Final Report
June 2010

Assessment of Cost of Service for supply to agricultural consumers and methods to reduce cross subsidy for agriculture category

Prepared for

Forum of Indian Regulators (FOIR)

By

The Energy and Resources Institute (TERI)
and
Dhiya Consulting Private Limited

Project Report No. 2008ER08

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Abbreviations

AERC	Assam Electricity Regulatory Commission
APCPDCL	Andhra Pradesh Central Distribution Company Ltd
APERC	Andhra Pradesh Electricity Regulatory Commission
APNPDCL	Andhra Pradesh Northern Power Distribution Company Ltd
APPA	American Public Power Association
ARR	Annual Revenue Requirement
BESCOM	Bangalore Electricity Supply Company
CoS	Cost of Service
CPD	Coincident Peak Demand
CPM	Coincident Peak Method
UHBVN	Uttar Haryana Bijli Vitran Nigam
EHT	Extra High Tension
GERC	Gujarat Electricity Regulatory Commission
GUVNL	Gujarat Urja Vikas Nigam Limited
HPERC	Himachal Pradesh State Electricity regulatory Commission
HPGCL	Haryana Power Generation Corporation Ltd
KERC	Karnataka State Electricity Regulatory Commission
KPTCL	Karnataka Power Transmission Corporation Ltd
LT/HT	Low Tension. High Tension
MPSEB	Madhya Pradesh State Electricity Board
NCPM	Non Coincident Peak Method
PGVCL	Paschim Gujarat Vij Company Ltd
PUVVNL	Poorvanchal Vidyut Vitran Nigam Ltd
PVVNL	Paschimanchal Vidyut Vitran Nigam Ltd
SHE	Short Elliott Hendrickson Inc.
SLDC	State Load Dispatch Centre
UGVCL	Uttar Gujarat Vij Company Ltd
USO	Universal Service Obligation

Executive Summary

Introduction

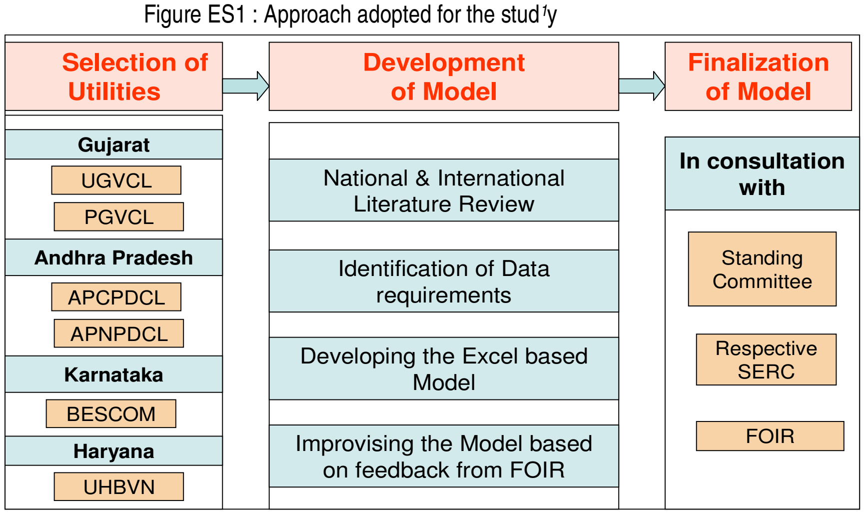
Forum of Indian Regulators (FOIR) entrusted a study to Consortium of TERI and Dhiya consortium for "Assessment of Cost of Service for supply to agricultural consumers and methods to reduce cross subsidy for agriculture category". The broad objectives of the study are:

- To formulate the methodology to determine the cost of service for agricultural consumers in accordance with economic principles and suggest a model
- To examine the issues related to determination of the cost of service to agricultural consumers taking into account the quality of supply, including hours of supply, voltage fluctuations, reliability of supply, etc
- To study and suggest whether the agricultural tariffs should be linked to the average cost of supply or the actual cost of service
- To suggest the options for reducing the cross-subsidy in agricultural tariffs, including study of the extent to which the cross-subsidy can be realistically reduced.

Approach adopted for the study

A step by step approach followed for the development of excel based model for assessment of cost of supply of power to agricultural consumers is presented in the figure below:

Figure ES1 : Approach adopted for the study[1]



[1] Two utilities of Uttar Pradesh- PUVVNL and PVVNL were also selected . Assessment of cost to serve for these utilities could not be carried out due to non availability of adequate data.

Conceptual framework and literature review

Cost of service model is the judicious segregation of total cost incurred by the utility into various consumer categories served. The two widely used methodologies for estimation of cost of service are the Embedded Cost approach and the Marginal Cost Approach. The difference between the two approaches lies in their different concepts of cost. The embedded cost study uses the accounting costs on the company's books during the test year as the basis for the study. In contrast, the marginal cost study estimates the resources costs of the utility in providing the last unit of production.

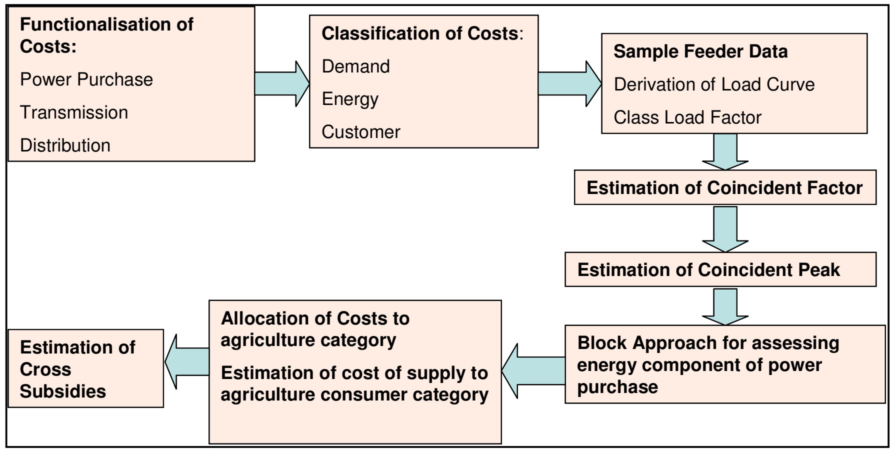
The embedded cost approach has an advantage of accessible and verifiable data as recorded in the books of the utility. However use of this approach is not forward looking and does not reflect the true economic cost. Marginal cost approach represents the economic value incurred by the utility to provide consumers with an additional unit of electricity and thus provide efficient price signals to consumers. However, it requires large quantum of data, which is not readily available. More so, when the forecasted values are used, the results are not very accurate. In Indian context, looking at the benefits of embedded cost approach and the fact that the tariff setting process is also based on it, it is meaningful to devise the methodology for assessment of cost of supply based embedded cost approach. Various Indian states such as Andhra Pradesh, Madhya Pradesh, Assam, Himachal Pradesh, Karnataka, Haryana and Gujarat have undertaken studies related to assessment of cost of service based on embedded cost approach.

Model for determination of cost of supply

Based on extensive literature review conducted both for national and international utilities and the discussion with relevant experts, excel based model has been developed to estimate the cost of supplying power to agricultural consumers of various utilities. The model is based on the marginal cost approach.

The figure Es2 explains the various steps involved in assessment of cost of supply of power to the agricultural category.

Figure ES2: Methodology for assessment for cost to serve



Step 1: Functionalisation of costs

Functionalisation is the process of dividing the total cost of the distribution utilities on basis of the functions performed such as power purchase, transmission and distribution. This shall facilitate in determination of function wise cost incurred in supplying power to agricultural consumer category.

Step 2: Classification of costs

Each of the functionalised cost is further classified as follows based on their intrinsic nature:

- *Demand related costs*: Demand related costs are generally of fixed nature. Such costs are related to capacity creation and hence are inclusive of cots such as interest on capital borrowing, depreciation, income tax, rate of return on equity.

- *Energy related costs*: Energy Costs depends on the quantum of electricity consumption of the users. Such costs are generally termed as variable costs and include costs such as fuel cost, interest on working capital etc.

- *Customer related cost*: Customer Costs are directly related to the services provided to customers. It varies according to the number of customers served in each category. Though fixed in nature, these costs are associated with the functions of metering, service connection and customer related activities. They include operating expenses associated with meter reading, billing and accounting.

Based on the above description of the functionalisation and further classification of cost, following table indicates how the cost related to different function can be classified into the demand related, energy related and consumer related.

Table Functionalisation and Classification of cost

Typical Cost Function	Typical Cost Classifications
1) Power Purchase	Demand Related
	Energy Related
2) Transmission	Demand Related
3) Distribution	Demand Related
	Energy Related
	Customer Related

Step 3: Sample feeder data analysis
Following approach is applied for sample feeder data analysis:

- *Identification of the sample feeders*: 10 sample feeders were selected from each selected distribution utilities for the load data. A selection criterion for sampling of feeders is the predominance of the agricultural load on the feeder. All feeders selected for the study has predominantly agricultural load wherein at least 80% of the load on feeder is agricultural load. Moreover, the sample feeders selected was representative of the different circle in the utility to capture the geographical spread of the utility.

- *Identification of the sample days for data collection*: 18 days were selected for data collection such that the days were uniformly spread across the entire year to capture the seasonality in agricultural demand of the utility. Apart from these 18 days, data was also collected for the day on which the utility had the peak demand during the year.

- *Derivation of load curve*: Based on the selected sample feeder and the selected days load curve for the sample feeders of agricultural consumers were obtained.

- *Estimation of Class Load Factor*: Class load factor of the category i.e agriculture consumers is estimated with the feeder data collected.

Class Load Factor = Average Demand/ Peak demand

Step 4: Estimation of Coincident Factor
As the agriculture category have no “voluntary” consumption of power as the supply is provided as per certain subjective ‘Supply

schedules' and are interrupted for variety of reasons. Hence the peak stack or the peak curve is quite an induced administrative one. Hence it is argued that if uninterrupted power is made available to Agriculture category, then the peak may shift to a more convenient trough during the day, as farmers may not load the system during night and therefore the load curve could have been different. Taking this into account, the use of single peak would over burden the agriculture category and hence use of average monthly peak is suggested. Using this approach, the coincident factor of each category can be arrived at as follows:

- Ascertain the time and magnitude of system peak for each of the 12 months separately
- Establish the corresponding load from the sample feeder data (average if there are more than two readings for the month)
- From the above, take a simple average of above 12 monthly readings.
- This average divided by the feeder sample peak gives the CF

Step 5: Estimation of coincident peak

Coincident peak[1] of the agricultural category is derived from its non coincident peak (NCP) using the coincident factor by application of following formula:

*Coincident Peak = NCP/(8.76*Coincident Factor)*

An important aspect for estimation of Non Coincident Peak (NCP) is the usage of load factor (LF) and load loss factor (LLF). In the situation of availability of segregated technical and commercial losses, the formula for calculation of NCP would be as follows:

*NCP = (Consumption and commercial losses in MU/(LF*8.76) +(Loss in MU)/(LLF*8.76)*

However, in situation where the losses could not be segregated into technical and commercial losses, the load loss factor cannot be used. Also where the readings are taken at the sending end of the 11 kv (or above as in case of AP), the load curve is either drawn taking the current flowing in the feeder or instantaneous Kw readings recorded at the sending end, the losses in the selected 11 kV feeder are captured to a large extent (though not fully) along with the actual load in the load factor only. Hence the NCP is calculated using load factor as follows:

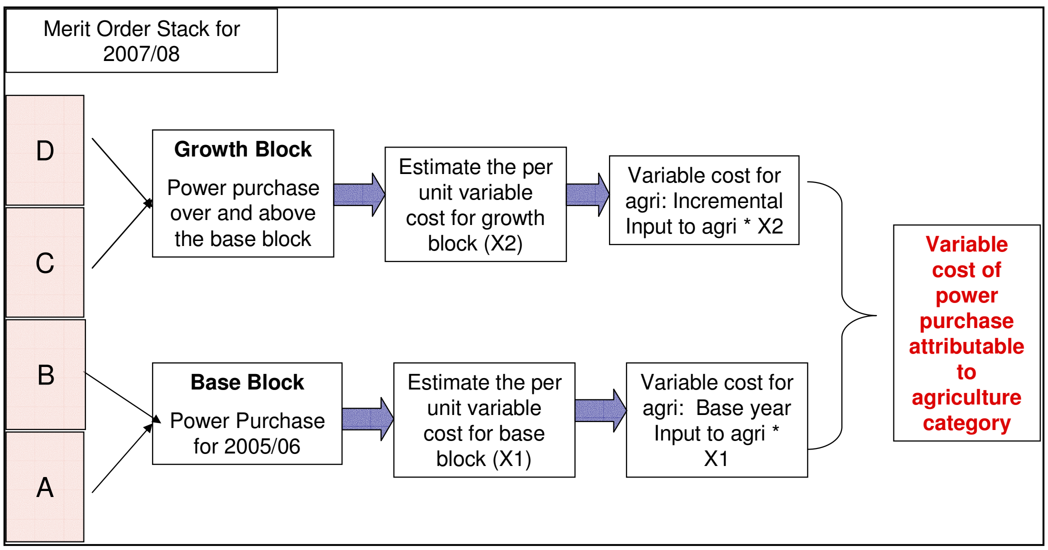
*NCP = (consumption + loss)/ (LF*8.76)*

[1] Coincident peak is the contribution of the agricultural demand to the system peak demand

Step 6: Block approach for assessing energy component of power purchase

It is observed that the different consumer categories pose different weights on the incremental power purchase over the years. In this regard, each category should be charged in accordance with their respective share of the incremental power purchase over the years. In this regard, a block approach on merit order dispatch is used to estimate the energy/ variable component of the power purchase cost which could be attributed to the agricultural category. Figure Es3 indicates the steps are carried out to allocate the variable cots of power purchase.

ES3: Block approach to allocate variable cost of power purchase



Step 7: Allocation of cost to the agricultural category

The costs when classified are then allocated to the agricultural consumer category. The objective is to allocate costs to customer classes in relation to the cost impact imposed by the consumer category on the power system. The different type of cost (Demand, Energy and Consumer) as classified in previous step are allocated to the agricultural category according to the following principles:

- *Allocation of Demand Costs*: Demand costs of all three functions such as power purchase, transmission and distribution function are allocated to agricultural consumers on the basis of the coincident peak demand.

- *Allocation of Energy Costs*: The energy cost component of power purchase is allocated to agricultural category on the basis of block approach as explained above.

Energy related cost of transmission and distribution function is allocated to the agricultural category on the basis of ratio of agricultural consumption to the total consumption of the utility.

- *Allocation of Customer Costs*: Customer related cost of all three functions is allocated to the agricultural consumer on the basis of the ratio of number of agricultural consumers to the total consumers of the utility.

Sum total of the different cost (demand, energy and customer related cost) allocated to the agricultural consumers gives the total cost of supplying power to agricultural consumers as incurred by the particular utility.

Step 8: Estimation of cross subsidies
Estimation of cross subsidies is the succeeding step after estimation of cost to serve to agricultural category. Following steps are carried out to estimate the same:

- Difference between the total cost of supplying power to agricultural consumers and the revenue collected from them in a particular year gives the estimate of total quantum of subsidies for the utility
- Difference between the total subsidy and the subsidy provided by the government estimates the extent of cross subsidy to the agricultural sector.

Results of Utility Wise Analysis

Following table indicates the cost of supply of power to agriculture consumer category of the selected utilities covered under the study and the extent of cross subsidization for the same.

<table>
<tr><th rowspan="2">Utilites</th><th>Per unit Cost of Supply</th><th>Total Cost of Supply</th><th>Revenue</th><th>Govt Subsidies</th><th>Cross Subsidies</th></tr>
<tr><th>Rs/Kwh</th><th>Rs Crores</th><th>Rs Crores</th><th>Rs Crores</th><th>Rs Crores</th></tr>
<tr><td colspan="6">Gujarat</td></tr>
<tr><td>UGVCL</td><td>2.81</td><td>1638.55</td><td>657.59</td><td>576.58</td><td>404.38</td></tr>
<tr><td>PGVCL</td><td>3.65</td><td>1533.06</td><td>470.14</td><td>419.62</td><td>643.30</td></tr>
<tr><td colspan="6">Karnataka</td></tr>
<tr><td>BESCOM</td><td>3.31</td><td>1195.98</td><td>330.64</td><td>196.26</td><td>669.08</td></tr>
<tr><td colspan="6">Andhra Pradesh</td></tr>
<tr><td colspan="6">APCPDCL</td></tr>
<tr><td>LT Agriculture</td><td>2.10</td><td>1303.38</td><td>7.30</td><td rowspan="3">1108.00</td><td rowspan="3">254.61</td></tr>
<tr><td>HT Agriculture (11 KV)</td><td>3.18</td><td>18.17</td><td rowspan="2">69.12</td></tr>
<tr><td>HT Agriculture (33 KV)</td><td>2.44</td><td>2.65</td></tr>
</table>

HT Agriculture (220 KV)	4.37	114.83			
APNPDCL					
LT Agriculture	2.50	906.47	3.34		
HT Agriculture (11 KV)	3.41	1.60			
HT Agriculture (33 KV)	2.59	2.33			
HT Agriculture (220 KV)	4.44	36.84	19.41	1078.95	-154.47
Haryana					
UHBVN	5.16	2361.88	119.58	1298.30	944.00

Conclusion

Move towards the actual cost to serve pricing principle

It is imperative that tariff of agriculture be determined as per cost to serve and this cost to serve be computed judiciously taking into account not only accounting costs, but also hours of supply and quality of power. Move towards the actual cost to serve pricing principle is required to introduce transparency in rate designing and subsequent assessment in subsidy requirement.

Special attention in allocation of power purchase

As power purchase costs forms about ~75% to 85% of the distribution value chain; it is evident that allocations of power purchase costs have the maximum effect on the cost of supply to consumer category. Thus, the treatment of the power purchase cost should be carefully dealt with while estimating the cost of supply.

Cost of serve to agriculture category to reflect reliability of supply (timing & availability)

Supply of electricity to agriculture category is erratic in nature wherein they receive power supply during odd hours and that too often of poor quality. In this regard, there is a need to compensate the agriculture consumers for the poor quality of supply. In the situation where the agricultural consumer category is not pre notified about the hours of power supply to them, It is suggested to provide differential treatment wherein a discount should be given to the cost of serve determined by the model described above in view of the inconvenience caused to the agricultural consumers. However, where the hours are regulated and notified well in advance, then agriculture supply cannot be said to have been discriminated and their cost of serve should not be discounted.

Cost of serve to agriculture category to reflect quality of supply

Supply of poor quality power is against the spirit of the Electricity Act and the Standards of Performance Regulations. Hence, it is important to link the total cost of power purchase incidental to agriculture consumption with the quality of power supply made available to agriculture consumers. This issue could be addressed either by modifying the total cost of power purchase on account of agriculture consumers considering the average voltage deviations beyond permissible limit or by aggregating the penalty levied on licensees due to poor quality supply and, thereby, moderating the power purchase cost.

Use of appropriate load curves

Agriculture demand widely varies across the year on account of different seasons, cropping and rainfall pattern. At the same time, availability and mix of supply also varies leading to different cost of power purchase. Therefore, it is essential to capture the diversity in agriculture demand for arriving co-incident peak by studying the behaviour of agriculture demand on significant number of days widely dispersed over the year or study period.

Capturing seasonal diversity

Agriculture demand widely varies across the year on account of different seasons, cropping and rainfall pattern. Therefore, it is essential to capture the diversity in agriculture demand for arriving co-incident peak by studying the behaviour of agriculture demand on significant number of days widely dispersed over the year or study period.

Usage of average monthly peak

As agricultural category receives restrictive power supply, it witnesses the administrative peak. In the situation of uninterrupted access of quality of supply to the agricultural category for the entire year (24 hrs in a year), then the consumption curve could have been different. Given this, it has been felt that the single "peak" may be imposing a higher burden on this category. Hence, usage of average if monthly peak is suggested as an alternative to use of single peak so that no single category is disadvantaged.

Need to change the assets/expenditure accounting practices

In order to compute the Cost of Supply with a greater degree of certainty, it is necessary that a policy be evolved and accounting of expenditure be done in a manner which makes it amenable to identify voltage wise and function wise costs.

CHAPTER 1: Introduction and conceptual framework

Background

The consumers of power are broadly categorised into domestic, commercial, industrial, agricultural consumers etc. The cost of supplying power to a particular category of consumer is dependent on the voltage of supply, the demand pattern of the category in relation to the demand pattern of DISCOM, energy consumption by the category, losses attributable to the category, etc. However, due to predominance of social and historical considerations, retail tariff for some consumer categories such as domestic and agriculture is less than the cost incurred in supplying power to these categories and are subsidized by industrial and commercial consumers. For many reasons, which are discussed in later sections, an overall average cost of supply is not an efficient criterion, especially when difference in true cost of supply between different categories is significant. The cross subsidization of electricity tariff across various consumer categories is regarded as economically inefficient due to many reasons.

In the subsidized sectors, incremental consumption of electricity has lower value attached by the consumers than the cost incurred to supply the power. This results in substantial wastage of economic resources. Also, it is regarded unfair to cross subsidizing categories to charge them much more than the real cost of supplying electricity to them.

Charging certain consumers categories with a price which is less than its cost of the supply encourages wasteful consumption and loss of revenue to the utilities. Thus, due to lower revenue realisation, there are regular hike in tariffs of both subsiding and subsidized consumer categories. With availability of more energy supply alternatives, price elasticity of demand for electricity is rising. Thus, with the tariff hike for the power supplied to subsiding category such as industrial consumers, they resort to alternative power supply provisions such as captive power generation or power purchase using open access mechanism. This leads to loss of high valued consumers to the utilities which eventually leads to further loss of revenues.

Moreover, at the outset it might appear that the link between cross subsidies and environmental degradation at best is weak. However, cross subsidies to the domestic sector and rural areas have grown over the years as demand for electricity in these sectors has increased significantly during the last two decades.

Low/free cost of power has resulted in indiscriminate pumping of ground water leading to depletion of ground water and posing serious threats to future of farming and food sustainability. Also, as thermal plants have considerable shorter gestation periods than hydel plants, the need to keep electricity shortages at bay has prompted greater dependence on thermal generation. The quality of coal used in electricity generation, however, leaves a lot to be desired as most types of coal in India have very high ash contents. In addition to this, the ever-increasing electricity tariffs for industries have compelled many industries to opt for captive generation, which relies greatly on diesel. Therefore, an inefficient market for electricity demand which arises from the distortion in tariff has a definitive adverse impact on environment.

Considering that there are, numerous inefficiencies and market distortion that arise due to cross-subsidization, there are strong legislative and policy directives for tariff of power to reflect their cost to serve. Instances of such directives are highlighted below in box 1.1.

Box 1.1: Legislative and policy directions

Electricity Regulatory Commissions Act, 1998
Section 29.e:
"…the consumers pay for the use of electricity in a reasonable manner based on the average cost of supply;"

Electricity Act, 2003
Section 61.g
"…that the tariff progressively reflects the cost of supply of electricity and also, reduces cross-subsidies within the period to be specified by the Appropriate Commission."

Section 62. (3)
"The Appropriate Commission shall not, while determining the tariff under this Act, show undue preference to any consumer of electricity but may differentiate according to the consumer's load factor, power factor, voltage, total consumption of electricity during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required."

Section 39 (2) (d) (ii)
–Any consumer as and when such open access is provided by the State Commission under sub section 2 of 42 on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission.

Section 8.3, National Tariff Policy
" For achieving the objective that the tariff progressively reflects the cost of supply of electricity, the SERC would notify roadmap within six months with a target that latest by the end of year 2010-2011 tariffs are within ± 20 % of the average cost of supply. The road map would also have intermediate milestones, based on the approach of a gradual reduction in cross subsidy."

In view of the strong policy directives towards tariff rationalisation, it is important to conduct a study which estimates the economic cost of power supply to different categories of consumers.

Importance of Cost of Service in the Agriculture sector

The Indian agriculture sector consumes around 26% of the total energy consumed[1]. In Indian agriculture sector, post independence, usage of electric pumps for groundwater irrigation has expanded, which in turn contributed to growth in agricultural productivity and aggregate output. By 1998/99, approximately 57 percent of net irrigated area in India was irrigated using groundwater. Groundwater irrigation's positive impact on agricultural productivity has been shown in various studies. Studies at the village level found that the use of electric pumps for irrigation increased aggregate agricultural output by 2 percent[2]. A study on the cost of unserved energy found estimated losses in crop production of 3.1 percent of agricultural gross state domestic product (GSDP) in Haryana and 13.3 percent in Karnataka.

Realizing the importance of the ground water irrigation with usage of electric pumps, state governments provided a onetime investment subsidy for digging wells and priced electricity to agriculture at very low rates or for free. As a result, electric pump usage jumped in most states. Between 1980/81 and 1998/99, some of the largest increases were in Andhra Pradesh (446,000 to 1.9 million), Madhya Pradesh (3 17,000 to 1.3 million), Maharashtra (668,000 to 2.2 million), Karnataka (309,000 to 1.1 million) and Tamil Nadu (92,000 to 1.6 million)[3].

Electricity tariffs for agriculture generally are set at a flat rate on a pump horsepower basis for unmetered category. Metered tariffs have also been introduced for agricultural category. Compared to other developing countries, India stands out as having the lowest average agricultural tariff rate. The ratio of agriculture to domestic tariff rates is approximately 0.22 in India, compared to 0.85 in Bangladesh, 1.77 in Pakistan, and 1.32 in Vietnam.

Electricity supply for agriculture is faced with certain peculiarities such as:

[1] Indiastat.com (projected figures)
2 Re-energizing the Agricultural Sector To Sustain Growth and Reduce Poverty. World Bank

Deterioration in quality of supply

The rapid deterioration in quality of service to electricity consumers in general and agricultural consumers in particular due to poor financial condition of the utilities, leads to frequent power interruption and voltage fluctuations resulting in pump burnouts, unreliability of irrigation water supplies, and ultimately undermining farm productivity and farm profits. Consequently, farmers' dissatisfaction grew, increasing their unwillingness to pay even the highly subsidized charges. This dissatisfaction contributed to delayed payment of electricity bills with an increasing resistance to tariff increases and thereby aggravating the financial crises in the utilities. Recent farm level studies in Haryana and Andhra Pradesh found that poor quality of supply imposes considerable additional costs on farmers. Motor pumps burnouts that cost approximately Rs 1,000 to Rs 4,000 to burdens, especially small and marginal farmers[1]. These repair costs accounted for approximately 10 percent of gross farm income for marginal farmers in Haryana and approximately 8 percent of gross farm income for marginal farmers in Andhra Pradesh. Notably, electricity tariffs account for a small but regressive share of gross farm incomes.

Thus it is necessary that tariff for agricultural consumer should reflect the improvement in quality of supply.

Low Collection efficiency

Agricultural power tariffs amount to approximately one-fifth or less of the collection efficiency. In 2000/01 the collection rate was only 28 percent in Orissa, 52 percent in Karnataka and 76 percent in Uttar Pradesh.

Over Exploitation of Resource

The under-pricing of electricity, leads to overexploitation of natural resources i.e ground water . In the state of Punjab, until 2002 power was provided to agriculture for free, and thus as a result, approximately 60 percent of the administrative blocks in which groundwater was used was already over-exploited. In Punjab’s Central region, in which average groundwater exploitation has reached 141 percent, 83 percent of the 69 blocks is over-exploited. Indeed, agricultural scientists in Punjab estimate that reducing the area under the rice-wheat system from 4 to 3 million hectare in the central region will balance water use and its

[1] Re-energizing the Agricultural Sector To Sustain Growth and Reduce Poverty. World Bank

replenishment[1]. In Haryana and Tamil Nadu, 40 percent of groundwater areas are over-exploited. In Tamil Nadu, of the 1.8 million wells in the state, approximately 10 percent are non-operational. The depth of borewells in hard rock areas has increased to as much as 600-1000 feet[2] (World Bank 2003). In Maharashtra, where groundwater accounted for nearly three-quarters of the increase in net irrigated area in the 1990s, excessive groundwater withdrawals in some districts (including Nasik, Ahmednagar, Jalgaon, Sangli, and Satara) caused the groundwater to drop by as much as 300 feet. This drop led to widespread drying up of drinking water wells, most of which are only 30-50 feet deep, forcing the state Ground Water Survey and Development Agency to dig borewells for drinking water in these areas (World Bank 2003).

High losses and data inconsistencies:

Agriculture sector is plagued with high losses. One of the important reasons is the adverse Low Tension. High Tension (LT/HT) ratio of predominately agricultural feeders . Another reason is that throughout India, agriculture consumption is unmetered to a large extent and as such the consumption always assessed consumption. This leads to excessive losses in other segments of the supply business to be masqueraded as agricultural consumption. Also, due to lack of metering, actual motor size and load may be quite different from the sanctioned load. All this leads to problems of data inconsistencies.

Thus it is clear that subsidizing agricultural consumers for electricity tariff has far reaching adverse impacts. In the above context, it becomes important to address the issues of the cross subsidies to the agricultural sector.

Objective of the study

In the above context, Forum of Indian Regulators (FOIR) entrusted a study to consortium of TERI and Dhiya Consulting Pvt Ltd for “Assessment of Cost of Service for supply to agricultural consumers and methods to reduce cross subsidy for agriculture category”. The broad objectives of the study are:

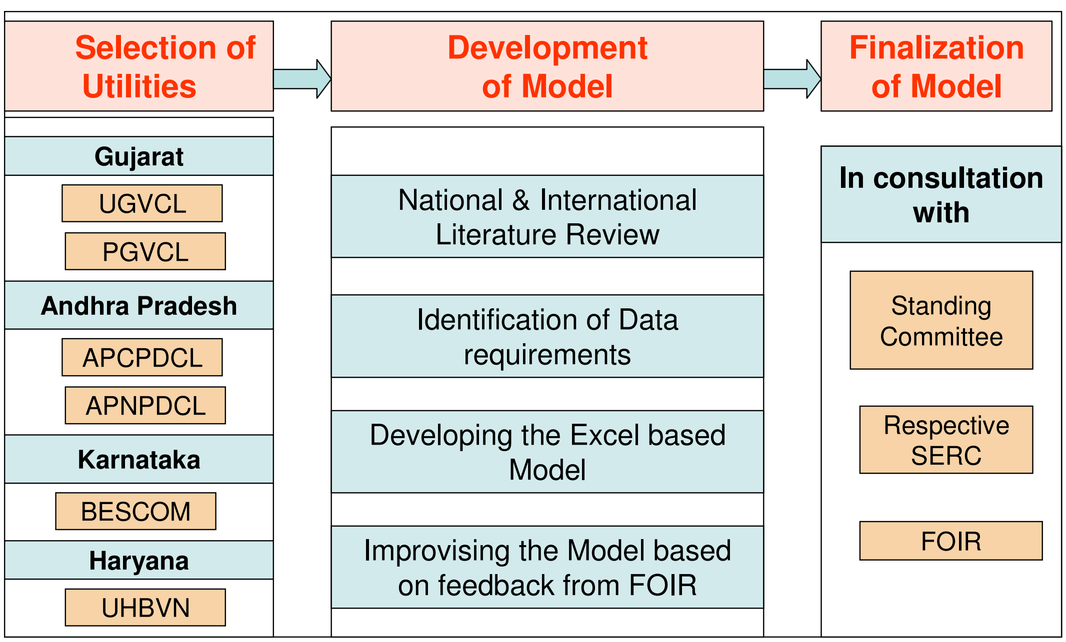
[1] Re-energizing the Agricultural Sector To Sustain Growth and Reduce Poverty. World Bank
[2] Re-energizing the Agricultural Sector To Sustain Growth and Reduce Poverty. World Bank

- To formulate the methodology to determine the cost of service for agricultural consumers in accordance with economic principles and suggest a model
- To examine the issues related to determination of the cost of service to agricultural consumers taking into account the quality of supply, including hours of supply, voltage fluctuations, reliability of supply, etc
- To study and suggest whether the agricultural tariffs should be linked to the average cost of supply or the actual cost of service
- To suggest the options for reducing the cross-subsidy in agricultural tariffs, including study of the extent to which the cross-subsidy can be realistically reduced.

Approach adopted for the study

Following figure depicts the approach adopted to conduct the study on estimation of the cost of service for supply of power to agricultural consumers followed by the detailed explanation of each step:

Figure: Approach for the study



Step1: Selection of utilities

Based on the discussions with FOIR, following utilities having substantial agricultural consumption are selected for the study:

Name of the State	Name of the DISCOM
Andhra Pradesh	Andhra Pradesh Central Distribution Company Ltd(APCPDCL)
	Andhra Pradesh Northern Power Distribution Company Ltd (APNPDCL)
Karnataka	Bangalore Electricity Supply Company (BESCOM)
Gujarat	Uttar Gujarat Vij Company Ltd (UGVCL)
	Paschim Gujarat Vij Company Ltd (PGVCL)
Haryana	Uttar Haryana Bijli Vij Ltd
Uttar Pradesh	Paschimnachal Vidyut Vitran Nigam Ltd
	Poorvanchal Vidyut Vitran Nigam ltd

Step 2: National and International approaches of agriculture tariff designing

Review of International and national experiences of agricultural tariff determination vis-à-vis the cost of service was carried out based on existing published literature.

Step 3: Developing cost of supply model for agricultural consumers

A model has been developed for determination of the Cost of Service for supplying power to agricultural consumers on the basis of economic principles. The model has broadly taken into account the following factors:

- Utility system load pattern
- Power purchase costs for the utility
- Energy consumption pattern of the utility
- Technical and commercial losses in agricultural category
- Voltage level wise classification of cost
- Apportionment of the costs
- Load data of the sample feeders
- Differential load growth of demand in agriculture

category versus demand growth in other categories

Step 4: Collection of key input parameters

While formulating the broad framework of the methodology and model for assessing cost of service for supplying power to agricultural consumers, input data is being collected on key input parameters. The data collection for input parameters includes both secondary data from published sources of information such as profit & Loss accounts, tariff order, annual report, balance sheet etc of the utility as well as the primary inputs which were collected while discussion with the key officials of the selected utility.

Step 5: Model Validation

The data collected are then fed into the model to get the results. These results are then discussed with the concerned utilities and FOIR to validate the model.

Step 6: Finalisation of Model

The model methodology was discussed with respective SERcs/utilities, FOIR and the Standing Committee of FOIR for the finalisation.

Conceptual Framework - Cost of Service

Cost of Service (CoS) is the segregation of the total cost (joint) into each consumer categories. Cost of service allocation system distributes costs to different category of consumers based on how the particular category of consumer causes the costs. CoS Model is developed to carryout comparative cost/revenue analysis that would enable utilities to develop various tariff s alternatives.

Cos Model leads to true assessment of the cost of supplying power to the particular consumer category. It will then assess the extent of cross subsidy prevalent in the system and will help in devising out measures to reduce e the cross subsidies.

Different Methodology for designing consumer tariffs[1]

Electricity distribution sector being monopolistic are subject to Regulatory Controls whereby tariffs structures which are based on cost plus regulated returns, rather than their true market value. Mostly the cost is defined in engineering and accounting terms. Many cost studies developed are based

[1] Electricity Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners

on historical capital expenditure (embedded) for plant and operating expenses and have divided those costs (fully allocated or distributed them) among the classes of customers according to principles of cost causation. The task for the researchers is to allocate, among customers, the costs identified for which the revenue requirement had been calculated.

The two widely used methodologies for estimation of cost of service are discussed below.

Embedded cost approach

The Embedded Cost Approach seeks to identify and assign the historical or accounting costs that make up a utility's revenue requirement. In such an analysis, the revenue requirement is allocated to classes of service to fix tariff based on various allocation factors. The factors can be the contribution of classes to the peak demand, the energy purchased by each class as a percentage of total sales, the number of consumers in the class etc. The present study has adopted the embedded cost approach and the methodology and rationale for adopting the same is discussed in detail in later sections.

Marginal Cost approach

In the new era of general inflation, high energy and construction costs, and competition, rates based on pre-inflationary historical costs often lead to poor price signals for customers, inefficient uses of resources for society, and repeated revenue deficit for the distribution companies. Regulators and utilities began to inquire whether the principles of marginal cost were the appropriate reference for regulated utilities rate structures. Such concepts had long been the theoretical economic framework for the analysis of competitive markets.

Marginal cost is derived from the neo-classical economics of the nineteenth century which states that in a perfectly competitive equilibrium, the amount consumers are willing to pay for the last unit of a good or service equals the cost of producing the last unit, i.e., its marginal cost. As a result, the amount customers are willing to pay for a good equals the value of the resources required to produce it, and society achieves the optimal level of output for any particular good or service. In a competitive market, this equilibrium is achieved as each firm expands its output until its marginal cost equals the price established by the forces of supply and demand. For the utility monopoly, the regulator attempts to achieve the same allocative efficiency by accepting the level of service demand by customers (the utility's obligation to serve) as the given and setting price (or rates) equal to the utility's marginal cost for that level of output. The analyst defines the cost as the change in cost due to the production of one unit more or less of the product, and various approaches have been advanced to measure the utility's marginal cost.

A deficiency of the marginal approach for ratemaking purposes is that marginal cost-based prices will yield the utility's allowed revenue requirement based on embedded costs only by rare coincidence. Since regulatory agencies are bound not to let the utility over-earn or under-earn, revenues from rates must be reconciled to the allowed revenue requirement. As the rates are reconciled to the revenue requirements and prices diverge from marginal cost, the sought after marginal cost prices signals may not be obtained. When prices do not exactly equal marginal cost there is no formal proof that the economic efficiency predicted by theory is achieved. Advocates of marginal cost pricing believe that approximations to marginal cost pricing must contribute to efficient resource allocation, although to an unspecifiable degree. Supporters of embedded cost pricing believe that the greater precision, verifiability and general simplicity of embedded cost methods outweigh any of the hoped for efficiency benefits of imperfect approximations to marginal cost pricing.

Marginal cost approach seeks to determine the incremental (marginal) change in total costs imposed on the system by a change in output (whether measured by Kwh, customer group or other relevant cost driver). This is done by:

- Determining the level of revenue realisation if marginal costs were charged as prices to each class.
- Comparing the total to the revenue requirement of the utility
- Closing any gap in a way that minimizes the distortions in consumption resulting in any necessary price deviations from marginal cost.

It may be further noted that in the distribution business, although demand increases in small steps of through addition of each consumer, capacity addition always occurs in large steps being the capacity of the plant installed. Thus, marginal cost method of allocating cost to each additional unit of demand does not appear to be practical.

Comparison of two approaches

It is important to note that the difference between an embedded cost of service study and a marginal cost of service study lies in their different concepts of cost. The embedded cost study uses the accounting costs on the company's books as the basis for the study. In contrast, the marginal cost study estimates the resource costs of the utility in providing the last unit of production. Once "cost" is determined, the procedures for allocating cost among services, jurisdictions and customers are largely the same.

There are three subjects of particular interest in the development of cost studies; treatment of joint and common costs, time-differentiation of rates, and incorporation of future costs. The following discussion will briefly address how the two types of studies deal with those issues.

Joint and Common Costs

Joint costs occur when the provision of one service is an automatic by-product of the production of another service. Common costs are incurred when an entity produces several services using the same facilities or inputs. In the electric industry, the most common occurrence of joint costs is the time jointness of the costs of production where the capacity installed to serve peak demands is also available to serve demands at other times of the day or year. Overhead expenses such as the president's salary or the accounting and legal expenses are examples of costs that are common to all of the separate services offered by the utility.

