64(100)	290.25 (0)
GUJARAT	0.00 (-100)	9.28 (0)	12.36 (-29)	153.31 (-3.2)
HARYANA	5.71 (765.2)	9.57 (0)	14.89 (-29.3)	159.22 (-3.7)
HIMACHAL PRADESH	0.09 (0)	4.81 (-18.2)	23.73 (-55.2)	102.38 (-28.3)
JAMMU& KASHMIR	0.00(100)	16.01 (23.7)	29.19 (-31.2)	225.07 (7.6)
KARNATAKA SEB	1.12 (-61.9)	9.68 (78.3)	11.70(8.9)	121.12(8.0)
KPC	3.11 (9.5)	5.64(16.3)	14.06(36.1)	47.52 (9.0)
KERALA	9.34 (336.4)	6.71 (7.0)	22.04 (7.9)	108.84(10.7)
MADHYA PRADESH	1.07(0)	13.05 (-11.4)	30.96 (-4.8)	141.15 (-10.6)
MAHARASHTRA	1.49(0)	12.61 (-0.08)	19.96 (-10.5)	145.02 (-4.7)
MEGHALAYA	0.00 (0)	15.12(43.2)	46.59(31.8)	153.94(57.5)
ORISSA	23.67(1.2)	8.76(1.2)	18.26 (-0.38)	138.26(3.8)
PUNJAB	0.26 (-78.7)	18.63 (62.9)	35.67 (11.2)	163.87(12.9)
RAJASTHAN	12.52(104.4)	20.81 (58.1)	31.54(26.2)	196.52(19.9)
TAMIL NADU	6.83(1001.6)	7.53(12.7)	14.74 (-0.41)	152.02(5.0)
UTTAR PRADESH	0.60 (500)	15.17(0.33)	48.52(12.3)	177.53 (22.7)
WEST BENGAL	3.16(16.8)	11.01 (-7.2)	21.82(0.93)	182.99(7.9)
WBPDC	0.00 (0)	15.46(187.9)	22.96 (-3.3)	112.30(2.1)
AVERAGE	3.34 (48.4)	12.17(43.2)	24.69 (88.5)	151.97 (-24.2)

SOURCE: **Annual Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi, 1999**
Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)
COST STRUCTURE OF SEBS, 1995-96, (PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	FUEL	POWER PURCHASE	OPERATION & MAINTENANCE	ESTABLISHMENT/ ADMINISTRATION
ANDHRA PRADESH	45.47 (46.0)	41.71(2.5)	5.81(1.4)	17.63 (-1.5)
ASSAM	54.78 (15.7)	83.06(17.7)	12.09 (2.9)	.61.71 (12.3)
BIHAR	21.64 (-2.2)	122.85 (31.6)	14.64 (-1.5)	47.92(14.1)
DELHIXDVB)	37.27 (3.7)	211.4(14.2)	11.98(3.7)	37.28 (30.5)
GUJARAT	74.63 (-6.3)	24.13(12.6)	4.82 (-15.7)	16.28 (-12.8)
HARYANA	46.21 (29.9)	79.99 (32.4)	11.80(69.1)	33.10(17.8)
HIMACHAL PRADESH	0.00 (-)	38.08 (37.4)	13.03 (4.4)	36.61 (9.1)
JAMMU &KASHMIR	13.91 (0.58)	202.51 (55.5)	6.95 (-3.3)	34.25 (19.6)
KARNATAKA SEB	4.47 (39.7)	93.27(38.1)	5.31 (0)	24.82(0.1)
KPC	29.22 (0.43)	0.00 (0)	1.79(84.5)	6.04 (83.0)
KERALA	0.00 (0)	36.50(17.9)	40.72 (2.4)	0.00 (0)
MADHYA PRADESH	32.81 (30.7)	59.95 (38.9)	7.44 (24.8)	25.43 (16.5)
MAHARASHTRA	53.31 (1.9)	49.64 (65.7)	10.68 (20.1)	22.59 (13.9)
MEGHALAYA	0.00 (0)	8.35 (9.2)	16.68 (-18.8)	58.64 (-8.4)
ORISSA	1.36 (-81.9)	126.0(166.4)	8.43 (14.9)	31.72(24.9)
PUNJAB	51.75(2.2)	32.39(10.9)	4.81 (10.1)	30.00 (-26.8)
RAJASTHAN	36.16(9.7)	29.25 (9.2)	7.90(11.1)	18.37 (-3.6)
TAMIL NADU	75.57 (27.5)	35.31 (-0.93)	4.88 (12.7)	24.34 (2.7)
UTTAR PRADESH	35.24 (0)	51.20 (-7.1)	9.96(22.1)	24.35 (34.2)
WEST BENGAL SEB	23.24 (-19.5)	100.78(13.2)	6.59 (-1.9)	23.13(3.1)
WBPDC	66.16(0.94)	0.00 (0)	8.07 (13.9)	0.00 (0)
AVERAGE	42.92 (13.9)	56.19(21.0)	8.44(12.2)	22.65 (12.5)

SOURCE: Annual **Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi, 1999**
Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)