In an embedded cost study the joint and common costs are allocated either on the basis of the overall ratios of those costs that have been directly assigned, or by a series of allocators that best reflect cost causation principles such as labour, wages or plant ratios, or by a detailed analysis of each account to determine beneficially. The classification and treatment of the joint and common costs requires considerable judgment in an embedded cost study.

In a marginal cost study, the variation of those common costs that vary with production is incorporated into the study through regression techniques and becomes a multiplier to the marginal cost per kilowatt or kilowatt-hour. There are fewer joint and common costs in marginal cost studies than in embedded because many of the common costs do not vary with changes in production. The presence of joint and common costs, both variable and non-variable, contributes to the inequality between the totals obtained from a marginal cost study and the revenue requirement based on the embedded test year costs.

Time Differentiation of Rates

Both embedded and marginal cost studies can be designed to recognize cost variations by time period. It is true that marginal cost studies are designed to calculate the energy and capacity costs attributable to operating the last (marginal) unit of production during every hour of the year. The hours can then be grouped into peak, off-peak and shoulder periods for costing and pricing purposes. However, in embedded studies, the baseload, intermediate and peak periods can be identified, and different configurations of production plants and their associated energy costs, can be assigned to each period. Thus, the primary difference between the two types of studies in regard to the calculation of times differentiated rates is that the costs fall naturally out of a marginal cost study while embedded cost analysts are required to perform a separate costing step before allocating costs to the customer classes.

Future Costs

To the extent that the price of inputs, technology, and managerial and technical efficiency causes the cost of providing service in the past to differ from the cost of service in the future, rates based on historic test years will over-or under-collect during the years the rates are in effect. Within the context of embedded studies, solutions to the need to incorporate future costs include recognition of known and measurable changes to the test year costs, step increases between rate cases, fuel adjustment mechanisms to give immediate recognition to variations in fuel costs and the use of a forward-looking test year for the cost study. This last is the most comprehensive response to the need to reflect future costs within an embedded study. However, it has the disadvantage of relying on estimated costs rather than costs that are subject to verification and audit. Thus, from the point of the view of the regulator, an embedded study based on a future test year loses one of the prime advantages it has over marginal cost studies.

In contrast to the standard embedded cost study, marginal costs by definitions, are future costs. Marginal cost studies estimate either the short-run marginal costs, in which plant, equipment and organizational skills are fixed, but labour, materials and supplies can be varied to satisfy the change in production, or the long-run marginal costs, in which all inputs including production capacity can be adjusted. As a matter of practicality, marginal cost studies usually adopt an intermediate period tied to the planning horizon of the utility.

Source of Data

While the data for cost studies are generally provided by the utility company, the documents that are relevant depends on the type of cost study being performed. Embedded cost studies rely on the company's historical records or projections of these records, whose accuracy can be audited and verified either at the time of filing or at the end of the period projected. Marginal cost studies use the company's planning documents.

For the embedded cost studies, the principal items of historical information required to develop cost allocations based on accounting costs are plant investment data, including detailed property records, balance sheets, information on operating expenses and on performance of generating units, load research (information on KWH consumption and the patterns of that consumption) and system maps. These costs are contained in the books and records maintained by the utility, and are performed to recognize known and measurable charges. The utility files projected revenues, investment and costs of all accounts in cost studies using projected test years.

The focus of marginal cost studies is on the estimated change in costs that results from providing an increment of services. The planning documents of the utility form the basis of the analysis, with those plans in turn being based on such tools and information as the output of the production costing model and the optimized generation planning model, the parameters established for reliability, stability and capability responsibility, and load and fuel forecasts. Costing for generation requires information on outage rates, operating and maintenance costs, alternate fuel capabilities and retirement schedules of existing plants, on the expected market for capacity purchases and sales, and on the capital and operating costs of alternate future generating units including their associated transmission.

Cost information on transmission, and to a lesser extent, distribution, is obtained from the utility's models of power flow analysis, with their associated transient stability programs, switching surge analyses and loss studies, and geographically specific load forecasts. Based on this information, the transmission and distribution planner will have developed a system expansion plan, the budget for which provides the cost data for the transmission and distribution potions of the marginal cost study.

Future customer and general administrative costs, and in less sophisticated studies distribution costs as well, are not thought to vary significantly from the immediate historically incurred costs. Therefore, the sources of data for a marginal study will be the historic account data.

Acceptability of approach

Having discussed the two approaches to designing the consumer tariffs, the embedded cost approach with suitable modification for certain factors is considered to be most appropriate by Electricity Regulatory Commission. Moreover, given the current tariff structure and low head rooms in tariffs to levy and collect, marginal pricing could only lead to over/under recovery of costs when compared to the Discom's accounts. Also presently all electricity regulatory commissions determines tariff based on embedded cost approach and thus all data are also maintained for the same, it is natural that for determination of cost of service to different consumer class, embedded cost approach shall be used.
Box 1.1 presents the merits and demerits of both approaches in a summarised form.

Box 1.1: Merits and Demerits of Two Approaches

Embedded Cost Approach

Advantages

The advantage of the embedded cost approach is that embedded costs and allocation factors can be measured based on data that is recorded in the books of the utility. Thus the data shall be readily available and verifiable as well as the historic cost of past year ensures that the costs are realistic.

Disadvantages

The main disadvantage with the Embedded Cost Approach is that it is not forward looking as it uses historic cost. It does not accounts for the inflation and thus do not reflect the true economic cost of the power delivered to the consumer. Embedded cost-based tariffs reflect the average historic costs of supply, which tend to significantly differ from the economic costs. For determination of economic costs (cost to serve) incurred in delivering electricity or service to each class of consumers a number of factors have to be taken into consideration in working out the actual cost incurred to serve each class of consumers. The main factors are: voltage at which the class of consumers is served, T&D losses at each voltage level, the contribution of the class to the coincident peak demand/non-coincident peak demand, demand/energy, and energy consumed by the class, nature of load etc.

Marginal Cost Approach

Advantages

Marginal cost represents the economic value that the utility has to incur in order to provide consumers with an additional unit of electricity. As a result, marginal cost based tariffs provide efficient price signals to consumers. The method also has an advantage of looking into the future for projecting the costs.

Disadvantages

The main disadvantage of the marginal cost approach is that it requires large quantum of data, which is not readily available. More so, when the forecasted values are used, the results are not very accurate. Also, Marginal Cost approach would not ensure appropriate cost for the utility, as the marginal cost tends to be lower or higher than the average cost of supply.

CHAPTER 2: Literature review

With the various policy directives, electricity regulatory commissions are placing increased importance on determining the cost of service for supplying power. In this regard, few commissions have supported certain studies assessing the cost of service. These studies are briefly discussed below.

Studies conducted nationally

1. Andhra Pradesh, Andhra Pradesh Electricity Regulatory Commission (APERC)[1]

APERC is amongst the few Commissions in India to have used the category wise Cost-of-Service (CoS) model to fix tariff. The central theme of the model is that the electricity supply planning is based on the requirement to meet peak demand.

CoS is the segregation of the total cost into each consumer categories. It ideally involves attributing costs to different consumer categories based on how those categories cause costs to be incurred. It also provide a scientific basis for allocating the amount of cross subsidy (available/required) for each category to ensure an equitable distribution of the cross subsidy among categories.

APERC uses embedded cost approach for determination of CoS where the historical or accounting costs are assigned.

The Module adopted by APERC is as follows:

Functionalization

All investment and operating cost are separated according to function. The typical cost functions in an electric utility allocation study are:

- Production
- Transmission
- Distribution
- Customer related facilities

[1] Presentation on Cost of Service, APERC, 2003

In the case of an unbundled utility (as in Andhra Pradesh) costs of generation and transmission are treated as exogenous to the CoS for the distribution component. However, in principle, transmission charges could also be computed on CoS basis.

Classification

The different fixed and variable costs are classified under three heads depending upon the intrinsic nature of underlying costs across the value chain:

Demand Costs

These costs are generally fixed in the short run and include interest, depreciation, return and a portion of repair & maintenance and employee costs. Such cost varies with the kW demand of the users.

Energy Costs

These vary with the usage levels of customers depending on the volume of energy consumed and include fuel expenses.

Customer Costs

These cost are generally fixed in nature and include operating expenses associated with meter reading, billing and accounting. Such cost is directly related to number of consumers served.

Allocation

Within the two broad categories of consumers depending on the voltage level, i.e HT and LT, the customers served by the utility are separated into several homogenous groups based on nature of service provided and load characteristics. Based on the consumers group, costs are allocated to customer classes consistent with the cost impact the class loads impose on the system. The fixed costs are allocated to the consumer classes in proportion to their respective contribution to total peak demand i.e coincident peak demand (CPD). Based on the meter reading of feeders of each consumer categories, load curves are derived which measures the energy consumed and pattern of energy consumption. The aggregation of load curves of all consumers' categories gives the system load curves from which the CPD is derived. The energy cost is the variable cost of Kwhrs generation and are attributed to different consumer classes as per the energy consumption.

Apportioning of losses is a crucial step in this module. After segregating the losses at voltage level, they are further allocated to different consumer categories. Technical losses and commercial losses are allocated on basis of sales and energy audit respectively.

Fixing of retail tariffs

The Commission determines the allowable cost based on Annual Revenue Requirement (ARR) filing and allocates to different consumer categories. Thereafter retail tariff are fixed for end consumer after fixing the cross subsidy.

Fixing cross subsidy and external subsidy

Once the cost of service is fully allocated to all consumer categories, these costs are compared with the projected revenues of each consumer category and subsequently cost recovery ratio i.e. the extent to which the current revenues recover the cost of service of that consumer category including cross subsidy and excluding government subsidy is calculated.

It thus helps in calculation of the amount of cross subsidy and financial gains and losses that each consumer category generates.

2. Madhya Pradesh, Madhya Pradesh State Electricity Board (MPSEB)

A review model evaluating the model adopted by Madhya Pradesh State Electricity Board for FY 2004 was prepared. It adopts the embedded cost approach for determination of cost of service for supplying power. The costs are first functionalised into generation, transmission and distribution. Secondly, as per the intrinsic nature of the underlying cost, these cost are classified into demand(fixed), energy (variable) and customer (fixed). Lastly the segregated costs are allocated to different consumer categories.

Following are the highlights of the Model:

- The Board estimates the load profile of 2-3 feeders catering to different categories of consumers over a period of one month. On the basis of load curves studies, the category coincident factor at the evening peak was derived. However it was suggested that the Board should take representative days covering working days, holidays and major festivals in a year to capture different consumption patterns for different days as well as seasonal variations.
- The review model calculates the load factor based on the ARR figures on connected load.
- Classification segment of the model classifies generation, transmission, distribution assets into demand, energy, customer heads and gives function

wise rate bases which are used as basis for allocation of certain expenses. The classification of different costs is given in the table 2.1.

Table 2.1 : Classification of cost, MPSEB

Classification Basis	Basis
Generation	
Purchase of Power	Fixed & variable charges of PP bill
Generation of Power	Energy
R&M Generation	Load Factor
R&M Trans & Dist.	Energy
Employee Costs, etc	Load Factor
Administration & General Expenses	Demand
Depreciation & Related Debits (Net)	Generation Net Fixed Assets
Interest & Financial charges	Generation Net Fixed Assets
Sundry Expense (incl Bad debts)	Generation Net Fixed Assets
Non Tariff Income	Demand
Reasonable Return (3%)	Generation Rate Base
Transmission	
Purchase of Power	Demand
Generation of Power	Demand
R&M Generation	Demand
R&M Trans & Dist.	Demand
Employee Costs, etc	Demand
Administration & General Expenses	Demand
Depreciation & Related Debits (Net)	Demand
Interest & Financial charges	Transmission Net Fixed Assets
Sundry Expense (incl Bad debts)	Transmission Net Fixed Assets
Non Tariff Income	Demand
Reasonable Return (3%)	Transmission Net Fixed Assets
Distribution	
Purchase of Power	Fixed & variable charges of PP bill
Generation of Power	Energy
R&M Generation	Distribution Rate Base
R&M Trans & Dist.	Distribution Rate Base
Employee Costs, etc	Demand 30%, Customer 70%
Administration & General Expenses	Demand
Depreciation & Related Debits (Net)	Distribution Rate Base
Interest & Financial charges	Distribution Net Fixed Assets
Sundry Expense (incl Bad debts)	Distribution Net Fixed Assets
Non Tariff Income	Demand 50%, Customer 50%
Reasonable Return (3%)	Distribution Rate Base

- The Board has used coincident demand to allocate the costs classified under demand for generation and transmission costs. Cost classified as demand costs under distribution costs are allocated on basis of non coincident demand. However the reviewer suggested to allocate all demand costs on coincident demand.

3. Assam, Assam Electricity Regulatory Commission (AERC)[1]

Assam State Electricity Regulatory commission issued a staff paper on Electricity Cost of Supply. The CoS for supplying power to various categories of consumers is the cost imposed by a particular category of consumers on the system in order to supply the electricity demanded by them. The cost of service is computed by separating the functional assets and expenditure related to generation, transmission and distribution that are involved in the supply of electricity. The paper indicates the usage of embedded cost approach for determination of CoS. The CoS is calculated by assigning the approved costs of generation, transmission, and distribution of electricity in Tariff Orders across different consumer categories on the basis of voltage-wise system costs and losses.

Following points were discussed in the paper:

Allocation of Distribution Cost

The design of the distribution system depends on the number and categories of customers and their demand. The study attempts to find out the portion of distribution cost which is customer-related and demand-related.

Trunk line 33 kV & 11 kV feeders, distribution substations, and higher voltage lines and substations owned by the distribution utility, are of various sizes based on near-term peak demands. These costs are determined during hours when load is close to capacity and are thus referred to as the demand-related distribution costs.

Meters and service drops are dedicated to a single customer (or building) and are treated as customer costs. As the local distribution costs are based on the design load of the customer, and not on the customer's actual peak load, the distribution costs are recovered in a fixed monthly charge imposed on the customer's design load.

The local distribution line feeders and distribution substations are designed according to the users' requirements. If a customer uses more electricity at an hour when its distribution substation is peaking, additional capacity will likely be required. If the customer reduces

[1] Staff paper on Electricity Cost of Supply, Assam Electricity Regulatory commission

usage at such an hour, capacity is freed for use by other customers. Therefore, these costs are user specific and thus included in the customer related cost.
The total cost of an electrical system is separated in terms of Demand Related, Energy Related and Customer Related Costs.

The study allocates the total demand related costs between different consumers in proportion in which they impose demand on the system during the peak demand period. The fixed cost of generation and distribution is allocated depending upon the percentage of demand imposed by such group of consumers during system peak period (Co-incidental Peak).

The energy related charge is allocated according to the percentage of the actual energy consumed by the group. The total consumer related cost is shared as per off peak demand percentage of each group, which may be termed as consumer charge by dividing it with the number of consumers of the category.

Due to presence of seasonal tariff in Assam in case of Tea Coffee & Rubber category, calculation of cost of supply may be done considering energy consumption data for seasonal and off seasonal period.

Table 2.2 indicates the calculation of the allocation of cost based on the concept.

Table 2.2: Sharing of costs, AERC

Classification Basis	**Basis**
Purchase of Power	Fixed & variable charges of PP bill
Generation of Power	Energy
R&M Generation	Load Factor
R&M Trans & Dist.	Energy
Employee Costs, etc	Load Factor
Administration & General Expenses	Demand
Depreciation & Related Debits (Net)	Generation Net Fixed Assets
Interest & Financial charges	Generation Net Fixed Assets
Sundry Expense (incl Bad debts)	Generation Net Fixed Assets
Non Tariff Income	Demand
Reasonable Return (3%)	Generation Rate Base
Purchase of Power	Demand
Generation of Power	Demand
R&M Generation	Demand
R&M Trans & Dist.	Demand
Employee Costs, etc	Demand
Administration & General Expenses	Demand
Depreciation & Related Debits (Net)	Demand
Interest & Financial charges	Transmission Net Fixed Assets
Sundry Expense (incl Bad debts)	Transmission Net Fixed Assets
Non Tariff Income	Demand
Reasonable Return (3%)	Transmission Net Fixed Assets
Purchase of Power	Fixed & variable charges of PP bill
Generation of Power	Energy
R&M Generation	Distribution Rate Base
R&M Trans & Dist.	Distribution Rate Base
Employee Costs, etc	Demand 30%, Customer 70%
Administration & General Expenses	Demand
Depreciation & Related Debits (Net)	Distribution Rate Base
Interest & Financial charges	Distribution Net Fixed Assets
Sundry Expense (incl Bad debts)	Distribution Net Fixed Assets
Non Tariff Income	Demand 50%, Customer 50%
Reasonable Return (3%)	Distribution Rate Base

Allocation of T&D Loss

The loss calculations in the paper are based on estimates of total losses at each voltage level for which costs are calculated. This factor may be termed as **Capacity Loss Factor** which reflects the fact that a kW of added load at a customer's meter requires successively larger additions to capacity as one moves up the system in order to accommodate both the incremental load imposed by the customer and the losses that occurs in moving the power through the system to the customer. This incremental loss at different segments of the electrical system was arrived at in consultation with the Discoms and consumers for the purpose of calculating overall loss of the system with respect to sale of electricity at different voltages. The element wise loss estimation of an electrical system is important as the overall loss of an integrated system may vary widely depending upon the sales mix at different voltage levels.

Estimation of Commercial Loss

Any excess loss above the norms agreed upon after consultations with the suppliers based on technical inputs may be termed as commercial loss which is attributable to direct theft from supplier by manipulation in the metering system. This loss can be removed from the system by adopting effective measures by the supplier. Improvement of billing and collection efficiency can reduce shortfall in collection.

4. Himachal Pradesh, Himachal Pradesh State Electricity regulatory Commission (HPERC)[1]

The Himachal Pradesh State Electricity Regulatory Commission has developed a Cost to Serve Model based on information available for computation of the cost of service of power for FY09. The Commission has considered the following assumptions:

- Only the energy input into the state transmission system is required for intra state consumption and it has not considered energy sale outside the state.
- Energy flows through each voltage level to reach Low Tension (LT) consumer. So the losses and costs at higher voltages are shared at lower voltages. This was made as an assumption due to lack of load flow study information and

[1] Concept Paper on Tariff Determination, Himachal Pradesh Electricity Regulatory Commission, 2005

accurate power flow diagram outlining the flow of energy from one voltage to another.

- Category-wise sales have been allocated to different voltages in the same proportion based on past information, except for the categories where sales data at different voltages is available like large industries, water pumping, and bulk supply.
- The losses at Extra High Tension (EHT) level have been estimated at 3.71% - similar to past year. The overall losses in the Board system for sales within the state has been benchmarked at 15.75% for FY09 - losses at 11 KV and above (HT) have been considered as 7.50% and resultant losses at voltage levels below 11 KV (LT) have been estimated at 17.46%.
- Cost segregation across voltage levels and consumer category wise is not available with the Commission. Segregation has been done based on the information provided by the Board in the past.

Methodology

Following steps are carried out to estimate the cost of supply of power:

- The unit cost of generation and power purchase has been determined by dividing the total generation and power purchase cost with the total energy input into the system for the state's own consumption.
- Cost of Supply to consumers at 66 kV and above has been determined by allocating the losses and cost according to the sales in this network (66 kV and above) and power wheeled through this network. Similarly, losses have been apportioned according to the sale at this system and the power wheeled through this system.
- Cost of Supply to consumers at High Tension (11 kV and upto 33kV) has been estimated by allocating costs and losses according to the sales to HT consumers and power wheeled to reach the LT network. It also proportionally includes the cost and losses incurred during the wheeling of power at 66 kV and above network.
- Cost of Supply for the consumers at Low Tension (below 11 kV) level has been estimated by ascertaining the distribution cost (below 11 kV), losses (below 11 kV) and sales to LT consumers. It also includes the proportional costs and losses incurred for wheeling the power at higher voltage levels.

Reducing cross Subsidies

In the previous Tariff Orders for FY05, FY06, FY07 and FY08, the Commission had taken steps towards reduction of cross-subsidy and had attempted to align the tariffs with the cost of supply at various voltage levels. In attempting to align tariffs with the cost of supply, the Commission acknowledged the fact that though there is an urgent need for ensuring recovery of the cost of supply from the consumers to ensure fiscal sustainability of the Board, the exercise should not send tariff shocks to any class of consumers. Moreover, a certain minimum level of support would be required to be given to make electricity affordable for households in BPL category. The Commission recognizes that the estimation of cost of supply at different voltage levels would require extensive, reliable and credible data and information at different voltage levels and is a separate detailed exercise on its own

5. Karnataka, Bangalore Electricity Supply Company (BESCOM)[1]

In 2008, Karnataka State Electricity Regulatory Commission (KERC) directed BESCOM to implement the cost to serve methodology for determination of tariff from the next control period. BESCOM undertook a study for development of cost to serve model.

The study has followed the embedded cost approach for calculating cost of supply. The methodology adopted for it is explained in brief below:

Step 1: Functionalization

The first step in the study was to functionalise the cost according to its primary characteristic, i.e., generation, transmission and distribution. As BESCOM is a power distribution company, it pays power purchase cost to generators based on the allocation of generation percentage made by the Government from time to time. This is taken as the generation cost for BESCOM. The transmission charges paid to Karnataka Power Transmission Corporation Ltd (KPTCL) are reckoned as the transmission cost. The transmission system is designed to handle certain peak demand and as such majority of the costs except the interest on working capital are fixed in nature & as such they can be treated as demand related.

Step 2: Classification of Costs

After functionalization, the next in the CoS process is to classify the distribution expenses (Revenue Requirement) as demand, energy and customer related. The study acknowledges in the absence of a detailed study of each cost and their relation to demand, energy and customer functions, true classification of costs may not possible. However, for the purpose this study, given the constraints,

[1] Cost of Service Study, Bangalore Electricity Supply Company

an effort has been made to properly classify the costs. This has been done after consultations with the BESCOM officials. The main points that emerge during the classification of cost are discussed below:

- Generally power purchase cost will have two elements i.e., fixed cost and variable cost. The fixed cost include costs associated with the plant capacity i.e. depreciation, interest relating to capital investment for the plant, income tax, rate of return etc. They are treated as demand related. Fuel cost, fuel related costs & interest on working capital are treated as variable or energy related costs.
- The distribution system will have costs associated with all the three components. Demand related costs include a major portion of deprecation, interest on capital borrowings, income tax, RoR etc. Interest on working capital is considered as energy related. Customer related costs generally include R&M expenses, Employee costs, A&G expenses, bad debts, interest on consumer security deposits & other debits are directly attributable to consumers.
- The study argues that more than 75% of the R&M expenses comprises of two items only. i.e. repairs to distribution transformers and repairs to lines and cable net works. Since a detailed study would be required to understand the classification of the expenditure in to demand, energy and customer related, the study has relied on the assumptions made by MECON in their report and have considered the classification accordingly.
- As regard the employee cost, time spent in percentage against each activity assuming normal working hours by employees of various cadres has been computed based on the matrix recommended by the internal committee of Bescom in 2006 for the purpose of MYT exercise.
- Classification of employees cost has made on the basis of judgement that employees associated with wires activity would spend more time in demand related functions, whereas employees associated with retail supply activity would spend more time on consumer related functions.
- Details of fixed Assets (Trial balance for FY 08) have been captured and segregation of assets in to various voltage classes have been made based on the methodology recommended by the internal committee of BESCOM for segregation of assets for the Multi Year Tariff exercise.

Step 3: Allocation of Costs

The final step in Embedded cost approach is the allocation of various costs (which has been divided into Demand, energy and customer in the previous section). The methodology adopted in the study is as follows:

- For the allocation of Demand Costs, Co-incident peak approach is preferred as all investments in generation, transmission and distribution are planned to cater to the system peak. This method is followed by most power utilities across the word. But no single costing methodology will be superior to any other and the choice of methodology will depend on the unique circumstances of each utility. However, in the CoS Model for Bescom the researchers have worked out cost to serve under Coincident Peak (CP), NCP and average and excess methods.
- For estimating the load curves for each consumer category, sample feeder were selected and load survey meters were fixed and monitored over a period of time. This presented better load curves, duration and consumption pattern, which were then be extrapolated to the population.
- BESCOM has about 2402 numbers 11KV feeders. In terms of energy handled, LT sales is about 60% and HT and EHT sales is about 40 respectively. Assuming that population is distributed normally, the sample feeders required to get 95% confidence level, with a margin of 5% error, is calculated to be 375.
- Data was collected for 2007-08 for sample feeders which predominantly (more than 80% energy) supplying power to different consumer categories. In order to obtain a truly representative data from the field units, across different seasons, hourly MW data was collected for sample feeders on 18 selected days which represents 6 days divided into working, festival and holiday from 3 seasons, namely, winters, monsoon and summers.
- Since most of the feeders would serve multiple categories, feeders which serve a predominant category (say 80%) have to be labelled accordingly. Based on such categorisation, load curves, load duration and consumption of particular feeder have to be collected over a number of days and analysed to arrive at a profile of a particular consumer category. Based on the above load profile the likely CP for the test year has been computed and this has been used for the purpose of allocation of costs in the CoS model.
- Allocation of losses: The difference between energy input and sales (metered + assessed) would be the total loss in the system. The difference between the technical loss and the total loss is treated as commercial loss and

is added to the category wise sales, to arrive at consumption. The segregation of technical losses in to HT and LT as well as the commercial losses for both the years as furnished by BESCOM has been considered. Assessment of HT and LT losses and voltage wise losses are based on the discussion with the BESCOM and the Commercial losses are distributed across all categories based on their sales

- All energy costs are divided in the ratio of energy consumed each of the categories, after including the AT&C losses.
- Customer Costs are allocated on the basis of number of customer in each category after assigning appropriate weights and adjustment. Weighing factors reflects differences in characteristics of customer within a class. The weights are based on two factors sales per customer and Load per customer.

6. Haryana, Dakshin Haryana Bijli Vitran Nigam (DHBVN)

Study conducted by DHBVNL for estimation of Cost of service in FY 2007-08, is based on the embedded cost of service approach

The various steps involved for the same is as follows:

Step 1: Functionalization

The first step in the study was to functionalise the cost according to its primary characteristic, i.e., generation, transmission and distribution.

Step 2: Classification

After Functionalization, all costs are classified into demand related, energy related and customer related. Following is the basis of classification of costs:

Power purchase expense of the Discom is equal to the power procurement cost by Haryana Power Generation Corporation Ltd (HPGCL) in addition to the wheeling charges and other expenses of HPGCL for power procurement. Total power procurement cost has both fixed and variable component as per the tariff of different sources of power. Hence, the power purchase expense by DHBVNL in classified into Demand related and Energy related.

Generally transmission costs are classified as demand related. However, the lines whose primary function is to carry energy from the generation stations to the transmission network can be classified as energy related. The study has divided transmission cost and the State Load Dispatch Centre (SLDC) charges, in 98:2 rations between demand related and energy related.

The distribution system generally consists of primary facilities (such as distribution sub stations and primary distribution feeders) and secondary demand facilities (such as lower voltage feeders and the line transformers). Therefore, demand costs can be further divided into primary and secondary demand costs.
Some distribution plant accounts and associated operation and maintenance charges are classified as jointly demand and customer related. These expenses are incurred to provide service to a customer and are also required to meet customer peak demand requirements. Therefore, these costs are classified into demand, energy and customer related on the basis of discussion with the experts.

Step 3: Allocation of Costs

The study has allocated various costs in the following manner:

- Demand related generation and transmission costs are allocated among the classes on the factors that measure the class contribution to system peak. For determining the coincident Peak Demand for each consumer, the load research study is conducted to prepare the coincident peak demand model. The load research study is described in next step.
- The distribution network has to serve local maximum demand hence investment are made on the basis of local peak demand. Therefore demand related distribution

costs are divided on the basis of non-coincident peak demand.

- Customer related cost allocations are distributed on the basis of number of customer in each category after assigning appropriate weights and adjustment. Weighing factors reflects differences in characteristics of customer within a class. The weights are based on two factors sales per customer and Load per customer.
- Energy related costs are allocated in the ratio of energy consumed by the customer classes as per the following formula:
- Category wise energy related costs= Total Energy Cost X (category wise sales + Category wise energy losses)/ Total energy purchases at distribution periphery. In the above formula, energy purchased at distribution periphery is determined by projecting the total sales considering the distribution losses of 28.5% in the DHBVNL distribution system.
- Total distribution losses were categorized into commercial and technical and there after into voltage wise lines as discussed with the DHBVNL officials.

Load Research Study

Highlights of the load research study are discussed below.

As part of the load research study, sampling is done at 11 kV feeder level. The sampling interval has been chosen in view of availability of data in the logbooks. Sample days are chosen in a way to capture the seasonal variations in an appropriate way. Also, in each season 15 days are short listed for the sample feeder survey. The days are selected in the manner to have sufficient representation of working days, holidays and festivals.
Feeders are chosen on the basis of predominance level of more than 50% for segregation at the consumer category level. However, out of the total category agriculture-metered and unmetered categories are merged with other consumer category to get the better result.

Using the sample theory , sample size of feeders is taken as 20 for those categorized where the total predominant feeders are more than 30 and for other categories sample size of feeders is as per actual. The total sample size of feeders is 189 for DHBVNL

The sequence of steps undertaken in the study to arrive at the load shape is as follows.

- Hourly reading for a feeder are divided by the peak load reading to arrive at percentage value where peak load reading is considered as 100%.

- The load shape for a category on a particular type of the day is derived by computing the weight age average of the load shapes of different feeders on the particular type of the day. The predominance factor is used as the weight for each feeder.
- Finally, a typical day load shape for a category is then obtained by merging the different day load shapes on weightage average basis. The weights assigned for the types of the days are equal to the number of the type of the day in the study.

The non-coincident peak day load curve for a category is constructed by the load research model considering the peak day sales for the category and the technical and commercial losses for the category are adjusted.

The system peak day load curve for a category is constructed by the load research model considering the peak day sales for the category and the technical and commercial losses for the category are adjusted.

The individual load curves of each category on the system peak day are combined to arrive at the system load curve for a system peak day.

The category load factors are computed using (a) the non-coincident peak demand obtained from the non-coincident peak day load curve of the category and (b) the average energy estimated based on the annual sales of the category combined with the technical and commercial losses.

The category coincidence factors are computer using (a) the coincident peak demand obtained from the system peak day load curve of the category and (b) the average energy estimated based on the annual sales of the category combined with the technical and commercial losses.

7. Gujarat Urja Vikas Nigam Limited (GUVNL), Vadodara[1]

The concept paper for Multi Year Tariff Principles by Gujarat Electricity Regulatory Commission (GERC) highlights the importance of cost of service model to understand the actual costs involved in the supply to each class on a scientific basis. The same paper states that the tariff to every class of customer shall reflect a minimum of 67% of licensee's average cost of supply of electricity to that

[1] This section incorporates extracts from the study conducted by Feedback Ventures Private Limited, for GUVNL in 2007

class within a period of 5 years from the commencement of The Electricity Act 2003. Also, the GERC in its Tariff Order dated 25.06.2004 has directed GEB to conduct a full-fledged Cost of Service Study. A systematic approach undertaken as part of this study involves three steps of functionalization, classification and allocation of costs to various customer categories. These are briefly described below to highlight the key assumptions undertaken to arrive at CoS estimates.

Functionalization of Costs

The first stage of a cost of service study involves functionalization of all the costs of the utility to various functions such as power purchase and distribution. The power purchase costs include the costs of transmission of power from the generating stations to the transmission-distribution interface point as the Bulk Supply Agreement between GUVNL and Distribution Companies envisages transmission-distribution interface as the delivery point. GUVNL calculated expenses as included in annual accounts. As per GERC's Terms and Conditions for Tariff, a 14% return on equity is allowed to distribution licensees.

Classification of Costs

The costs so functionalised are then classified as being demand, energy or customer/service related. Such a classification is done on the basis of the cause of such costs, i.e., the costs which are triggered by peak demands imposed on the system are classified as "demand related" those related to level of power consumption as "energy related" and those by number and type of customers as "customer related".

Classification of costs involves identification of costs as demand related, energy related and customer related based on some notion of cost causation. Demand-related costs are those triggered by peak demands imposed on the system. Energy-related costs are related to the level of energy production. Customer costs vary according to the number and type of customers. Given accordance with the regulations, return on equity has been considered.

Power purchase costs are identified to be energy as well as demand related as the utility should not only be able to supply the energy required over a period of time but must also install or purchase sufficient capacity to meet the peak demand of the system. The variable costs associated with operating generation plants are clearly a function of energy produced and hence these costs are usually classified as energy-related while those that are fixed may be classified as demand related.

Distribution costs are classified as either demand related or customer related or a combination of the two.

- Distribution related components like meters are considered 100% customer related. Distribution assets that are used by a single customer (e.g., Service Lines) also are classified as entirely customer related. The costs associated with such items can also be classified as entirely customer related.
- Distribution costs other than those entirely customer related may be classified using the following methods
- 100% demand related approach classifies all other costs as entirely demand related on the rationale that distribution networks are set up to meet the local maximum demands.
- Partly demand and partly customer related approach attempts to work out appropriate ratios for each component of distribution costs for classification into demand related and customer related costs. The rationale given for this approach is that the extent of distribution lines, especially in a Universal Service Obligation (USO) scenario, depends upon the location and number of customers. Hence, a component of customer related distribution cost exists. The distribution system apart from serving the demand also provides various services to the customers such as metering, billing, break down repair etc. Hence, distribution costs need to be classified as partly demand related and partly customer related.

The choices for allocation criteria for demand related costs presents a number of options that may have significant impact on the cost allocation to various classes. The choice will depend upon data availability, characteristics of the utility and the objectives of the study. Box 2.1 explains the various allocation criteria briefly.

Box 2.1: Allocation Criteria

The following are the various allocation criteria for demand related costs:

Co-incident Peak Contribution

The category coincident demand or contribution to the system peak demand may be defined as the demand in MW for each category of customer that occurs at the time of the system's peak demand. The sum of all such demand for every customer category plus losses will be equal to the peak demand of the system.

Non-Coincident Peak

The non - coincident demand may be defined as the demand in MW for each category of customer regardless of when it happens. This non-coincident demand will be greater than or equal to the category's contribution to the system's maximum demand. Thus, the sum of all such demand for every customer category will be greater than the peak demand of the system.

Average and Excess

This method allocates demand related cost to the customer category using factors that combine the category average demand and excess demand. Excess demand for a category is defined as:

Category Excess Demand = Non-Coincident Demand - Average Demand

The method uses two factors for allocation. The first component, or contribution to average, is the proportion of category's average demand to the system average demand times the system load factor.

Contribution to Average =

(Category Average Demand/System Average Demand) * System Load Factor

The second component, or contribution to excess, reflects the proportion of the excess demand (non coincident peak demand minus the average demand) of the category to the sum of excess demand of all categories. The advantage of the said approach is that coincident peak demand for a category is not required.

Contribution to Excess = (Category Excess Demand/ Category Excess Demand) * (1 - System Load Factor)

Allocation of Costs:

The functionalised and classified costs are then allocated between various customer classes of the utility based on allocation factors derived from demand, consumption of energy and number of customers. Such allocation arrives at the cost of service for each customer class. The classified costs may be allocated on the basis on time differentiated allocation factors. The energy and demand related costs are split into several costing periods. The energy usage and a measure of demand (peak, average etc.) within such periods form the basis for allocation of costs. The total revenue from each of the customer classes together with the cost of service so derived reflects upon the adequacy of current tariffs and the level of cross subsidies between classes existent in the utility's system.

Allocation of Customer Related Costs

Customer related costs, primarily, include the costs of providing servicing other than supply of electricity, namely - metering, billing, collection, fault repair etc. These costs, though directly relate to the number of customers in a particular category, vary significantly with across categories. For instance, the per customer servicing costs for HT Industrial category will be much higher than that for a Residential category customer.

Category Wise Customer Weightage

To address the variance in per customer service costs across categories, category wise weight-ages have been derived to determine allocation factors for customer-related costs. The weight-ages are a function of two parameters - Sales per Customer and Load per Customer. Category wise parameters have been divided by average of such parameter for arrive at a ratio. The minimum & maximum limit for such ratios has been set at 1 and 200 respectively. The average of these two ratios for each category gives the 'Category Wise Customer Weightage.

Allocation of demand related costs are as follows:

Demand related power purchase costs

The power purchase, serves the entire system and further investments are triggered by increase in the peak demand of the system as a whole. Hence, category co-incident peak demand is the appropriate criteria for allocation of such costs. However, due to non-availability of the data with regards to the category co-incident peak, the Average and Excess method as discussed earlier is a suitable alternative.

Demand related distribution costs

The distribution network services local maximum demands and investments are triggered by the local (in other words, non co-incident) peaks in demand. Therefore, the category non co-incident peak demand for each class is the most appropriate basis for allocation of demand related distribution costs.

Allocation of Energy Related Costs

Energy related costs are allocated in the ratio of energy consumed by the customer classes. The energy consumed includes sales to categories and allocated losses.

Allocation of Losses

Though sales to each of the classes are easily available, allocation of losses requires considerable judgement. The allocation of technical losses is largely dependent upon the voltage at which a customer category is connected. However, before allocating technical losses, commercial losses are allocated to various categories. The technical losses are then allocated in the ratio of sales plus commercial losses for a category.

Determination of Technical and Commercial Losses

The total transmission and distribution losses of GUVNL 28.35%, including both technical and commercial losses. Distribution Losses (Total Losses -Transmission Losses) need to broken up into technical and commercial losses. The technical losses of GUVNL distribution system are 24.08%. The technical losses are further broken up into HT and LT level losses. The HT level technical losses (upto 11 KV) are assessed by GUVNL. The HT losses are 5.16% and LT losses are 6.31%. The remaining losses are taken commercial distribution losses

Allocation of Commercial Losses

Commercial losses are determined as the difference between total losses and technical losses. The commercial losses are allocated to the customer categories in ratio of sales. In other words, no commercial losses are allocated the energy transferred to the lower voltage level, as the consumers using such energy are not responsible for commercial losses at the higher voltage.

Technical losses at EHV, HV and LV levels are allocated to the categories in ratio of sales to customer categories connected at that voltage and energy transferred to the immediate lower voltage level. For instance, if at EHV level sale to EHV Industry is 20 MU while the sales to other categories at EHV level is 5 MU and the transfer to HV level is 75 MU - 20% of the losses at EHV level will be allocated to EHV Industry category. Similar practice is followed for HV category.

The above method for allocation of technical losses is done in two steps. Firstly, the losses are allocated to various voltages levels in the ratio of voltage level sales and transfer (to next category). Then, the losses allocated to various voltage levels are allocated to the respective categories in the ratio of category sales.

Allocation of Energy Related Costs

Energy related costs are allocated to categories in the ratio of energy consumed. The energy consumed includes both the sales and the losses allocated to the respective categories.

Concluding results

The cost of service study seeks to establish the adequacy of tariffs, category wise cross subsidy in the system and provide a path for elimination of the same. The results of the study also establish the cross subsidy surcharge applicable to open access consumers. The table 2.3 compares the cost of service and average realisation.

Table 2.3 : Comparison of Cost of Service against Average Realisation

Particulars	Cost of Service	Realisation
Low Tension		
Domestic	4.59	2.95
Commercial	3.95	4.72
Industrial Low Voltage	3.47	4.24
Street Light	3.71	3.38
Irrigation Agricultural	3.76	0.92

Particulars	Cost of Service	Realisation
Public Water Works	3.73	2.8
High Tension		
Industrial High Voltage	2.95	4.1
Industrial E. High Voltage	2.59	4.96
Railway Traction	2.85	5.11
Licensees	0	-
TOTAL (ALL CATEGORIES)	3.59	2.87

International studies

City of Norway, Norway Michigan[1]

The purpose of the study was to identify the utility's cost of providing electric service to its customers and to propose rates reflecting the utility's cost structure. Short Elliott Hendrickson Inc. (SHE) developed a series of integrated spreadsheets and graphical charts as a key component of the electric rate study. It identifies the cost of service and evaluates the impacts of proposed rate changes on both utility revenues and customer charges.

The American Public Power Association (APPA) offers a methodology to establish cost of service rates for municipal utilities. The SHE study applied the same methodology to the City of Norway, with some minor modifications to accommodate local situations specific to Norway.

There are three major steps in the APPA cost of service methodology. These steps are as follows:

- Functionalize the utility revenue requirements according to CoS type
- Classify the utility revenue requirements according to the services provided
- Allocate the utility revenue requirements among customer classes

Each of the APPA steps is described below.

Functionalization of Revenue Requirements

Cost of service rates are based on the revenue requirements of the utility. An electric utility has a set of costs that must be met in order to stay in business each year. The utility must have enough revenue each year to meet these costs.

[1] Electric Utility Cost of Service Study, City of Norway,Michigan, Short Elliott Hendrickson Inc.

Historical costs and revenues of past years probably offer indication requirements in future years.
For cost of service purposes, utility costs are typically broken down, or functionalized into the following cost functions:

- Production or Purchased Power
- Transmission
- Distribution
- Customer Service
- Administration
- Revenue

The first four items are self-explanatory in nature. Administration refers largely to general office functions and overhead. The revenue function refers to other operating and non-operating revenue sources generally not part of the utility's primary purpose of providing reliable electric service to its customers. The revenue components can be positive or negative. For example, revenues from the sale of surplus materials and equipment would represent a positive revenue component. The transfer of utility revenues to the city general fund would be a negative revenue component. The annual utility and city financial reports provide a good start to functionalizing the utility's operating expenses. Adjustments to the financial data were made to further functionalize these expenses.

Classification of Revenue Requirements

After the utility revenue requirements have been separated by function, they can be classified according to cost component. The typical utility cost components are as follows:

- Energy
- Demand
- Customer
- Revenue
- Direct

Energy costs are associated with the supply of energy to meet the electric requirements of the utility customers. These costs vary with kWh energy consumption.

Demand costs are associated with the peak demand of each customer and overall peak demand of the utility. The peak occurs when utility customers are using the highest amounts of energy. Peak electric demand periods typically take place during hot summer weather when customers are making heavy use of air conditioning or during exceptionally cold winter weather when electric heat is operating.

Customer costs are associated with billing functions and serving the utility's customers. Customer costs typically vary with the number of customers that a utility serves.

Revenue costs were described previously and are associated with the sale of surplus equipment, financial transfers to the city general fund or other sources of income and disbursements not generally associated with the utility's core function of providing electric service.

Direct costs are costs clearly related to a specific customer or class of customers. Special services to a key industrial customer or to a specific group of rural customers are examples of direct costs. Street lighting might also be considered a direct cost.

The functionalization and classification processes are typically straightforward with the possible exception of general and administrative costs. The utility financial data has many entries devoted to general expenses. These expenses should be broken down into the classifications described above. The allocation factors are somewhat arbitrary. The study has assumed that 30% of the utility general expenses can be allocated to each of the functions represented by power generation (demand), distribution system and customer service. Energy is allocated 5%, revenue 4% and street lighting 1%. The classification of generation plant expenses is again somewhat arbitrary. The study assumed that 40% of the utility generation plant expenses can be allocated to power (demand) while 60% can be allocated to energy.

Allocation of Revenue Requirements to Customer Classes

Next step undertaken is to allocate costs fairly to the utility customer classes to determine the cost of serving each customer class. The City of Norway has five primary customer classes as follows:

- Residential
- Commercial
- Small Industrial
- Industrial
- Street Lighting

Customer service costs vary with the number of customers, or meters, that a utility supplies. Typically, some types of customers require more customer service attention than others. Three phase customers may have higher metering costs or may have more questions regarding their bills, service connection or power quality. For these and other reasons, it is customary to apply weighting factors to the raw quantity of customer meters in each customer class. Residential customers are typically assigned a weighting factor of one. A weighting factor of three have been assigned to commercial customers and small industrial customers. The industrial customers receive a weighting factor of five. Street lighting customers have been assigned a weighting factor of 0.5.

The weighting factors are used to adjust the quantity of meters in each customer class and the overall total for the utility. The weighted quantity of meters in each customer class can be divided by the total number of utility meters to obtain an allocation factor. This allocation factor, expressed as a percentage of the total meters, will be used later to fairly allocate the customer service costs to each class of utility customers.

Energy costs are easy to apply toward cost of service rate-making since they are largely associated with purchased energy. These costs can be allocated to the individual customer classes on a per kWh basis. The annual electric kWh sales obtained from utility historical data, along with the percentage of total utility annual energy used by each customer class during the year. The percentages for kWh sales are used in the analysis to allocate the cost of purchased energy to Norway's various customer classes.

Demand costs are not so easily allocated. Demand costs represent kW load and it is not practical to meter for residential and commercial customers. To allocate demand-related costs, certain assumptions have been be made with regard to average load factors for residential and commercial customers. Load factor is a measure of how effectively a utility customer or customer group uses the electric distribution system. Load factor is expressed as a percentage representing the energy a customer actually used during the year compared to how much they could have possibly consumed if the customer one-time peak demand had lasted throughout the entire year instead of just occurring once. Load factor is calculated as follows:

(Annual customer actual kWh energy use)/ {(Peak customer kW demand) X (8760 hours per year)}

A customer having a high load factor makes effective use of the utility distribution system because the customer's electric equipment runs near its peak consumption rate for most of the year. Convenience stores generally have high load factors because they are open for business on a 24-hour basis. The refrigerated coolers, lighting, heating or air conditioning equipment is always running. A grain elevator will typically have a very low load factor since the large electric motors for conveying and grain drying is operated only on an intermittent basis.

Key conclusion from the CoS results of City of Norway

The study concluded that the cost of serving the residential electric customers is higher than the revenues generated by the residential rates. The study estimated that commercial and industrial customers are helping to fund the utility services used by residential customers. The study also proposed significant rate increase. The increase is based in part on the planned capital improvement projects. The proposed rate changes were expected to help correct the revenue imbalance associated with the present rate structure. The proposed rates will help allocate the costs of operating the utility more fairly among the customer classes.

Conclusions of literature review

The aforementioned studies covering different states of India highlights the increased importance given to assessment of cost of supply in India. On international arena also similar studies have been conducted. Form the literature review key conclusions drawn are as follows:

- Embedded cost approach had been adopted by all the studies.

- Common methodology is adopted by all wherein it follows a three step process of functionalisation, classification and allocation of cost. However, each study is different from each other in terms of the assumptions made , scope of primary field work done etc.

- As the accounts of utilities are not prepared in a manner so as to to allocate each component of cost to the consumer category causing it, serious limitations in availability of data in required format has been observed. Hence, the key to all the reviewed studies has been allocation of the costs on the basis of value judgement and informed discussions with key stakeholders. The costs, such as employee salaries, R&M etc, were allocated after the discussion with the concerned officials.

- The studies reviewed have concluded that domestic and agriculture consumer categories are subsidized by overcharging industry and commercial sectors in the Indian context.

- Different load growth of different category of consumers: The growth in demand and consumption are very different for different categories of consumers. From a study of different tariff orders, it is seen that while there is generally eight to twenty percent growth rate in electricity consumption in industry, commercial and residential categories, the growth rate in electricity consumption of agriculture is rather subdued being in the range of zero to two three percent. The growth in requirement of power is met from new intra state power generation, extra allocation from CPSUs , long term power purchase agreements from IPPs/merchant power plants, short term bilateral arrangements and power purchase through the power exchanges. The cost of this power on per unit basis is generally higher than the cost of power without the growth. This leads us to the question of methodology for allocation of increase in per unit power purchase cost. The cost of supply is based on the simple premise of allocation of cost to the category causing it. Hence, the increase in per unit cost of power should be allocated to the category which caused the growth in requirement of power on pro rata basis.

- Relevance of average of monthly peaks over single peak: Generally single coincident peak or non coincident peak is used for determination of demand related costs. This methodology does not take into account variation in demand due to seasonality. Also, all category of consumers do not get the same preference in supply with agriculture and rural domestic being the first to be rationed in case of shortage of power. Hence, it is felt that using a single peak may not correctly reflect the distribution of demand related costs. It would be more appropriate to use average of monthly peaks and compute the demand related costs accordingly.

- Rostered supply to agriculture and its effect on peak as well as consumption: The supply to agriculture is generally rostered ie the total agriculture load is divided into separate blocks and each block gets supply for six to eight hours. This has the effect of reducing the load on the system due to agriculture to about one third of the total agriculture load. Also, as agriculture gets power even at odd hours when other demand is low, it has the effect of stabilizing the power generation.

- Quality of data: Feeder load data is available as reading of current flowing through the feeder and not the MW load being serviced by the feeder. As the feeder voltage and the power factor is not always the same, the ampere readings may not at times reflect the MW load accurately. Hence, in order to carry out Cost of Supply studies, it would be better to install appropriate meters on sample feeders and use the meter dumps for the feeder loads.

- High level of T&D Loss: The T&D loss is generally very high in India being in the region of 20% to 50 % whereas that in advanced country it is as low as 6%. Also, the losses are not known voltage wise or category wise. Due to this it is not possible to accurately allocate the losses to the category causing it.

- High level of cross subsidy: The actual tariff of any consumer category is rarely, if ever, close to its cost of supply. Certain categories such as industry and commercial have high tariff and cross subsidise domestic categories which have low tariffs. The National Electricity Policy envisages that cross subsidy shall be brought down gradually to +/- 20 %

CHAPTER 3: Peculiarities of power demand & supply in agriculture category

Following are the certain peculiarities of the agriculture category with respect to power consumption in this sector which needs to be kept in mind while devising the model methodology for assessment of cost to serve to agriculture category:

Agriculture category gets supply during odd hours of the day

In most cases agriculture category gets supply during odd hours which causes inconvenience to the farmers for their work in fields. However, there could be few exceptions such as in case of UGVCL which supplies to agriculture category in regulated manner. In case of UGVCL all agriculture consumers are divided into various groups. UGVCL announces the weekly time schedule for supply to agriculture for each group wherein each group receives 8 hours of power during the day on rotational basis. Hence all agricultural consumers receive the power supply during odd hours. However, as in most cases agriculture category is featured with odd hour power supply, it is necessary to take this into account while designing the model methodology for assessment of cost to serve for agriculture consumers.

Agriculture contribution to system peak

Assessment of cost to serve for agriculture consumer category should take into account the contribution of agriculture category to the system peak. The contribution of agriculture to system peak varies widely across the state wherein utilities like UGVCL and APCDCL have high coincident peak of 37% and 34% respectively indicating higher contribution of the category to the system peak.

Low growth of agriculture power demand

Assessment of cost to serve for a particular category should take into account the growth of power consumption of the category over the years. This is particularly necessary to take into account the burden posed by the category on the power purchase requirement of the utility. In case of agriculture it has been observed that the growth in agriculture consumption is usually lower than in other categories. For instance in case of UGVCL, consumption in agriculture category grew by 7% in 2009/10 over 2005/06 vis a vis growth of about 29% in other categories over the same time period. In such scenario, it is important to take special attention of the growth in the agriculture power demand so as to not to burden the agriculture category with the higher cost of overall incremental power purchase.

Poor quality of power supply to agriculture

It has been observed that the agriculture category is often characterized by poor voltage profile and unreliable supply wherein they experience frequent power cuts and fluctuating power supply. It is important that the assessment of cost to serve for agriculture category should take this feature into account.

Administered peak for agriculture

It is observed that the agriculture category does not receive round the clock supply. Supply is regulated and rostered leading to "Administered Peak". It is important to consider this feature of power supply to agriculture consumers while assessment of their cost to serve. Flexibility in usage hours could further increase class peak and coincident peak.

Diversity in agriculture power demand over the year

As the power demand from the agricultural category varies widely over the year depending upon the seasons &cropping pattern, therefore, it is important that the model methodology for assessment of cost to serve for agricultural category to capture the seasonality in demand from agriculture category.

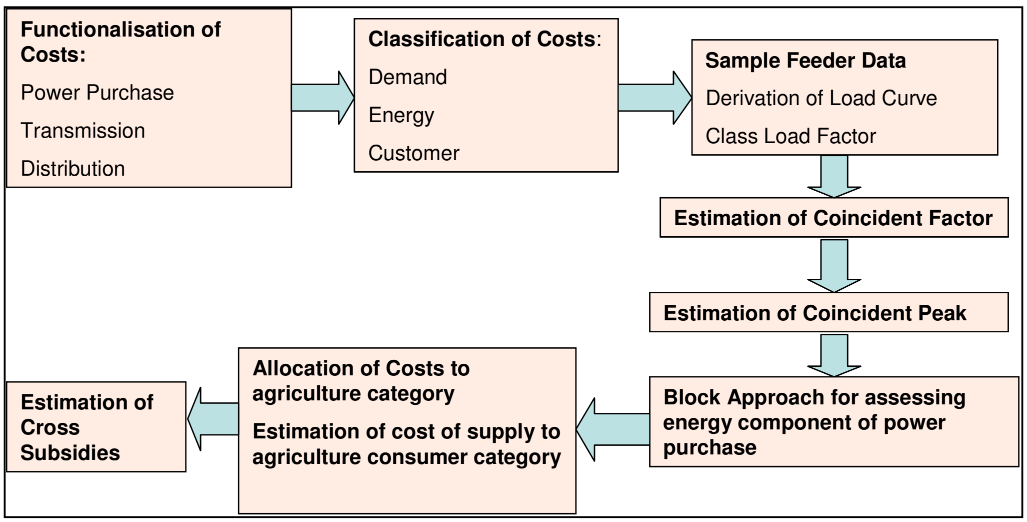
Estimation of losses incurred in supplying to agriculture category

As the agriculture category has substantial unmetered consumption losses accrued to this category is not known appropriately (including the breakup in terms of technical and commercial component). Taking this into account, proper treatment of losses should be considered while developing a model methodology for assessment of cost to serve to agriculture category.

CHAPTER 4: Model for Determination of Cost of Supply for Agricultural Consumers

Based on extensive literature review conducted both for national and international utilities and the discussion with relevant experts, excel based model has been developed to estimate the cost of supplying power to agricultural consumers of various utilities. The model is based on the marginal cost approach.

The following figure explains the various steps involved in assessment of cost of supply of power to the agricultural category.



Step 1: Functionalisation of costs

Functionalisation is the process of dividing the total cost of the distribution utilities on basis of the functions performed such as power purchase, transmission and distribution. This shall facilitate in determination of function wise cost incurred in supplying power to agricultural consumer category. Following is a brief description of the nature of cost to be categorised as power purchase, transmission and distribution related cost:

- *Power Purchase Function*: All costs related to purchase of power are included under the function. It is inclusive of inhouse generation cost, power purchase through long term, short term power purchase contracts as well through trading and unscheduled interface mechanism.

- *Transmission Function*: Transmission function includes all costs associated with the transfer of power from the power plant to the boundaries of the concerned utility. These cost are predominantly fixed costs by nature and do not vary with the quantity of energy transmitted.

- *Distribution Function*: Distribution function includes all costs associated with the transfer of power from the transmission system through the distribution system to the consumer (end user). These include, costs incurred by the utility in activities such as repairs & maintenance of the distribution system, operating expenses, administrative and general expenses, and employees related expenses etc. These costs primarily depend on voltage of connection, demand and number of customers of various classes.

Step 2: Classification of costs

Each of the functionalised cost is further classified as follows based on their intrinsic nature:

- *Demand related costs*: Demand related costs are generally of fixed nature. Such costs are related to capacity creation and hence are inclusive of cots such as interest on capital borrowing, depreciation, income tax, rate of return on equity.

- *Energy related costs*: Energy Costs depends on the quantum of electricity consumption of the users. Such costs are generally termed as variable costs and include costs such as fuel cost, interest on working capital etc.

- *Customer related cost*: Customer Costs are directly related to the services provided to customers. It varies according to the number of customers served in each category. Though fixed in nature, these costs are associated with the functions of metering, service connection and customer related activities. They include operating expenses associated with meter reading, billing and accounting.

Based on the above description of the functionalisation and further classification of cost, table 4.1 indicates how the cost related to different function can be classified into the demand related, energy related and consumer related.

Table 4.1 Functionalisation and Classification of cost

Typical Cost Function	Typical Cost Classifications
1) Power Purchase	Demand Related
	Energy Related
2) Transmission	Demand Related
3) Distribution	Demand Related
	Energy Related
	Customer Related

Step 3: Sample feeder data analysis
Following approach is applied for sample feeder data analysis:

- *Identification of the sample feeders*: 10 sample feeders were selected from each selected distribution utilities for the load data. A selection criterion for sampling of feeders is the predominance of the agricultural load on the feeder. All feeders selected for the study has predominantly agricultural load wherein at least 80% of the load on feeder is agricultural load. Moreover, the sample feeders selected was representative of the different circle in the utility to capture the geographical spread of the utility.

- *Identification of the sample days for data collection*: 18 days were selected for data collection such that the days were uniformly spread across the entire year to capture the seasonality in agricultural demand of the utility. Apart from these 18 days, data was also collected for the day on which the utility had the peak demand during the year.

- *Derivation of load curve*: Based on the selected sample feeder and the selected days load curve for the sample feeders of agricultural consumers were obtained.

- *Estimation of Class Load Factor*: Class load factor of the category i.e agriculture consumers is estimated with the feeder data collected. The Electric Power Research Institute (EPRI) has presented an empirical equation in its recent Technical Assessment Guide to calculate the energy losses. This equation is commonly used by electrical engineers to estimate energy losses.

Class Load Factor = Average Demand/ Peak demand

Step 4: Estimation of Coincident Factor
The traditional approach to estimate cost to serve to a category calculates the share of that category during the peak to estimate the coincident factor . The main argument against the

traditional approach is that there are certain loads in the consumer category which have no “voluntary” consumption viz. agriculture where the load is serviced by certain subjective ‘Supply schedules’ and are interrupted for variety of reasons. Hence the peak stack or the peak curve is quite an induced administrative one. Further, large portion of the load to this category is also serviced during odd hours (0000 hrs to 0600 hrs) when most of the other loads like non-process industries, commercial etc are not consuming. Hence it is argued that if uninterrupted power is made available to Agriculture category, then the peak may shift to a more convenient trough during the day, as farmers may not load the system during night and therefore the load curve could have been different.

Moreover, it is observed that the monthly peaks of the distribution utilities vary across seasons. A study of the monthly peaks across 2007-08 indicates that the peaks have a varying seasonality depending on the weather, type of consumption, hour of day etc. For instance in case of AP, it can be seen that many times in a year, peak happens around afternoon or in morning reflecting the consumption needs of categories like domestic/ commercial/ industrial during hot months and for agriculture category during Rabi season etc. A similar study of the Karnataka state shows that the peaks generally occur at 8 PM (almost 7 times a year) reflecting the growing consumption from Domestic/ commercial/ street lights etc. There are four months in a year when the consumption peaks during the day reflecting the increasing need of agriculture and domestic as well (where during the colder months there could be some heating requirement as well).

Given the varying factors, it can be argued that a single peak may be inappropriate and hence alternative would be to average them out, so that no single category is disadvantaged. An ideal case would be to derive the average using certain weights for the time of the day/ connected load etc but given paucity of data, simple average can be started with.

Using this approach, the coincident factor of each category can be arrived at as follows:

- Ascertain the time and magnitude of system peak for each of the 12 months separately
- Establish the corresponding load from the sample feeder data (average if there are more than two readings for the month)
- From the above, take a simple average of above 12 monthly readings.
- This average divided by the feeder sample peak gives the CF

Step 5: Estimation of coincident peak

Coincident peak[1] of the agricultural category is derived from its non coincident peak (NCP) using the coincident factor by application of following formula:

*Coincident Peak = NCP/(8.76*Coincident Factor)*

An important aspect for estimation of Non Coincident Peak (NCP) is the usage of load factor and load loss factor. The ideal approach would be to download consumer meter readings of all consumers on a feeder for sample day and aggregate the consumption to arrive at day's consumption and aggregate the 24 hour load profile to arrive at consumer category load profile (provided tri vector meters were installed at all consumer's premises). The losses (both in-terms of energy and peak) should be arrived at from the meter readings of the concerned feeder (in case of energy loss component) and through tri vector meters (in case of load loss). Since agricultural consumers are mostly un-metered and do not have such sophisticated tri vector meters, it is not possible to use this scientific method for determining the load loss (particularly). Hence, the practical approach could be to establish the load pattern (i.e. load curve) from the sample feeders and arrive at Load Factor, which can then be used to estimate the Load Loss Factor and peak of agriculture category.

In the situation of availability of segregated technical and commercial losses, the formula for calculation of NCP would be as follows:

*NCP = (Consumption and commercial losses in MU/(LF*8.76) +(Loss in MU)/(LLF*8.76)*

However, in situation where the losses could not be segregated into technical and commercial losses, the load loss factor cannot be used. Also where the readings are taken at the sending end of the 11 kv (or above as in case of AP), the load curve is either drawn taking the current flowing in the feeder or instantaneous Kw readings recorded at the sending end, the losses in the selected 11 kV feeder are captured to a large extent (though not fully) along with the actual load in the load factor only. Hence the NCP is calculated using load factor as follows:

*NCP = (consumption + loss)/ (LF*8.76)*

[1] Coincident peak is the contribution of the agricultural demand to the system peak demand

Step 6: Block approach for assessing energy component of power purchase

It is observed that the different consumer categories pose different weights on the incremental power purchase over the years. In this regard, each category should be charged in accordance with their respective share of the incremental power purchase over the years. Conventionally, the variable/energy charge of the power purchase is averaged out for the entire utility and is allocated to all categories depending on their contribution to power consumption. The main logic being that the energy consumed by various categories is pooled from the portfolio of generation assets handled by a utility. This argument hides certain ground realities wherein a faster growing segment may be forcing higher requirement of supply expansion or purchase through spot or bilateral arrangements to meet the demand. There could be categories like agriculture which is heavily administered and not in a position to consume as per their requirement and hence should not be penalised with higher 'average rate'.

In this regard, a block approach on merit order dispatch is used to estimate the energy/ variable component of the power purchase cost which could be attributed to the agricultural category. Following steps are carried out to estimate the same:

- Identify a base year (in our case 2005-06)
- Consumption and losses in this base year is called 'Base block'
- Consumption and losses in the current year (in our case 2007/08), over and above the base block is called 'Growth block'
- For any given year (say 2007-08), stack the power stations actually dispatched on their merit order (increasing variable cost/ single part for spot or bilateral purchase)
- From the merit order, identify the stations that shall together serve that 'Base block' and thereby compute the total variable cost of power for base block. Thereafter, per unit variable cost of base block is computed (say X1)
- The balance stations serve the growth block and the total cost of power for growth block and the per unit variable cost for growth block can be computed (say X2)
- Variable cost of agriculture category for the base year is estimated by multiplying the input of power to agricultural category with the per unit variable cost of base block(i.e X1) as computed above.
- Similarly, variable cots of incremental input of power to agricultural category is calculated by multiplying the quantum of incremental input of power to agricultural

category with the per unit variable cost of growth block as computed above (i.e X2).

- Summation of variable cost of agricultural category for base year and the variable cost of incremental input of power to agricultural category gives the variable cost of power purchase attributable to the agricultural category.

Some of the points to be considered while adopting this block approach

a. What should be the period which would form the 'Base block' – should it be fixed for one arbitrary period say 2005-06 or should it be an moving average to accommodate the increasing 'life style' of the same consumers.
b. There could be argument that the new consumers joining the Grid would be always paying the higher variable charges in the block approach, as they would be clubbed into the 'growth' block. Hence SERCs should not discriminate within the category but only across categories
c. Base block approach would perpetuate the differences between the categories for eg. A good economy and hydrology can make the categories stack up in a way that would be different in a bad economy and bad hydrology or in any combination thereof
d. This method needs to be further adjusted wherein there's negative consumption compared to abase period – fall out of point c above, in this case, the category would need to be provided some relief, probably excluding higher MoD stations within the base block itself
e. Should the MoD approach be based on the entire State as a whole or as per the individual Discom (once the Multi-buyer model is implemented, then this needs to be addressed)
f. This method could keep the cross-subsidising category's growth at higher cost and can lead to uneconomical HT tariff and ultimately affect the attractiveness of the State as a investment destination
g. Some of the 'Spot purchases' could be caused by the station in the MoD not being able to supply the base block and this would be attributed to the 'growth block' and thereby end in an unequitable distribution of costs – it defeats the primary cause and effect chain to be developed in allocation

Step 7: Allocation of cost to the agricultural category

The costs when classified are then allocated to the agricultural consumer category. The objective is to allocate costs to customer classes in relation to the cost impact imposed by the consumer category on the power system. The different type of cost (Demand, Energy and Consumer) as classified in previous step are allocated to the agricultural category according to the following principles:

- *Allocation of Demand Costs*: Demand costs of all three functions such as power purchase, transmission and distribution function are allocated to agricultural consumers on the basis of the coincident peak demand.

- *Allocation of Energy Costs*: The energy cost component of power purchase is allocated to agricultural category on the basis of block approach as explained above. Energy related cost of transmission and distribution function is allocated to the agricultural category on the basis of ratio of agricultural consumption to the total consumption of the utility.

- *Allocation of Customer Costs*: Customer related cost of all three functions is allocated to the agricultural consumer on the basis of the ratio of number of agricultural consumers to the total consumers of the utility.

Sum total of the different cost (demand, energy and customer related cost) allocated to the agricultural consumers gives the total cost of supplying power to agricultural consumers as incurred by the particular utility.

Step 8: Estimation of cross subsidies

Estimation of cross subsidies is the succeeding step after estimation of cost to serve to agricultural category. Following steps are carried out to estimate the same:

- Difference between the total cost of supplying power to agricultural consumers and the revenue collected from them in a particular year gives the estimate of total quantum of subsidies for the utility
- Difference between the total subsidy and the subsidy provided by the government estimates the extent of cross subsidy to the agricultural sector.

Data requirement

The description of the above model give s the estimate of the extensive data required for the model. Broadly following data specific to each utility would be required for the model:

- Utility system load details
- Power purchase details
- Energy details of the utility
- Profit & loss accounts of the utility
- Balance sheet and its respective schedules of the utility
- Revenue details of the utility
- Detailed composition of all costs incurred by the utility
- Details of technical and commercial losses in agricultural category
- Voltage level wise classification of cost
- Load data of the sample feeders

The aforementioned data and the other operating data were obtained from the secondary sources such as Tariff orders, Profit & Los Accounts, Trial balance, Balance sheet etc. and with the discussions with the concerned utilities and State Electricity Regulatory Commission. Load studies were be based on sample survey in consultation with the concerned utilities.

Excel Based Model

An excel based model has been developed to estimate the cost of supplying power to agricultural consumers in various utilities.

Input Modules

Operating data

It has power purchase and energy & losses details for 2007/08 . Also, system peak demand data and technical data are included.

Profit & Loss Account

Profit and loss account details of selected utility 2007-08 is included in this module.

Revenue Details

Actual revenue incurred by the selected utility during 2007/08 is included in this module.

Fixed Assets

Details of fixed Assets for 2007/08 have been captured and segregation of assets in to various voltage classes and thereafter into demand, energy and customer related charges have been made based the discussion with the selected utility.

Work sheets: Cost Analysis

Various cost as per Profit & Loss accounts such as repairs & maintenance, administrative & general expenses, employees cost, interest & financial charges, other debits, prior period expenses etc are classified into various voltage classes and thereafter into demand, energy and customer related charges based on the discussion with the selected utility.

Analysis/process modules

Functionalisation & classification Matrix

This gives the classification of the functionalised cost (power purchase, transmission and distribution cots) into various voltage categories and thereafter into demand, energy and customer related costs.

Calculation of Coincident Peak

This module calculates the coincident peak of the selected utility.

Revenue Requirement Classification

This module captures the various items of costs and the net annual revenue requirement and classifies the same to various voltage classes under demand, energy and customer heads.

Merit order

This module captures the merit order of the utility and assesses the variable cost of power purchase attributable to agriculture category using the block approach.

Output Modules

allocation

This module captures the allocation of the various costs to the agricultural consumers.

Cost to serve

This module compares the cost of serving the agricultural consumers and revenue realised from them for the year 2007/08.

CHAPTER 5: Utility Wise Analysis

Based on the discussions with FOIR, following utilities having substantial agricultural consumption level have been selected for the study

Table 5.1: utilities having substantial agricultural consumption level

Name of the State	Name of the DISCOM
Andhra Pradesh	Andhra Pradesh Central Distribution Company Ltd(APCPDCL)
	Andhra Pradesh Northern Power Distribution Company Ltd (APNPDCL)
Karnataka	Bangalore Electricity Supply Company (BESCOM)
Gujarat	Uttar Gujarat Vij Company Ltd (UGVCL)
	Paschim Gujarat Vij Company Ltd (PGVCL)
Haryana	Uttar Haryana Bijli Vitran Nigam (UHBVN)
Uttar Pradesh	Paschimnachal Vidyut Vitran Nigam Ltd
	Poorvanchal Vidyut Vitran Nigam ltd

Following section describes the assessment of cost to serve in the selected utilities.

5.1 Andhra Pradesh

State – Agricultural background

Agriculture (including horticulture, animal husbandry) accounts for significant share (~22%) in the State's GSDP[1] Nearly 2/3 of the working population is engaged in Agriculture. The sector is mainly rain fed and hence monsoon and seasonality play an important role.

As can be seen in figure 5.1, of the total land available, excluding forest area, the area under agriculture (including trees,

[1] All statistics pertaining to Agriculture in this section have been sourced from An Outline of Agricultural Situation in Andhra Pradesh for 2007-2008, published by the Department of Economics & Statistics, Government of Andhra Pradesh, Hyderabad.

horticulture etc) is almost ~49% of the State's area and is much higher than the national average (~40%). The gross irrigated area is ~46% and the Net sown area is ~ 39% (after adjusting for the area sown more than once).

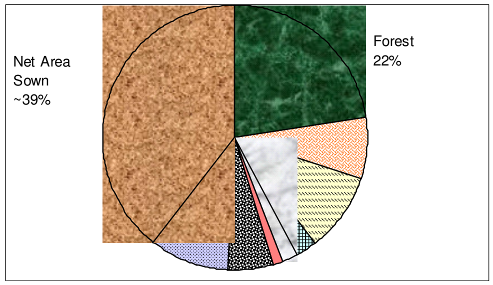


Fig 5.1. Land Usage in Andhra Pradesh (2007-08)

Figure 5.2 shows the source-wise irrigation in 2007-08. Canals and tube wells account for the majority of irrigation (~75%) both have almost an equal share.

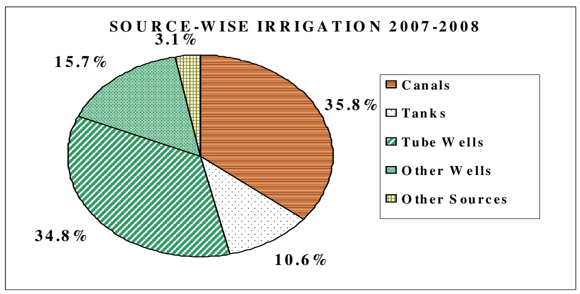


Fig 5.2. Type of Irrigation 2007-08

Nearly 2/3rds of the area under agriculture is used for producing food crops such as paddy, jowar and bajra. Paddy accounts for ~60% of the total crop in 2007-08. Other significant crops are sugar cane (~6%), maize (~6%), groundnut (~5%), cotton (~4%), chillies (~3%) and sunflower (~3%). In terms of seasonality, Kharif produces ~57% of the total production in the year with the balance being produced in the Rabi season.

Rainfall

Table 5.2. Rainfall Pattern over 5 decades ending 2007-08

Analysis of Rainfall between 1995 to 2008									
	South-West Monsoon (June – Sept)			North-East Monsoon (Oct – Dec)			Total for the Year (Jan – May)		
	Actual	Normal	% Dev	Actual	Normal	% Dev	Actual	Normal	% Dev
Average	634	612	4	215	200	9	935	901	4
Maximum	994	634	54	390	224	103	1,343	940	45
Minimum	400	595	(34)	60	154	(70)	613	840	(35)
Median	630	603	4	219	204	8	926	896	1

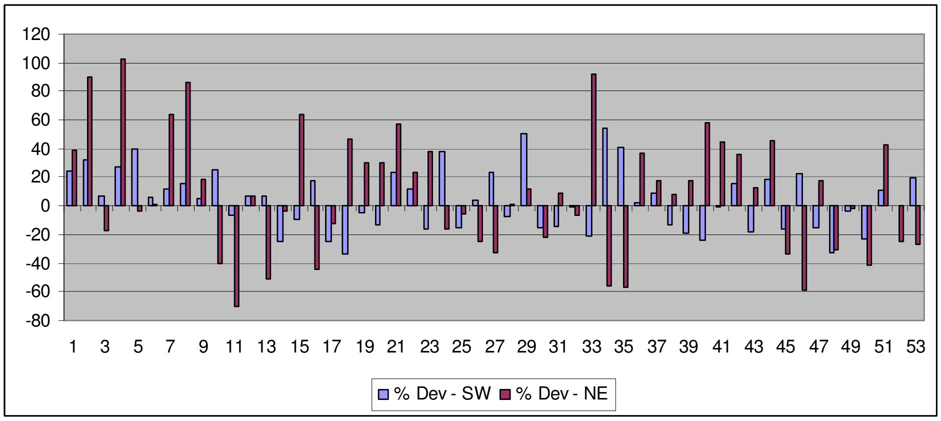


Fig 5.3. % Deviations from Normal in last 5 decades ending 2007-08

Table 5.2 and Figure 5.3 present an interesting reading on the rainfall pattern over AP. On an average, there is excess of rainfall to the extent of ~4%. However, the deviation is between 54% to – 34%.

Moreover, almost excess rainfall decades are followed by almost 4 years of drought (deficit rainfall). Northeast (NE) rainfall has more spikes (up or down) but generally follows South West (SW) pattern. (Rigorous statistical analysis is required before any patterns can be discerned).

During the year 2007-08, the state had received 15% excess rainfall. The rainfall had been excess during the South-west (20% from June-Sep) and also in the Winter (197% Jan-Feb) & Hot period (65% Mar-May). However, during the Rabi period (Oct – Dec) it had been in deficit (27%).

Table 5.3 District wise Rainfall – APCPDCL 2007-08

(in mm)

Region-wise Rainfall in Andhra Pradesh 2007-2008				
Sl No	**Region**	**Normal**	**Actual**	**% Dev over Normal**
1	Andhra	1078	1255	16
2	Rayalaseema	715	1015	42
3	Telangana	907	948	5
Andhra Pradesh		940	1080	15

As seen in Table 5.3, the dispersion of this rainfall had been such that the region of Telengana had only 5% excess whereas Andhra (16%) and Rayalseema regions (42%) had more rainfall. The implication to the State is that power requirement for agriculture (~30% of energy sales) will have varied requirements across time (Kharif, Rabi) as well as area (Telengana, Rayalaseems, Andhra).

Of interest to this study, Telangana accounts for the total area for APNPDCL and ~1/2 of APCPDCL. Hence changes in rainfall affect these discoms more than others. Even within the season, delay in onset or delays in pattern of rain affect the sowing and watering of the farms and hence can affect the electricity drawn from the grid.

Further, a good rain in Kharif season not only helps in farming but also ensures that the water table is adequately charged so that the Rabi season is not affected. Electricity is maximum used in Rabi season, as there's no direct rain-fed agriculture during this season.

Paddy accounts for more than 60% of the total area sown and is mostly irrigated from the canals rather than wells. Even though wells do not form more than a quarter of the sources of paddy irrigation, it still accounts for ½ of the entire wells that are pressed into the service of agriculture. Thus, the most water intense crop forms the mainstay for the State and is cultivated in both the seasons.

This has major implication on the electricity use as delays in water release into canals, delays in monsoon (or rain feed) poses a huge burden on the State electricity utilities. In the current year, anecdotal evidence points that the delay in South West monsoon has already increased the demand for electricity from the agriculture sector by ~30% as compared to similar period of last year.

Area, Irrigation and Crops

The total Gross area under cultivation in the past 5 decades has hardly shown any improvement, except to the extent that the area sown more than once has increased by a compounded average of 2%.

Similarly, the area under cultivation during Kharif and Rabi seasons show hardly any change in the past 4 decades and have more or less stayed constant.

In terms of area under different irrigation sources, over last 4 decades, canals and wells has hardly shown a compounded growth of 1%. Major growth has happened under the area irrigated by tube wells which has shown a growth of 3%. This growth triples upto 9% from 1980 to date, which shows that the unmetered electricity (and/ or low charges for electricity) might have contributed to the increase in the area under cultivation.

Table 5.4 Type of Irrigation – food-grain-wise 2007-08

(Area in '000 Hect.)

Crop	Canals	Tanks	Tube Wells	Other Wells	Other Sources	Total Irrigated	% of Irrigated
Paddy	2002	622	743	339	144	3850	61.3
Jowar	15	N	10	2	1	28	0.4
Bajra	N	N	15	6	N	21	0.3
Maize	39	1	158	143	8	349	5.6
Ragi	N	N	6	3	1	10	0.2
Chillies	40	1	78	49	10	178	2.8
Turmeric	1	N	30	29	1	61	1
Sugarcane	60	30	262	38	6	396	6.3
Cotton	24	N	65	125	3	217	3.5
Groundnut	23	6	197	82	7	315	5
Sesamum	1	1	6	3	N	11	0.2
Sunflower	17	2	130	22	2	173	2.7
Onion	1	N	23	7	1	32	0.5
Tobacco	1	N	27	1	5	34	0.5
Other	26	6	438	137	3	610	9.7
Total	**2250**	**669**	**2188**	**986**	**192**	**6285**	**100**

Area under paddy, in Kharif season, in the last 2 decades has hardly shown any growth (in fact a -1% growth), whereas during Rabi it has shown a marked improvement of compounded 2% growth. This trend is reflected in the current period 2007-08.

Table 5.5 Area under production 2007-08

	Area (Lakh Hectares)			Production (Lakh Tonnes)		
	Kaharif	**Rabi**	**Total**	**Kaharif**	**Rabi**	**Total**
2003-04	43.03	25.04	68.07	86.49	50.48	136.97
2004-05	39.91	22.75	62.66	83.97	49.97	133.94
2005-06	43.15	28.53	71.68	93.79	75.71	169.5
2006-07	42.18	30.56	72.74	87.74	74.55	162.29
2007-08	42.42	31.45	73.87	114.33	83.84	198.17
Average	41.44	26.17	67.61	83.7	58.15	141.85

Kharif is the season for maximum sowing and harvesting of food grains (~60% on an average) between the two seasons. However, if one were to look at the area under harvest, Kharif shows a marginal decline in the last 5 years, whereas Rabi area is increasing steadily and shows a compounded growth of ~6%.