COST STRUCTURE OF SEBS, 1995-96, (PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	MISCELLANEOUS EXPENSES	DEPRECIATION	INTEREST	TOTAL
ANDHRA PRADESH	4.49 (-1.9)	12.17 (-2.0)	34.01(18.9)	161.28(14.3)
ASSAM	3.46 (-13.8)	21.11 (-93.4)	119.88(12.1	356.07(9.03)
BIHAR	0.00 (0)	23.74 (27.2)	21.61(0.79)	252.40(18.8)
DELHI (DVB)	7.16(100)	12.70(21.4)	0.00(-100)	317.81(9.5)
GUJARAT	0.00 (0)	13.81 (48.8)	11.42(-7.6)	145.09(-5.4)
HARYANA	2.41 (-57.8)	16.90(76.6)	18.31(22.9)	208.72(31.1)
HIMACHAL PRADESH	0.53 (488.9)	5.16(7.3)	17.74(-25.2)	111.15(8.6)
JAMMU &KASHMIR	0.00 (0)	19.75 (23.4)	51.91(77.8)	329.28(46.3)
KARNATAKA SEB	-1.80 (-260.7)	11.13(14.9)	15.14(29.4)	152.34(25.8)
KPC	2.74 (-11.9)	9.63 (70.7)	17.23(22.5)	66.66(40.3)
KERALA	8.41 (-9.9)	7.59(13.1)	29.36(33.2)	122.58(12.6)
MADHYA PRADESH	2.05(91.6)	18.44(41.3)	35.28(13.9)	181.39(28.5)
MAHARASHTRA	1.44 (-3.4)	20.46 (62.3)	19.08(-4.4)	177.21(22.2)
MEGHALAYA	0.00 (0)	13.34 (-11.8)	49.88(7.1)	146.90(-4.6)
ORISSA	19.04 (-19.6)	15.52(77.2)	25.42(39.2)	227.49(64.5)
PUNJAB	0.22 (-15.4)	20.68 (11.0)	32.99(-7.5)	172.83(5.5)
RAJASTHAN	21.99(75.6)	14.58 (-29.9)	34.86(10.5)	213.12(8.4)
TAMIL NADU	6.28 (-8.1)	8.94(18.7)	15.43(4.7)	170.75(12.3)
UTTAR PRADESH	0.33 (-45.0)	19.29(27.2)	51.31(5.7)	191.89(8.1)
WEST BENGAL SEB	3.49(10.4)	10.69 (-2.9)	21.42(-1.8)	189.35(3.5)
WBPDC	0.00 (0)	6.18 (-60.02)	17.83(-22.3)	108.23(-3.6)
AVERAGE	3.42 (2.4)	15.34(26.0)	25.97(5.2)	174.94(15.1)

SOURCE: Annual Report on the working of SEBs and EDs, Power and Energy Division, Government of India, New Delhi, 1999

Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)
COST STUCTURE OF SEBS,1996-97, (PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	FUEL	POWER PURCHASE	OPERATION & MAINTENANCE	ESTABLISH MENT/ ADMINISTR ATION
ANDHRA PRADESH	60.19(32.4)	47.84 (14.7)	8.53(31.9)	24.92 (4.3)
ASSAM	51.77 (-5.5)	112.22(35.1)	12.14(0.41)	69.07 (11.9)
BIHAR	21.88(1.11)	160.44(30.6)	14.56 (-0.55)	46.85 (-2.2)
DELHI (DVB)	33.01(-11.4)	227.49 (7.6)	11.43 (-4.6)	34.34 (-7.9)
GUJARAT	90.26 (20.9)	56.88(135.7)	6.13(27.2)	12.18 (-25.2)
HARYANA	51.97(12.5)	89.42(11.8)	11.10 (-5.9)	37.95 (14.7)
HIMACHAL PRADESH	0.00 (-)	50.35 (32.2)	15.44(18.5)	39.56(8.1)
JAMMU &KASHMIR	11.93(-14.2)	173.67 (-14.2)	5.96 (-14.2)	29.37 (-14.2)
KARNATAKA SEB	5.46(22.1)	112.60(20.7)	6.88 (29.6)	32.52(31.02)
KPC	43.42 (48.6)	0.00 (0)	2.92(63.1)	8.72 (44.4)
KERALA	0.00 (-)	51.70(41.6)	54.41 (33.6)	0.00 (0)
MADHYA PRADESH	41.12(25.3)	68.16(13.7)	8.32(11.8)	32.02 (25.9)
MAHARASHTRA	63.23(18.6)	53.30 (7.4)	11.28(5.6)	24.52 (8.5)
MEGHALAYA	0.00 (-)	9.24(10.7)	20.68 (23.9)	24.58 (8.8)
ORISSA	0.00 (-)	180.25(43)	9.84(16.7)	31.52 (-46.2)
PUNJAB	62.18(20.2)	35.00(8.1)	6.19(0.87)	32.06(1.1)
RAJASTHAN	43.26(-42.8)	79.32 (20.09)	9.95 (25.9)	20.60 (-31.3)
TAMIL NADU	84.00 (11.2)	38.15(8.0)	4.83 (-1.02)	30.88 (68.!)
UTTAR PRADESH	37.49 (6.4)	62.03(21.2)	10.71(7.5)	25.00 (2.7)
WEST BENGAL SEB	27.68(19.1)	107.05 (6.2)	7.74(17.5)	23.74 (2.6)
WBPDC	83.86 (26.8)	0.00 (0)	9.35 (15.9)	0.00 (0)
AVERAGE		67.88 (20.8)	9.75 (15.5)	26.09(15.2)

SOURCErAnnual Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi, 1999
Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)
COST STRUCTURE OF SEBS,1996-97,(PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	M1SCELLANEOUS EXPENSES	DEPRECIATION	INTEREST	TOTAL
ANDHRA PRADESH	4.70 (4.7)	19.11 (57.1)	39.79(16.9)	205.08(27.2)
ASSAM	4.85 (40.2)	31.11 (47.4)	12084(0.80)	401.99(12.91
BIHAR	0.00 (0)	24.40 (2.8)	22.41 (3.7)	290.53(15.1)
DELHI (DVB)	0.00 (-100)	13.55(6.7)	0.00 (0)	300.77(-5.4)
GUJARAT	0.00 (0)	17.30(25.3)	16.94(48.3)	199.70(37.6)
HARYANA	2.99 (-223.7)	16.16 (-4.4)	20.99 (14.6)	230.60(10.5)
HIMACHAL PRADESH	0.33 (-37.7)	5.53 (4.2)	18.18(2.5)	129.39(16.4)
JAMMU &KASHMIR	0.00 (0)	16.93(0.14)	51.54 (-0.7)	289.40(-12.1)
KARNATAKA SEB	7.41 (511.7)	13.21 (18.7)	16.14(6.6)	194.21(27.5)
KPC	2.31 (-15.7)	11.97 (24.3)	23.92 (38.8)	93.27(39.9)
KERALA	11.79 (40.2)	9.42 (24.1)	33.80(15.1)	161.12(31.4)
MADHYA PRADESH	4.24(106.8)	20.66 (12.0)	32.97 (-6.5)	207.49(14.4)
MAHARASHTRA	1.52(5.6)	21.86(6.8)	20.10(5.3)	195.89(10.5)
MEGHALAYA	0.00 (0)	11.67 (-12.5)	44.05(11.7)	160.20(9.1)
ORISSA	0.27 (-98.6)	24.53(58.1)	17.39(31.6)	263.80(15.9)
PUNJAB	2.45(1013.6)	21.98(6.3)	33.60(1.8)	187.27(8.4)
RAJASTHAN	31.59(43.7)	11.76 (-19.3)	38.92(11.6)	239.41(12.3)
TAMIL NADU	-2.74 (-143.6)	12.28 (37.4)	16.46(6.7)	184.97(8.3)
UTTAR PRADESH	0.29 (-12.1)	27.24 (41.2)	55.04(7.3)	222.28(15.8)
WEST BENGAL SEB	4.65 (32.4)	11.24(5.1)	21.94(2.4)	204.06(7.8)
WBPDC	0.00 (0)	18.79(204.0)	24.61(38.02	136.60(26.2)
AVERAGE	3.47(1.5)	18.15(18.3)	28.08(8.1)	204.57(16.9)