Similarly, Kharif production has grown by a compounded rate of 6%, whereas Rabi has shown a compounding of ~15% (more than double). This trend is accentuated, when one looks into Paddy cultivation. Apart from the increasing trend of area under utilization, average yield in Rabi season is almost a third more than that of Kharif.

This could be more to do with concentrated areas under farming (without small and medium holdings pulling down the averages, yield) rather than any improved farming or water management. Of course, more studies needs to be carried out to study the impact of these on the electricity sector.

Agricultural characteristics of Discoms

APCPDCL

Andhra Pradesh Central Power Distribution Company Limited ("APCPDCL" – Central Discom) shows a higher than the State's average in terms of Net area sown (~45%). The district wise spread is shown below in Table 5.6. The area is equally divided between the Rayalaseema and Telengana area (~50% each) with their varied rainfall impacts.

Table 5.6. Land Usage – CPDCL 2007-08

	Net area shown ('000 H)	
	2007-08	***%***
Ananthapur	1114	28%
Kurnool	894	23%
Mahbubnagar	772	20%
Rangareddy	206	5%
Hyderabad		
Medak	458	12%
Nalgonda	511	13%
Total	**3955**	

The rainfall across the seasons and districts are shown in Figure 5.4. It can be seen that there's a heavy dependency on the South West only and the North East contributes not more than 10% - 20% across the districts. Except for Ananthapur, other districts have a higher share in both SW and NE monsoon periods. Ananthapur alone contributes to ~ 28% of the total area under agriculture for the Central Discom.

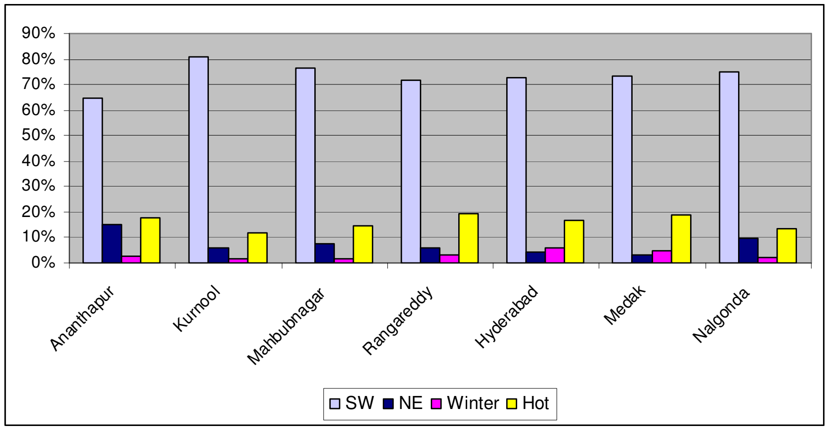


Fig 5.4. Rainfall across CPDCL 2007-08

Table 5.7 shows the type of irrigation used across the districts within the discom.

Table 5.7 Type of Irrigation 2007-08

Type of Irrigation	*% of areas*			
	Canals	***Tanks***	***Wells***	***Others***
Ananthapur	17%	3%	79%	1%
Kurnool	40%	7%	48%	5%
Mahbubnagar	15%	3%	78%	4%
Rangareddy	1%	3%	93%	3%
Hyderabad	0%	0%	0%	0%
Medak	1%	2%	97%	0%
Nalgonda	34%	6%	56%	4%

It can be seen that except for Kurnool (~23% of sown area), all are significantly dependent on the wells as a source of their water, which has a high implication for the utility in terms of electricity consumption.

Table 5.8 Area and Production of Rice 2007-08

Crop: Rice	**Karif**		**Rabi**	
	Area '000H	**Kg/Hect**	**Area '000H**	**Kg/Hect**
	2007-08	**2007-08**	**2007-08**	**2007-08**
Ananthapur	30	3,171	14	2576
Kurnool	90	3687	19	2758
Mahbubnagar	102	2923	46	2769
Rangareddy	19	2461	12	2652
Hyderabad	0	-	0	-
Medak	58	2841	35	3349
Nalgonda	163	3166	148	3207

As seen in Table 5.8, Rayalaseema area (Ananthapur, Kurnool) has more yields during Kharif than in Rabi.

Land holding across the districts present an interesting study and may really contribute to the varying patterns seen in the area under cultivation as well as yield[1].

Table 5.9 Land Holding across CPDCL 2007-08

	MARGINAL		SMALL		SEMIMEDIUM		MEDIUM		LARGE	
	NO.	AREA	NO.	AREA	NO.	AREA	NO.	AREA	NO.	AREA
Ananthapur	34%	10%	32%	24%	25%	32%	8%	24%	1%	9%
Kurnool	40%	12%	29%	21%	20%	29%	9%	29%	1%	10%
Mahbubnagar	50%	16%	26%	24%	16%	29%	6%	22%	1%	9%
Rangareddy	52%	17%	27%	25%	15%	27%	6%	21%	1%	9%
Medak	64%	25%	22%	28%	10%	23%	3%	17%	0%	7%
Nalgonda	55%	18%	25%	25%	14%	27%	6%	23%	1%	7%

Significant number dispersion seems to be around the marginal and small, whereas in areas its between the small and medium (between an average of 1.5 to 5.7 hectares).

APNPDCL

Northern Power Distribution Company of AP Limited (“APNPDCL” – North Discom) shows a lower than the State’s average, in terms of Net area sown (~32%). The district wise spread is shown below in Table 5.10. The entire Discom area falls in Telengana region with its lower than State’s average of excess rainfall.

Table 5.10 Land Usage – NPDCL 2007-08

	Net area shown (000 H)	
	2007-2008	%
Nizamabad	268	13%
Adilabad	507	24%
Karimnagar	429	20%
Warangal	452	21%
Khammam	453	21%

The rainfall across the seasons and districts are shown in figure 5.5. It can be seen that there’s a heavy dependency on the South West only and the North East contributes not more than 5% to 10% across the districts.

[1] In terms of classification Marginal is defined as upto 1 hectare, Small as between 1 to 2, Small Medium from 2 to 4, Medium from 4 to 10 and Large as above 10 hectares.

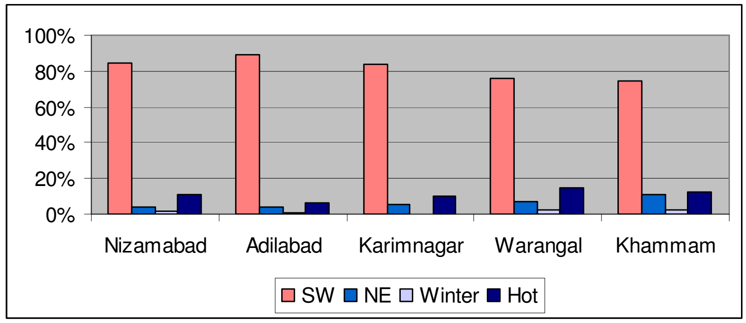


Fig 5.5. Rainfall across NPDCL 2007-08

The following table shows the type of irrigation used across the districts within the discom

Table 5.11 Type of Irrigation 2007-08

Type of Irrigation				**% of Area**
	Canals	**Tanks**	**Wells**	**Others**
Nizamabad	6%	2%	89%	2%
Adilabad	7%	12%	79%	1%
Karimnagar	11%	8%	81%	0%
Warangal	1%	18%	80%	1%
Khammam	36%	18%	36%	9%

It can be seen from Table 5.11 that all districts are significantly dependent on the wells as a source of their water, which has a high implication for the utility in terms of electricity consumption.

Table 5.12 Area and Production of Rice 2007-08

Crop: Rice	**Karif**		**Rabi**	
	Area '000H	**Kg/Hect**	**Area '000H**	**Kg/Hect**
	2007-08	**2007-08**	**2007-08**	**2007-08**
Nizamabad	71	3589	57	3510
Adilabad	40	2378	12	2353
Karimnagar	130	3391	152	3586
Warangal	115	3084	72	2855
Khammam	146	3085	30	3229

In the production of rice as seen in Table 5.12, the trend in the district is different from the trend of the state. The trend seems to be that both in Kharif as well as Rabi, the yield per Hectare seems to be equal. May be since the cultivation is more well dependent (unlike rain fed) there seems to be closer to uniformity in yield.

Land holding across the districts as seen in Table 5.13 present an interesting study and may really contribute to the varying patterns seen in the area under cultivation as well as yield.

Table 5.13 Land Holding across NPDCL 2007-08

	MARGINAL		SMALL		SEMIMEDIUM		MEDIUM		LARGE	
	NO.	AREA	NO.	AREA	NO.	AREA	NO.	AREA	NO.	AREA
Nizamabad	67%	32%	23%	34%	8%	22%	2%	10%	0%	2%
Adilabad	48%	14%	26%	24%	19%	33%	6%	23%	1%	6%
Karimnagar	66%	28%	21%	29%	10%	25%	3%	15%	0%	4%
Warangal	63%	22%	21%	24%	11%	23%	5%	21%	1%	10%
Khammam	57%	20%	23%	24%	14%	28%	6%	23%	1%	6%

Significant number dispersion seems to be around the marginal and small farmers. In area holding, marginal to small medium categories form the bulk with land holdings on an average between 0.46 to 2.7 hectares.

Energy characteristics of Andhra Pradesh

AP system has a contracted capacity of ~11,500 MW from APGenco, Central Stations, IPPs and Non-Conventional energy sources.

Table 5.14 AP Energy Supply System – 2008

	MW	%
APGenco – Thermal	3,383	29%
APGenco – Hydel	3,588	31%
CGS	2,026	18%
NTPC (Simhadri)	1,000	9%
IPPs	997	9%
NCEs	470	4%
Others	59	1%
Total	**11,523**	

It can be seen from Table 5.14 that APGenco's capacity dominates the system and its hydel plays an important role in the supply of energy within the State.

IPPs (including NTPC – Simhadri, a dedicated station for the State) account for less than a fifth of the State's requirement. The State had purchased ~2.6% of its energy requirement from traders (at an average cost of Rs 5.44 / kWh), paying ~7% of its total costs (including transmission charges). This has increased the PP cost for Discoms by almost Rs 0.06/ kWh.

Table 5.15 Power Costs break-up 2007-08

	Fixed Cost Rs Crores	Variable Cost Rs Crores	% of Fixed to Total Cost
APGenco	1,890	2,755	41%
CGS	1,006	2,357	30%
IPPs	768	1,089	41%
Others	86	1,565	5%
Total	3,751	7,765	33%
PGCIL	320		
APTransco	623		
SLDC	22		
Grand Total	**4,715**	**7,765**	**38%**

The important point of note here is that the fixed cost component of the stations are almost a third of the total cost and this would have an impact on the cost to study, as demand costs are allotted on the basis of coincident or non-coincident peaks.

APGenco has higher ratio of fixed costs even when the vintage of plants are definitely older than the IPPs. This is could be the result of first transfer scheme and hence may not be truly reflective of the economic value.

'Others', in Table 5.15 above, include a large share of purchases through Trading and hence will not reflect any fixed cost component.

Load Analysis – AP State

Load duration

For load analysis, the data has been collected from the Energy Billing Centre in APTransco. This unit collects meter readings from all the G-D and T-D interface meters and prepares the energy accounting for the State. The meter readings (1/2 hour intervals) have been aggregated to arrive at the hourly values for the study.

Figure 5.6 sets out the load duration (as supplied with restriction on rural, agricultural and industrial loads) during the year 2007-08.

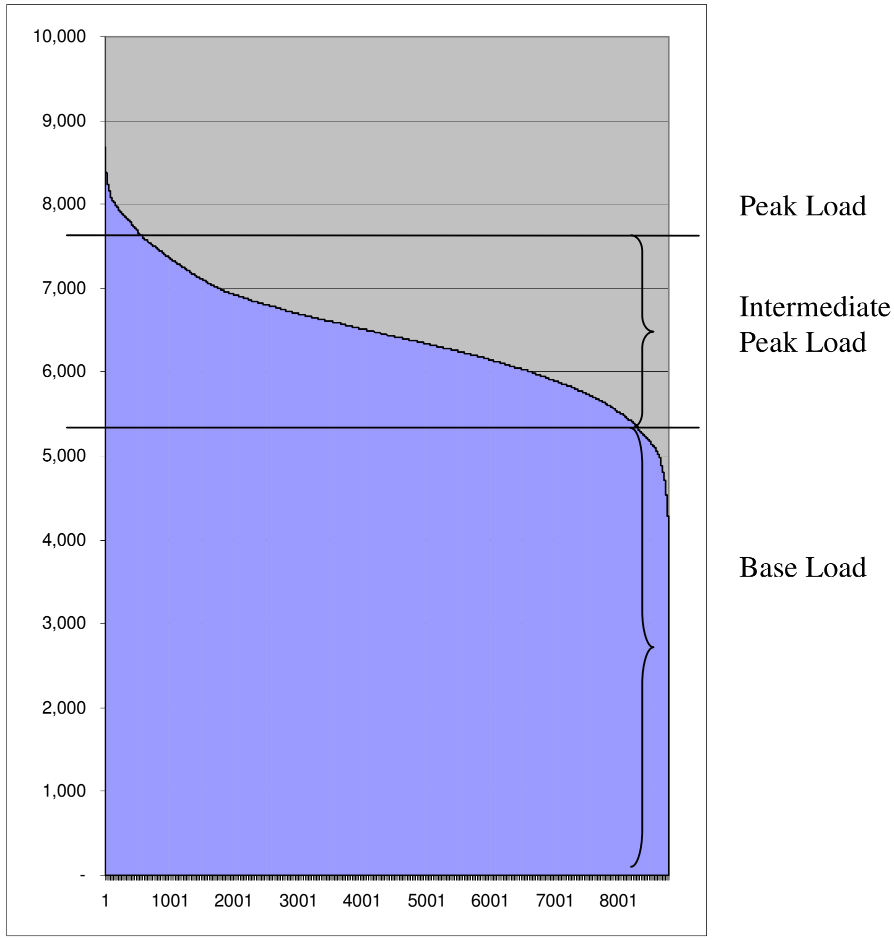


Fig 5.6 Load duration curve for AP – 2007-08

AP system moves between a base load of ~5000 MW and upto ~6700 MW during the intermediate peak. It hits a peak of 8,681 MW (on 20th March 2008 at 0600 Hrs). The median value load is ~6,444 MW.

The duration of loads in a frequency interval of say 500 MWs has been presented in Table 5.16 .

Table 5.16 Duration of various loads – AP – 2007-08

MW	Duration in Hrs.
4,000	0
4,500	34
5,000	119
5,500	570
6,000	1,426
6,500	2,545
7,000	2,326
7,500	1,003
8,000	607
8,500	149
9,000	5

This table shows that for ~ 292 days in a year (80% of the time), the load is within the band of 5000-7,000 MW. For ~ 42 days, the system needs another 500 MW. Another 26 days, the system requirement has increased by 500 MW. Thus for ~360 days (out of 366 days in 2007-08), the system managed with 8,000 MW. For the remaining 6 days, the requirement increased by another 500 MW. The last ~181 MW were required for a mere 5 hours in the year.

The caveat to be noted here is that the system is a heavily administered one, with high finesse in demand side management. Loads are interrupted to safe guard the system as well as not incur penalties under UI or trading in costly power.

Table 5.17 shows the load duration profile from the agricultural season of Kharif and Rabi.

Table 5.17 Load duration during Kharif & Rabi Seasons – 2007-08, AP

Jun – Sep ---→	Kharif	Nov – Mar --→	Rabi
MW	**Duration in Hr**	**MW**	**Duration in Hr**
4,000	-	4,000	-
4,500	34	4,500	-
5,000	91	5,000	23
5,500	275	5,500	239
6,000	587	6,000	452
6,500	840	6,500	767
7,000	764	7,000	930
7,500	259	7,500	588
8,000	75	8,000	498
8,500	3	8,500	146
9,000	-	9,000	5
-	33%	0	42%

It can be seen from the loads that Rabi would require higher loads (as there would be least rainfall) and the peak happens only during this period. Rabi season would require additionally ~680 MW (almost 10% of the base and intermediate load) more than the Kharif season (assuming that the SW monsoon has been normal or excess and timely).

Monthly peaks of the State are mapped below in Table 5.18.

Table 5.18 AP Monthly Peaks – 2007-08

Month	Max	Time - Hrs
Apr	7,848	11:00 PM
May	7,193	2:00 PM
Jun	6,834	8:00 PM
Jul	7,353	2:00 PM
Aug	8,134	1:00 PM
Sep	7,414	1:00 PM
Oct	7,813	1:00 PM

Nov	7,135	9:00 AM
Dec	7,841	1:00 PM
Jan	8,118	9:00 AM
Feb	8,332	6:00 AM
Mar	8,681	6:00 AM

It can be seen from the above readings that most of the peaks happen between 1 PM and 2 PM (50%) whereas peaks at morning 6 AM and 9 AM occurs for a third of the year. Evening peak has happened only for 2 months. Moreover, the loads at evening peaks are significantly less than the morning peaks (by 10%) thereby providing a strong argument to consider either morning peak (the highest for the year) or an average between morning and afternoon peaks.

Central Discom (APCPDCL) load behaviour

Central Discom recorded a peak of 4,150 MW on 21st March 2008 (a day later than the State peak) at 9 AM (instead of State's peak at 6 AM). Comparison of these two days (20th and 21st March) shows that the morning loads are more are less very close and the divergence happens in the evening, where on 21st, the load falls by more than 500 MW.

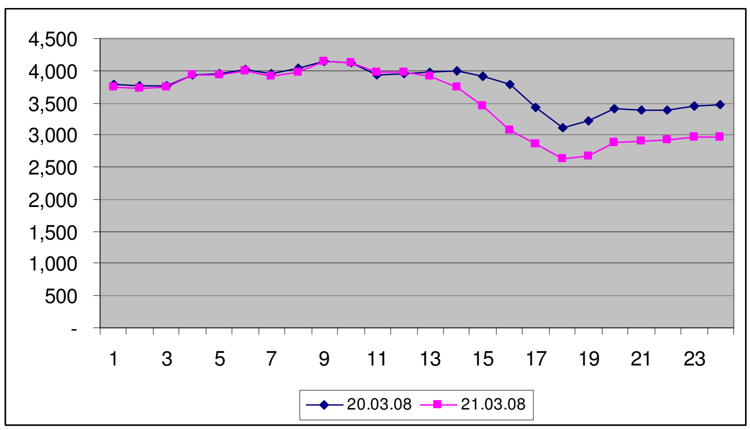


Fig 5.7 CPDCL – Loads during 20th and 21st March 2008

Further, it can be seen from the above that the evening peak is ~15%-20% lower than the morning peak.

The load duration curve for the Central Discom is shown in the frequency table below. It can be seen from the table that ~ 94% of time in a year, a load of 3,600 MW is the requirement. Additional 300 MW is required for less than a month and the final 250 MW is needed for ~2.5 days in a year.

Table 5.19 Load Duration of CPDCL – 2007-08

MW	Duration in Hrs.
1,500	0
1,800	4
2,100	31
2,400	232
2,700	1,198
3,000	3,083
3,300	2,339
3,600	1,320
3,900	521
4,200	56
4,500	-

Table 5.20 CPDCL Loads during Kharif and Rabi – 2007-08

Jun – Sep ---→	Kharif	Nov – Mar --→	Rabi
MW	Duration in Hr	MW	Duration in Hr
1,500	-	1,500	-
1,800	4	1,800	-
2,100	29	2,100	-
2,400	156	2,400	56
2,700	526	2,700	470
3,000	1,081	3,000	945
3,300	686	3,300	913
3,600	373	3,600	769
3,900	72	3,900	441
4,200	1	4,200	56
4,500	-	4,500	-
	33%		42%

It can be seen from Table 5.20 that CPDCL also follows the State pattern between the Kharif and Rabi seasons and the peaking happens during Rabi season.

Northern Discom (APNPDCL) load behaviour

Northern Discom recorded a peak of 1,616.6 MW on 20th March 2008 at 10 PM (instead of State's peak at 6 AM). A review of the graph below shows, that at 10 PM there's an abrupt increase of ~425 MW (35% higher than the previous hour), which then tones down in next two hours. Compared to the gradual slope of the morning, the evening peak shows an abrupt profile. Further, compared to the 10 PM peak, preceding 3 hours are lower by more than 25% to 40%. Similarly, in comparison with the load at 6 AM (State peak time), the evening loads are lower by ~15%.

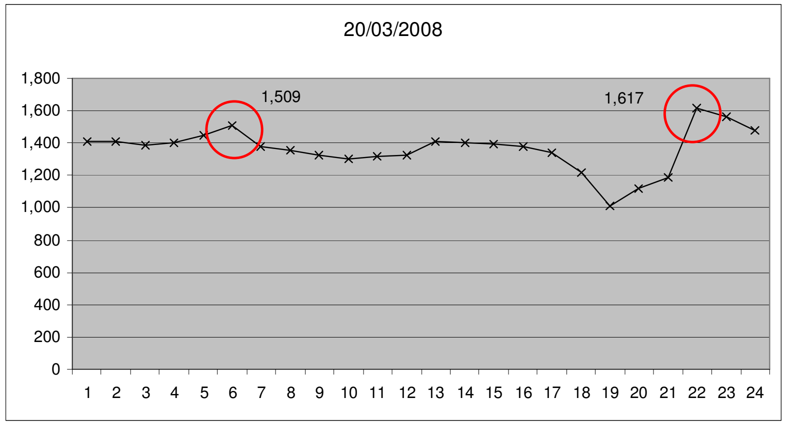


Fig 5.8 NPDCL – Loads during 20th March 2008

This is not an isolated spike, as can be seen from Figure 5.8, where ~ 4 or more months in a year, the spike occurs at this time.

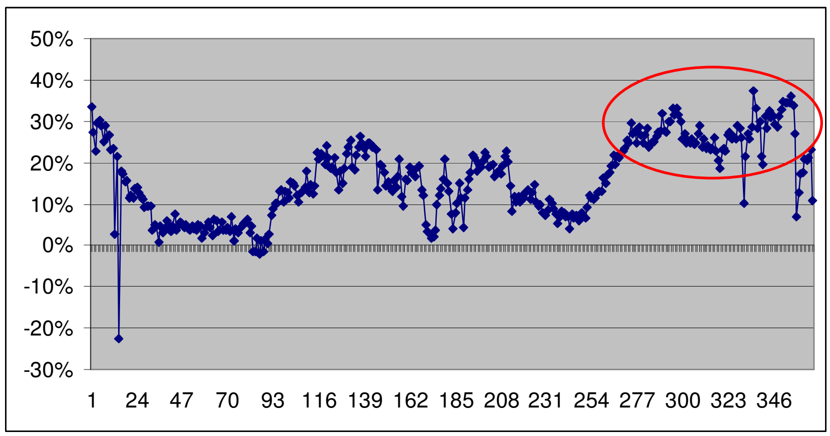


Fig 5.9 Spikes in Consumption between 9 to 10 PM – 2007-08

The load duration curve for the Northern Discom is shown in the frequency table below. It can be seen from the table that ~ 91% of time in a year, a load of 1,310 MW is the requirement. Additional 130 MW is required for a month. Another 130 MW is required for 2.5 days and the final 47 MW is needed for ~4 hours in a year.

Table 5.21 Load Duration of NPDCL – 2007-08

MW	Duration in Hr
400	0
530	20
660	189
790	973
920	1,569

MW	Duration in Hr
1,050	2,066
1,180	1,803
1,310	1,386
1,440	714
1,570	60
1,700	4

Table 5.22 NPDCL Loads during Kharif and Rabi – 2007-08

Jun – Sep ---→	Kharif	Nov – Mar --→	Rabi
MW	Duration in Hr	MW	Duration in Hr
400	-	400	-
530	17	530	-
660	168	660	3
790	492	790	114
920	611	920	304
1,050	620	1,050	959
1,180	632	1,180	750
1,310	338	1,310	794
1,440	49	1,440	661
1,570	1	1,570	59
1,700	-	1,700	4
	33%		42%

It can be seen that NPDCL also follows the State pattern between the Kharif and Rabi seasons and the peaking happens during Rabi season.

Cost to Serve – Agriculture Sector - CPDCL

Data gathering

Team identification

For the above study, Chief General Manager (Commercial) of CPDCL and Deputy Director of APERC were nominated as the Nodal officers in April 2009. Detailed discussions were held with these officers about the scope of work and the data requirement. CPDCL Divisional Engineer (RAC) was requested to collect and provide the necessary information to the consultants.

Identification of data requirement

Keeping in view the nature of study and the limitations of the distribution utilities in collecting and collating the data, the data requirement (as discussed in Chapter 4) was finalized after necessary consultations with the staff of FOIR. Necessary data reporting formats were also designed and circulated.

Sampling

With a view to obtain a truly representative data from the field units across different seasons, following dates were selected in consultation with CPDCL covering summer, winter and monsoon seasons as well as working days, holidays, festival days.

Table 5.23 Days selected

Days	Season	Date
Festival	Summer	06.04.07
Working	Summer	11.04.07
Holiday	Summer	01.05.07
Working	Monsoon	13.06.07
Holiday	Monsoon	15.07.07
Working	Monsoon	19.07.07
Working	Monsoon	09.08.07
Holiday	Monsoon	15.08.07
Discom Peak	Monsoon	20.08.07
Festival	Monsoon	15.09.07
Festival	Winter	15.10.07
Working	Winter	20.10.07
Working	Winter	20.11.07
Working	Winter	05.12.07
Holiday	Winter	09.12.07
Holiday	Winter	26.01.08
Working	Summer	22.02.08
Working	Summer	15.03.08
State Peak	Summer	20.03.08

In case of HT Agriculture (Category IVa, IVb), meter dumps for the entire year (with methods to fill in the data, wherever missing) were collected from the DE (Load Survey).
The consumers selected and their meter numbers are set out in the table below.

Table 5.24 HT – Cat IVa, IVb – CPDCL – 2007-08

CONS NO.	CONS NAME	VOL-RATING	METER NO.
ATP239	Deputy Executive Engineer / PR	11	APE05263
ATP272	Executive Engineer	11	APE12537
KNL302	The President	11	APE05230
MBN325	Deputy Executive Engineer	11	APE01169
MBN548	Sri Kurumurthyraraya Lift Irrigation	11	APE05677
MBN549	Amarchintha L.I. Scheme Beneficiary	33	APE01723
MBN562	Deputy Executive Engineer	11	APE05705
MBN605	K Hanumanth Reddy	33	APE03150
MBN621	The President	11	APE12946
NLG459	The Executive Engineer (PR)	11	APE05788
NLG413	The Executive Engineer	220	00034356

Data collection

- The data collection formats and & methodology were explained to the CPDCL team before initiation of work
- Logic for identification of predominant feeders was decided and explained
- Data sent by filed units were reviewed and discussions were held with the CPDCL team before finalising the hourly loads of the feeders for the sample days

Table 5.25 Feeders Selected for LT Category V – 2007-08

Sl.No	Name of the circle	No. of feeders data collected
1	Nalgonda	3
2	Ranga Reddy	1
3	Medak	1
	Total	**5**

Analysis of sample feeder results

As explained earlier, inputs received from the field units on the hourly loads on 11 KV feeders for the LT Category V consumption (as there is no meters to measure) and meter dumps for HT Category IV (11 kV, 33 kV, 220 kV) are used to calculate the Class Load Factor ("CLF"), Loss Load Factor ("LLF"), category peak and Coincident Factor ("CF"). The results are as under:-

LT Category V

Table 5.26 LT Cat V – Calculation

LT Agriculture - Cat V					
	Weights		**Average**	**Maximum**	**Maximum of All Categories**
Working	283		285	799	
Holiday	53		278	729	
Festival	30		290	598	799
Sum of 3 type of days with weights = Avg*wt				104010.3	
AMPs to MWs Multiplication Factor			15.2416	1.59	
AMPs to MWs for Max		=Max*wt*conversion		4.46	
Class Load Factor		=MW/ Maximum		36%	
Loss Load Factor		(0.3 *LF +0.7 (LF)^2		20%	
Calculation of Coincident Factor (CF)				35%	

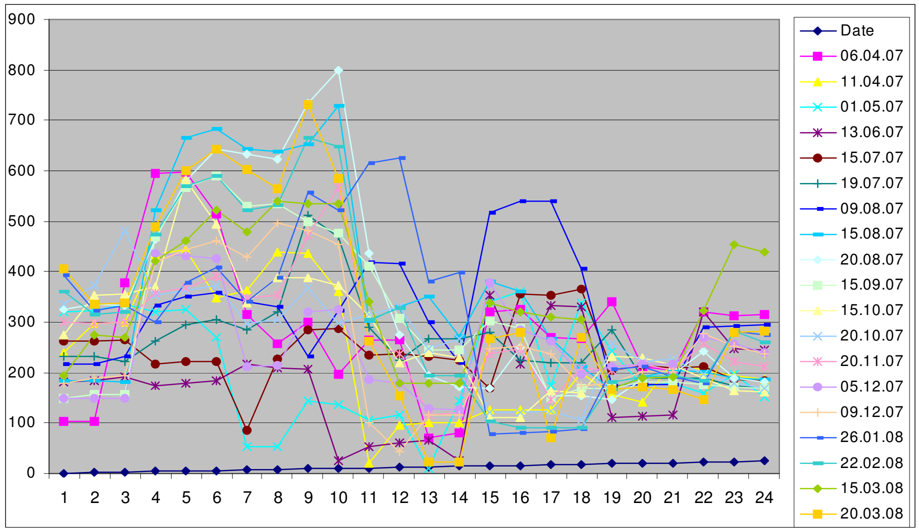


Fig 5.10 LT Cat V Load Curves 2007-08

The Load curves reflect the Load Restriction that happen, as not all feeders are energized at the same time. AP follows a ration rotation wherein ~ 1/3 of feeders are supplied power. This is one of the arguments of the company that the sample may not be true reflection of the rostering followed by company.

Though, this is valid generally in sampling techniques, the same argument will show that any randomly selected feeder has a similar bias i.e. non supply for a third of time and low class load factor.

This is reflected in the derived Class Load factor for the category - ~36% (which shows that the load is active for not more than a third of time – approximately reflecting a 7-8 hour supply). However, as the graph above shows, most of the load happens in the morning only and it is next to nothing during the evening (when only lighting load is allowed on these feeders by way of single phase supply) on these feeders.

This also coincides with the morning peak recorded at the State level, showing a clear correlation, enhancing the rationale for considering the morning peak only.

HT Categories (based on metered reading for the year)

Table 5.27 HT – Cat IVb – 11 kV

CLF	13.2%	LLF	5.2%
CF- Average of Peaks	35.1%		

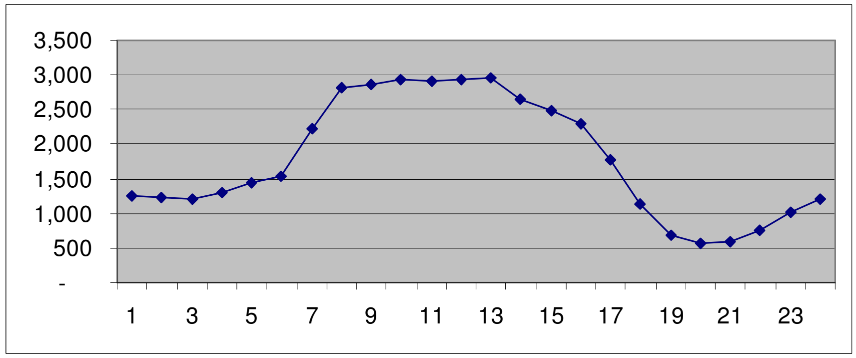


Fig 5.11 HT-Cat IVb – 11 kV – Average Load curve

Table 5.28 HT – Cat IVb – 33 kV

CLF	15.1%	LLF	6.2%
CF- Avergae Peaks	28.3%		

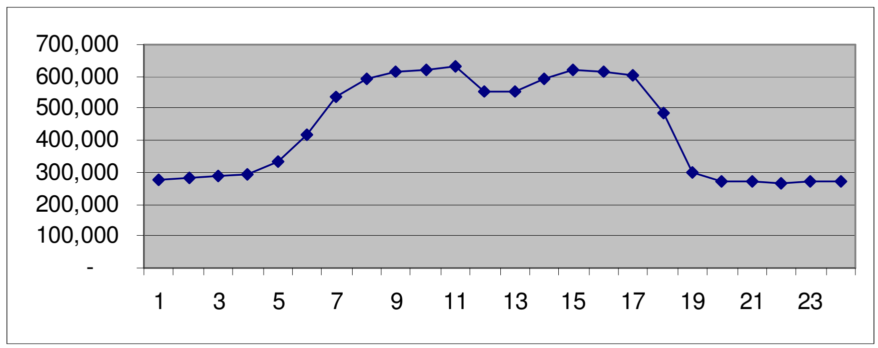


Fig 5.12 HT-Cat IVb – 33 kV

Table 5.29 HT- Cat IVa – 220 kV

CLF	10%	LLF	4%
CF- Avg peaks	42.5%		

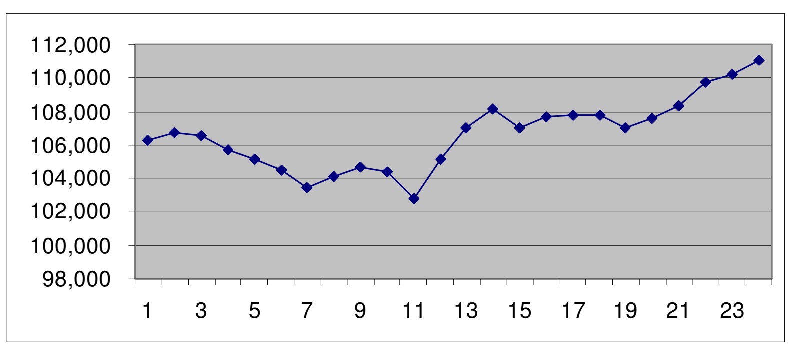


Fig 5.13 HT- Cat IVa – 220 kV – Average Load curve

Clearly, HT also shows a more tilt towards morning hours rather than the evening peak, except for 220 kV, Lift Irrigation consumer, which has increasing loads towards the evening as well.

Development of CoS model

Model description

As discussed in Chapter 4, the CoS Model has the following work sheets:-

- Operating data sheet
- P&L account
- Revenue details
- Voltage wise Assets allocation
- Revenue expenditure allocation matrix
- Functionalization and classification
- Hourly data of sample feeders
- Allocation of costs and results

f) Model processes

Operating data

Technical, operational, financial and commercial data for the year 2007-08 required for the development of model have been captured in this work sheet.

Profit & Loss Account

Profit and loss account of the year 2007-08, as per the audited accounts of the company has been captured in this work sheet. Trial balance has been used to provide details of individual items like Transmission charges, Interest on Security deposit from consumers, Provision for Bad and Doubtful debts etc.

Revenue details

Revenue from sale of power for the year 2007-08, as per the audited accounts of the company has been captured in this work sheet.

Fixed Asset details

Details of fixed Assets (as per Trial balance for FY 08) have been captured and segregation of assets in to various voltage classes have been made based on the methodology as followed by Company in its filing of ARR for 2007-08.

Table 5.30 CPDCL- Asset Classification – Voltage wise, Business wise – 2007-08

Asset Group	33KV				11KV				LT network				Retail supply				Grand Total
	Demand	Energy	Consumer	Total	Demand	Energy	Consumer	Total	Demand	Energy	Consumer	Total	Demand	Energy	Consumer	Total	
Land & Rights	1139466		-	1,139,466	6651720			6651720	16838041			16838041			3068953	3068953	27698180
Buildings	39966109		-	39,966,109	233305181			233305181	590584428			590584428			107641740	107641740	971497457
Hydraulic Works	0	-	-	-	0			0	0			0			0	0	0
Other Civil Works	3790688	-	-	3,790,688	22128426			22128426	56015490			56015490			10209556	10209556	92144160
Plant & Machinery	620362339	-	-	620,362,339	3621412047			3621412047	9167175617			9167175617			1670837706	1670837706	15079787709
Lines, Cable, Network, Meters, Metering Equipetc.	887839516	-	-	887,839,516	5182830284			5182830284	13119720923			13119720923			2391240806	2391240806	21581631529
Vehicles	1507369	-	-	1,507,369	8799382			8799382	22274594			22274594			4059836	4059836	36641182
Furniture and Fixtures	1552395			1,552,395	9062224			9062224	22939946			22939946			4181105	4181105	37735670
Office Equipments	10126478	-	-	10,126,478	59114082			59114082	149640295			149640295			27273902	27273902	246154756
Computer Software and others	171891	-	-	171,891	1003428			1003428	2540059			2540059			462959	462959	4178338
Total	**1,566,456,251**	**-**	**-**	**1,566,456,251**	**9144306773**	**0**	**0**	**9144306773**	**23147729393**	**0**	**0**	**23147729393**	**0**	**0**	**4218976563**	**4218976563**	**38077468981**
Voltage wise assets (as a % to the overall)				**4.11%**				**24.02%**				**60.79%**				**11.08%**	**100%**

Apportionment of Fixed Assets (in %)*				
33 KV	**11KV**	**LT network**	**Retail supply**	**Total**
4%	24%	61%	11%	100%

Revenue Expenditure matrix

Based on the nature of expenditure, the expenditure has been allotted to the wires or retail supply business. Where they are common to both, the asset base has been used to split the expense. Expenses like Power Purchase, Transmission cost, Interest on consumer security deposits, Provision for bad and doubtful debts have been allocated in full to Retail supply business (consumer related).

Rs 525 crores of Provision for bad and doubtful debts does not pertain to Agriculture Sector and has been specifically excluded (the company has made a strong case to say that since the fact is known as to the nature of expense, it should be excluded). In fact in coming years, Activity Based Costing and allocation would improve the quality of data that can be used to arrive at better CoS.

Table 5.31 Revenue Expenditure Allocation Matrix

	Revenue Expenditure Matrix	**Cost allocation % adopted**				
Sl.No.	**Nomenclature**	**33 KV**	**11 KV**	**LT Network**	**Retail supply**	**Total**
1	Purchase of Power	-	-	-	100%	100%
2	Transmission Charges	-	-	-	100%	100%
3	Repairs & Maintenance	4%	24%	61%	11%	100%
4	Employee Costs	4%	24%	61%	11%	100%
5	Administration & General expense	4%	24%	61%	11%	100%
6	Depreciation & Related	4%	24%	61%	11%	100%
7	Interest & Financial Charges	4%	24%	61%	11%	100%
8	Interest on working capital	4%	24%	61%	11%	100%
9	Interest on con.security deposits	-	0%	0%	100%	100%
10	Interest on power purchase dues					0%
	SUB-TOTAL	-				0%
11	Less: Expenses Capitalised	-	-	-	-	0%
12	Less: Interest & Finance Charges	-	-	-	-	0%
12	Other Expenses	-	-	-	-	0%
	SUB-TOTAL					
14	Other Debits (incl. Bad debts)	1%	7%	16%	76%	100%
14	Extra Ordinary Items	-	-	-	-	0%
16	Net Prior Period Charges/Credits	4%	24%	61%	11%	100%
17	Income Tax	4%	24%	61%	11%	100%
18	ROE/ROR	4%	24%	61%	11%	100%
		-				0%
	TOTAL RR	-				0%
	Less:	-				0%
	Other income	4%	24%	61%	11%	100%
	Miscellaneous income	4%	24%	61%	11%	100%
		-				0%
	Total	-				0%
	NET TOTAL EXPENSES	-				0%

Functionalization & classification matrix

For cost of service purposes, as first step, utility costs have been broken down, or functionalized in to the following cost functions

- Generation or Power Purchase cost
- Transmission cost
- Distribution cost

After the utility revenue requirements have been separated by function, they have to be classified according to cost component. The typical utility cost components are as follows:

- Demand related
- Energy related
- Customer related

In the context of CPDCL, since it is a power distribution company, it pays power purchase cost to generators based on the allocation of generation % made by the Government from time to time. This constitutes the generation cost for CPDCL. Similarly, the transmission & SLDC charges paid to APTransco is the Transmission cost.