SOURCE: Annual Report on **the working of SEBs and EDs,Power and Energy Division, Government of India,** New Delhi, **1999**
Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)
COST STRUCTURE OF SEBS, 1997-98 (PAISE PER KWHROF SALE), INDIA

STATE ELECTRICITY BOARDS	FUEL	POWER PURCHASE	OPERATION & MAINTENANCE	ESTABLISHMENT/ ADMINISTRATION
ANDHRA PRADESH	59.33 (-1.4)	68.00(42.1)	7.65 (-103)	20.71 (-16.9)
ASSAM	50.72 (-2.02)	127.78(13.9)	11.71 (-3.5)	86.74 (25.6)
BIHAR	15.67 (-28.4)	172.74(7.7)	14.40 (-1.1)	0.00 (-100)
DELHI (DVB)	35.52 (7.6)	259.72 (14.2)	10.74 (-6.0)	31.33 (-8.8)
GUJARAT	101.58(12.5)	77.01 (35.4)	6.34 (3.4)	19.89 (63.3)
HARYANA	53.36 (2.7)	99.63 (11.4)	11.88(7.0)	39.10(3.03)
HIMACHAL PRADESH	0.00 (-)	55.00 (9.2)	21.26(37.7)	44.53 (12.6)
JAMMU &KASHMIR	8.11 (-32.0)	181.02(4.2)	6.46 (8.4)	25.70 (-12.5)
KARNATAKA SEB	7.01 (28.4)	103.77 (-7.8)	8.09(17.6)	31.92 (-1.8)
KPC	37.81 (-12.9)	0.00 (0)	8.68(197.3)	7.29 (-16.4)
KERALA	6.19(0)	60.64(17.3)	53.72 (-1.3)	0.00 (0)
MADHYA PRADESH	44.81 (8.9)	71.43(4.8)	8.91 (7.1)	32.89 (2.7)
MAHARASHTRA	67.28 (6.4)	56.74 (6.5)	12.10(0.07)	25.03 (2.1)
MEGHALAYA	0.00 (-)	10.46(13.2)	22.83 (10.4)	85.41 (247.5)
ORISSA	0.00 (-)	187.67(4.1)	9.65 (-1.9)	33.20 (5.3)
PUNJAB	75.60(21.6)	42.19(20.5)	6.66 (7.6)	41.05(28.0)
RAJASTHAN	52.14(20.5)	83.60 (5.4)	8.19 (-17.7)	27.00(31.1)
TAMIL NADU	89.20 (6.2)	46.11 (20.9)	5.23 (8.3)	42.09 (36.3)
UTTAR PRADESH	48.46 (29.3)	66.00 (6.4)	11.00 (2.7)	31.31 (25.2)
WEST BENGAL SEB	35.56 (28.5)	142.81 (32.8)	8.95 (15.6)	26.81 (2.9)
WBPDC	109.43(30.5)	0.00 (0)	10.75(14.9)	0.00 (0)
AVERAGE	56.19(31.4)	76.74(13.1)	10.02 (2.8)	27.29 (4.6)

SOURCE: Annual Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi, 1999
Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)
COST STRUCTURE OF SEBS, 1997-98, (PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	MISCELLANEOUS EXPENSES	DEPRECIATION	INTEREST	TOTAL
ANDHRA PRADESH	3.08 (-34.5)	16.62 (-13.0)	42.02 (5.6)	217.42(6.0)
ASSAM	4.40 (-9.3)	30.01 (-3.5)	111.84(-7.4)	423.19 (5.3)
BIHAR	47.41 (100)	23.96 (-1.8)	21.10 (-5.8)	295.28(1.6)
DELHI (DVB)	0.00 (0)	14.00(3.3)	0.00 (0)	351.30(16.8)
GUJARAT	0.00 (0)	16.74 (-3.2)	13.82(-18.4)	235.37 (17.9)
HARYANA	0.00 (0)	16.92 (4.7)	23.20(10.5)	244.10(5.9)
HIMACHAL PRADESH	0.00 (-100)	6.44(16.5)	32.81(-36.3)	160.01(23.7)
JAMMU &KASHMIR	0.00 (0)	16.11 (-4.8)	50.00 (-2.9)	287.40(-0.69)
KARNATAKA SEB	7.14(0)	13.09 (-0.9)	17.58 (8.9)	188.61(-2.9)
KPC	2.71 (17.3)	9.81(4.1)	19.37(-19.0)	79.77 (-14.5)
KERALA	3.15 (-73.3)	8.54 (-9.3)	47.10(39.3)	179.35(11.3)
MADHYA PRADESH	4.14 (-2.4)	21.98(6.4)	32.7(-0.79)	216.86(4.5)
MAHARASHTRA	1.41 (-7.2)	20.96 (-4.1)	23.28(15.8)	206.80 (5.6)
MEGHALAYA	0.00 (0)	11.88(1.8)	36.14(-17.9)	166.73(4.1)
ORISSA	0.22 (-18.5)	23.32 (-4.9)	17.93(3.1)	271.99(3.1)
PUNJAB	1.36 (-44.5)	17.39 (-20.9)	41.43(23.3)	225.68 (20.5)
RAJASTHAN	26.78 (-15.2)	16.24 (0.38)	45.79 (17.7)	259.74 (8.5)
TAMIL NADU	0.68 (-6.8)	14.96(21.8)	18.78(14.1)	217.05 (17.4)
UTTAR PRADESH	0.33 (13.8)	27.74(1.8)	54.73(-0.56)	239.57 (7.8)
WEST BENGAL SEB	3.88 (-16.6)	12.93(15.0)	23.73 (8.2)	254.67 (24.8)
WBPDC	0.00 (0)	19.81 (5.4)	20.82(-15.4)	160.82(17.7)
AVERAGE	4.18(20.5)	18.09 (-0.33)	29.70 (5.8)	222.21 (8.6)