Following table indicates the functionalisation of generation, transmission and distribution costs.

Table 5.32 Functionalisation of Costs

Particulars	A/C Group	Methodology	Generation /Power purchase cost			Transmission			Distribution				
			Demand	Energy	Cus.	Demand	Energy	Cus.	33KV	11 KV	LT Net work	Retail	Total
Generation	70	FC demand related	38.11%	61.89%	0.00%								
		EC energy related											
Transmission	70	Demand related				100.00%	0.00%	0.00%					
Distribution	74 to 83	Functionalisation of Fixed assets is made on basis of % allocation							4.11%	24.02%	60.79%	11.08%	100.00%

After functionalisation & classification of generation and transmission expenses as well as functionalisation of distribution expenses, the next step in the CoS process is to classify the distribution expenses (Revenue Requirement) as demand, energy and customer related. Classification of Revenue Requirement under various heads between 33 kV, 11 KV, LT net work and retail supply has been made as under:

On the basis of above principles, the classification of costs have been made as under:-

Table 5.33 Functionalisation of Costs

Revenue Expenditure Matrix	**Distribution**			
Nomenclature	**33KV**	**11KV**	**LT Network**	**Retail**
Purchase of Power	-	-	-	5,379.19
Transmission Charges	-	-	-	418.39
Repairs & Maintenance	4.23	24.67	62.45	11.38
Employee Costs	15.99	93.35	236.30	43.07
Administration & General expense	2.50	14.57	36.88	6.72
Depreciation & Related	9.61	56.12	142.07	25.89
Interest & Financial Charges	2.60	15.18	38.42	7.00
Interest on working capital	0.57	3.32	8.41	1.53
Interest on con.security deposits	-	-	-	44.71
Interest on power purchase dues	35.50	207.21	524.54	5,937.90
SUB-TOTAL				
Less: Expenses Capitalised				
Less: Interest & Finance Charges				
Other Expenses				
SUB-TOTAL				
Other Debits (incl. Bad debts)	6.99	48.91	111.80	531.06
Extra Ordinary Items				
Net Prior Period Charges/Credits	(0.53)	(3.07)	(7.78)	(1.42)
Income Tax	0.11	0.61	1.55	0.28
ROE/ROR	0.47	2.73	6.91	1.26
TOTAL RR				
Less:	42.53	256.40	637.02	6,469.08
Other income	-	-	-	-
Miscellaneous income	(17.50)	(102.15)	(258.59)	(47.13)
Total	(17.50)	(102.15)	(258.59)	(47.13)
NET TOTAL EXPENSES	25.03	154.24	378.43	6,421.95

The above costs are further segregated as demand, energy and customer related costs as under:-

Table 5.34 Segregation of Costs – Demand, Energy and Consumer

Revenue Expenditure Matrix	PP Cost		Transmission	33 KV	11 KV%	LT Network	Retail
Nomenclature	**Demand**	**Energy**	**Demand**	**Demand**	**Demand**	**Demand**	**Consumer**
Purchase of Power	2,050	3,329					
Transmission Charges			418.39				
Repairs & Maintenance				4.23	24.67	62.45	11.38
Employee Costs				15.99	93.35	236.30	43.07
Administration & General expense				2.50	14.57	36.88	6.72
Depreciation & Related				9.61	56.12	142.07	25.89
Interest & Financial Charges				2.60	15.18	38.42	7.00
Interest on working capital				0.57	3.32	8.41	1.53
Interest on con.security deposits				-	-	-	44.71
Interest on power purchase dues	2,050.25	3,328.95	418.39	35.50	207.21	524.54	140.31
SUB-TOTAL							
Less: Expenses Capitalised							
Less: Interest & Finance Charges							
Other Expenses							
SUB-TOTAL							
Other Debits (incl. Bad debts)				6.99	48.91	111.80	531.06
Extra Ordinary Items							
Net Prior Period Charges/Credits				(0.53)	(3.07)	(7.78)	(1.42)
Income Tax				0.11	0.61	1.55	0.28
ROE/ROR				0.47	2.73	6.91	1.26
TOTAL RR							
Less:	2,050.25	3,328.95	418.39	42.53	256.40	637.02	671.49
Other income				-	-	-	-
Miscellaneous income				(17.50)	(102.15)	(258.59)	(47.13)
Total	-		-	(17.50)	(102.15)	(258.59)	(47.13)
NET TOTAL EXPENSES	2,050.25	3,328.95	418.39	25.03	154.24	378.43	624.36

Table 5.35 indicates the grouping of Power purchase variable costs – on block basis

Table 5.35: Grouping of Power Purchase

MoD	Station	Energy	% cp share	cum energy	Var Charges Rs	var chgs Rs/ kWh	Remars
1	KAIGA	714	310	310	89.51	1.25	Must Run
1	MAPS	151	66	376	12.23	0.81	Must Run
1	APGPCL	238	103	479	16.33	0.69	Must Run
1	SLBPH	2,540	1,104	1,584	4.85	0.02	
2	Ex SLBPH	7,026	3,055	4,639	60.06	0.09	
3	NTPC (Talcher)	3,442	1,497	6,135	94.74	0.28	
4	Vemagiri	268	116	6,252	11.49	0.43	
4	SPIIL	1	0	6,252	0.03	0.43	
5	NTPC (Sim)	7,285	3,168	9,420	330.82	0.45	
6	NTPC(SR)	4,381	1,905	11,325	227.33	0.52	
7	APGencoTherma	20,316	8,834	20,158	1,056.75	0.52	
8	NLC -I	755	328	20,487	40.85	0.54	
8	NLC-II	1,319	574	21,060	71.38	0.54	
9	NTPC (SR)-III	1,414	615	21,675	76.69	0.54	
10	SPECRUM	1,493	649	22,324	82.57	0.55	
11	RTPP-II	969	421	22,746	53.73	0.55	
12	GVK	1,279	556	23,302	72.83	0.57	
13	Srivastha	100	43	23,345	6.08	0.61	
14	Reliance	1,143	497	23,842	75.14	0.66	
15	VSP	27	12	23,853	2.02	0.76	
16	Common (NCL T.	21	9	23,863	1.66	0.77	
17	LANCO	2,276	990	24,853	227.93	1.00	
18	CPDCL	380	165	25,018	48.63	1.28	
19	EPDCL	282	123	25,141	36.29	1.28	
20	SPDCL	697	303	25,444	89.99	1.29	
20	NPDCL	250	108	25,552	32.18	1.29	
21	Kesoram	4	2	25,554	0.61	1.41	
25	NBVL	38	17	25,571	5.38	1.41	
26	SITAPURAM	3	1	25,572	0.39	1.48	
27	Essar Steel	6	3	25,574	0.95	1.64	
28	Heavy Water Plar	2	1	25,575	0.26	1.71	
29	ADANI	209	91	25,666	47.85	2.29	
30	PTC	112	49	25,715	26.17	2.33	
31	RETL	462	201	25,916	108.25	2.34	
32	JSWPTC	587	255	26,171	139.62	2.38	
33	LEUL	74	32	26,203	18.12	2.44	
34	TATA	94	41	26,244	25.45	2.71	
35	NVVNL	55	24	26,268	15.30	2.79	
36	VISA	1	1	26,269	0.39	2.91	
37	PATNI	3	1	26,270	0.85	3.08	
38	KALYANI	0	0	26,270	0.09	3.10	
39	UI, Others	352	153	26,423	57		
	Grand Total				3,269.21		

AP as a Whole			
Variabble cost	Units	Rs crores	Rs/ kWh
Base Bloack	21,383	2,065	0.97
Growth Block	5,040	1,204	2.39
Total	26,423	3,269	1.24
Share of Agriculture - CP	Units	Rs crores	Rs/ kWh
Base Block	7,696	743.17	0.97
Growth Block	(459)	(109.64)	2.39
Total	7,237	633.53	0.88

Model outputs

As stated in the previous chapter, the Coincidence Peak is the sum of monthly peaks in a year and the coincidence of individual category to this peak has been studied. The study uses average peak CP method to allocate the final cost to the agriculture category.

Calculation of Non-Coincident peak for each sub-category class is easy. However, since, the exercise for calculating cost to serve for all categories has not be carried out, the basis for share to be allotted to the particular category is not very scientific. This study uses the Discom load factor as an approximation to arrive at the total non-coincident peak and further uses that to allot the share of Agriculture.

In cost allocation under the method used in this study, it has been ensured that all the voltages capture only the upstream costs and not the down stream costs. Thus, a 33 kV consumer would attract costs upto that level and not necessary demand charges of the 11 kV or LT consumer.

Table 5.36 Details of calculation of CP, NCP – MW

Select as 0 or 1 - Single Peak or avergae Peak					0											
Load Factors & Coincident Factors (LF_CF)																
Tariff Category	**Consumer category**	**Load factor (as per sample feeders)**	**LLF**	**CF**	**No. of Consumers**	**Consumer weightage**	**No. of equivalent consumers**	**Consumption (MU)**	**Allocation-Tech. Loss -MU**	**Allocation- Comml. Loss -MU**	**Allocation of Total Loss -MU**	**Consumption + Loss (MU)**	**Consumption in MW**	**Loss MW**	**NCP MW**	**CP-MW**
LT Agriculture	LT Cat I\V	36%	20%	35%	857,652	0.44	375,223	6,213	428	249	678	6,891	1,989	395	2,384	836
HT Agriculture (11 KV)	Cat IV (11 KV)	13%	5%	34%	96	3	240	57	3	0.3	3	60	49	6	56	19
HT Agriculture (33 KV)	Cat IV (33 KV)	15%	6%	28%	5	3	13	11	0.5	-	0	11	8	1	9	3
HT Agriculture (220 KV)	Cat IV (220 KV)	10%	4%	43%	1	3	3	263	12	-	12	274	304	37	341	145
Discom Total		80%	68%					21,793	3,492	971	4,463	26,257	3,113	743	3,856	
Calculation of NCP																
CPDCL - Peak		4,150														
CP Loadfactor		63%	47%					21,793	3,492	971	4,463	26,257	3,922	1,081	5,003	

Cost allocation under Average Peaks CP method

Table 5.37 Cost Allocation under Average peaks CP (in Cr)

Basis	CP	Mu		CP			CP			CP			CP					Cons				
	Power Purchase			Transmission			Distribution- 33 KV			Distribution- 11 KV			Distribution- LT network			Retail supply			Total			G Total
	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	
LT Agriculture	427.93	601.51		87.33			5.22			32.19			129.96					19.25	682.63	601.51	19.25	1,303.38
HT Agriculture (11 KV)	9.77	5.53		1.99			0.12			0.74			-					0.02	12.62	5.53	0.02	18.17
HT Agriculture (33 KV)	1.31	1.05		0.27			0.02			-			-					0.00	1.60	1.05	0.00	2.65
HT Agriculture (220 KV)	74.24	25.44		15.15			-			-			-					0.00	89.39	25.44	0.00	114.83

Table 5.38 Cost/ kWh under Average Peaks CP(Allocation of cost (Rs/kwh))

	Power Purchase			Transmission			Distribution- 33 KV			Distribution- 11 KV			Distribution- LT network			Retail supply			Total			G Total
	Demand	Energy	Cust	Demand	Energy	Custo	Demand	Energy	Cust	Demand	Energy	Cust	Demand	Energy	Cust	Demand	Energy	Cust	Demand	Energy	Cust	
LT Agriculture	0.69	0.97	-	0.14	-	-	0.01	-	-	0.05	-	-	0.21	-	-	-	-	0.03	1.10	0.97	0.03	2.10
HT Agriculture (11 KV)	1.71	0.97	-	0.35	-	-	0.02	-	-	0.13	-	-	-	-	-	-	-	0.00	2.21	0.97	0.00	3.18
HT Agriculture (33 KV)	1.21	0.97	-	0.25	-	-	0.01	-	-	-	-	-	-	-	-	-	-	0.00	1.47	0.97	0.00	2.44
HT Agriculture (220 KV)	2.83	0.97	-	0.58	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	3.40	0.97	0.00	4.37

Final Result of Analysis

The following table sets out the final results as arrived under the cost of service methodology. It is assumed that the entire subsidy is available to the company for supply to Agriculture only (which ignores certain Below Poverty Line consumption under Domestic category). Considering this, the following table indicate the extent of cross subsidy as well.

Table 5.39 Final results- APCPDCL

Methods	Energy Sold (MU)	Revenue at Current Tariff Rate (Rs cr)	Avg. Realn. (Rs./KWH) at current rates	CoS (Rs./ KWH)	Total Cost (Rs cr)	Total Subsidy	Subsidy Recd (Rs Cr)	Cross Subsidy(Rs cr)
CP Method								
LT Agriculture	6213.47	7.30	0.01	2.10	1303.38	1296.08		
HT Agriculture (11 KV)		69.12	2.09	3.18	18.17			
HT Agriculture (33 KV)				2.44	2.65			
HT Agriculture (220 KV)	330.75			4.37	114.83	66.53	1108.00	254.61

Cost to Serve – Agriculture Sector - NPDCL

Data gathering

Team identification

For the above study, General Manager (Planning) of NPDCL was nominated as the Nodal officer in April 09. Detailed discussions were held with the officers in NPDCL about the scope of work and the data requirement. NPDCL Divisional Engineer (RAC) was requested to collect and provide the necessary information to the consultants.

Identification of data requirement

Keeping in view the nature of study and the limitations of the distribution utilities in collecting and collating the data, the data requirement as discussed in Chapter 4 was finalized after necessary consultations with the staff of FOIR. Necessary data reporting formats were also designed and circulated

Sampling

With a view to obtain a truly representative data from the field units across different seasons, following dates were selected in consultation with NPDCL covering summer, winter and monsoon seasons as well as working days, holidays, festival days.

HT installations meter dump were found to be not fully sanitized (missing months, meters not properly downloaded etc), it was felt that the sample as collected for CPDCL would be used. However, the caveat is that the individual meter analysis may present a different picture.

In respect of LT consumers (Cat V), NPDCL has in the past collected details for ~61 days from the field spanning 13 feeders across 5 circles. To this, the State peak day data was collected and added. This gives a better representation of the load curve in the Discom

Table 5.40 Days selected

Days	Season	Date	Days	Season	Date
Holidays & Festivals	Summer	03.03.07	Sundays	Summer	11.03.07
	Summer	20.03.07		Summer	25.03.07
	Summer	27.03.07		Summer	01.04.07
	Summer	05.04.07		Summer	15.04.07
	Summer	01.05.07		Summer	06.05.07
	Monsoon	15.08.07		Monsoon	10.06.07
	Monsoon	28.08.07		Monsoon	15.07.07
	Monsoon	15.09.07		Monsoon	19.08.07
	Monsoon	02.10.07		Monsoon	16.08.07
	Monsoon	19.10.07		Monsoon	28.10.07
	Winter	08.11.07		Winter	04.11.07
	Winter	25.12.07		Winter	23.12.07
	Winter	14.01.08		Winter	05.01.08
	Winter	26.01.08		Winter	10.02.08
	Winter	11.02.08		Winter	24.02.08
	Winter	12.02.08			
Working Days	Summer	02.03.07	Working Days	Monsoon	19.09.07
	Summer	13.03.07		Monsoon	28.09.07
	Summer	04.04.07		Monsoon	05.10.07
	Summer	19.04.07		Monsoon	23.10.07
	Summer	28.04.07		Winter	03.11.07
	Summer	05.05.07		Winter	28.11.07
	Summer	15.05.07		Winter	05.12.07
	Summer	28.05.07		Winter	20.12.07
	Summer	07.06.07		Winter	05.01.08
	Summer	23.06.07		Winter	15.01.08
	Monsoon	11.07.07		Winter	28.01.08
	Monsoon	28.07.07		Winter	03.02.08
	Monsoon	03.08.07		Winter	13.02.08
	Monsoon	14.08.07		Winter	28.02.08
	Monsoon	30.08.07		Winter	20.03.08
	Monsoon	03.09.07			

Data collection

- The data collection formats and methodology were explained to the NPDCL team before initiation of work

- Logic for identification of predominant feeders was decided and explained
- Data sent by filed units were reviewed and discussions were held with the NPDCL team before finalising the hourly loads of the feeders for the sample days

Table 5.41 Feeders Selected for LT Category V – 2007-08

Circle	Feeders	No
Khammam	V.R.Peta, K.nuru, Bayyaram, Remidicherla	4
Warangal	Somidi - Agl	1
Nizamabad	Ankapur, Bodepally, Rampur, Manjeera	4
Karimnagar	Chintakapur, Singapur, Nittu+peddakalwal, Appananpet	4

Analysis of sample feeder results

As explained earlier, inputs received from the field units on the hourly loads on 11 KV feeders for the LT Category V consumption (as there is no meters to measure) and meter dumps for HT Category IV (11 kV, 33 kV, 220 kV) are used to calculate the Class Load Factor ("CLF"), Loss Load Factor ("LLF"), category peak and Coincident Factor ("CF"). The results are as under:-

LT Category V

Table 5.42 LT Cat V – Calculation

	Weights		Average	Maximum	Annual Maximum
Working	283		30	37	
Holiday	53		33	41	
Festival	30		33	40	41
Sum of 3 type of days with weights =Avg*wt				11337.6	
AMPs to MWs			15.2416	0.17	
AMPs to MWs for Max		=Max*wt*conversion		0.23	
Class Load Factor		=MW/ Maximum		75%	
Loss Load Factor		(0.3 *LF +0.7 (LF)^2		62%	
Calculation of Coincident Factor (CF) - Average Peaks				84%	

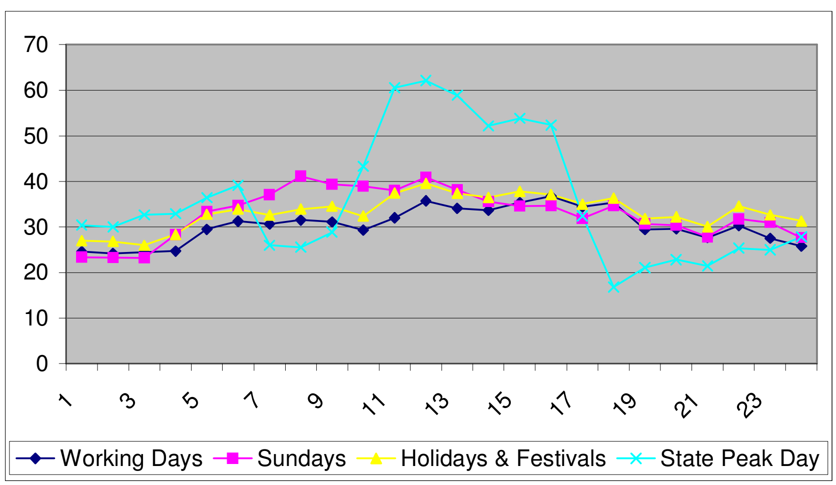


Fig 5.14 LT Cat V Load Curves

This also coincides with the morning peak recorded at the State level, showing a clear correlation, enhancing the rationale for considering the morning peak only.

Table 5.43HT – Cat IVb – 11 kV

CLF	13.2%	LLF	5.2%
CF- Avg Peaks	34%		

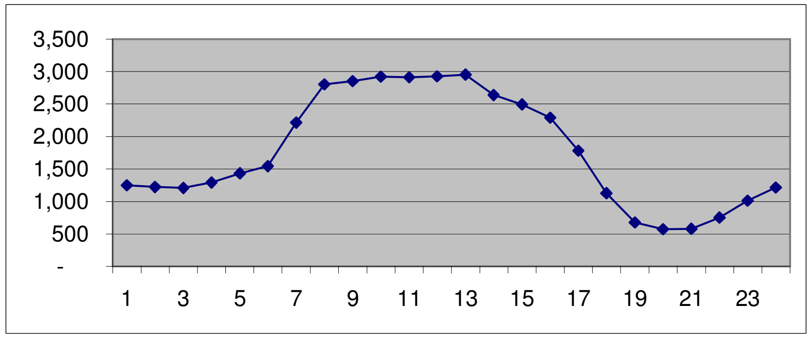


Fig 5.15 HT-Cat IVb – 11 kV – Average Load curve

Table 5.44 HT – Cat IVb – 33 kV

CLF	15.1%	LLF	6.2%
CF- Avg Peaks	28%		

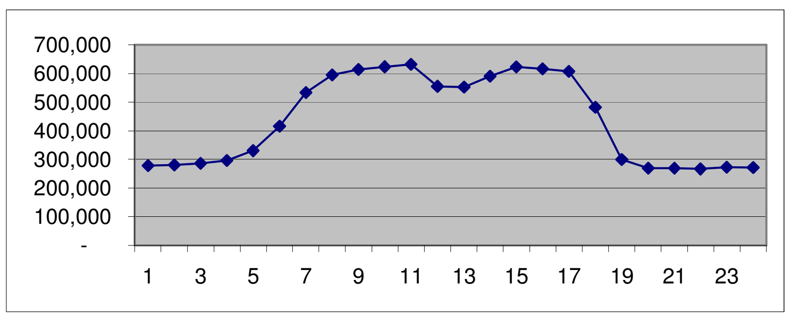


Fig 5.16 HT-Cat IVb – 33 kV

Table 5.45 HT- Cat IVa – 220 kV

CLF	10%	LLF	4%
CF- Avg Peaks	43%		

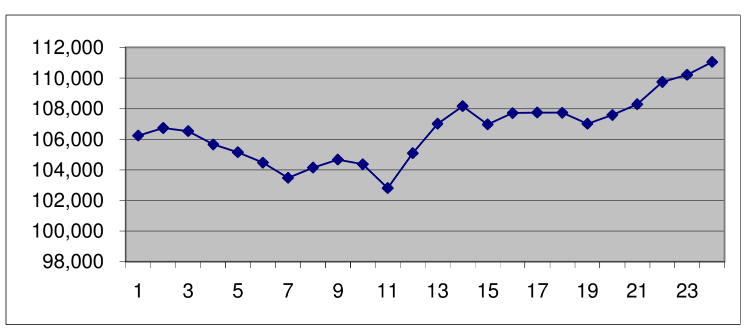


Fig 5.17 HT- Cat IVa – 220 kV – Average Load curve

Clearly, HT also shows a more tilt towards morning hours rather than the evening peak, except for 220 kV, Lift Irrigation consumer, who has increasing loads towards the evening as well.

Development of CoS model

Model description

The CoS Model has the following work sheets:-

- Operating data sheet
- P&L account
- Revenue details
- Voltage wise Assets allocation
- Revenue expenditure allocation matrix
- Functionalization and classification
- Hourly data of sample feeders
- Allocation of costs and results

Model processes

Operating data

Technical, operational, financial and commercial data for the year 2007-08 required for the development of model have been captured in this work sheet.

Profit & Loss Account

Profit and loss account of the year 2007-08, as per the audited accounts of the company has been captured in this work sheet. Trial balance has been used to provide details of individual items like Transmission charges, Interest on Security deposit from consumers, Provision for Bad and Doubtful debts etc.

Revenue details

Revenue from sale of power for the year 2007-08, as per the audited accounts of the company has been captured in this work sheet.

Fixed Asset details

Details of fixed Assets (as per Trial balance for FY 08) have been captured and segregation of assets in to various voltage classes have been made based on the methodology as followed by Company in its filing of ARR for 2007-08.

Table 5.46 CPDCL- Asset Classification – Voltage wise, Business wise – 2007-08

Asset Group	33KV				11KV				LT network				Retail supply				Grand Total
	Demand	Energy	Consumer	Total	Demand	Energy	Consumer	Total	Demand	Energy	Consumer	Total	Demand	Energy	Consum er	Total	
Land & Rights	691053			691,053	4494118			4494118	11046931			11046931			1571219	1571219	17803321
Buildings	8157706			8,157,706	53051944			53051944	130406275			130406275			18547852	18547852	210163778
Hydraulic Works	0				0			0	0			0			0	0	0
Other Civil Works	1691744			1,691,744	11001908			11001908	27043644			27043644			3846452	3846452	43583749
Plant & Machinery	310791134			310,791,134	2021165534			2021165534	4968199998			4968199998			706633474	706633474	8006790140
Lines, Cable, Network, Meters, Metering Equipetc.	415104269			415,104,269	2699544324			2699544324	6635713840			6635713840			943806112	943806112	10694168544
Vehicles	882537			882,537	5739397			5739397	14107936			14107936			2006590	2006590	22736460
Furniture and Fixtures	1196832			1,196,832	7783347			7783347	19132142			19132142			2721189	2721189	30833510
Office Equipments	283568			283,568	1844128			1844128	4533025			4533025			644738	644738	7305459
Computer Software and others	4920426			4,920,426	31998965			31998965	78656228			78656228			11187376	11187376	126762994
Total	**743,719,269**			**743,719,269**	**4836623664**	**0**	**0**	**4836623664**	**11888840020**	**0**	**0**	**11888840020**	**0**	**0**	**1690965003**	**1690965003**	**19160147955**
Voltage wise assests (as a % to the overall)				**3.88%**				**25.24%**				**62.05%**				**8.83%**	**100%**

Apportionment of Fixed Assets (in %)*				
33 KV	**11KV**	**LT network**	**Retail supply**	**Total**
4%	25%	62%	9%	100%

Revenue Expenditure matrix

Based o the nature of expenditure, the expenditure has been allotted to the wires or retail supply business. Where they are common to both, the asset base has been used to split the expense. Expenses like Power Purchase, Transmission cost, Interest on consumer security deposits, Provision for bad and doubtful debts have been allocated in full to Retail supply business (consumer related).

Table 5.47 Revenue Expenditure Allocation Matrix

Revenue Expenditure Matrix	**Cost allocation % adopted**				
Nomenclature	**33 KV**	**11 KV**	**LT Network**	**Retail supply**	**Total**
Purchase of Power	-	-	-	100%	100%
Transmission Charges	-	-	-	100%	100%
Repairs & Maintenance	4%	25%	62%	9%	100%
Employee Costs	4%	25%	62%	9%	100%
Administration & General expense	4%	25%	62%	9%	100%
Depreciation & Related	4%	25%	62%	9%	100%
Interest & Financial Charges	4%	25%	62%	9%	100%
Interest on working capital	4%	25%	62%	9%	100%
Interest on con.security deposits		0%	0%	100%	100%
Interest on power purchase dues					0%
SUB-TOTAL	-				0%
Less: Expenses Capitalised					0%
Less: Interest & Finance Charges					0%
Other Expenses					0%
SUB-TOTAL					
Other Debits (incl. Bad debts)	0%	1%	3%	95%	100%
Extra Ordinary Items					0%
Net Prior Period Charges/Credits	4%	25%	62%	9%	100%
Income Tax	4%	25%	62%	9%	100%
ROE/ROR	4%	25%	62%	9%	100%
					0%
TOTAL RR					0%
Less:					0%
Other income	4%	25%	62%	9%	100%
Miscellaneous income	4%	25%	62%	9%	100%
					0%
Total					0%
NET TOTAL EXPENSES					0%

Functionalization & classification matrix

For cost of service purposes, as first step, utility costs have been broken down, or functionalized in to the following cost functions:

- Generation or Power Purchase cost
- Transmission cost
- Distribution cost

After the utility revenue requirements have been separated by function, they have to be classified according to cost component. The typical utility cost components are as follows:

- Demand related
- Energy related
- Customer related

In the context of NPDCL, since it is a power distribution company, it pays power purchase cost to generators based on the allocation of generation % made by the Government from time to time. This constitutes the generation cost for NPDCL. Similarly, the transmission & SLDC charges paid to APTransco is reckoned as the Transmission cost.

Following table indicates the functionalisation of generation, transmission and distribution costs.

Table 5.48 Functionalisation of Costs

Particulars	A/C Group	Methodology	Generation / Power purchase cost			Transmission			Distribution				Total
			Demand	Energy	Cus.	Demand	Energy	Cus.	33KV	11 KV	LT Net work	Retail	
Generation	70	FC demand related	38.84%	61.16%	0.00%								
		EC energy related											
Transmission	70	Demand related				100.00%	0.00%	0.00%					
Distribution	74 to 83	Functionalisation of Fixed assets is made on basis of % allocation							3.88%	25.24%	62.05%	8.83%	100.00%

After functionalisation and classification of generation & transmission expenses as well as functionalisation of distribution expenses, the next step in the CoS process is to classify the distribution expenses (Revenue Requirement) as demand, energy and customer related. Classification of Revenue Requirement under various heads between 33 kV, 11 KV, LT net work and retail supply has been made as under:

On the basis of above principles, the classification of costs have been made as under:-

Table 5.49 Functionalisation of Costs

Revenue Expenditure Matrix	Distribution			
Nomenclature	**33KV**	**11KV**	**LT Netywork**	**Retail**
Purchase of Power	-	-	-	2,054.12
Transmission Charges	-	-	-	108.24
Repairs & Maintenance	1.15	7.49	18.42	2.62
Employee Costs	6.58	42.82	105.25	14.97
Administration & General expense	1.11	7.24	17.81	2.53
Depreciation & Related	4.68	30.41	74.76	10.63

Revenue Expenditure Matrix	Distribution			
Nomenclature	**33KV**	**11KV**	**LT Netywork**	**Retail**
Interest & Financial Charges	2.54	16.50	40.57	5.77
Interest on working capital	0.06	0.37	0.91	0.13
Interest on con.security deposits	-	-	-	12.52
Interest on power purchase dues	16.12	104.85	257.72	2,211.54
SUB-TOTAL				
Less: Expenses Capitalised				
Less: Interest & Finance Charges				
Other Expenses				
SUB-TOTAL				
Other Debits (incl. Bad debts)	0.19	1.23	3.03	84.68
Extra Ordinary Items				
Net Prior Period Charges/Credits	0.03	0.17	0.43	0.06
Income Tax	0.06	0.37	0.91	0.13
ROE/ROR	0.25	1.65	4.05	0.58
TOTAL RR				
Less:	16.65	108.27	266.14	2,296.98
Other income	-	-	-	-
Miscellaneous income	(4.82)	(31.32)	(76.99)	(10.95)
Total	(4.82)	(31.32)	(76.99)	(10.95)
NET TOTAL EXPENSES	11.83	76.95	189.15	2,286.03

The above costs are further segregated as demand, energy and customer related costs as under:-

Table 5.50 Segregation of Costs – Demand, Energy and Consumer

Revenue Expenditure Matrix	PP Cost		Transmission	33 KV	11 KV%	LT Network	Retail
Nomenclature	**Demand**	**Energy**	**Demand**	**Demand**	**Demand**	**Demand**	**Consumer**
Purchase of Power	798	1,256					
Transmission Charges			108.24				
Repairs & Maintenance				1.15	7.49	18.42	2.62
Employee Costs				6.58	42.82	105.25	14.97
Administration & General expense				1.11	7.24	17.81	2.53
Depreciation & Related				4.68	30.41	74.76	10.63
Interest & Financial Charges				2.54	16.50	40.57	5.77
Interest on working capital				0.06	0.37	0.91	0.13
Interest on con.security deposits				-	-		12.52
Interest on power purchase dues	797.84	1,256.27	108.24	16.12	104.85	257.72	49.18
SUB-TOTAL							
Less: Expenses Capitalised							
Less: Interest & Finance							

Revenue Expenditure Matrix	**PP Cost**		**Transmission**	**33 KV**	**11 KV%**	**LT Network**	**Retail**
Nomenclature	**Demand**	**Energy**	**Demand**	**Demand**	**Demand**	**Demand**	**Consumer**
Charges							
Other Expenses							
SUB-TOTAL							
Other Debits (incl. Bad debts)				0.19	1.23	3.03	84.68
Extra Ordinary Items							
Net Prior Period Charges/Credits				0.03	0.17	0.43	0.06
Income Tax				0.06	0.37	0.91	0.13
ROE/ROR				0.25	1.65	4.05	0.58
TOTAL RR							
Less:	797.84	1,256.27	108.24	16.65	108.27	266.14	134.62
Other income				-	-		
Miscellaneous income				(4.82)	(31.32)	(76.99)	(10.95)
Total	-	-	-	(4.82)	(31.32)	(76.99)	(10.95)
NET TOTAL EXPENSES	797.84	1,256.27	108.24	11.83	76.95	189.15	123.67

Model outputs

Table 5.51 Details of calculation of CP, NCP – MW

Tariff Category	Consumer category	Load factor (as per sample feeders)	LLF	CF	No. of Consumers	Consumer weightage	No. of equivalent consumers	Consumption (MU)	Allocation-Tech. Loss - MU	Allocation-Comml. Loss - MU	Allocation of Total Loss -MU	Consumption + Loss (MU)	Consumption in MW	Loss MW	NCP MW	CP-MW
LT Agriculture	LT Cat I\V	75%	62%	84%	782,919	0.44	342,527	3,622	216	164	379	4,001	548	69	617	519
HT Agriculture (11 KV)	Cat IV (11 KV)	13%	5%	34%	96	3	240	5	0	0.0	0	5	4	0	5	2
HT Agriculture (33 KV)	Cat IV (33 KV)	15%	6%	28%	5	3	13	9	0.3	-	0	9	7	1	7	2
HT Agriculture (220 KV)	Cat IV (220 KV)	10%	4%	43%	1	3	3	83	3	-	3	86	96	10	106	45
Discom Total		80%	68%					7,748	1,066	389	1,455	9,203	1,107	242	1,349	
Calculation of NCP																
NPDCL - Peak		1,617														
NP Loadfactor		57%	40%					7,748	1,066	389	1,455	9,203	1,549	417	1,966	

Cost allocation under Average Peaks Coincident method:-

Table 5.52 Cost Allocation under Average Peaks CF

(Allocation of cost (Rs. in crs))

Basis	CP Power Purchase	Mu	CP Transmission	CP Distribution- 33 KV	CP Distribution- 11 KV	CP Distribution- LT network	Cons Retail supply	Total Deamand	Energy	Cust	G Total
LT Agriculture	274.34	456.47	37.22	4.07	26.46	86.83	21.09	428.91	456.47	21.09	906.47
HT Agriculture (11 KV)	0.82	0.56	0.11	0.01	0.08	-	0.02	1.02	0.56	0.02	1.60
HT Agriculture (33 KV)	1.10	1.06	0.15	0.02	-	-	0.00	1.27	1.06	0.00	2.33
HT Agriculture (220 KV)	23.79	9.82	3.23	-	-	-	-	27.01	9.82	-	37.19

Table 5.53 Cost/ kWh under Average Peaks CF

(Allocation of cost (Rs/kwh))

	Power Purchase			Transmission			Distribution- 33 KV			Distribution- 11 KV			Distribution- LT network			Retail supply			Total			G Total
	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	
LT Agriculture	0.76	1.26	-	0.10	-	-	0.01	-	-	0.07	-	-	0.24	-	-	-	-	0.06	1.18	1.26	0.06	2.50
HT Agriculture (11 KV)	1.75	1.19	-	0.24	-	-	0.03	-	-	0.17	-	-	-	-	-	-	-	0.04	2.18	1.19	0.04	3.41
HT Agriculture (33 KV)	1.23	1.18	-	0.17	-	-	0.02	-	-	-	-	-	-	-	-	-	-	0.00	1.41	1.18	0.00	2.59
HT Agriculture (220 KV)	2.86	1.18	-	0.39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.25	1.18	-	4.48

Final Result of Analysis

The following table sets out the final results as arrived under the cost of service methodology. It is assumed that the entire subsidy is available to the company for supply to Agriculture only (which ignores certain Below Poverty Line consumption under Domestic category). Considering this, the following table indicate the extent of cross subsidy as well.

Table 5.54 Final Result- APNPDCL

Methods	Energy Sold (MU)	Revenue at Current Tariff Rate (Rs cr)	Avg. Realn. (Rs./KWH) at current rates	CoS (Rs./KWH)	Total Cost (Rs cr)	Total Subsidy	Subsidy Recived from Govt (Rs Cr)	Cross Subsidy(Rs cr)
LT Agriculture	3622.14	3.34	0.01	2.50	906.47	903.13		
HT Agriculture (11 KV)				3.41	1.60			
HT Agriculture (33 KV)				2.59	2.33			
HT Agriculture (220 KV)	96.71	19.41	2.01	4.48	37.19	21.70	1078.95	(154.11)

5.2 Karnataka

Agricultural Background

Agriculture plays an important role in the economy of Karnataka. It contributes about 28% of the State Domestic Product and is also the largest source of employment. About 71% of the total population is dependent on agriculture. Of the total geographic area of 190.5 lakh hectares (excluding forest area), the total area under agriculture is 68%[19]. The net sown area is 65% (after adjusting for the area sown more than once) while the gross irrigated area is 24%.

Canals are the pre-dominant source of irrigation, accounting for 35% of the net irrigated area, closely followed tubewells. This is evident from Figure 5.18, which shows the net area irrigated by source in Karnataka in 2005-06.

[19] Total cropped area has been taken as the total area under agriculture.

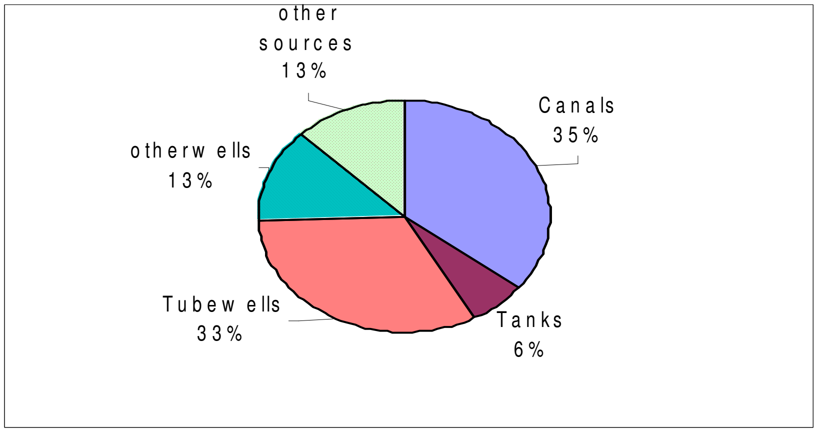


Figure 5.18: Source wise net area irrigated in 2005-06 (Provisional)

Source: Fertilizer statistics 2007-08

The principle crops grown in the state are cereals, pulses, oilseeds and commercial crops such as sugarcane, cotton and turmeric. In 2006-07 , cereals accounted for 48% of the net area sown, followed by pulses and oilseeds constituting 23% and 22% respectively of the net area sown, while the rest of the area was under sugarcane and cotton production. (Figure 5.19)

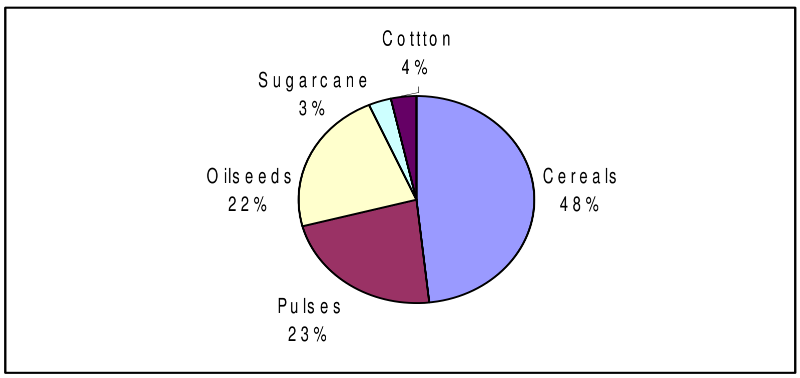


Figure 5.19: Area-wise classification of principle crops in 2006-07 (Provisional)

Source: Fertilizer statistics 2007-08

Seasonal discipline

Agricultural production in the state is spread over three seasons namely Kharif, Rabi and summer. These seasons account for nearly 70%, 22% and 8% of annual food grain production respectively. Area coverage under Kharif, Rabi and summer seasons is around 70 lakh hectares, 30 lakh hectares and 6 lakh hectares respectively.