SOURCE: Annual Report on the working of SEBs and EDs, Power **and Energy Division, Government of India, New Delhi, 1999**
Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)

COST STRUCTURE OF SEBS, 1998-99, (PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	FUEL	POWER PURCHASE	OPERATION & MAINTENANCE	ESTABLISHMENT/ ADMINISTRATION
ANDHRA PRADESH	58.30 (-1.7)	78.43(15.3)	8.03 (4.9)	22.84(10.3)
ASSAM	68.40 (34.9)	123.16(-3.6)	11.20 (4.4)	62.62 (-27.8)
BIHAR	29.78 (90.0)	148.03(-14.3)	11.95 (-17.0)	41.16(0)
DELHI (DVB)	35.06 (-1.3)	259.88(0.06)	11.08 (3.2)	45.72 (45.9)
GUJARAT	99.03 (-2.5)	112.06(45.5)	6.59 (3.9)	48.26 (142.6)
HARYANA	51.80 (-2.9)	97.56(2.1)	13.26(11.6)	56.44 (44.3)
HIMACHAL PRADESH	0.00 (-)	57.59 (4.7)	21.60(0.02)	55.30 (24.2)
JAMMU &KASHMIR	6.75 (-16.8)	181.10(0.04)	6.19(4.2)	23.57 (-8.3)
KARNATAKA SEB	8.75 (24.8)	109.75 (5.8)	8.42(4.1)	37.58(17.7)
KPC	39.75(5.1)	0.00 (0)	3.23 (-62.8)	8.16(11.9)
KERALA	18.69(201.9)	58.85 (-2.9)	60.09 (11.9)	0.00 (0)
MADHYA PRADESH	44.3(-1.03)	76.23 (6.7)	9.57 (7.4)	34.66 (5.4)
MAHARASHTRA	71.39(6.1)	59.80 (5.4)	13.81(14.1)	29.86 (19.3)
MEGHALAYA	0.00 (-)	35.60 (240.3)	26.24 (5.0)	103.74(21.5)
ORISSA	0.00 (-)	183.18 (-2.4)	9.49 (-1.7)	42.73 (28.7)
PUNJAB	78.59 (3.9)	38.77 (-8.1)	7.25 (8.9)	47.38 (15.4)
RAJASTHAN	57.49(10.3)	84.38 (0.93)	8.06 (-1.6)	26.59 (-1.5)
TAMIL NADU	101.96(14.3)	60.40 (30.9)	5.75 (9.9)	44.20 (5.0)
UTTAR PRADESH	49.43 (2.0)	61.63 (-6.6)	11.50 (4.5)	35.15(12.3)
WEST BENGAL SEB	34.23 (-3.7)	148.70(4.1)	9.97(11.4)	38.17(42.4)
WBPDC	109.03(-0.37	0.00 (0)	12.92 (20.2)	0.00 (0)
AVERAGE	59.04 (0.25)	82.62 (7.7)	10.83 (8.1)	31.76(16.4)

SOURCE: Annual Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi, 1999

Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)
COST STRUCTURE OF SEBS, 1998-99, (PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	MISCELLANEOUS EXPENSES	DEPRECIATION	INTEREST	TOTAL
ANDHRA PRADESH	3.11 (0.97)	18.38(10.6)	44.92(6.9)	234.00(7.6)
ASSAM	3.92 (-10.9)	26.89 (-10.4)	124.36(11.2)	420.56(-0.62)
BIHAR	0.00(100)	21.05 (-12.1)	16.75(-20.6)	268.71 (-8.9)
DELHI (DVB)	0.00 (0)	14.58(4.1)	0.00 (-100)	366.32(4.3)
GUJARAT	0.00 (0)	13.74 (-17.9)	12.30(-26.5)	261.98(11.3)
HARYANA	0.00 (0)	28.31(67.3)	31.36(85.3)	278.73(14.2)
HIMACHAL PRADESH	0.00 (0)	6.66 (3.4)	35.16(445.9)	176.31(10.2)
JAMMU &KASHMIR	0.00 (0)	16.10 (-0.06)	13.34(-17.2)	247.06(-14.0)
KARNATAKA SEB	2.47 (-65.4)	15.91 (21.5)	24.66(151.4)	207.54(10.03)
KPC	2.62 (-3.3)	11.99 (22.2)	32.13(65.9)	97.88 (22.7)
KERALA	2.85 (-9.5)	9.43 (10.4)	51.64(9.6)	201.56(12.4)
MADHYA PRADESH	4.90(18.4)	22.68 (3.2)	38.15(16.6)	230.54(6.3)
MAHARASHTRA	1.53(8.5)	23.97 (14.4)	26.13(12.2)	226.49(9.5)
MEGHALAYA	0.00 (0)	13.86(16.7)	227.58(529.7)	407.02(144.0)
ORISSA	0.19(13.6)	21.12 (-94.3)	24.06(34.2)	280.77(3.2)
PUNJAB	0.75 (-44.5)	19.14(10.1)	46.08(11.2)	237.95(5.4)
RAJASTHAN	23.11 (-13.7)	16.84(3.7)	48.13(5.1)	264.62(1.9)
TAMIL NADU	4.17(513.2)	13.46 (-10.02)	20.21(7.6)	244.16(12.5)
UTTAR PRADESH	0.31 (-6.1)	30.38 (9.5)	58.79 (7.4)	248.25(3.6)
WEST BENGAL SEB	4.02 (3.6)	14.25 (10.2)	27.99(17.9)	277.33(8.9)
WBPDC	0.00 (0)	18.58 (-6.2)	25.01 (20.1)	165.54(2.9)
AVERAGE	2.90 (-30.6)	19.45 (7.5)	33.10(11.4)	239.68(7.9)

SOURCE: Annual **Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi, 1999**
Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)

COST STRUCTURE OF SEBS,1999 2000 (PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	FUEL	POWER PURCHASE	OPERATION & MAINTENANCE	ESTABLISHMENT/ ADMINISTRATION
ANDHRA PRADESH	68.18	96.91	9.51	30.25
ASSAM	56.98	139.57	13.48	93.90
BIHAR	29.28	162.95	11.10	42.56
DELHI (DVB)	34.91	156.20	10.51	33.63
GUJARAT	118.69	98.29	8.73	21.91
HARYANA	67.51	180.06	14.84	64.74
HIMACHAL PRADESH	0.00	75.08	25.10	62.32
JAMMU &KASHMIR	2.55	199.48	5.69	22.13
KARNATAKA SEB	5.71	152.59	5.83	30.63
KPC	52.35	0.00	3.70	9.26
KERALA	12.84	106.44	5.13	47.93
MADHYA PRADESH	52.68	79.34	12.27	43.54
MAHARASHTRA	63.38	89.71	14.22	28.67
MEGHALAYA	0.00	32.46	30.04	118.92
ORISSA	0.00	199.48	10.17	36.52
PUNJAB	78.69	40.01	9.01	49.85
RAJASTHAN	62.21	95.47	9.09	27.54
TAMIL NADU	82.30	64.49	5.88	46.21
UTTAR PRADESH	52.50	86.41	12.46	44.20
WEST BENGAL SEB	35.66	155.37	8.22	34.49
WBPDC	104.50	0.00	8.17	6.33
AVERAGE	63.82	105.55	10.60	37.72

SOURCE: Annual **Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi, 1999**

Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.9 (Contd..)
COST STRUCTURE OF SEBS, 1999-2000, (PAISE PER KWHR OF SALE), INDIA

STATE ELECTRICITY BOARDS	MISCELLANEOUS EXPENSES	DEPRECIATION	INTEREST	TOTAL
ANDHRA PRADESH	4.25	20.11	65.51	294.71
ASSAM	5.80	38.20	105.10	453.04
BIHAR	0.00	18.33	14.23	278.46
DELHI (DVB)	0.00	14.06	13.65	362.95
GUJARAT	0.00	19.31	20.37	287.30
HARYANA	2.79	16.29	30.82	377.06
HIMACHAL PRADESH	0.00	6.97	22.52	192.00
JAMMU &KASHMIR	0.00	16.18	45.77	291.80
KARNATAKA SEB	2.89	14.81	21.28	233.73
KPC	2.33	15.42	23.04	106.15
KERALA	5.26	11.84	45.07	234.51
MADHYA PRADESH	6.04	18.70	40.15	252.72
MAHARASHTRA	6.99	24.51	26.88	254.36
MEGHALAYA	0.00	31.21	68.81	281.45
ORISSA	1.36	20.65	36.01	304.19
PUNJAB	0.70	19.12	49.73	247.12
RAJASTHAN	23.25	21.68	47.75	286.98
TAMIL NADU	1.73	19.12	25.64	255.38
UTTAR PRADESH	0.50	28.88	53.25	278.21
WEST BENGAL SEB	6.00	15.20	33.36	288.30
WBPDC	0.17	17.50	25.00	161.67
AVERAGE	4.27	21.21	37.71	280.88

SOURCE: Annual **Report on the working of SEBs and EDs,Power and Energy Division, Government of India, New Delhi,** 1999
Note: The numbers in parenthesis are growth rates.

APPENDIX A.8.10

COMMERCIAL PROFIT / LOSS (WITH OUT SUBSIDY) (Rs. CRORE)

SL.NO	STATE ELECTRICITY BOARD	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000
1	Andhra Pradesh	-4.30	-22.70	-37.30	3.90	-938.90	-503.40	-1011.40	-2703.00
2	Assam	-205.40	-197.30	-255.30	-260.70	-353.00	-440.50	-368.90	-336.00
3	Bihar	-279.60	-189.70	-188.90	-211.40	-441.60	-370.20	-239.50	548.00
4	Delhi (DVB)	-207.30	NA	NA	-578.00	-626.40	-759.90	-961.50	-794.00
5	Gujarat	100.00	92.00	106.00	108.00	111.00	-770.00	-653.00	-893.00
6	Haryana	-368.30	-446.90	-12.90	46.00	6.70	-275.60	-375.40	-90.00
7	Himachal Pradesh	1.60	-50.60	19.40	10.70	19.30	-18.90	-39.30	-4.00
8	Jammu & Kashmir	-224.50	-293.20	-346.70	-363.20	-506.90	-608.60	-665.50	-347.00
9	Karnataka	32.20	33.90	43.10	51.20	58.50	60.70	69.10	77.00
10	Kerala	-65.30	-75.00	-120.30	-130.00	-176.50	-218.80	-199.90	-451.00
11	Madya Pradesh	-112.90	38.10	-79.50	-8.00	-19.90	-322.10	-735.40	-1655.00
12	Maharashtra	161.60	189.00	276.00	221.70	166.50	111.80	196.50	214.00
13	Meghalaya	-1.90	-3.00	-13.50	-11.90	-5.90	-10.10	-118.60	214.00
14	Orissa	26.00	29.90	24.90	26.90	-308.40	-257.90	-211.00	-148.00
15	Punjab	-626.30	-693.20	-680.60	-643.70	-600.20	-1346.00	-1611.70	-1223.00
16	Rajathan	22.10	10.40	77.10	80.80	63.20	-506.60	-619.80	-882.00
17	Tamila Nadu	92.40	225.50	347.80	339.20	329.60	-194.80	-209.70	-459.00
18	Uttar pradesh	-807.50	-1201.50	85.00	380.80	-264.30	-63.80	-221.90	-2142.00
19	West Bengal	-254.50	-158.00	-242.10	-240.10	-206.50	-483.10	-486.10	-608.00
	AVERAGE	-2724.90	-2705.60	-998.00	-1177.70	-3693.80	-6977.80	-8463.00	-11682.00

APPENDIX A.8.11

EFFECTIVE SUBSIDY FOR AGRICULTURAL CONSUMERS(RS CRORE)