Rainfall

As 76% of the total area under crops is rain fed, rainfall is in extremely important factor determining crop production. The remaining 24% of the area is under irrigation. During 2007-08 the state received an average rainfall of 1163 mm in excess of the normal level at 1140 mm. Kharif crops received majority of the rainfall (approx. 782 mm) during the months of June-September, followed by summer crops which received rainfall of 238 mm during the months of January-March. Electricity for irrigation is primarily used for Rabi crops as they do not receive much rainfall during Oct-March.

Figure 5.20 shows the trend in annual rainfall from 1998-2008.

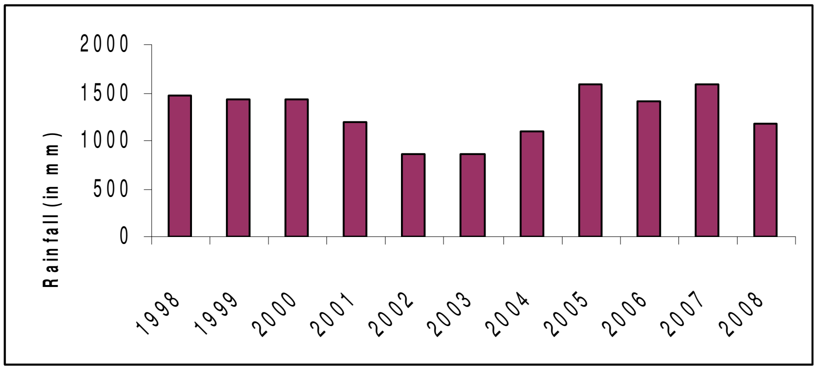


Figure 5.20: Trend in annual rainfall (1998-2008)

Source: http://raitamitra.kar.nic.in/statistics.html#B20

Within the state, coastal Karnataka receives most of the rainfall, followed by Southern Karnataka. Table 5.55 shows the region wise rainfall in Karnataka in 2007-08. It can be clearly seen from the table below that all the regions received excess rainfall during the South west monsoon period as compare to the pre and post monsoon period. This implies that demand for irrigation is much more during these seasons as compared to others and consequently the demand for electricity is higher during these periods.

Table 5.55: Region wise rainfall in Karnataka in 2007-08

Region	Coastal Karnataka	North Interior Karnataka	South Interior Karnataka
Pre monsoon period (March- May)			
Actual	109	51	107
Normal	179	88	150
Excess/ Deficient (%)	-39	-42	-29
South West monsoon period (June -Sept)			
Actual	3588	686	917
Normal	3174	491	659
Excess/ Deficient (%)	13	40	39
Post Monsoon period (Oct-Dec)			
Actual	215	52	206
Normal	258	137	200
Excess/ Deficient (%)	-17	-62	3
Winter Monsoon period (Jan-Feb)			

Actual	9	7	20
Normal	2	5	5
Excess/ Deficient (%)	366	44	259

Source: Fertilizer statistics 2007-08

Area, irrigation and crops

The total cropped area has increased by 24 % from 104 lakh hectares to 129 lakh hectares over the last 52 years.

In terms of irrigation, the gross total area irrigated by all the crops was about 36.3 lakh hectares in 2005-06. Table 5.56 gives the crop wise gross irrigated area in 2005-06.

Table 5.56: Crop wise gross irrigated area (2005-06)

Crop	**Area in ' 000 hectares**
Cereals	
Rice	1120
Jowar	132
Bajra	39
Maize	379
Ragi	44
Wheat	130
Barley	0
Other cereals and millets	0
Total cereals	1844
Pulses	
Gram	68
Arhar	19
Total pulses (excl gram and Arhar)	106
Total food grains (cereals+ pulses)	1950
Total oilseeds	683
Sugarcane	416
Total area	3049

Source: Fertilizer statistics 2007-08

While area under Kharif crops has increased by 18% during 2001-02 and 2005-06, the production has recorded a growth of 36%. Though the production has increased for Rabi crops the area under Rabi crops has declined by 14%.Maximum growth has been in case of summer crops which have grown by more than 50% during 2001-02 and 2005-06. (Table 5.57)

Table 5.57: Crop wise gross irrigated area (2005-06)

Crop	**2001-02**	**2005-06**	**% increase**
Kharif			
Area	30.09	35.55	18%

Production	56.38	76.8	36%
Yield	1972	2274	15%
Rabi			
Area	19.01	16.17	-15%
Production	14.78	16.8	14%
Yield	819	1094	34%
Summer			
Area	3.02	3.91	29%
Production	7.92	11.97	51%
Yield	2759	3222	17%

Source: Fully revised estimates of principal crops in Karnataka for the Year 2005-2006, Directorate of Economics and Statistics

Agricultural characteristics of BESCOM

BESCOM's service area covers eight districts viz. Bangalore Urban, Bangalore Rural, Kolar, Tumkur, Chitradurga, Davangere, Ramnagaram, Chikballapura. Its areas of jurisdiction constitute 20% of the net area sown of the state. Among all districts Tumkur and Chitradurga together have half of the net sown area. (Table 5.58)

Table 5.58: District wise net sown area in 2007-08

District	Net area sown	%
Bangalore (Urban	58884	3%
Bangalore (Rural)	103852	5%
Kolar	172861	8%
Tumkur	608193	29%
Chitradurga	435436	21%
Chikkaballapur	170699	8%
Davanagere	389771	19%
Ramanagar	158929	8%
Total area	2098625	100%

Source: http://raitamitra.kar.nic.in/imp_agri_stat.html

Rainfall across districts has been depicted in the figure below. Rainfall statistics indicate that all the districts are heavily dependent on southwest monsoon which contributed to majority of the rainfall in state.

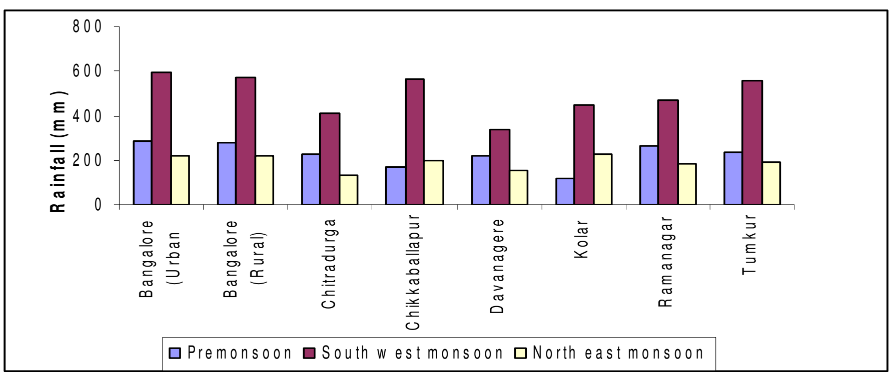


Figure 5.21: District wise rainfall in 2007-08

Source: Economic survey 2008-09

District and source wise irrigation in 2007-08 has been indicated in Table 5.59. It can be seen from the table that sources of irrigation differ widely across districts. While canals accounted for about 31% of the gross irrigated area in Davanagare, they accounted only for about 1% in Tumkur. However all the districts have a high dependency on tubewells and borewells which has a significant impact on electricity consumption and therefore has an important implication for BESCOM.

Table 5.59: Share of different sources of irrigation in the gross irrigated area (2007-08)

District	Canals	Tanks	Wells	Tube/Bore wells	Lift Irrigation (*)	Other Sources (*)
Bangalore (Urban)	0%	6%	2%	92%	0%	0%
Bangalore (Rural)	0%	0%	0%	99%	0%	0%
Chikkaballapur	0%	0%	0%	100%	0%	0%
Chitradurga	6%	1%	0%	93%	0%	0%
Davanagare	31%	17%	18%	65%	0%	0%
Kolar	0%	0%	0%	100%	0%	0%
Ramnagar	8%	0%	0%	91%	1%	0%
Tumkur	1%	17%	1%	81%	0%	0%

Source: http://raitamitra.kar.nic.in/statistics.html#B4

Land use pattern across districts as seen in Table 5.60 indicates that majority of the farmers are small and marginal farmers.

Table 5.60: District-wise and size-wise Agricultural holdings (2005-06)

District	Marginal Farmers		Small Farmers		Semi-med. Farmers		Medium farmers		Large farmers	
	No.	Area (000' hectares)	No.	Area (000' hectares	No.	Area (000' hectares	No.	Area (000' hectares	No.	Area (000' hectares
Bangalore (Urban)	64%	24%	21%	24%	11%	25%	4%	20%	0%	7%
Bangalore (Rural)	67%	28%	20%	26%	9%	24%	3%	17%	0%	5%
Chitradurga	36%	10%	31%	22%	21%	28%	10%	28%	2%	13%
Davanagere	45%	15%	30%	27%	17%	29%	6%	23%	1%	6%
Kolar	62%	24%	22%	27%	11%	25%	4%	19%	0%	5%
Tumkur	49%	14%	26%	22%	17%	28%	8%	26%	1%	9%

* Holding Size:
Marginal Farmers: Below 1 hect., Small Farmers : 1 to 2 hects., Semi-medium Farmers 2 to 4 hects. Medium Farmers 4 to 10 hects. Large farmers 10 hects. and above.

Source : http://raitamitra.kar.nic.in/imp_agri_stat.html

Energy characteristics of Karnataka

Karnataka system has a contracted capacity of ~6,700 MW, from KPCL, Central Stations, IPPs and Non-Conventional energy sources.

Table 5.61. Karnataka Energy Supply System – 2008

	MW	%
KPCL - Thermal	1470.00	22%
KPCL – Hydel	3165.95	47%
VVNL	354.32	5%
CGS	1458.91	22%
IPPs	329.10	5%
Others		
Transmission/ SLDC		
Total	**6778.28**	

It can be seen that KPCL's capacity dominates the system and its hydel plays an important role in the supply of energy within the State. IPPs account for ~5% of the State's requirement.

Table 5.62. Power Costs breakup 2007-08

	Fixed Cost	Varaibale Cost	% of FC to Total Cost
KPCL - Thermal	208.49	1158.31	12%
KPCL - Hydel		311.98	
VVNL	28.36	158.93	15%
CGS	291.82	613.13	32%
IPPs	332.21	483.87	41%
Others		1352.89	
Transmission/ SLDC			
Total	**860.88**	**4079.11**	**17%**

The important point of note from table 5.62 is that the fixed cost component of the stations are less than a sixth of the total cost and this would have an impact on the cost to study, as demand costs are allotted on the basis of coincident or non-coincident peaks.

Though the IPPs have a larger fixed cost element, the vintage plants of KPCL (with its dominant share) reduce the impact of the overall fixed cost in the system.

Load Curve Analysis – Karnataka State [BESCOM]

Load duration

For load analysis, the data has been collected from the SLDC in Bangalore.

The following graph sets out the load duration (as supplied with restriction on rural, agricultural and industrial loads) during the year 2007-08.

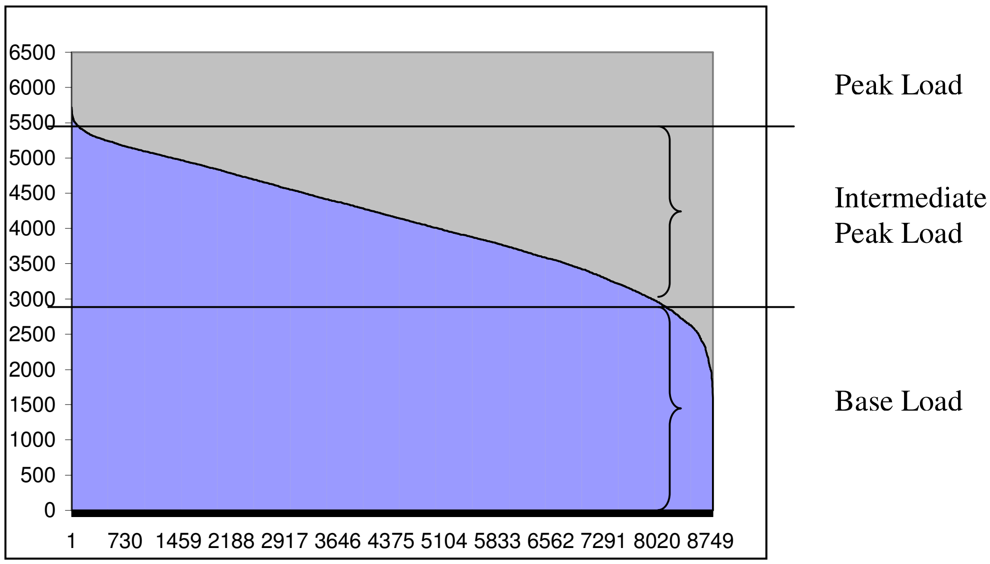


Fig 5.22 Load duration curve for AP – 2007-08

Karnakata system moves between a base load of ~2900 MW and upto ~4900 MW during the intermediate peak. It hits a peak of 5,715 MW (on 18th March 2008 at 2000 Hrs). The median value load is ~4,170 MW.

The duration of loads in a frequency interval of say 500 MWs has been presented in the table below.

Table 5.63 Duration of various loads –Karnataka State - 2007-08

MW	Hrs	% oy year	No of Days
1400	1	0%	0
1900	17	0%	1
2400	134	2%	6
2900	512	6%	21
3400	1063	12%	44
3900	1654	19%	69

This table shows that for ~ 293 days in a year (80% of the time), the load is within the band of 2000-4,900 MW. For ~ 67 days, the system needs another 500 MW. Another 26 days, the system requirement has increased by 500 MW. Thus for ~360 days (out of 366 days in 2007-08), the system managed with 5,400 MW. For the remaining 6 days, the requirement increased by another 315 MW.

The caveat to be noted here is that the system is a heavily administered one, with high finesse in demand side management. Loads are interrupted to safe guard the system as well as not incur penalties under UI or trading in costly power.

The following table looks at the load duration profile from the agricultural season of Kharif and Rabi.

Table 5.64 Load duration during Kharif & Rabi Seasons – 2007-08, Karnataka

Khariff (Jun – Sep)				Rabi (Nov – Mar)			
MW	Hrs	% of year	No of Days	MW	Hrs	% of year	No of Days
1400	1	0%	0	1400	0	0%	-
1900	17	0%	1	1900	0	0%	-
2400	132	2%	6	2400	1	0%	0
2900	390	4%	16	2900	59	1%	2
3400	726	8%	30	3400	127	1%	5
3900	845	10%	35	3900	415	5%	17
4400	607	7%	25	4400	661	8%	28

It can be seen from the loads that Rabi would require higher loads (as there would be least rainfall) and the peak happens only during this period. Rabi season would require additionally ~815 MW (almost 20% of the base and intermediate load) more than the Kharif season (assuming that the SW monsoon has been normal or excess and timely).

Monthly peaks of the State are mapped below.

Table 5.65 Karnataka Monthly Peaks – 2007-08

Month	Max	Hrs
April	5644	8:00 PM
May	5704	8:00 PM
June	5086	8:00 PM
July	4849	8:00 PM
August	5023	8:00 PM
September	4777	8:00 PM
October	5465	7:00 PM
November	5200	8:00 AM
December	5441	10:00 AM
January	5646	10:00 AM
February	5658	8:00 AM
March	5715	8:00 PM

It can be seen from the above readings that most of the peaks happen at 8 PM (60%) whereas peaks at morning 8 AM and 10 AM occurs for a third of the year. Morning peak has happened only for 4 months. The system moves into a high gear between December to March, wherein most of the morning peaks occur. However, the general tendency is to have an administered evening peak.

As explained earlier, instead of taking a single peak, the average of the State's monthly peaks has been considered for calculating the 'Coincident peak'

Estimation of Cost to Serve for BESCOM

Team Identification

For the study, General Manager (O&M) of BESCOM and Technical Assistant to the Chairman of KERC were nominated as the Nodal officers. Detailed discussions were held with these officers about the scope of work and the data requirement. General Manager (O&M), BESCOM identified two Executive Engineers in his office to collect and provide the necessary information to the consultants.

Sampling

Data for 14 feeders which have at least 80% of the connected load form the LT Agriculture or HT agriculture load across 4 rural circles of BESCOM (Two circles of Bangalore city were not considered) was collected and tabulated. Table 5.66 indicated the feeders selected in each circle.

Table 5.66 Selected feeders across various circle

Sl.No	Name of the circle	No. of feeders data collected
1	Bangalore Rural Circle	5
2	Davanagere Circle	3
3	Tumkur Circle	4
4	Kolar Circle	2
	Total	**14**

With a view to obtain a truly representative data from the field units across different seasons, certain dates were selected (as indicated in Table 5.67) in consultation with BESCOM team covering summer, winter and monsoon seasons as well as working days, holidays, festival days.

Table 5.67 Selected days for sampling

Sample Days	Hourly load in MW	Type of the Day

Sample Days	Hourly load in MW	Type of the Day
06-04-07	Summer	Festival day
11-04-07		Working day
01-05-07		Holiday
13-06-07	Monsoon	Working day
15-07-07		Holiday
19-07-07		Working day
09-08-07		Working day
15-08-07		Holiday
15-09-07		Festival day
15-10-07	Winter	Festival day
20-10-07		Working day
20-11-07		Working day
05-12-07		Working day
09-12-07		Holiday
26-01-08		Holiday
22-02-08		Working day
15-03-08	Summer	Working day
18-03-08		Peak day

Analysis of sample feeder results

Based on the inputs received from the field units on the hourly loads on 11 KV feeders (Bescom system does not have 33 KV network), the LF, LLF, category peak, CF and CP were calculated. The results are presented in table 5.68

Table 5.68 feeder Data Analysis

Calculation of class Load Factor							
				Hours	**Total Hours**		
	Summer days	(Feb, March, April May)	121	24	2904		
	Monsoon days	(June, July, August, Sept)	122	24	2928		
	Winter days	(Oct, Nov, Dec, Jan)	123	24	2952		39.38%
Calculation of LLF		(0.3 *LF +0.7 (LF)^2					23%
Calculation of category peak load MW							
		(sales/8.784*LF) + (energy losses/8.784*LLF)					
	Category sales Mus	3613					
	Category losses	1154				MW	1624
	Total	4767					
Calculation of CF							36%
Calculation of Co-incident peak						MW	680

The load curve for the sample feeders is presented in figure 5.23.

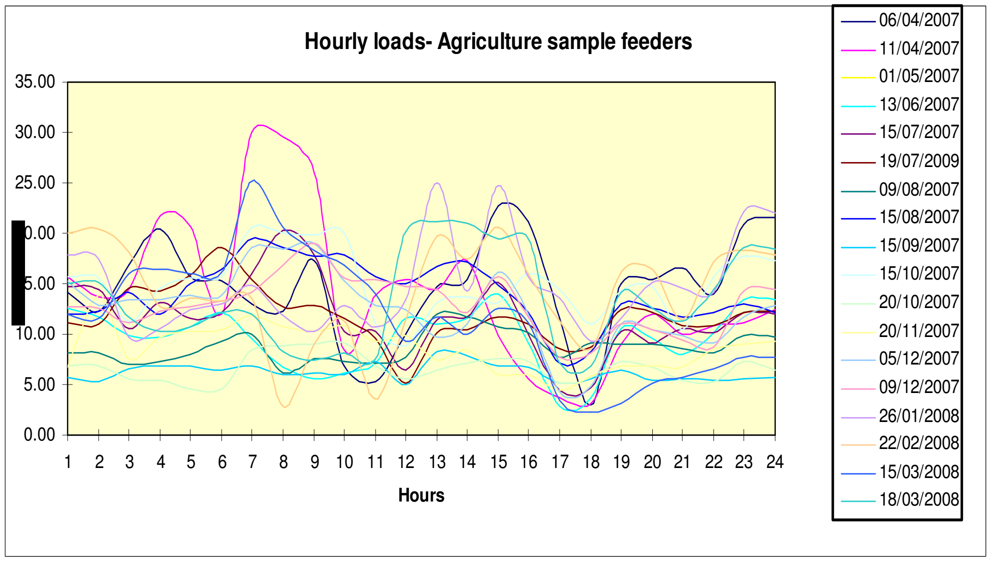


Figure 5.23: Agricultural Feeder Data Analysis

Model processes

This section details out the process for calculating the cost of service of power to the agricultural consumers and the analysis of the results derived.

Step 1: Functionalisation

As per BESCOM's annual accounts for 2007/08, a summary of costs incurred by the utility as functionalised into power purchase, transmission and distribution related is presented in table 5.69

Table 5.69 Functionalised Cost of BESCOM

	Power Purchase	Transmission	Distribution
	Rs cr	**Rs cr**	**Rs cr**
Purchase of Power	4,511.13		
Transmission Charges		428.86	
Repairs & Maintenance			43.45
Employee Costs			347.02
Administration & General expense			67.81
Depreciation & Related			48.07
Interest & Financial Charges			61.33
Interest on working capital			-
Interest on con.security deposits			91.77
Interest on power purchase dues			18.97
SUB-TOTAL	4,511.13	428.86	5,618.41
Less: Expenses Capitalised			
Less: Interest & Finance Charges			-

	Power Purchase	Transmission	Distribution
	Rs cr	Rs cr	Rs cr
Other Expenses			-
SUB-TOTAL			-
Other Debits (incl. Bad debts)			230.44
Extra Ordinary Items			-
Net Prior Period Charges/Credits			52.68
Income Tax			2.36
ROE/ROR			12.58
TOTAL RR			5,916.47
Less:			
Other income			109.79
Miscellaneous income			40.29
Total			150.08
NET TOTAL EXPENSES	4,511.13	428.86	5,766.39

Step 2: Classification

Details of fixed Assets (as per Trial balance for FY 08) have been captured and segregation of assets in to various voltage classes have been made based on the methodology recommended by the internal committee of BESCOM for segregation of assets for the MYT exercise. Table 5.70 & 5.71 presents the classification of the fixed assets into different voltage classes and their further segregation into demand, energy and customer category.

Table 5.70 Percentage wise classification of fixed assets

Asset	11KV				LT network				Retail supply			
Group	Demand	Energy	Consumer	Total	Demand	Energy	Consumer	Total	Demand	Energy	Consumer	Total
10.1	50%	0%	50%	100%	50%	0%	50%	100%	50%	0%	50%	100%
10.2	53%	0%	47%	100%	34%	0%	66%	100%	25%	0%	75%	100%
10.3	50%	0%	50%	100%	50%	0%	50%	100%	50%	0%	50%	100%
10.4	50%	0%	50%	100%	50%	0%	50%	100%	50%	0%	50%	100%
10.5	99%	0%	1%	100%	96%	0%	4%	100%	25%	0%	75%	100%
10.6	96%	0%	4%	100%	91%	0%	9%	100%	16%	0%	84%	100%
10.7	50%	0%	50%	100%	50%	0%	50%	100%	50%	0%	50%	100%
10.8	25%	0%	75%	100%	25%	0%	75%	100%	25%	0%	75%	100%
10.9	9%	0%	91%	100%	14%	0%	86%	100%	9%	0%	91%	100%
Total	**97%**	**0%**	**3%**	**100%**	**90%**	**0%**	**10%**	**100%**	**17%**	**0%**	**83%**	**100%**

Table 5.71 Classification of fixed assets in monetary terms (Rs)

Asset Group	11KV				LT network				Retail supply				Grand Total
	Demand	Energy	Consumer	Total	Demand	Energy	Consumer	Total	Demand	Energy	Consumer	Total	
10.1	6539321	0	6539321	13078641	17244222	0	17244222	34488445	19811928	0	19811928	39623855	87190941
10.2	29975777	0	26839881	56815658	45387101	0	86446081	131833183	27232261	0	81424103	108656364	297305205
10.3	2225780	0	2225780	4451560	4451560	0	4451560	8903120	4451560	0	4451560	8903120	22257799
10.4	428661	0	428661	857321	857321	0	857321	1714642	857321	0	857321	1714642	4286605
10.5	4012678963	0	20633315	4033312278	1738748233	0	80566728	1819314961	28119067	0	85467777	113586844	5966214083
10.6	10190157837	0	377726522	10567884360	6839630622	0	702060710	7541691332	515375337	0	2729789533	3245164870	21354740561
10.7	7360057	0	7360057	14720114	34430869	0	34430869	68861739	7396030	0	7396030	14792060	98373913
10.8	1506139	0	4518417	6024555	6024555	0	18073666	24098222	7530694	0	22592083	30122777	60245555
10.9	282794	0	2987616	3270410	629685	0	4028288	4657973	2235945	0	23821702	26057647	33986030
Total	**14251155328**	**0**	**449259569**	**14700414897**	**8687404170**	**0**	**948159446**	**9635563616**	**613010143**	**0**	**2975612037**	**3588622180**	**27924600693**
Voltage wise assets (as a % to the overall)				**53%**				**35%**				**13%**	**100%**

The functionalised cost is classified into demand, energy and customer related cost. Table 5.72 presents the classification of power purchase cost, transmission and distribution cost into demand, energy and customer related costs.

Table 5.72 Classification of Functionalised cost

Particulars	A/C Group	Methodology	Generation / Power purchase cost			Transmission			Distribution			
			Demand	Energy	Cus.	Demand	Energy	Cus.	11 KV	Net work	Retail	Total
Generation	70	FC demand related EC energy related	17.43%	82.57%	0.00%							
Transmission	70	Demand related				100.00 %	0.00 %	0.00 %				
Distribution	74 to 83	Functionalisation of Fixed assets is made on basis of % allocation							52.64%	34.51%	12.85%	100.00%
		Functionalisation of distribution cost							13.57%	21.29%	65.14%	100.00%

The next step in the CoS process is to classify the distribution expenses (Revenue Requirement) as demand, energy and customer related. Classification of Revenue Requirement under various heads between 11 KV, LT net work and retail supply is presented in table 5.73.

Table 5.73 Revenue Expenditure Matrix

	Revenue Expenditure Matrix	Cost allocation % adopted				
Sl.No.	**Nomenclature**	**33 KV**	**11 KV**	**LT Network**	**Retail supply**	**Total**
1	Purchase of Power	-	-	-	100%	100%
2	Transmission Charges	-	-	-	100%	100%
3	Repairs & Maintenance	-	55%	35%	11%	100%
4	Employee Costs	-	18%	33%	48%	100%
5	Administration & General expense	-	10%	31%	58%	100%
6	Depreciation & Related	-	52%	36%	13%	100%
7	Interest & Financial Charges	-	52%	36%	13%	100%
8	Interest on working capital	-	6%	4%	90%	100%
9	Interest on con.security deposits	-	0%	0%	100%	100%
10	Interest on power purchase dues	-	0%	0%	100%	100%
	SUB-TOTAL	-				
11	Less: Expenses Capitalised	-	-	-	-	-
12	Less: Interest & Finance Charges	-	-	-	-	-
12	Other Expenses	-	-	-	-	-
	SUB-TOTAL					
14	Other Debits (incl. Bad debts)	-	1%	1%	98%	100%
14	Extra Ordinary Items	-	-	-	-	-
16	Net Prior Period Charges/Credits	-	14%	32%	53%	100%
17	Income Tax	-	52%	36%	13%	100%
18	ROE/ROR	-	52%	36%	13%	100%
	TOTAL RR	-				
	Less:	-				
	Other income	-	52%	36%	13%	100%
	Miscellaneous income	-	0%	0%	100%	100%
	Total	-				
	NET TOTAL EXPENSES	-				

Table 5.74 presents the further classification of costs the above mentioned voltage wise segregated cost.

Table 5.74 classification of costs

Distribution	**A/C Group**	**Classification methodology**	**Distribution- 11 KV**			**Distribution- LT net work**			**Retail supply**			**Distribution-Total**		
			Demand	**Energy**	**Cus.**	**Demand**	**Energy**	**Cus.**	**Demand**	**Energy**	**Cus.**	**Demand**	**Energy**	**Cus.**
Revenue Requirement Classification														
R&M	74	As per R&M analysis	80%	0%	20%	50%	0%	50%	20%	0%	80%	63%	0%	37%
Employee Costs	75	As per Employee data analysis	75%	0%	25%	75%	0%	25%	10%	0%	90%	43%	0%	57%
A&G expenses	76	As per A&G exp. Analysis	73%	0%	27%	71%	0%	29%	22%	0%	78%	43%	0%	57%
Other debits	79	As per Other debits analysis	100%	0%	0%	100%	0%	0%	1%	0%	99%	3%	0%	97%
Prior period items	83	As per prior period analysis. Considered as 100% demand related for wires and 100% energy related for supply	100%	0%	0%	100%	0%	0%	0%	100%	0%	47%	53%	0%
Interest on WC	78	As per Int. on WC allocation.	0%	100%	0%	0%	100%	0%	0%	100%	0%	0%	100%	0%

Distribution	A/C Group	Classification methodology	Distribution- 11 KV			Distribution- LT net work			Retail supply			Distribution-Total		
			Demand	Energy	Cus.	Demand	Energy	Cus.	Demand	Energy	Cus.	Demand	Energy	Cus.
		Considered as 100% energy related												
Interest on consumer security dep.	78	Retail supply. Considered as 100% customer related	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	100%
Interest on power purchase dues	78	Retail supply. Considered as 100% energy related	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	100%	0%
Extraordinary items	79.8	As per asset allocation to Wires business. Considered as demand related	100%	0%	0%	100%	0%	0%	100%	0%	0%	0%	0%	0%
Depreciation	77	As per Asset distribution	97%	0%	3%	90%	0%	10%	17%	0%	83%	84%	0%	16%
Interest & Financial Charges	78	As per Asset distribution	97%	0%	3%	90%	0%	10%	17%	0%	83%	84%	0%	16%
Income Tax & RoR		As per Asset distribution	97%	0%	3%	90%	0%	10%	17%	0%	83%	84%	0%	16%
Capitalization of int. fin charges	78.9 Cr.	As per Asset distribution	97%	0%	3%	90%	0%	10%	17%	0%	83%	84%	0%	16%
Capitalization of other expenses	Credit	As per Asset distribution	97%	0%	3%	90%	0%	10%	17%	0%	83%	84%	0%	16%
Asset Base														
Land & Rights	10.1	As per Trial balance analysis	50%	0%	50%	50%	0%	50%	50%	0%	50%	50%	0%	50%
Buildings	10.2	As per Trial balance analysis	53%	0%	47%	34%	0%	66%	25%	0%	75%	35%	0%	65%
Hydraulic works	10.3	As per Trial balance analysis	50%	0%	50%	50%	0%	50%	50%	0%	50%	50%	0%	50%
Civil works	10.4	As per Trial balance analysis	50%	0%	50%	50%	0%	50%	50%	0%	50%	50%	0%	50%
P&M	10.5	As per Trial balance analysis	99%	0%	1%	96%	0%	4%	25%	0%	75%	97%	0%	3%
Lines, cables, networks	10.6	As per Trial balance analysis	96%	0%	4%	91%	0%	9%	16%	0%	84%	82%	0%	18%
Vehicles	10.7	As per Trial balance analysis	50%	0%	50%	50%	0%	50%	50%	0%	50%	50%	0%	50%
F&F	10.8	As per Trial balance analysis	25%	0%	75%	25%	0%	75%	25%	0%	75%	25%	0%	75%
Office equipment	10.9	As per Trial balance analysis	9%	0%	91%	14%	0%	86%	9%	0%	91%	9%	0%	91%
Less														
Grants & subsidies		As per Trial balance analysis	100%	0%	0%	100%	0%	0%	0%	0%	0%	100%	0%	0%
Consumer contributions		As per Trial balance analysis	100%	0%	0%	100%	0%	0%	0%	0%	0%	100%	0%	0%
Total asset base with adjustments			97%	0%	3%	90%	0%	10%	17%	0%	83%	84%	0%	16%
Other Income & Miscellaneous revenue														
Other Income	62	As per Assets distribution. Considered as 100% demand related	100%	0%	0%	100%	0%	0%	100%	0%	0%	100%	0%	0%
Miscellaneous revenue	61.5, 6,&7	Retail supply. Considered as 100% customer related	0%	0%	100%	0%	0%	100%	0%	0%	100%	0%	0%	100%

On the basis of above principles, the classification of costs have been made as presented in table 5.75.

Table 5.75 Classification of fixed assets (Rscr)

Expenditure Head	**Total Expenditure**	**Distribution**			
Rs. In Crs.	as per FY 08 A/Cs	**33KV**	**11KV**	**LT Network**	**Retail**
Purchase of Power	4,511.13	-	-	-	4,511.13
Transmission Charges	428.86	-	-	-	428.86
Repairs & Maintenance	43.45	-	23.80	15.08	4.57
Employee Costs	347.02	-	63.36	115.37	168.30
Administration & General expense	67.81	-	7.07	21.27	39.46
Depreciation & Related	48.07	-	24.78	17.18	6.11
Interest & Financial Charges	61.33	-	31.61	21.92	7.80
Interest on working capital	-	-	-	-	-
Interest on con. security deposits	91.77	-	-	-	91.77
Interest on power purchase dues	18.97	-	-	-	18.97
SUB-TOTAL	**5,618.41**	**-**	**150.63**	**190.82**	**5,276.97**
Less: Expenses Capitalised					
Less: Interest & Finance Charges	-	-	-	-	-
Other Expenses	-	-	-	-	-
SUB-TOTAL	-	-	-	-	-
Other Debits (incl. Bad debts)	230.44	-	2.84	1.97	225.62
Extra Ordinary Items	-	-	-	-	-
Net Prior Period Charges/Credits	52.68	-	7.56	17.02	28.10
Income Tax	2.36	-	1.22	0.84	0.30
ROE/ROR	12.58	-	6.48	4.50	1.60
		-	-	-	-
TOTAL RR	**5,916.47**	**-**	**168.73**	**215.15**	**5,532.59**
Less:		-	-	-	-
Other income	109.79	-	56.59	39.24	13.96
Miscellaneous income	40.29	-	-	-	40.29
		-	-	-	-
Total	150.08	-	56.59	39.24	54.25
NET TOTAL EXPENSES	**5,766.39**	**-**	**112.13**	**175.91**	**5,478.35**

The above costs are further segregated as demand, energy and customer related costs as indicated in table 5.76.

Table 5.76 Second level classification of fixed assets (Rs cr)

Expenditure Head	**Total Expenditure**	**PP Cost**			**Trasmission**			**11 KV**			**LT Netwrok**			**Retail**		
Rs. In Crs.	**as per FY 08 A/Cs**	**Demand**	**Energy**	**Consumer**	**Demand**	**Energy**	**Consumer**	**Demand**	**Energy**	**Consumer**	**Demand**	**Energy**	**Consumer**	**Demand**	**Energy**	**Consumer**
Purchase of Power	4,511.13	786.14	3,724.99	-				-	-	-	-	-	-	-	-	-
Transmission Charges	428.86				428.86	-	-	-	-	-	-	-	-	-	-	-
Repairs & Maintenance	43.45							19.04	-	4.76	7.54	-	7.54	0.91	-	3.65
Employee Costs	347.02							47.52	-	15.84	86.52	-	28.84	16.83	-	151.47

Expenditure Head	Total Expenditure	PP Cost			Trasmission			11 KV			LT Netwrok			Retail		
Rs. In Crs.	**as per FY 08 A/Cs**	**Demand**	**Energy**	**Consumer**	**Demand**	**Energy**	**Consumer**	**Demand**	**Energy**	**Consumer**	**Demand**	**Energy**	**Consumer**	**Demand**	**Energy**	**Consumer**
Administration & General expense	67.81							5.19	-	1.88	15.17	-	6.10	8.83	-	30.64
Depreciation & Related	48.07							24.02	-	0.76	15.49	-	1.69	1.04	-	5.07
Interest & Financial Charges	61.33							30.65	-	0.97	19.76	-	2.16	1.33	-	6.46
Interest on working capital	-							-	-	-	-	-	-	-	-	-
Interest on con.security deposits	91.77							-	-	-	-	-	-	-	-	91.77
Interest on power purchase dues	18.97							-	-	-	-	-	-	-	18.97	-
SUB-TOTAL	**5,618.41**	**786.14**	**3,724.99**	**-**	**428.86**	**-**	**-**	**126.42**	**-**	**24.21**	**144.49**	**-**	**46.33**	**28.95**	**18.97**	**289.06**
Less: Expenses Capitalised																
Less: Interest & Finance Charges	-							-	-	-	-	-	-	-	-	-
Other Expenses	-							-	-	-	-	-	-	-	-	-
SUB-TOTAL	-															
Other Debits (incl. Bad debts)	230.44							2.76	-	0.09	1.78	-	0.19	38.54	-	187.08
Extra Ordinary Items	-							-	-	-	-	-	-	-	-	-
Net Prior Period Charges/Credits	52.68							7.56	-	-	17.02	-	-	-	28.10	-
Income Tax	2.36							1.18	-	0.04	0.76	-	0.08	0.05	-	0.25
ROE/ROR	12.58							6.29	-	0.20	4.05	-	0.44	0.27	-	1.33
TOTAL RR	**5,916.47**	**786.14**	**3,724.99**	**-**	**428.86**	**-**	**-**	**144.20**	**-**	**24.53**	**168.10**	**-**	**47.05**	**67.81**	**47.07**	**477.72**
Less:																
Other income	109.79							56.59	-	-	39.24	-	-	13.96	-	-
Miscellaneous income	40.29							-	-	-	-	-	-	-	-	40.29
Total	150.08							56.59	-	-	39.24	-	-	13.96	-	40.29
NET TOTAL EXPENSES	**5,766.39**	**786.14**	**3,724.99**	**-**	**428.86**	**-**	**-**	**87.61**	**-**	**24.53**	**128.86**	**-**	**47.05**	**53.85**	**47.07**	**437.43**

Table 5.77 presents the grouping of Power purchase on Block basis

Table 5.77: Grouping of power purchase cost

Plant	MW	Share-Bescoı	Units (Mu)	VC - Crs	VC - rs/kWh
Sharavathi	1,035	369	2,054	26	0.13
Bhadra	39	18	24	0	0.13
Linganamakk	55	25	150	3	0.21
Supa	100	46	240	9	0.36
Kalinadi(Naga	855	393	1,484	53	0.36
Shimsa	17	8	27	1	0.37
Chakra			166	6	0.39
TB Dam			25	1	0.39
Mani Dam	9	4	19	1	0.52
Varahi	230	106	628	35	0.56
Munirabad	28	13	49	3	0.60
Ghataprabha	32	15	53	4	0.68
NTPC-Talche	320	147	1,388	103	0.74
Shiva	42	19	133	13	0.94
MGHE-Jog	139	64	137	14	1.04
Kalmala	0	0	0	0	1.16
Sirwar	1	0	0	0	1.16
Mallapur & O	9	4	7	1	1.16
NLC TPS1-E:	115	53	350	42	1.19
Kodasalli Dar	120	55	177	22	1.23
N.T.P.C-Ram	417	192	1,383	171	1.24
NTPC-VII	108	50	387	51	1.31
Almatti	290	83	301	44	1.47
Kadra Dam	150	69	188	28	1.51
RTPS 5 & 6	420	206	1,423	224	1.57
NLC TPS2-St	196	90	524	83	1.58
NLC TPS2-St	146	67	395	65	1.65
RTPS 7	210	96	681	117	1.71
Bhadra RBC			5	1	1.72
RTPS -1 & 2	420	193	1,258	225	1.79
MAPS	26	12	49	9	1.90
RTPS 3	210	144	993	199	2.01
Gerusoppa/S	240	110	289	79	2.73
Kaiga 3 & 4			46	13	2.84
Kaiga	132	60	233	70	2.99
III) Mini Hydel		111	405	122	3.00
RTPS 4	210	193	1,286	393	3.05
IV) Wind mill		584	1,293	442	3.42
I)Co-generation		70	330	115	3.47
II) Biomass		29	127	50	3.93
Short term procurement from PTC, bi-late			424	173	4.09
Tata Co	220	179	187	96	5.14
Diesel-Yalaha	128	128	206	128	6.21
Rayalseema	28	23	57	38	6.72
Tanir Bavi	81	66	418	349	8.35
Genekal	0	0	0	0	11.60
Others				28.39	
Grand Total			19,834	3,650.25	
Variabble cost		Units	Rs crores	Rs/ kWh	
Base Block		15,321	1,796	1.17	
Growth Block		4,513	1,854	4.11	
Total		19,834	3,650	1.84	
Share of Agriculture					
Base Block		3,809	447	1.17	
Growth Block		957	393	4.11	
Total		4,766	840	1.76	

Step 3: Allocation

Cost to serve for agriculture category is estimated using average CP method

Table 5.78 indicates the coincident peak for the agricultural consumer category of BESCOM.

Table 5.79 Coincident peak of BESCOM

Tariff Category	Consumer category	Load factor (as per sample feeders)	LLF	CF	No. of Consumers	Consumer weightage	No. of equivalent consumers	Consumption (MU)	Allocation-Tech. Loss -MU	Allocation- Comml. Loss - MU	Consumption + Loss (MU)	Consumptio inclusive of comm. Loss n in MW	Technical Loss MW	NCP MW	CP-MW	% of Cat to Discom Peak - MW	% of Cat to Discom NCP* MW
																2,653	3,085
LT Agriculture	LT 4	39%	23%	36%	616,733	0.44	269,821	3,613	972	182	4,766	1097	488	1,585	576	21.70%	51.37%

Table 5.80 & 5.81 presents the allocation of the costs to the agricultural category using the Coincident Peak Method.

Table 5.80 Allocation of cost – Average PeaksCF Method (Rs. in crs)

	Power Purchase			Transmission			Distribution- 11 KV		Distribution- LT network			Retail supply			Total			
	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Total
LT Agri	170.59	839.81	-	93.06	-	-	19.01	1.05	27.96	-	2.02	11.69	12.02	18.81	322.30	851.83	21.89	1196.02

Table 5.81 Allocation of cost – Average peaks CF Method (Rs/kwh)

	Power Purchase			Transmission			Distribution- 11 KV		Distribution- LT network			Retail supply			Total			
	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Total
LT Agriculture	0.47	2.32	-	0.26	-	-	0.05	0	0.08	-	0.01	0.03	0.03	0.05	0.89	2.36	0.06	3.31

Final Results

At the present tariff which is charged from the agricultural consumers, only about 23% of cost of supplying power is recovered which leads to large quantum of cross subsidies to this consumer category. The table 5.82 presents a comparison for the cost of serve and the revenue realised from the agricultural consumer category.

Table 5.82 Comparison of Cost to serve and Revenue realisation

Tariff Cat.	Energy Sold (MU)	Revenue at Current Tariff (Rs. in Crs.)	Average tariff rate in Rs./kwh	CoS rate in Rs./kwh	Revenue at CoS rate (Rs. in Crs.)	Govt subsidy	Cross subsidy amount +subsidizing (subsidized) Rs. In Crs.
LT 4	3,613	330.64	0.92	3.31	1,196.02	196.26	669.12

5.3 Gujarat

Agricultural Background of the state

Agriculture in Gujarat forms a major part of the state economy. Agriculture continues to be the primary occupation in the state where two-thirds of the population is engaged in agriculture and earn livelihood directly from this occupation. Moreover, agriculture provides indirect employment to large portion of population in agro-based occupations. Thus prosperity and well being of people in Gujarat is closely linked with agriculture and allied activities.

The total cropped area is around 58% of the state's geographical area of 19602 thousand hectares with a cropping intensity of 114.7%.The net irrigated area is around 34% and the net sown area is ~ 50% (after adjusting for the area sown more than once). In Gujarat state, there is not much scope to bring additional land under cultivation and hence, for increasing the agricultural production, the state will have to concentrate on exploiting the yield potential of different crops and thereby achieving higher productivity.

The various used of the total geographical area is given below:

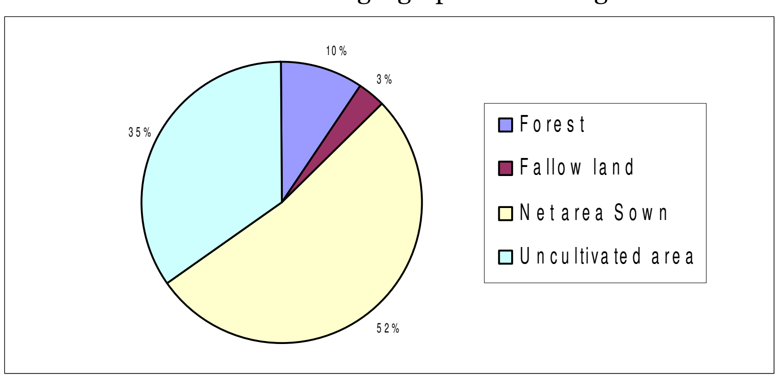


Fig. 5.24 used geographical area

Source: Fertilizer Statistics 2007-08, Ministry of Agriculture

The net irrigated area is 33.88 lakh hectares. The distribution of irrigated areas based on the various sources of irrigation is as follows:

Irrigation by sources

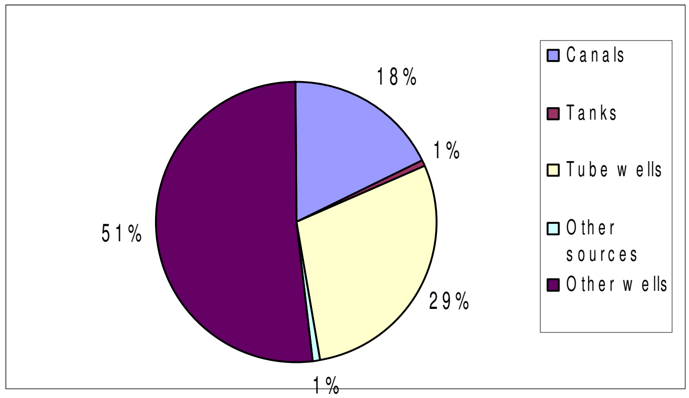


Fig 5.25 Tanks, Tubewells etc.

Source: Fertilizer Statistics 2007-08, Ministry of Agriculture

The above figure indicates that Tube wells and other wells account for majority of irrigation (80%).

The major food crops in the state are Rice, Wheat, Jowar, Bajra, Maize, Tur, Gram, Groundnut while major non food crops are Cotton, Tobacco. Nearly 35% of the total cropped area (113.05 lakh hectares) is used for producing food grains. Of the total food grain production in 2006-07, wheat and rice together accounted for ~68% followed by Bajra that accounted for ~16%[20].

[20] Fertilizer statistics

Rainfall

The State being located at the peripheral boundary of the main current of the South-West monsoon, the distribution of rainfall has been extremely uneven and irregular. The average annual rainfall over different parts of the state varies widely from 300 mm in the Western half of Kutch to 2100 mm in the Southern part of Valsad district and the Dangs. The monsoon usually commences by the middle of June and withdraws by the end of September, about 95% of the total annual rainfall being received during these months.

The annual rainfall in the state was 976.5 mm, with 95.2 % of the rainfall had been in the month of June to September. In Gujarat, the five districts having mean annual rainfall of 750-1250 mm and moisture availability for at least 150 days are: Surat, Bharuch, Baroda, Ahmedabad and Panchmahal.

On an average, there has been a deficit in the rainfall in the state during March 2007 to February 2008. However, the deviation is between 25% to (–) 99% as shown below:

Table 5.83 Rainfall

Period	Actual	Normal	Excess/ Deficit (%)
Pre Monsoon period 1st March to 31st May 2007	NA	9	-99
South West Monsoon period Ist June to 30th Sep 2007	1164	934	25
Post Monsoon Period 1st Oct 2007 to 31st Dec 2007	1	35	-96
Winter Monsoon Period 1st Jan 2008 to 28th Feb 2008	NA	2	-99

Source: Fertilizer statistics, Ministry of Agriculture 2007-08

The district-wise trend in rainfall (mm) during the period from 2000 to 2005 is given below:

Table 5.84 District Rainfall (2000 to 2005)

Sr. No.	District	Av. Rainfall 1995 – 2005	2000	2001	2002	2003	2004	2005
1	Ahmedabad	637	498.0	734.6	327.3	749.2	751	1135
2	Amreli	582	302.7	524.0	558.6	672.9	592	1089
3	Anand	638	344.9	472.1	400.3	965.1	679	1295
4	Banaskantha	472	356.1	562.3	209.1	783.3	391	744
5	Bharuch	658	389.5	614.9	714.4	805.8	786	889

Sr. No.	District	Av. Rainfall 1995 – 2005	2000	2001	2002	2003	2004	2005
6	Bhavnagar	548	227.0	579.0	662.5	608.7	509	927
7	Dahod	640	337.6	547.6	605.4	916.6	1041	560
8	Dang	2718	1431.0	2200.0	2442.0	2129.0	2642	3825
9	Gandhinagar	698	298.0	484.5	323.0	1125.3	806	1369
10	Jamnagar	555	395.7	626.2	325.4	828.5	546	618
11	Junagadh	744	470.8	782.6	432.3	943.8	1004	967
12	Kheda	822	468.5	672.2	518.8	1110.0	841	1271
13	Kutch	312	240.8	360.9	135.8	711.6	417	304
14	Mehsana	618	300.4	662.6	291.3	821.7	565	1218
15	Narmada	1059	458.5	950.0	854.0	1338.8	1130	1164
16	Navsari	1782	1401.0	1872.0	1373.8	2470.8	2102	2865
17	Panchmahal	722	402.1	563.9	851.0	948.6	954	873
18	Patan	529	306.0	463.3	209.2	753.1	462	749
19	Porbandar	595	447.0	653.3	275.3	742.7	583	827
20	Rajkot	523	295.0	508.9	341.4	740.0	558	739
21	Sabarkantha	717	445.5	526.8	372.5	846.2	733	1035
22	Surat	1376	760.8	1386.3	1077.5	1944.2	1810	2319
23	Surendranagar	536	324.6	595.4	319.0	580.1	608	967
24	Vadodara	937	448.9	961.5	742.1	1068.7	1028	1321
25	Valsad	2147	1825.0	2121.4	1814.8	2354.6	2589	3130
	Gujarat	**863**	**528.7**	**817.2**	**636.3**	**1078.4**	**960**	**1288**

Area, Irrigation and Crops

The total cropped area has not shown any significant change over the past years. It has increased from 106.35 lakh hectares in 1995-96[21] to 113.05 lakh hectres in 2005-06, an increase of only around 6% in the 10 years.

The Important Agricultural Crops Grown in Gujarat State are:

Table 5.85 Agricultural crops

Crop Group	Kharif Crops	Rabi Crops	Summer Crops
Cereals	Bajra,Rice,Jowar,Maize Wheat & Bajra	Wheat	Bajra
Pulses	Tur, Moong, Udid, Math	Gram	
Oilseeds	Ground-nut, Sesamum,Castor	Rapeseed & Mustard	Ground-nut
Commercial Crop	Cotton,Sugarcane, Tobacco	Potato	

[21] Source: Statistical abstract of Gujarat 2006

The area, production and average yield of various crops in 2006-07 is given below:

Table 5.86 area, production and average yield of various crops in 2006-07

S .No	Crop	Area ('000 hectares)	Production ('000 tonnes)	Yield (Kg/hectare)
1	Rice	734	1390	1894
2	Wheat	1201	3000	2498
3	Jowar	124	103	831
4	Bajra	937	1019	1088
5	Maize	520	363	698
6	Ragi	17	11	647
7	Small Millets	35	20	571
8	**Total Cereals (1+2+3+4+5+6+7)**	3568	5906	1655
9	Gram	246	214	870
10	Tur	289	217	751
11	**Total pulses**	1000	593	593
12	**Total Food grains (8+11)**	4568	6499	1423
13	Ground nut	1733	1435	809
14	Soya bean	51	26	510
15	**Total Oil seeds**	2828	2569	908
16	Sugar cane	214	15630	73037
17	Cotton	2390	8787	625

Source: Fertilizer statistics 2007-08

The above table indicates that sugarcane accounts for ~47% of the total production of principal crops in 2006-07, followed by cotton (26.24%) and food grains (19.4%). However, in terms of area, the majority is covered by food grains with a share of 45.68% followed by oil seeds (28.3%) and cotton (24%).

The gross irrigated area was 4292 thousand hectares in 2005-06. The percentage of irrigated area to the total area under principal crops in 2005-06 is shown below:

Table 5.87 percentage of irrigated area

Crop	% of area
Rice	57.5
Jowar	7.6
Bajra	16.9
Maize	6.7
Wheat	87.5
Barley	100

Crop	% of area
Total Cereals	**43.6**
Gram	28.7
Total pulses	**10.2**
Total food grains	**37.1**
Ground nut	7.5
Rapeseed and mustard	98
Total oilseeds	**24.1**
Sugarcane	100
Cotton	44.7
Tobacco	89
All crops	**38**

In 2005-06, 38% of the total cropped area was irrigated in Gujarat. However, the percentage of gross cropped area which is irrigated varies across crops. It varies from 100% for sugarcane and barley, followed by rapeseed (98%), tobacco (89%) to as low as 6.7% for maize and 7.5% in groundnut.

In terms of sources of irrigation, tube wells and other wells constitute 81% of the net irrigated area. Over the last four decades, there have been changes in the share of canals and wells in the net irrigated area in 2000-01 as compared to 1990-91. The share of canals has reduced in 2000-01 from 19% in 1990-91 to 12%, while the corresponding share of tube wells and other wells has increased from 79% to 87%.

Table 5.88 Decadal trends in sources of irrigation

Year	Canals	Tube wells and other wells	Tanks	Other sources
1970-71	17%	79%	3%	1%
1980-81	18%	79%	2%	0%
1990-91	19%	79%	1%	0%
2000-01	12%	87%	1%	0%

However, during the current decade, while the share of canals has increased from 12% in 2000-01 to 18% in 2005-06, the share of tube wells and other wells has decreased from 87% to 81% during the five year period.

The absolute net irrigated area has increased by 21% pushing the irrigated area as a percentage of net sown from 29.75% to 34.39% during the same period

Table 5.89 Irrigation by sources (2000-01 and 2005-06)

Particulars	2000-01[22]	2005-06[23]
Canals	348	600
Tube wells and other wells	2435	2737
Tanks	15	26
Other sources	8	25
Total	**2806**	**3388**
Net irrigated area as % of net sown area	29.75	34.39%

Agricultural characteristics of Discoms – PGVCL

PGVCL is feeding electricity in 8 district of Gujarat namely Rajkot, Jamnagar, Junagadh, Porbandar, Bhuj, Bhavnagar, Surendranagar and Amreli covering total 83 Talukas. All the districts (excluding Bhuj) accounts for 38% of the net sown area of Gujarat. The district wise spread is shown below.

Table 5.90 District-wise net sown area (2003-04)

District[24]	Net sown area ('00 hectares)	%
Amreli	5407	14%
Bhavnagar	5474	15%
Jamnagar	5997	16%
Junagadh	5238	14%
Porbandar	1122	3%
Rajkot	7378	20%
Surendranagar	6862	18%
Total	**37478**	

In 2006, the actual rainfall in various 8 districts is given below:

Table 5.91 Actual rainfall in various 8 Districts (2006)

District	Rainfall (mm)
Surendranagar	733
Rajkot	913
Jamnagar	666
Porbandar	803
Junagadh	1053
Amreli	1167
Bhavnagar	1033
Bhuj	596

[22] Source: Statistical Abstract of Gujarat 2006

[23] Source: Fertilizer Statistics

[24] Since data was not available for Bhuj, it is not included in the table

The maximum rainfall had been during June to September during the year. The month-wise rainfall during 2006 for all the districts is as follows:

Table 5.92 Rainfall during June to September

(In MM)

District	June	July	August	September	October	Total
Bhuj	20	268	250	33	0	571
Surendranagar	67	373	108	104	0	652
Rajkot	84	491	148	120	0	843
Jamnagar	53	360	238	115	0	766
Porbandar	55	516	268	132	0	971
Junagadh	145	527	213	118	6	1009
Amreli	179	483	82	76	3	823
Bhavnagar	127	453	93	59	1	733

The rainfall during these months accounts for 91% of the rainfall in all the districts covered by PGVCL in 2006.

The districts covered by PGVCL accounts for 24% of the gross irrigated area of Gujarat in 2001-02. The following table shows the type of irrigation used across the districts within the discom.

Table 5.93 District wise source of irrigation as %age of gross irrigated area

District	Canals	Tanks	Tube Wells	Wells	Other Sources
Amreli	2%	0%	0%	98%	0%
Bhavnagar	5%	0%	0%	95%	0%
Jamnagar	4%	0%	0%	96%	0%
Junagadh	5%	0%	0%	95%	0%
Porbander	0%	0%	0%	100%	0%
Rajkot	0%	0%	0%	100%	0%
Surendranagar	1%	0%	58%	41%	0%

Source: indiastat.com

It can be seen that all the districts depend on the wells for their irrigation purposes. This has implication for the utility in terms of electricity consumption.

Agricultural characteristics of Discoms – UGVCL

UGVCL is feeding electricity mainly in 6 districts[25] of Gujarat namely Sabarkantha Gandhinagar, Ahmedabad, Mehsana, Patan, Banaskantha. All the districts together (excluding Bhuj)

[25] There are other 3 districts which are overlapping with other discoms and hence not included in the analysis

account for 27% of the net sown area of Gujarat. The district wise spread is shown below.

Table 5.94 District-wise net sown area (2003-04)

District[26]	Net sown area ('00 hectares)	%
Ahmedabad	5056	20%
Banaskantha	7364	29%
Gandhinagar	1597	6%
Mehsana	3464	13%
Patan	3866	15%
Sabarkantha	4381	17%
	25728	

In 2006, the actual rainfall in various 6 districts is given below:

Table 5.95 Actual rainfall in various 6 Districts (2006)

District	Rainfall (mm)
BanasKantha	1578
Patan	1675
Mahesana	1282
SabarKantha	1590
Gandhinagar	1133
Ahmadabad	1044

The month-wise rainfall during June to September 2006 for all the 6 districts is as follows:

Table 5.96 month wise rainfall during June – Sept 2006

(In MM)

District	June	July	August	September	October	Total
Patan	43	245	568	119	0	975
Mahesana	101	359	810	150	0	1420
Sabar Kantha	126	436	922	236	1	1721
Gandhinagar	69	328	524	145	0	1066
Ahmadabad	95	461	274	111	0	941
Banas Kantha	59	278	839	195	0	1371

The above months contributed 78% of the total rainfall in these districts in the year 2006.

The districts covered by UGVCL accounts for 33% of the gross irrigated area of Gujarat in 2001-02. The following table shows the type of irrigation used across the districts within the discom.

[26] Since data was not available for Bhuj, it is not included in the table

Table 5.97 District wise source of irrigation as %age of gross irrigated area

District	Canals	Tanks	Tube Wells	Wells	Other Sources
Ahmedabad	16%	0%	48%	36%	0%
Banaskantha	0%	0%	57%	43%	0%
Gandhinagar	0%	0%	96%	4%	0%
Mehsana	0%	0%	67%	33%	0%
Patan	0%	0%	90%	10%	0%

It can be seen that, except Ahmedabad, the districts depend on wells for their irrigation purposes indicating high implication for the utility in terms of electricity consumption

Energy characteristics of Gujarat

Gujarat system has a contracted capacity of ~12,170 MW from GSECL, Central Stations, IPPs and Non-Conventional energy sources.

Table 5.98 Gujarat Energy Supply System – as on 31.3.2009

Sources	Capacity (MW)	% of total
GSECL – Thermal *	4905.00	41%
GSECL – Hydro *	772.00	6%
NCE *	24.30	0.2%
IPPs *	3895.90	32%
CGS **	2573.00	21%
Total	**12170.20**	

Sources: * Generation Installed Capacity (MW) of Power Utilities in States/UTs, Central Electricity Authority (CEA)

** Allocation of Power from Central Generating Stations (CGSs), CEA

It can be seen that GSECL's capacity dominates the system and its thermal plays major role in the supply of energy within the State. IPPs account for more than 30% of the State's requirement.

Table 5.99 Power Costs breakup 2009-10

Power Purchase Sources	Fixed Cost (Rs Cr)	Variable Cost (Rs Cr)	% of Fixed to Total Costs
GSECL	1,827.50	2,808.83	30%
IPPs	1,071.05	1,506.09	18%
CGSs	1,094.25	2,239.70	18%
Others (Incl. NCE)	978.03	1,419.31	16%
Other Costs	64.80	-	1%
Sub-total	5,035.63	7,973.93	
PGCIL	112.88	-	
GETCO	814.32	-	
GUVNL	84.02	-	
Total	**6,046.85**	**7,973.93**	

Sources: As per GERC MYT Order for Discoms for FY 2008-11

* As per GERC MYT Order for GSECL for FY 2008-11

** As per GERC MYT Order for GETCO for FY 2008-11

The important point of note here is that the fixed cost component of the stations are almost a third of the total cost and this would have an impact on the cost to study, as demand costs are allotted on the basis of coincident or non-coincident peaks.

GSECL has higher ratio of fixed costs even when the vintage of plants are definitely older than the IPPs. Others, in the table above, include a large share of purchases through Trading and hence will not reflect any fixed cost component.

Load Curve Analysis for Gujarat

Load duration

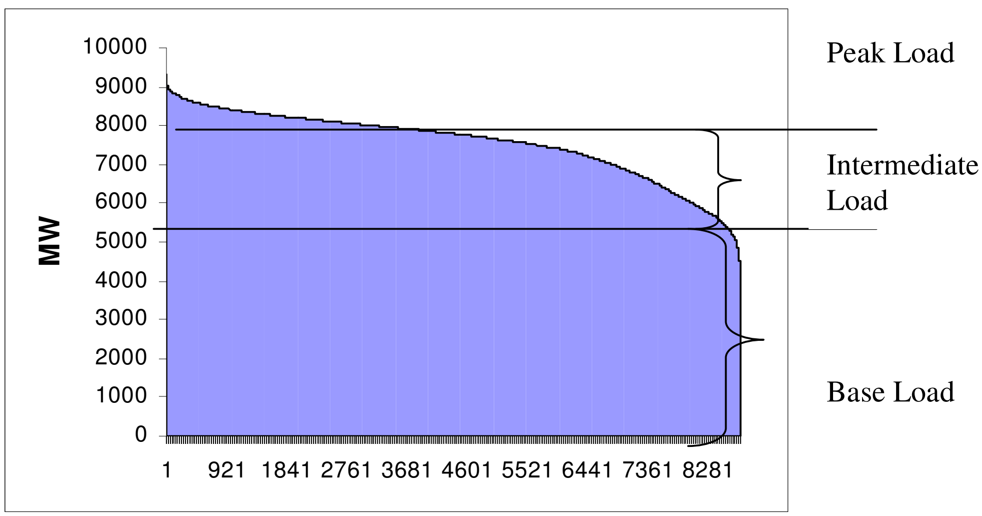


Fig 5.26 Load duration curve Gujarat – 2007-08

Gujarat system moves between a base load of ~4500 MW and upto ~8500 MW during the intermediate peak. It hit a peak of 9,335 MW (on 29th October, 2007 at 1900 Hrs). The median value load is ~7794 MW.

The duration of loads in a frequency interval of say 500 MWs has been presented in the table below.

Table 5.100 Duration of various loads –Gujarat State - 2007-08

	Frequency				
MW (From)	MW (To)	Cumulative duration (hrs)	Duration in hrs	No of Days in a year	% duration in a year
	4000	0	0	0.00	0.00%
4000	4500	14	14	0.58	0.16%
4500	5000	63	49	2.04	0.56%
5000	5500	280	217	9.04	2.48%
5500	6000	737	457	19.04	5.22%

Frequency					
MW (From)	MW (To)	Cumulative duration (hrs)	Duration in hrs	No of Days in a year	% duration in a year
6000	6500	1264	527	21.96	6.02%
6500	7000	1958	694	28.92	7.92%
7000	7500	3116	1158	48.25	13.22%
7500	8000	5612	2496	104.00	28.49%
8000	8500	8055	2443	101.79	27.89%
8500	9000	8735	680	28.33	7.76%
9000	9500	8760	25	1.04	0.29%

This table shows that for ~ 336 days in a year (92% of the time), the load is within the band of 4000-8,500 MW. For ~ 28 days, the system needs another 500 MW. For the remaining 1 days, the requirement increased by another 335 MW.

The caveat to be noted here is that the system is a heavily administered one, with high finesse in demand side management. Loads are interrupted to safe guard the system as well as not incur penalties under UI or trading in costly power. However, as per information made available to the team during its visit to Gujarat, the agriculture load has been divided into blocks of feeders and each block of feeder gets uninterrupted 8 hours supply.is supplied

The following table looks at the load duration profile from the agricultural season of Kharif and Rabi.

Table 5.101 Load duration during Kharif & Rabi Seasons – 2007-08, Gujarat

Frequency Range		Monsoon season 1st Jun-30th Sept			Khariff season 1st Nov-31st March		
MW (From)	MW (To)	Duration in hrs	No of Days in a year	% duration in a year	Duration in hrs	No of Days in a year	% duration in a year
	4000	0	0	0.0%	0	0.0	0.0%
4000	4500	14	0.6	0.2%	0	0.0	0.0%
4500	5000	49	2.0	0.6%	0	0.0	0.0%
5000	5500	214	8.9	2.4%	0	0.0	0.0%
5500	6000	449	18.7	5.1%	3	0.1	0.0%
6000	6500	493	20.5	5.6%	8	0.3	0.1%
6500	7000	568	23.7	6.5%	34	1.4	0.4%
7000	7500	510	21.3	5.8%	109	4.5	1.2%
7500	8000	450	18.8	5.1%	445	18.5	5.1%
8000	8500	163	6.8	1.9%	1134	47.3	12.9%
8500	9000	18	0.8	0.2%	1519	63.3	17.3%
9000	9500	0	0	0.0%	367	15.3	4.2%

It can be seen from the loads that Rabi would require higher loads (as there would be less rainfall) and the peak happens only during this period. Rabi season would require additionally

~1500 MW more than the Kharif season (assuming that the monsoon has been normal or excess and timely).

Monthly peaks of the State are mapped below.

Table 5.102 Gujarat Monthly Peaks – 2007-08

Month	Min	Max	Hrs at which peak occurred
Apr	7106	8814	3:00 PM
May	6933	8759	12:00 Noon
Jun	5020	8435	3:00 PM
Jul	4148	8434	3:00 PM
Aug	4733	8169	12:00 Noon
Sep	5207	8904	3:00 PM
Oct	6568	9335	7:00 PM
Nov	5371	8921	7:00 PM
Dec	6522	9197	9:00 AM
Jan	5928	8937	8:00 AM
Feb	6567	8775	11:00 PM
Mar	5529	9050	3:00 PM

It can be seen from the above readings that out of 12 months , peaks of 5 months have occurred at 3 PM (40%), 2 peaks occurred at 7:00 PM, 2 peaks at 12:00 Noon, one at 11:00 PM and during the whole year only 2 peaks have occurred in the morning. The system demand is highest between October to March. It appears that there is a general tendency is to have an administered evening peak. As indicated earlier, average of monthly peak is used for analysis.

Load Curve Analysis of UGVCL

UGVCL recorded a peak of 2,154 MW on 24th Nov, 2007 at 9 AM. The peak recorded for the State was on 24th Oct, 2007 at 07:00 PM.

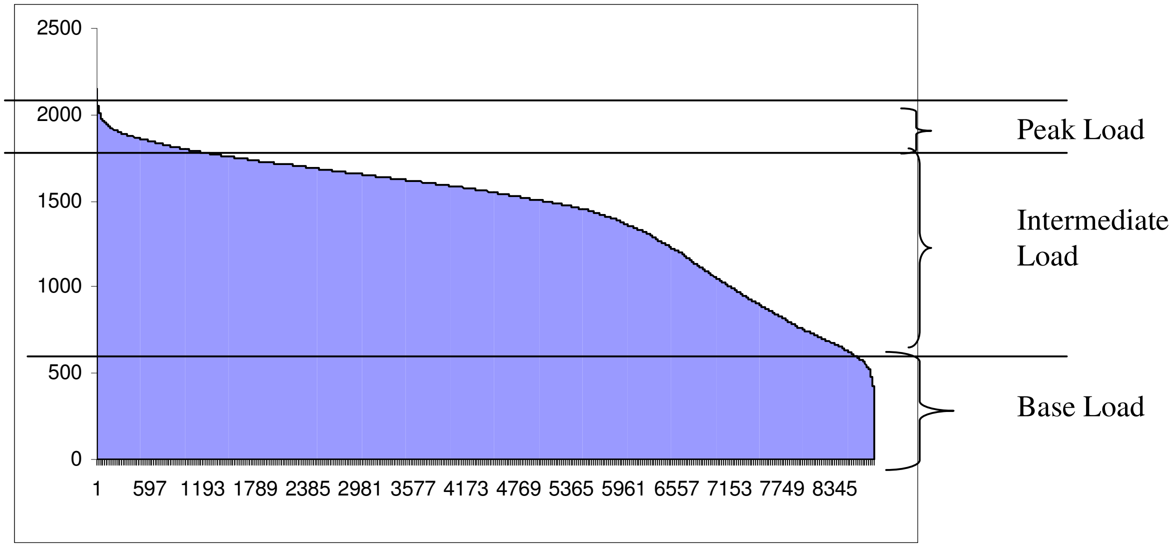


Fig 5.27 Load duration curve Gujarat – 2007-08

The load duration curve of UGVL is shown ion table below. It is seen from the Load Duration Curve of UGVCL as well as the Load duration table, that UGVCL is having a rather flat load curve. Around 75% of the time, the load is between 1200 MW to 2000 MW. Requirement of load greater than 2000 MW is only for 1.7 days in a year.

Table 5.103 Duration of various loads –Gujarat State - 2007-08

	Frequency				
MW (From)	MW (To)	Cumulative hours	Duration in hrs	Duration in days	% duration
	400	6	6	0.25	0.07%
400	800	973	967	40.291667	11.01%
800	1200	2195	1222	50.916667	13.91%
1200	1600	4965	2770	115.41667	31.53%
1600	2000	8744	3779	157.45833	43.02%
2000	2400	8784	40	1.6666667	0.46%

Also, it can be seen from table below, that similar to the state drawl, there is higher drawl for the DISCOM during rabi season than during Khariff season.

Table 5.104 Load duration during Kharif & Rabi Seasons – 2007-08, Gujarat

		Frequency for 01.06.07-30.07.07			Frequency for 01.06.07-30.07.07		
MW		**Duration in hrs**	**Days**	**%**	**Hrs**	**Days**	**%**
400	6	6	0.25	0.20%	0	0	0.0%
800	973	967	40.291667	33.03%	0	0	0.0%
1200	2129	1156	48.166667	39.48%	6	0.25	0.2%
1600	2879	750	31.25	25.61%	1096	45.666667	30.0%
2000	2928	49	2.0416667	1.67%	2517	104.875	69.0%
2400	2928	0	0	0.00%	29	1.2083333	0.8%

The peak day load curve is shown below. It shows that during the peak day, the morning period demand was greater than that during the evening.

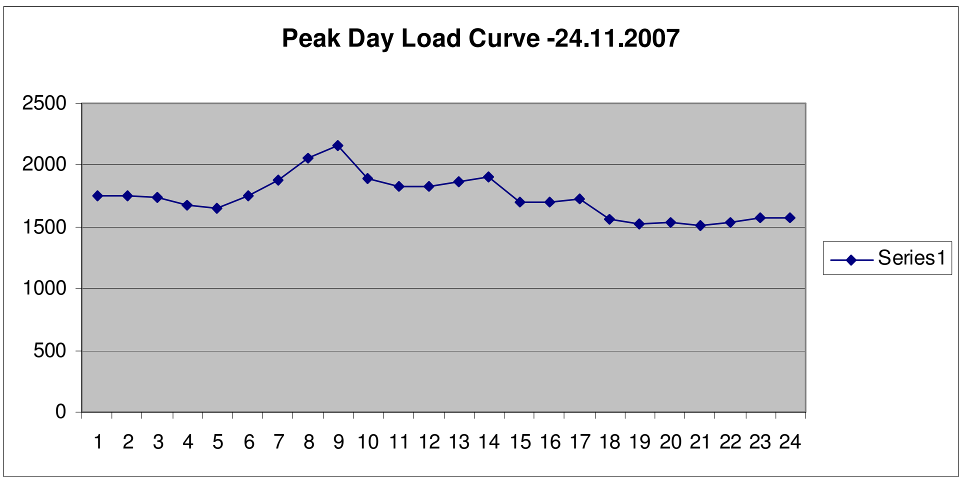


Fig 5.28 Peak Day Load Curve

Load Curve Analysis of PGVCL

PGVCL Load Behaviour

PGVCL recorded a peak of 2,955 MW on 8th December 2007 at 9 AM (instead of State's peak at 7 PM). A review of the graph below shows, that the load has gradually increased from 5 AM in the morning and has gradually declined over the next two hours. Also, the load curve has stayed around 2500 MW from around 11 AM to around 7 PM. This indicated adoption of load management techniques to keep the load curve as flat as possible.

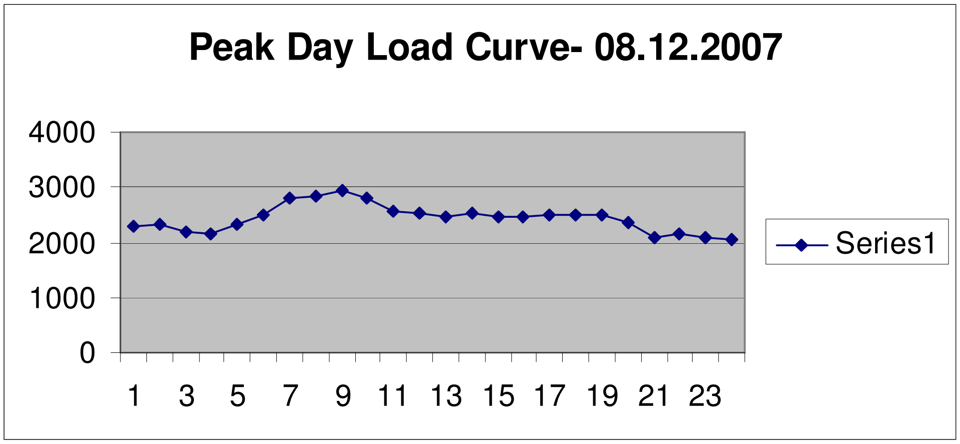


Fig 5.29 Peak day load curve

The load duration curve for the PGVCL is shown in the frequency table below. It can be seen from the table that ~ 82% of time in a year, the requirement of load is 2400. Additional 400 MW is required for 17.6 % of the time ie 64% of the time. and another 155 MW only for 8 hours.

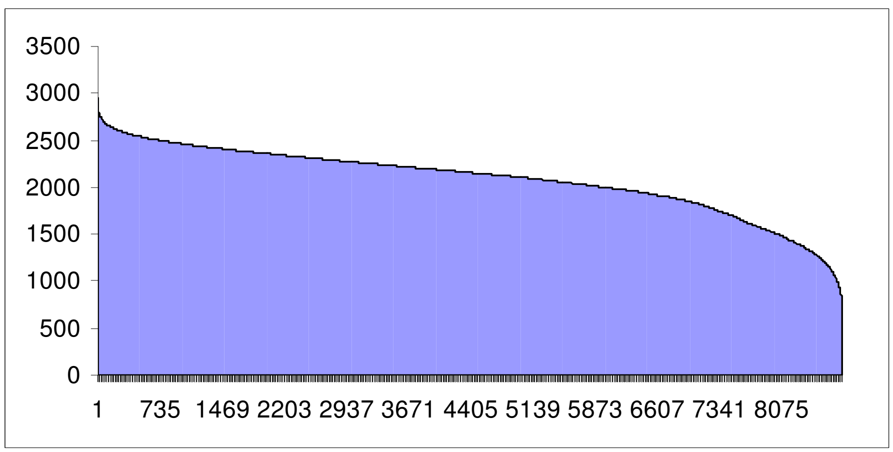


Fig 5.30 Load duration curve

Table 5.109 Load duration frequency – 2007-08, Gujarat

		Frequency for the year 2007-08		
MW		Duration in hrs	Duration days	%
400	0	0	0	0.00%
800	4	4	0.1666667	0.05%
1200	204	200	8.3333333	2.28%
1600	1048	844	35.166667	9.61%
2000	2808	1760	73.333333	20.04%
2400	7231	4423	184.29167	50.35%
2800	8776	1545	64.375	17.59%
3200	8784	8	0.3333333	0.09%

The load duration table for the khariff and rabi season is given below. From this table it is evident, that the load requirement during the rabi season is distinctly higher than in the khariff season with the DISCOM peak happening during the rabi season.

Table 5.105 Load duration during Kharif & Rabi Seasons – 2007-08, Gujarat

Frequency for the year 1st June 2007-30 Sept 2007			Frequency for the year 1st Nov 2007-31st Mar 2007		
Duration in hrs	Duration in days	%	Duration in hrs	Duration in days	%
0	0		0	0	
4	0.17	0.14%	0	0.00	0.00%
200	8.33	6.83%	0	0.00	0.00%
844	35.17	28.83%	0	0.00	0.00%
1048	43.67	35.79%	150	6.25	4.11%
775	32.29	26.47%	2425	101.04	66.47%
57	2.38	1.95%	1065	44.38	29.19%
0	0	0	8	0.3333333	0.22%

Estimation of Cost to Serve for UGVCL

Team Identification

For the study, Mr R P Rawal, EE (Commercial) and Mr D B Patel, D E (Commerce) were nominated as the Nodal officers. Detailed discussions were held with these officers about the scope of work and the data requirement. Further details discussions were also held with other officials of UGVCL about the different aspects of the study. Theses officials include:

- Mr M G Patel, C E (Operations), UGVCL
- Mr R B Kothari, G M (Finance), UGVCL
- Mr D S Doshi, S E (Commercial), UGVCL
- Mr P V Desai, D E (Distribution), UGVCL
- Mr C L Sharma, S E (Vigilance), UGVCL
- Mr V A Patel, D E (Commerce), UGVCL
- Mr H M Shah, D E (R&D), UGVCL

Sampling

For the feeder data analysis, ten feeders are selected which have predominantly i.e 80% of the agricultural load. Table 5.106 presents the circle wise list of selected feeders.