SL.NO	STATE ELECTRICITY BOARD	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000
1	Andhra Pradesh	725.90	925.40	135.03	1747.70	1678.80	1815.50	2142.80	2796.00
2	Assam	6.20	8.80	11.00	8.70	6.00	14.10	16.30	13.00
3	Bihar	267.60	251.90	297.10	299.50	350.70	390.80	447.80	521.00
4	Delhi (DVB)	8.60	0.00	0.00	0.00	0.00	0.00	25.40	27.00
5	Gujarat	1055.40	1206.00	1266.20	1646.80	1812.60	2503.90	3180.60	3466.00
6	Haryana	456.30	540.00	489.80	612.30	727.40	742.70	889.90	1288.00
7	Himachal Pradesh	1.00	1.50	0.90	0.70	0.90	1.40	1.60	2.00
8	Jammu & Kashmir	27.50	53.40	66.80	70.60	90.70	116.70	131.90	30.00
9	Karnataka	496.50	667.90	870.70	1109.20	910.00	825.20	922.80	2232.00
10	Kerala	0.00	16.40	23.00	35.70	47.00	51.70	67.20	91.00
11	Madya Pradesh	421.10	756.20	1103.70	1416.40	1724.90	1854.20	2046.30	2503.00
12	Maharashtra	1030.90	1130.90	1647.00	2249.80	2553.60	2875.80	3373.10	3593.00
13	Meghalaya	0.00	0.10	0.10	0.20	0.20	0.20	0.70	0.00
14	Orissa	20.70	39.20	20.20	30.30	40.80	48.30	57.40	48.00
15	Punjab	687.10	797.30	780.90	828.50	1008.30	1473.10	1553.20	0.00
16	Rajathan	347.50	468.40	622.60	807.60	1055.00	1040.90	1147.40	1453.00
17	Tamila Nadu	642.50	759.80	946.80	1133.30	1280.20	1561.70	1787.40	1982.00
18	Uttar pradesh	1035.40	1227.40	1275.10	1402.40	1762.30	1890.00	2019.00	2204.00
19	West Benqal	104.20	115.00	168.80	2065.00	249.60	324.90	391.60	453.00
	TOTAL	7334.90	89656.00	10941.00	136060.00	15299.00	17531.30	20197.30	22703.00

Source: Planning commission, 1999, Annual report on the working of SEBs and Electricity Departments,. P:131,New Delhi, Power and Energy Division, Planning commission,

APPENDIX A.8.12

SUBSIDY FOR DOMESTIC CONSUMERS (RS CRORE)

SLNO	STATE ELECTRICITY BOARD	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000
1	Andhra Pradesh	40.40	63.60	118.70	159.30	238.00	255.80	368.20	898.40
2	Assam	37.20	82.40	79.30	90.10	119.10	118.90	163.50	176.50
3	Bihar	40.00	56.30	89.20	118.90	158.30	177.90	192.90	196.50
4	Delhi (DVB)	297.40	0.00	0.00	0.00	0.00	0.00	422.70	371.30
5	Gujarat	88.00	94.90	121.80	136.10	112.20	92.10	22.80	145.90
6	Haryana	95.60	137.20	113.20	123.10	109.60	11.00	68.10	205.00
7	Himachal Pradesh	13.70	25.90	23.20	19.90	29.60	45.10	53.00	74.30
8	Jammu & Kashmir	49.50	62.00	70.00	93.80	127.70	156.40	163.00	205.00
9	Karnataka	22.50	9.20	35.30	118.50	252.30	220.70	211.40	74.30
10	Kerala	60.50	83.40	114.70	204.00	374.80	344.30	483.00	133.40
11	Madya Pradesh	252.70	258.40	315.40	401.50	510.40	592.90	714.90	118.60
12	Maharashtra	151.60	193.30	190.20	326.70	423.80	295.50	457.40	838.00
13	Meghalaya	1.40	1.10	2.80	5.90	6.70	7.60	29.60	843.60
14	Orissa	80.40	122.40	92.10	143.50	196.30	228.30	253.40	573.60
15	Punjab	54.30	83.10	108.10	119.60	162.30	252.10	320.70	19.30
16	Rajathan	183.30	127.50	163.40	220.70	218.00	264.80	247.90	278.00
17	Tamila Nadu	141.80	147.60	158.60	192.70	237.50	304.60	337.90	280.00
18	Uttar pradesh	331.80	468.50	563.50	557.50	807.10	987.70	1135.40	427.20
19	West Bengal	92.90	114.00	177.30	192.60	258.80	329.30	385.40	432.20
									1626.60
									447.70
	TOTAL	2034.90	2130.80	2536.80	3224.40	4342.80	4685.00	6081.20	8082.60

Source: Planning commission, 1999, Annual report on the working of SEBs and Electricity Departments,. P:134,New Delhi, Power and Energy Division, Planning commission, Govt. of India.

APPENDIX A. 10.1

POWER TARIFF PROJECTIONS FOR RAYALASEEMA THERMAL POWER STATION STAGE II (2x210) MW AT 80% PLF FOR A LIFE PERIOD OF 30 Years

	Stabilisation period	2002-2003	2007-2008	2012-2013	2017-2018	2022-2023	2027-2028
Installed Capacity(MW)							
Unit-1	210	210	210	210	210	210	210
Unit-2	210	210	210	210	210	210	210
Plant load Factor							
Unit-1 (Hrs/Year)	6381	7008	7008	7008	7008	7008	7008
Unit-2 (Hrs/Year)	5754	7008	7008	7008	7008	7008	7008
Total Net Generation(MU)	2328.19822	2693.1744	2693.1744	2693.1744	2693.1744	2693.1744	2693.1744
FIXED CHARGES:(Rs.Crores)							
Return on equity	50.04	50.04	50.04	50.04	50.04	50.04	50.04
Operation and maintenance ex	39.09	39.09	39.09	39.09	39.09	39.09	39.09
Depreciation	123.69	123.69	123.69	0	0	0	0
Interest on loans	94.54	87.11	36.68	0	0	0	0
Interest on working capital	20.48	21.68	21.17	17.34	17.34	17.34	17.34
Incentives	0	2.37	2.37	2.18	2.18	2.18	2.18
Taxation	0	0	0	0	26.94	26.94	26.94
Total fixed charge(Rs.in Crs.)	327.83	323.98	273.04	108.65	135.59	135.59	135.59
Cost per KWH (in Paise)	140.81	120.3	101.38	40.34	50.35	50.35	50.35
VARIABLE CHARGES:							
Total coal requirement (Tonnes	1578396	1804744	1804744	1804744	1804744	1804744	1804744
Price of coal per metric ton	1667.52	1667.52	1667.52	1667.52	1667.52	1667.52	1667.52
Cost of coal (Rs.in Crs)	263.32	300.94	300.94	300.94	300.94	300.94	300.94
Total oil requirement(KL)	6159.83	5886.72	5886.72	5886.72	5886.72	5886.72	5886.72
Price of oil per kilo litre	7960	7960	7960	7960	7960	7960	7960
Cost of oil(Rs.in Crores)	4.9	4.69	4.69	4.69	4.69	4.69	4.69
Total cost of fuel (Rs.in Crs.)	268.1	305.63	305.63	305.63	305.63	305.63	305.63
Cost per unit of fuel cost (Ps/kw	126.46	144.29	144.29	144.29	144.29	144.29	144.29
Power Tariff	267.27	264.59	245.67	184.63	194.64	194.64	194.64

APPENDIX A. 10.3

POWER TARIFF PROJECTIONS FOR SPECTRUM POWER GENERATION LIMITED STAGE I (208 MW) AT 68.5% PLF FOR A LIFE PERIOD OF 18 YEARS

	1997-1998	2002-2003	2007-2008	2012-2013	2017-2018
Installed Capacity(MW)	208	208	208	208	208
Plant load Factor (%)	68.5	68.5	68.5	68.58	68.5
Total Net Generation(MU)	1210.7	1210.7	1210.7	1210.7	1210.7
FIXED CHARGES:(Rs.Crores)					
Return on equity	35.92	35.92	35.92	35.92	35.92
Operation and maintenance expenses	18.71	18.71	18.71	18.71	18.71
Depreciation	57.72	57.72	57.72	0.32	0.32
Interest on rupee term loans	55.05	22.67	0	0	0
Interest on foreign exchange loans	16.73	7.92	0	0	0
Interest on working capital	8.7	8.25	7.31	0.32	0.32
Incentives	0	0	0	0	0
Taxation	0	0	63.34	25.53	26.29
Total fixed charge(Rs.in Crs.)	192.83	151.19	183	80.8	81.56
Cost per KWH (in Paise)	1.59	1.25	1.51	0.67	0.67
VARIABLE CHARGES:					
Cost of fuel (Rs.Crores)	57.91	57.91	57.91	57.91	57.91
Cost of gas per unit(Rs)	0.46	0.46	0.46	0.46	0.46
Cost of Naphtha per unit(Rs.)	0.99	0.99	0.99	0.99	0.99
Average cost of units generated (Rs)	0.46	0.46	0.46	0.46	0.46
Average cost of units delivered (Rs)	0.48	0.48	0.48	0.48	0.48
Unit Variable Cost(Rs.)	0.48	0.48	0.48	0.48	0.48
Power tariff	2.07	1.73	1.99	1.15	1.15

APPENDIX A. 10.4

POWER TARIFF PROJECTIONS FOR SPECTRUM POWER GENERATION LIMITED STAGE I (208 MW) FOR A LIFE PERIOD OF 18 YEARS

	1997-1998	2002-2003	2007-2008	2012-2013	2017-2018
Installed Capacity(MW)	208	208	208	208	208
Plant load Factor (%)	68.5	68.5	68.5	68.58	68.5
Total Net Generation(MU)	1210.7	1210.7	1210.7	1210.7	1210.7
FIXED CHARGES:(Rs.Crores)					
Return on equity	35.92	35.92	35.92	35.92	35.92
Operation and maintenance expenses	18.71	25.02	35.49	47.5	53.37
Depreciation	57.72	57.72	57.72	0.32	0.32
Interest on rupee term loans	55.05	22.67	0	0	0
Interest on foreign exchange loans	16.73	7.92	0	0	0
Interest on working capital	8.7	8.25	7.31	0.32	0.32
Incentives	0	0	0	0	0
Taxation	0	0	63.34	25.53	26.29
Total fixed charge(Rs.in Crs.)	196.57	157.5	199.78	109.59	116.22
Cost per KWH (in Paise)	1.62	1.3	1.65	0.91	0.96
VARIABLE CHARGES:					
Cost of fuel (Rs.Crores)	57.91	57.91	57.91	57.91	57.91
Cost of gas per unit(Rs)	0.46	0.46	0.46	0.46	0.46
Cost of Naphtha per unit(Rs.)	0.99	0.99	0.99	0.99	0.99
Average cost of units generated (Rs)	0.46	0.46	0.46	0.46	0.46
Average cost of units delivered (Rs)	0.48	0.48	0.48	0.48	0.48
Unit Variable Cost(Rs.)	0.48	0.64	0.85	1.15	1.29
Power tariff	2.1	1.94	2.5	2.06	2.25

APPENDIX A.10.5

POWER TARIFF PROJECTIONS FOR SPECTRUM POWER GENERATION LIMITED STAGE II (208 MW) AT 95% PLF FOR A LIFE PERIOD OF 18 YEARS

	1997-98	2002-2003	2007-2008	2012-2013	2014-2015
Installed Capacity(MW)	208	208	208	208	208
Plant load Factor (%)	95	95	95	95	95
Total Net Generation(MU)	1430.7	1430.7	1430.7	1430.7	1430.7
FIXED CHARGES:					
Return on equity	35.92	35.92	35.92	35.92	35.92
Operation and maintenance expenses	18.71	18.71	18.71	18.71	18.71
Depreciation	57.72	57.72	57.72	0.32	0.32
Interest on rupee term loans	55.05	22.67	0	0	0
Interest on foreign exchange loans	16.73	7.92	0	0	0
Interest on working capital	8.7	8.25	7.31	5.53	5.53
Incentives	35.7	35.7	35.7	35.7	35.7
Taxation	0	0	63.34	25.53	26.29
Insurance	3.74	3.74	3.74	3.74	3.74
Total fixed charge(Rs.in Crs.)	232.27	190.63	222.44	125.45	126.21
Cost per KWH (in Paise)	1.63	1.33	1.55	0.88	0.88
VARIABLE CHARGES:					
Cost of fuel (Rs.Crores)	103.02	103.02	103.02	103.02	103.02
Cost of gas per unit(Rs)	0.46	0.46	0.46	0.46	0.46
Cost of Naphtha per unit(Rs.)	0.99	0.99	0.99	0.99	0.99
Average cost of units generated (Rs)	0.66	0.66	0.66	0.66	0.66
Average cost of units delivered (Rs)	0.62	0.62	0.62	0.62	0.62
Unit Variable Cost(Rs.)	0.62	0.62	0.62	0.62	0.62
Power tariff	2.25	1.95	2.17	1.5	1.5

APPENDIX A.10.6

POWER TARIFF PROJECTIONS FOR SPECTRUM POWER GENERATION LIMITED STAGE II (208 MW) AT 95% PLF FOR A LIFE PERIOD OF 18 YEARS

	1997-98	2002-2003	2007-2008	2012-2013	2014-2015
Installed Capacity(MW)	208	208	208	208	208
Plant load Factor (%)	95	95	95	95	95
Total Net Generation(MU)	1430.7	1430.7	1430.7	1430.7	1430.7
FIXED CHARGES:					
Return on equity	35.92	35.92	35.92	35.92	35.92
Operation and maintenance expenses	18.71	25.02	35.49	47.5	53.37
Depreciation	57.72	57.72	57.72	0.32	0.32
Interest on rupee term loans	55.05	22.67	0	0	0
Interest on foreign exchange loans	16.73	7.92	0	0	0
Interest on working capital	8.7	8.25	7.31	5.53	5.53
Incentives	35.7	35.7	35.7	35.7	35.7
Taxation	0	0	63.34	25.53	26.29
Insurance	3.74	3.74	3.74	3.74	3.74
Total fixed charge(Rs.in Crs.)	232.27	196.94	239.22	154.24	160.87
Cost per KWH (in Paise)	1.62	1.38	1.67	0.108	0.112
VARIABLE CHARGES:					
Cost of fuel (Rs.Crores)	103.02	103.02	103.02	103.02	103.02
Cost of gas per unit(Rs)	0.46	0.46	0.46	0.46	0.46
Cost of Naphtha per unit(Rs.)	0.99	0.99	0.99	0.99	0.99
Average cost of units generated (Rs)	0.66	0.66	0.66	0.66	0.66
Average cost of units delivered (Rs)	0.62	0.62	0.62	0.62	0.62
Unit Variable Cost(Rs.)	0.62	0.82	1.11	1.48	1.66
Power tariff	2.24	2.2	2.78	1.59	1.77

COMPUTATION OF TARIFF WITH OPERATION AND MAINTENANCE AND FUEL COST ESCALATION

APPENDIX A. 10.7

POWER TARIFF PROJECTIONS FOR GVK JEGURUPADU GAS POWER PLANT (216 MW) AT 80% PLF FOR A LIFE PERIOD OF 15 YEARS

	2002-2003	2007-2008	2012-2013	2016-2017
Installed Capacity(MW)	**216**	**216**	**216**	**216**
Plant load Factor (%)	**80**	**80**	**80**	**80**
Total Net Generation(MU)	1541.76	**1541.76**	**1541.76**	**1541.76**
FIXED **CHARGES:(Rs.Crores)**				
Return on equity	22.4	**22.4**	**22.4**	**22.4**
Operation and maintenance expenses	17.5	17.5	**17.5**	17.5
Depreciation	54.88	54.88	54.85	**0.32**
Interest on rupee term loans	55.05	22.67	0	**0**
Interest on foreign **exchange loans**	16.73	**7.92**	0	0
Interest on working capital	10.8	8.25	**7.31**	**5.53**
Incentives	0	0	0	**0**
Taxation	25.53	25.53	25.53	25.53
Insurance	**3.5**	**3.5**	**3.5**	**3.5**
Total fixed charge(Rs.in Crs.)	206.39	162.65	131.09	**74.78**
Cost **per KWH (in Paise)**	**1.34**	**1.05**	**0.85**	**0.49**
VARIABLE CHARGES:				
Cost of fuel (Rs.Crores)	**85**	**85**	**85**	**85**
Cost of gas per unit(Rs)	0.55	0.55	0.55	**0.55**
Average cost of units generated (Rs)	0.55	0.55	0.55	**0.55**
Average cost of units delivered (Rs)	**0.57**	0.57	**0.57**	**0.57**
Unit Variable Cost(Rs.)	**0.69**	**0.69**	**0.69**	**0.69**
Power tariff	2.03	**1.74**	1.54	**1.18**

APPENDIX A. 10.8

POWER TARIFF PROJECTIONS FOR GVK JEGURUPADU GAS BASED PLANT (216 MW) AT 90% PLF FOR A LIFE PERIOD OF 15 YEARS

	2002-2003	2007-2008	2012-2013	2016-2017
Installed Capacity(MW)	216	216	216	216
Plant load Factor (%)	80	80	80	80
Total Net Generation(MU)	1541.76	1541.76	1541.76	1541.76
FIXED CHARGES:(Rs.Crores)				
Return on equity	22.4	22.4	22.4	22.4
Operation and maintenance expenses	17.5	17.5	17.5	17.5
Depreciation	54.88	54.88	54.85	0.32
Interest on rupee term loans	55.05	22.67	0	0
Interest on foreign exchange loans	16.73	7.92	0	0
Interest on working capital	10.8	8.25	7.31	5.53
Incentives	0	0	0	0
Taxation	25.53	25.53	25.53	25.53
Insurance	3.5	3.5	3.5	3.5
Total fixed charge(Rs.in Crs.)	206.39	162.65	131.09	74.78
Cost per KWH (in Paise)	1.34	1.05	0.85	0.49
VARIABLE CHARGES:				
Cost of fuel (Rs.Crores)	85	85	85	85
Cost of gas per unit(Rs)	0.55	0.55	0.55	0.55
Average cost of units generated (Rs)	0.55	0.55	0.55	0.55
Average cost of units delivered (Rs)	0.57	0.57	0.57	0.57
Unit Variable Cost(Rs.)	0.66	0.66	0.66	0.66
Power tariff	2	1.71	1.51	1.15