Table 5.106 Sample Feeders selected across various circle

Name of the Circle	No of Sample Feeders
Mehsana	3
Palanpur	2
Himatnagar	2
Sabarmati	3
Total	10

18 days uniformly spread across the year are selected to collect the load details of the selected feeder. This captured the seasonality factor in the agricultural power consumption. Load details of selected feeder are also collected for the peak day of the utility. The selected days are presented in table 5.107.

Table 5.107 days Selected for collection of load data from sample feeders

06.04.2007	Summer
22.04.2007	Summer
02.05.2007	Summer
19.05.2007	Summer
14.06.2007	Monsoon
15.07.2007	Monsoon
25.07.2007	Monsoon
15.08.200	Monsoon
04.09.2007	Monsoon
26.09.2007	Monsoon
08.10.2007	Winter
18.11.2007	Winter
01.12.2007	Winter
11.12.2007	Winter
25.12.2007	Winter
12.01.2008	Winter
14.01.08	Winter
20.02.2008	Summer
14.03.08	Summer

Analysis of the sample feeder data

Figure 5.31 presents the load curves aggregated for 10 selected feeders across different selected days.

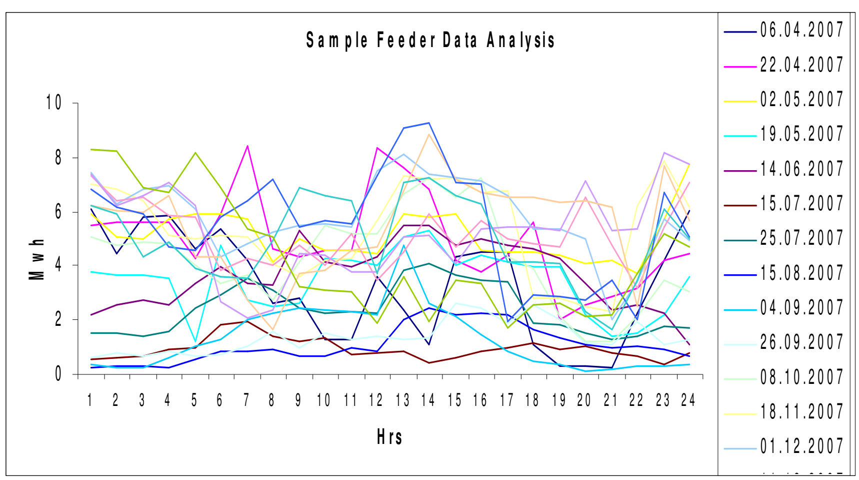


Fig 5.31 Agricultural Feeder Data Analysis

Table 5.108 gives the Load factor, load loss factor and coincident factor of the agricultural feeder data.

Table 5.108 Feeder Data Analysis

Calculation of class load factor		
Average (Mwh)		3.881515
Max (Mwh)		9.25
Load factor (%)		**41.97%**
Calculation of load loss factor		
Formula	(0.3 *LF +0.7 (LF)^2	**24.93%**
Calculation of CF		**37.97%**

Model Process

This section details out the process for calculating the cost of service of power to the agricultural consumers and the analysis of the results derived.

Step 1: Functionalisation

As per UGVCL's annual accounts for 2007/08, a summary of costs incurred by the utility as functionalised into power purchase, transmission and distribution related is presented in table 5.109.

Table 5.109 Functionalised Cost of UGVCL

	UGVCL	**Power Purchase**	**Transmission**	**Distribution**
	Rs Cr	**Rs Cr**	**Rs Cr**	**Rs Cr**
Power Purchase	2930.86	2699.36	231.50	
Repairs & Maintenance	75.86			75.86
Employee Costs	187.20			187.20
Administration & General expense	29.30			29.30
Depreciation & Related	89.27			89.27
Interest on WC	28.36			28.36
Interest & Financial Charges	61.36			61.36
Other Debits (incl. Bad debts)	1.84			1.84
Provison of Income Tax	0.99			0.99
Rate of Retun	0.85			0.85
Sub Total (1)	3405.90	2699.36	231.50	**475.04**
Less				
Expenses capitalised	50.79			50.79
Net Prior Period Charges/Credits	-6.67			-6.67
Sub Total (2)	44.12			44.12
Grand Total (1-2)	**3361.78**	2699.36	231.50	**430.92**

Source : Annual Accounts, UGVCL, 2007/08

Discussions with UGVCL revealed that the power purchase cost of Rs 2390.86 Crore is combined cost which is inclusive of the transmission charges. Thus, this power purchase cost is functionalised into power purchase and transmission charges based on the ratio of transmission charges in total power purchase as approved by the Gujarat Electricity Regulatory Commission (GERC) for the tariff determination for 2007/08.

Step 2: Classification

Details of fixed Assets have been captured and segregation of assets in to various voltage classes has been made based on the discussion with then UGVCL officials. Table 5.110 & 5.111 presents the classification of the fixed assets into different voltage classes and their further segregation into demand, energy and customer category respectively.

Table 5.110 Classification of fixed assets voltage wise

Description	Amount Rs Cr	Apportionment of Fixed Assets (in %)*					Apportionment of Fixed Assets amount (In Rs Cr)				
		33 KV	11KV	LT Network	Retail Supply	Total	33 KV	11KV	LT network	Retail supply	Total
Land	10.05	0%	5%	15%	80%	100%	0.00	0.50	1.51	8.04	10.05
Buildings	7.98	0%	15%	15%	70%	100%	0.00	1.20	1.20	5.58	7.98
Vehicles	2.57	0%	15%	15%	70%	100%	0.00	0.39	0.39	1.80	2.57
Furniture & Fixtures	1.79	0%	15%	15%	70%	100%	0.00	0.27	0.27	1.25	1.79
Office Equipment	12.28	0%	5%	15%	80%	100%	0.00	0.61	1.84	9.82	12.28
Plant & Machinery	542.31	0%	70%	30%	0%	100%	0.00	379.62	162.69	0.00	542.31
Hydraulic Works	0.59	0%	60%	30%	10%	100%	0.00	0.35	0.18	0.06	0.59
Other Civil works	1.19	0%	60%	30%	10%	100%	0.00	0.72	0.36	0.12	1.19
lines cables	1464.60	0%	50%	45%	5%	100%	0.00	732.30	659.07	73.23	1464.60
Total Fixed Assets	**2043.35**						**0**	**1116**	**827**	**100**	**2043**

Table 5.111 Classification of Fixed assets into demand, energy and customer related costs

Description	Amount Rs Cr	Fixed Assets classification (In %)			33 KV Fixed Assets classification (In Rs Cr)				11 KV Fixed Assets classification (In Rs Cr)				LT net work Fixed Assets classification (In Rs Cr)				Retail supply Fixed Assets classification (In Rs Cr)			
		Demand	Energy	Customer	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Land	10.05	50%	0%	50%	0.00	0.00	0.00	0.00	0.25	0.00	0.25	0.50	0.75	0.00	0.75	1.51	4.02	0.00	4.02	8.04
Buildings	7.98	50%	0%	50%	0.00	0.00	0.00	0.00	0.60	0.00	0.60	1.20	0.60	0.00	0.60	1.20	2.79	0.00	2.79	5.58
Vehicles	2.57	50%	0%	50%	0.00	0.00	0.00	0.00	0.19	0.00	0.19	0.39	0.19	0.00	0.19	0.39	0.90	0.00	0.90	1.80
Furniture & Fixtures	1.79	50%	0%	50%	0.00	0.00	0.00	0.00	0.13	0.00	0.13	0.27	0.13	0.00	0.13	0.27	0.63	0.00	0.63	1.25
Office Equipment	12.28	50%	0%	50%	0.00	0.00	0.00	0.00	0.31	0.00	0.31	0.61	0.92	0.00	0.92	1.84	4.91	0.00	4.91	9.82
Plant & Machinery	542.31	80%	0%	20%	0.00	0.00	0.00	0.00	303.69	0.00	75.92	379.62	130.15	0.00	32.54	162.69	0.00	0.00	0.00	0.00

Description	Amount Rs Cr	Fixed Assets classification (In %)			33 KV Fixed Assets classification (In Rs Cr)				11 KV Fixed Assets classification (In Rs Cr)				LT net work Fixed Assets classification (In Rs Cr)				Retail supply Fixed Assets classification (In Rs Cr)			
		Demand	Energy	Customer	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Hydraulic Works	0.59	80%	0%	20%	0.00	0.00	0.00	0.00	0.28	0.00	0.07	0.35	0.14	0.00	0.04	0.18	0.05	0.00	0.01	0.06
Other Civil works	1.19	50%	0%	50%	0.00	0.00	0.00	0.00	0.36	0.00	0.36	0.72	0.18	0.00	0.18	0.36	0.06	0.00	0.06	0.12
lines cables	1464.60	80%	0%	20%	0.00	0	0	0	585.84	0.00	146.46	732.30	527.26	0.00	131.81	659.07	58.58	0.00	14.65	73.23
Total Fixed Assets	**2043.35**				**0.00**	**0.00**	**0.00**	**0.00**	**891.66**	**0.00**	**224.30**	**1115.95**	**660.33**	**0.00**	**167.17**	**827.50**	**71.94**	**0.00**	**27.96**	**99.90**

The functionalised cost is classified into demand, energy and customer related cost. Table 5.112 presents the classification of power purchase cost and transmission cost into demand, energy and customer related costs.

Table 5.112 Classification of Power Purchase and Transmission Charges

Particulars	Demand	Energy	Customer
Generation /Power Purchase	32.88%	67.12%	0%
Transmission	100%	0%	0%

Power purchase cost has both energy and demand related component as the utility maintains its power system to supply energy across the year and to meet the peak demand as well. The power purchase cost is classified into demand and energy related component in the ratio of fixed and variable cost in total power purchase cost as approved by the Gujarat Electricity Regulatory Commission (GERC) for the tariff determination for 2007/08. Transmission charges are incurred to supply energy across the year and thus transmission charges are classified as demand related.

Classification of distribution cost is carried out at two levels wherein at first level, distribution costs are classified at different voltage level of 11KV, LT Network and Retail Supply as presented in table 5.113. This classification is based on the discussion with UGVCL officials wherein the percentage allocation for classifying each item of distribution expenses such as repairs & maintenance, employees cost were discussed in great details.

Table 5.113 Classification of Distribution Cost- Voltage level wise

Particulars	Distribution (%)				Distribution (Rs Cr)			
	11 KV	LT Net work	Retail Supply	Total	11 KV	LT Net work	Retail Supply	Total
Repairs & Maintenance	52%	40%	8%	100%	39.41	30.03	6.42	75.86
Employee Costs	35%	35%	30%	100%	65.56	65.56	56.19	187.20
Administration & General expense	20%	40%	40%	100%	5.86	11.72	11.72	29.30
Depreciation & Related	55%	40%	5%	100%	48.75	36.15	4.36	89.27
Interest on WC	55%	40%	5%	100%	15.49	11.48	1.39	28.36
Interest & Financial Charges	55%	40%	5%	100%	33.51	24.85	3.00	61.36
Other Debits (incl. Bad debts)	59%	41%	0%	100%	0.00	1.08	0.75	1.84
Provison of Income Tax	55%	40%	5%	100%	0.54	0.40	0.05	0.99
Rate of Retun	55%	40%	5%	100%	0.46	0.34	0.02	0.85
SUB-TOTAL					**209.59**	**181.62**	**83.91**	**475.04**
Less								
Expenses capitalised	55%	40%	5%	100%	27.74	20.57	2.48	**50.79**
Net Prior Period Charges/Credits	17%	11%	71%	100%	-1.16	-0.76	-4.73	**-6.67**
TOTAL RR					**183.01**	**161.81**	**86.16**	**430.92**

Again, based on the discussion with UGVCL officials, second level classification of each voltage specific distribution cost is carried wherein the costs are classified into demand, energy and customer related cost depending on its intrinsic nature. Table 5.114 presents the classification of the voltage wise distribution cost.

Table 5.114 Second Level Classification of Distribution Cost

Distribution	Distribution- 11 KV			Distribution- LT net work			Retail supply			Distribution-Total		
	Demand	Energy	Cus.	Demand	Energy	Cus.	Demand	Energy	Cus.	Demand	Energy	Cus.
Revenue Requirement Classification												
R&M	81%	10%	9%	52%	10%	38%	20%	0%	80%	65%	9%	26%
Employee Costs	70%	0%	30%	70%	0%	30%	70%	0%	30%	70%	0%	30%
A&G expenses	50%	0%	50%	50%	0%	50%	50%	0%	50%	50%	0%	50%
Other debits	100%	0%	0%	100%	0%	0%	100%	0%	0%	100%	0%	0%
Prior period items	100%	0%	0%	100%	0%	0%	0%	100%	0%	29%	71%	0%
Interest on WC	80%	0%	20%	56%	44%	0%	11%	52%	37%	62%	27%	11%
Depreciation	80%	0%	20%	80%	0%	20%	72%	0%	28%	79%	0%	21%
Interest & Financial Charges	80%	0%	20%	80%	0%	20%	72%	0%	28%	79%	0%	21%
Income Tax & RoR	80%	0%	20%	80%	0%	20%	72%	0%	28%	79%	0%	21%
Expenses capitalised(Interest and Finance Charges)	80%	0%	20%	80%	0%	20%	72%	0%	28%	79%	0%	21%

Based on the above table, the costs at each voltage level are then classified into demand (D), energy (E) and customers (C) as indicated in table 5.115.

Table 5.115 Second Level Classification (Rs Cr)

	Distribution 11KV			Distribution LT network			Retail supply		
	Demand	**Energy**	**Cust**	**Demand**	**Energy**	**Cust**	**Demand**	**Energy**	**Cust**
Repairs & Maintenance	31.95	3.94	3.52	15.74	3.00	11.28	1.28	0.00	5.14
Employee Costs	45.89	0.00	19.67	45.89	0.00	19.67	39.33	0.00	16.86
Administration & General expense	2.93	0.00	2.93	5.86	0.00	5.86	5.86	0.00	5.86
Depreciation & Related	38.95	0.00	9.80	28.85	0.00	7.30	3.14	0.00	1.22
Interest on WC	26.78	0.00	6.74	6.39	5.10	0.00	0.15	0.72	0.52
Interest & Financial Charges	26.78	0.00	6.74	19.83	0.00	5.02	2.16	0.00	0.84
Other Debits (incl. Bad debts)	0.00	0.00	0.00	1.08	0.00	0.00	0.75	0.00	0.00
Provision of Income Tax	0.43	0.00	0.11	0.32	0.00	0.08	0.04	0.00	0.01
Rate of Return	0.37	0.00	0.09	0.27	0.00	0.07	0.02	0.00	0.01
SUB-TOTAL	**174.08**	**3.94**	**49.59**	**124.23**	**8.10**	**49.28**	**52.73**	**0.72**	**30.46**
Less									
Expenses capitalised	22.16	0.00	5.58	16.41	0.00	4.16	1.79	0.00	0.70
Net Prior Period Charges/Credits	-1.16	0.00	0.00	-0.76	0.00	0.00	0.00	-4.73	0.00
TOTAL RR	**153.08**	**3.94**	**44.01**	**108.58**	**8.10**	**45.13**	**50.94**	**5.45**	**29.76**

Grouping of Power Purchase on Block Basis

The energy cost component of power purchase could be segregated on block basis using merit order purchase. Table 5.116 presents the merit order dispatch for the utility.

Table 5.116: Merit Order Dispatch for UGVCL

	Total Energy share	**Energy despatchable**	**Shared fixed cost**	**Variable cost**	**Total variable cost**	**Incentive**	**Total Cost**	**Cumulative energy**
Station	(MU)	(MU)	(Rs. Lakhs)	(Rs./kWh)	(Rs. lakhs)	(Rs. lakhs)		
Ukai TPS	1775	1775	6453	1.47	26093		32546	1775
Ukai Hydro	131	131	663	0	0		663	1906
Gandhinagar I-IV	2004	1005	11173	1.65	16583		27756	2911
Wanakbori I-VI	4881	4060	17734	1.65	66990		84724	6971
Wanakbori VII	1107	1107	5864	1.63	18044		23908	8078
Kutch – Lignite I-III	285	285	4039	1.07	3050		7089	8363
GIPCL-II (160)	273	273	1381	1.67	4559		5940	8636
GIPCL – SLPP	394	394	4577	0.94	3704		8281	9030

	Total Energy share	Energy despatchable	Shared fixed cost	Variable cost	Total variable cost	Incentive	Total Cost	Cumulative energy
Station	(MU)	(MU)	(Rs. Lakhs)	(Rs./kWh)	(Rs. lakhs)	(Rs. lakhs)		
GMDC-Akrimota	392	392	5268	0.51	1999		7267	9422
NPC – Tarapur 1&2	253	253	0	0.95	2404	91	2495	9675
NPC – Korba	344	344	1018	0.58	1995	124	3137	10019
NPC – Vindhyachal-I	368	368	1344	1.01	3717	132	5193	10387
NPC – Vindhyachal-II	387	387	2673	0.92	3560	139	6372	10774
NTPC – Jannur	1207	1207	14611	1.54	18588	434	33633	11981
SSNNL – Hydro	72	72	148	0	0		148	12053
Captive Power	83	83	0	2.04	1693		1693	12136
NTPC - ER	-						0	12136
Adjustment to match with Annual accounts		865						
Total		13001	76946		172979	920	250845	

The table 5.117 indicates the computation of energy cost allocated to agricultural category.

Table 5.117: Allocation of energy cost to agricultural category

	Units	Variable Power Purchase (Rs crores)	Per Unit Variable Power purchase cost (Rs/ kWh)
Base Block	12130	1728.93	1.43
Growth Block	871	82.79	0.95
Total	13001	1811.73	1.39
Share of Agriculture - CP			
Base Block	7129.39	1016.18	1.43
Growth Block	607.61	57.76	0.95
Total	7737.00	1073.93	1.39

Step 3: Allocation

Once the costs are classified into demand, energy and customer related cost, they are then finally allocated to the agricultural consumer category in manner as explained in Chapter 4.

For allocation of cost to agricultural consumers, either Coincident peak or the non coincident peak may be used. Table 5.118 indicates the coincident and non coincident peak for the agricultural consumer category of UGVCL.

Table 5.118 Coincident and Non coincident peak of UGVCL

	Load factor (as per sample feeders)	LLF	CF	No. of Consumers	Consumer weightage	No. of equivalent consumers	Consumption (MU)	Allocation of Total Loss -MU	Consumption + Loss (MU)	NCP MW+ Loss	CP-MW
Agricultural Consumer	41.97%	24..93%	37.97%	213,559	2.5	533,898	5837	1900	7737	2104.18	798.89
Total NO of Consumers In UGVCL				2,197,246							
Total Consumption							10,240	2761	13001		
Share of agricultural consumers and consumption in Total				9.7%		24.30%	57.0%		59.51%		
Total Discom	60.36%									2458.9	
System Peak											2154
Ratio of Coincident and Non coincident Peak										85.57%	37.09%

Table 5.119 presents the allocation of the costs to the agricultural category using the Average CP Method.

Table 5.119 Allocation of cost – CP Method

	Power Purchase Cost			Transmission charges			Distribution Total			Total Cost Rs Cr
	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	
c	Demand	Energy	Customer	Demand	Energy	Cust	Demand	Energy	Cust	
Total UGVCL Cost	887.63	1811.73		231.50			296.96	19.41	114.66	3361.88
Allocation of Cost to Agricultural Consumer Category	329.21	1073.93		85.86			110.14	11.55	27.86	1638.55
Per unit Cost to agricultural consumers (Rs /Kwh)	0.56			0.15			0.19	0.02	0.05	2.81
Avg Cost as per Annual Report										3.33
Avg Cost as per Tariff Order										3.31

Final Results from the Model

Following table summarises the cost of supply as per the model. It also presents a comparison for the cost of serve and the revenue realised from the agricultural consumer category.

Table 5.120 Comparison of Cost to serve and Revenue realisation

Category	Energy Sold (MU)	Revenue at Current Tariff Rate (Rs cr)	Avg. Realn. (Rs./KWH) at current rates	CoS (Rs./KWH)	Total Cost of supply	Total Subsidy	Subsidy Recived from Govt	Cross Subsidy
LT Agriculture	5837	657.59	1.13	2.81	1638.55	980.96	576.58	404.38

Estimation of Cost to Serve for PGVCL

Team Identification

For the study, Mr D Y Harsora, PGVCL was nominated as the Nodal officers. Detailed discussions were held with the PGVCL officers about the scope of work and the data requirement. Theses officials include:

- Mr R J Vala, Executive Assistant and Deputy engineer, Chairman Office, PGVCL
- Mr Dinesh J. Lakhani, Contoller of Accounts
- Mr Kintkumar Malkan, General Manager (F&A)
- Mr Kirit M Bhuva, Superintending Engineer, PGVCL
- Mr Sudhir Bhatt, Company Secretary, PGVCL

Sampling

For the feeder data analysis, 18 feeders are selected which have predominantly i.e 80% of the agricultural load. Table 5.121 presents the circle wise list of selected feeders.

Table 5.121 Sample Feeders selected across various circle

Name of the Circle	No of Sample Feeders
Bhavnagar	2
Surendernagar	2
Rajkot City	2
Rajkot Rural	2
Kutch	1
Bhuj	1
Amrelo	2
Porbandar	2
Junagarh	2
Jamnagar	2
Total	**18**

18 days uniformly spread across the year are selected to collect the load details of the selected feeder. This captured the seasonality factor in the agricultural power consumption. Load

details of selected feeder are also collected for the peak day of the utility. The selected days are presented in table 5.122.

Table 5.122 days Selected for collection of load data from sample feeders

06.04.2007	Summer
22.04.2007	Summer
02.05.2007	Summer
19.05.2007	Summer
14.06.2007	Monsoon
15.07.2007	Monsoon
25.07.2007	Monsoon
15.08.200	Monsoon
04.09.2007	Monsoon
26.09.2007	Monsoon
08.10.2007	Winter
18.11.2007	Winter
01.12.2007	Winter
11.12.2007	Winter
25.12.2007	Winter
12.01.2008	Winter
14.01.08	Winter
20.02.2008	Summer
14.03.08	Summer

Analysis of the sample feeder data

Figure 5.32 presents the load curves aggregated for 18 selected feeders across different selected days.

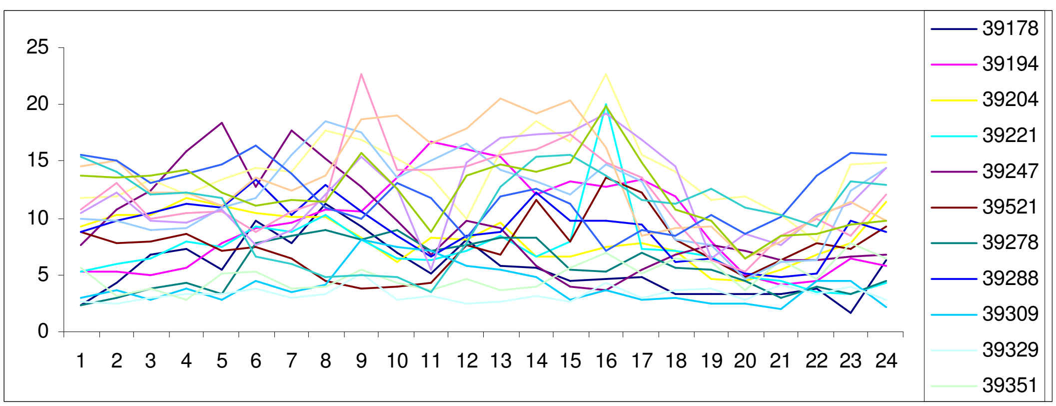


Figure 5.32 Agricultural Feeder Data Analysis

Table 5.123 gives the Load factor, load loss factor and coincident factor of the agricultural feeder data.

Table 5.123 Feeder Data Analysis

Calculation of class load factor	
Average (Mwh)	9.122

Max (Mwh)		22.26
Load factor (%)		**40.26%**
Calculation of load loss factor		
Formula	(0.3 *LF +0.7 (LF)^2	**23.43%**
Calculation of CF		**44.74%**

Model Process

This section details out the process for calculating the cost of service of power to the agricultural consumers and the analysis of the results derived.

Step 1: Functionalisation

As per PGVCL's annual accounts for 2007/08, a summary of costs incurred by the utility as functionalised into power purchase, transmission and distribution related is presented in table 5.124.

Table 5.124 Functionalised Cost of PGVCL

	PP cost	**Tr. Charges**	**Distribution**	**Total UGVCL**
	Rs Cr	Rs Cr	Rs Cr	Rs Cr
Purchase of Power	3,642.83			3,642.83
Transmission Charges		353.66		353.66
Repairs & Maintenance			82.83	82.83
Employee Costs			290.15	290.15
Administration & General expense			57.84	57.84
Depreciation & Related			143.33	143.33
Interest & Financial Charges			106.70	106.70
Interest on working capital			35.82	35.82
Provison for Tax			0.99	0.99
Rate of Return			1.19	1.19
SUB-TOTAL	**3,642.83**		**718.85**	**4,361.68**
Less				
Expenses capitalised			42.46	42.46
net prior period			(28.67)	(28.67)
NET TOTAL EXPENSES	**3,642.83**	**353.66**	**705.06**	**4,347.89**

Source : Annual Accounts, PGVCL, 2007/08

Discussions with PGVCL revealed that the power purchase cost of Rs 3996.49 cr is combined cost which is inclusive of the transmission charges. Thus, this power purchase cost is functionalised into power purchase and transmission charges based on the ratio of transmission charges in total power purchase as approved by the Gujarat Electricity Regulatory Commission (GERC) for the tariff determination for 2007/08.

Step 2: Classification

Details of fixed Assets have been captured and segregation of assets in to various voltage classes have been made based on the discussion with then PGVCL offcials. Table 5.125 & 5.126 presents the classification of the fixed assets into different voltage classes and their further segregation into demand, energy and customer category.

Table 5.125 Classification of fixed assets voltage wise

Description	Amount (Rs Cr)	Apportionment of Fixed Assets (in %)					Apportionment of Fixed Assets amount (In Rs)				
		33 KV	11KV	LT Network	Retail Supply	Total	33 KV	11KV	LT Network	Retail Supply	Total
Land	0.89	0%	5%	15%	80%	100%	0	0.04	0.13	0.71	0.89
Buildings	12.32	0%	15%	15%	70%	100%	0	1.85	1.85	8.62	12.32
Vehicles	5.13	0%	15%	15%	70%	100%	0	0.77	0.77	3.59	5.13
Furniture & Fixtures	4.51	0%	15%	15%	70%	100%	0	0.68	0.68	3.16	4.51
Office Equipment	18.19	0%	5%	15%	80%	100%	0	0.91	2.73	14.55	18.19
Plant & Machinery	790.20	0%	70%	30%	0%	100%	0	553.14	237.06	0.00	790.20
hYdraulic Works	0.10	0%	60%	30%	10%	100%	0	0.06	0.03	0.01	0.10
Other Civil works	1.95	0%	60%	30%	10%	100%	0	1.17	0.59	0.20	1.95
Lines & cables	2431.26	0%	50%	45%	5%	100%	0	1215.63	1094.07	121.56	2431.26
Total Fixed Assets	**3264.55**							**1774**	**1338**	**152**	**3265**

Table 5.126 Classification of Fixed assets into demand, energy and customer related costs

Description	Amount (Rs Cr)	Fixed Assets classification (In %)			33 KV Fixed Assets classification (In Rs)				11 KV Fixed Assets classification				LT net work Fixed Assets classification				Retail supply Fixed Assets classification			
		Demand	Energy	Customer	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Land	0.89	50%	0%	50%	0.00	0.00	0.00	0.00	0.02	0.00	0.02	0.04	0.07	0.00	0.07	0.13	0.36	0.00	0.36	0.71
Buildings	12.32	50%	0%	50%	0.00	0.00	0.00	0.00	0.92	0.00	0.92	1.85	0.92	0.00	0.92	1.85	4.31	0.00	4.31	8.62
Vehicles	5.13	50%	0%	50%	0.00	0.00	0.00	0.00	0.39	0.00	0.39	0.77	0.39	0.00	0.39	0.77	1.80	0.00	1.80	3.59
Furniture & Fixtures	4.51	50%	0%	50%	0.00	0.00	0.00	0.00	0.34	0.00	0.34	0.68	0.34	0.00	0.34	0.68	1.58	0.00	1.58	3.16
Office Equipment	18.19	50%	0%	50%	0.00	0.00	0.00	0.00	0.45	0.00	0.45	0.91	1.36	0.00	1.36	2.73	7.27	0.00	7.27	14.55
Plant & Machinery	790.20	80%	0%	20%	0.00	0.00	0.00	0.00	442.51	0.00	110.63	553.14	189.65	0.00	47.41	237.06	0.00	0.00	0.00	0.00
hYdraulic Works	0.10	80%	0%	20%	0.00	0.00	0.00	0.00	0.05	0.00	0.01	0.06	0.02	0.00	0.01	0.03	0.01	0.00	0.00	0.01
Other Civil works	1.95	50%	0%	50%	0.00	0.00	0.00	0.00	0.59	0.00	0.59	1.17	0.29	0.00	0.29	0.59	0.10	0.00	0.10	0.20
Lines & cables	2431.26	80%	0%	20%	0.00	0.00	0.00	0.00	972.50	0.00	243.13	1215.63	875.25	0.00	218.81	1094.07	97.25	0.00	24.31	121.56
Total Fixed Assets	**3264.55**				**0.00**	**0.00**	**0.00**	**0.00**	**1417.77**	**0.00**	**356.47**	**1774.25**	**1068.30**	**0.00**	**269.60**	**1337.90**	**112.67**	**0.00**	**39.73**	**152.41**

The functionalised cost is classified into demand, energy and customer related cost. Table 5.127 presents the classification of power purchase cost and transmission cost into demand, energy and customer related costs.

Table 5.127 Classification of Power Purchase and Transmission Charges

Particulars	Demand	Energy	Customer
Generation /Power Purchase	34.91%	65.09%	0%
Transmission	100%	0%	0%

Power purchase cost has both energy and demand related component as the utility maintains its power system to supply energy across the year and to meet the peak demand as well. The power purchase cost is classified into demand and energy related component in the ratio of fixed and variable cost in total power purchase cost as approved by the Gujarat Electricity Regulatory Commission (GERC) for the tariff determination for 2007/08. Transmission charges are incurred to supply energy across the year and thus transmission charges are classified as demand related.

Classification of distribution cost is carried out at two levels wherein at first level, distribution costs are classified at different voltage level of 11KV, LT Network and Retail Supply as presented in table 5.128. This classification is based on the discussion with PGVCL officials wherein the percentage allocation for classifying each item of distribution expenses such as repairs & maintenance, employees cost were discussed in great details.

Table 5.128 Classification of Distribution Cost- Voltage level wise

Particulars	Distribution (%)				Distribution (Rs Cr)			
	11 KV	LT Net work	Retail Supply	Total	11 KV	LT Net work	Retail Supply	Total
Repairs & Maintenance	56%	34%	9%	100%	46.42	28.52	7.86	82.8
Employee Costs	35%	35%	30%	100%	101.54	101.54	87.03	290.12
Administration & General expense	20%	40%	40%	100%	11.57	23.13	23.13	57.3
Depreciation & Related	54%	41%	5%	100%	77.9	58.74	6.69	143.33
Interest on WC	54%	41%	5%	100%	19.47	14.68	1.67	35.82
Interest & Financial Charges	54%	41%	5%	100%	57.99	43.73	4.98	106.7
Provison of Income Tax	55%	40%	5%	100%	0.54	0.41	0.05	0.99
TOTAL					**209.12**	**181.28**	**83.89**	**474.29**

Again, based on the discussion with PGVCL officials, second level classification of each voltage specific distribution cost is carried wherein the costs are classified into demand, energy and customer related cost depending on its intrinsic nature. Table 5.129 presents the classification of the voltage wise distribution cost.

Table 5.129 Second Level Classification of Distribution Cost

Distribution	Distribution- 11 KV			Distribution- LT net work			Retail supply			Distribution-Total		
	Demand	Energy	Cus.	Demand	Energy	Cus.	Demand	Energy	Cus.	Demand	Energy	Cus.
R&M	82%	10%	8%	56%	10%	34%	20%	0%	80%	67%	9%	23%
Employee Costs	70%	0%	30%	70%	0%	30%	40%	0%	60%	61%	0%	39%
A&G expenses	50%	0%	50%	50%	0%	50%	50%	0%	50%	50%	0%	50%
Prior period items	100%	0%	0%	100%	0%	0%	0%	100%	0%	50%	50%	0%
Interest on WC	0%	100%	0%	0%	100%	0%	0%	100%	0%	0%	100%	0%
Depreciation	80%	0%	20%	80%	0%	20%	80%	0%	20%	80%	0%	20%
Interest & Financial Charges	0%	100%	0%	0%	100%	0%	0%	100%	0%	0%	100%	0%
Income Tax & RoR	80%	0%	20%	80%	0%	20%	80%	0%	20%	80%	0%	20%
Capitalization of int. fin charges	80%	0%	20%	80%	0%	20%	80%	0%	20%	80%	0%	20%
Capitalization of other expenses	80%	0%	20%	80%	0%	20%	80%	0%	20%	80%	0%	20%

Based on the above table, the costs at each voltage level are then classified into demand, energy and customers as indicated in table 5.130.

Table 5.130. Second Level Classification (Rs Cr)

Particulars	Distribution 11KV			Distribution LT network			Retail supply		
	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Repairs & Maintenance	38.20	4.64	3.57	16.09	2.85	9.58	1.57	0.00	6.29
Employee Costs	71.08	0.00	30.46	71.08	0.00	30.46	34.81	0.00	52.22
Administration & General expense	5.50	0.00	5.50	10.99	0.00	10.99	10.99	0.00	10.99
Depreciation & Related	62.25	0.00	15.65	46.94	0.00	11.80	5.35	0.00	1.34
Interest & Financial Charges	0.00	57.99	0.00	0.00	43.73	0.00	0.00	4.98	0.00
Interest on WCl	0.00	19.47	0.00	0.00	14.68	0.00	0.00	1.67	0.00
Provison for Tax	0.51	0.00	0.11	0.33	0.00	0.08	0.04	0.00	0.01
Rate of Return	0.43	0.00	0.11	0.39	0.00	0.10	0.04	0.00	0.01
SUB-TOTAL	**177.97**	**82.10**	**55.40**	**145.81**	**61.26**	**63.01**	**52.80**	**6.65**	**70.86**
Less									
Expenses capitalised	18.44	0.00	4.64	13.91	0.00	3.50	1.58	0.00	0.40
net prior period	-15.58	0.00	0.00	-11.75	0.00	0.00	0.00	-1.34	0.00
NET TOTAL EXPENSES	**175.11**	**82.10**	**50.76**	**143.66**	**61.26**	**59.52**	**51.22**	**7.99**	**70.47**

Grouping of Power Purchase cost on Block Basis

Table 5.131 presents the segregation of power purchase cost on the basis of merit order dispatch.

Table 5.131: Merit Order Dispatch of PGVCL

	(MU)	(MU)	Rs./ Lakh(s)	Rs/kwh)	(Rs.lakhs)	(Rs.lakhs)	Rs/Kwh	
Source	**Energy Available**	**Energy despatch able**	**Fixed Cost**	**Unit Variable Cost/ kWh**	**Total Variable Cost**	**Total Cost**	**Total Cost**	**Cummulative Units**
Ukai Hydro	394	394	1996	0		1996	0.51	394
NPC – Tarapur1&2	759	759		0.95	7210	7210	0.95	1153
SSNL – Hydro	216	216	443	2.05	4428	4871	2.26	1369
GMDC-Akrimote	1189	1189	15973	0.51	6064	22037	1.85	2558
NTPC – Korba	1985	1985	5877	0.58	11513	17390	0.88	4543
NTPC – Vindhyachal – II	1167	1167	8060	0.92	10736	18796	1.61	5710
GIPCL - SLPP	1196	1196	13879	0.94	11242	25121	2.10	6906
NTPC – Vindhyachal – I	1103	1103	4031	1.01	11140	15171	1.38	8009
Kutch Lignite I to III	872	872	12345	1.07	9330	21675	2.49	8881
Ukai TPS	597	597	2171	1.47	8776	10947	1.83	9478
NTPC – Jhanor	409	409	4946	1.54	6299	11245	2.75	9887
Wanakbori – VII	374	374	1979	1.63	6096	8075	2.16	10261
Wanakbori I to VI	3254	3254	11823	1.65	53691	65514	2.01	13515
Gandhinagar I to IV	1336	1336	7448	1.65	22044	29492	2.21	14851
GIPCL II (160)	819	819	4144	1.67	13677	17821	2.18	15670
Captive capacity	270	270		2.02	5454	5454	2.02	15940
Other sources	1100	422		2.2	9284	9284	2.20	16362
Adjustment to match with annual accounts		2051.00			40113			18413
Total		18413			237097			

Table 5.132 presents the allocation of energy component of power purchase cost to agricultural category.

Table 5.132: Allocated energy cost to agricultural category

	Units	**Variable Power Purchase Cost (Rs crores)**	**Per Unit Variable power purchase cost(Rs/ kWh)**
Base Block	15694	1848.03	1.18
Growth Block	2719.00	523	1.92
Total	18413.00	2371	1.29
Share of Agriculture - CP			
Base Block	7617.28	897	1.18

Growth Block	-930.92	-179	1.92
Total	6686.36	861	1.29

Step 3: Allocation

Once the costs are classified into demand, energy and customer related cost, they are then finally allocated to the agricultural consumer category in manner as explained in Chapter 4.

For allocation of cost to agricultural consumers, either Coincident peak or the non coincident peak may be used. Table 5.133 indicates the coincident and non coincident peak for the agricultural consumer category of PGVCL.

Table 5.133 Coincident and Non coincident peak

	Load factor (as per sample feeders)	LLF	CF	No. of Consumers	Consumer weightage	No. of equivalent consumers	Consumption (MU)	Allocation of Total Loss - MU	Consumption + Loss (MU)	NCP MW+ Loss	CP-MW
Agricultural Consumer	40.26%	23.43%	44.74%	381,011	2.5	952,527.50	4198	2,488	6,686	1895.74	848.17
Total NO of Consumers In PGVCL				3,341,431							
Total Consumption							11,837	6,576	18,413		
Share of agricultural consumers and consumption in Total				11.4%		28.51%	35.5%		36.31%		
Total Discom	62.31%	45.87%								3373.29	
System Peak											2,955
Ratio of Coincident and Non coincident peak										56.20%	28.70%

Table 5.134 presents the allocation of the costs to the agricultural category using the Average Peak- Coincident Peak Method.

Table 5.134 Allocation of cost – CP Method

	PP cost			Transmission charges			Distribution Total			Total Cost
	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr
	Demand	Energy	Cust	Demand	Energy	Cust	Demand	Energy	Cust	
Total Cost	1271.86	2370.97		353.66			442.36	57.54	202.21	4698.60
Allocation of Cost to Agri Category	365.06	860.98		101.51			126.97	20.89	57.64	1533.06
Per Unit allocated Cost (Rs/Kwh)	0.87	2.05		0.24			0.30	0.05	0.14	3.65
Avg Cost (Rs/Kwh)										3.97

Final Results of Model

Following table summarises the cost of supply as per the model methodology. It also presents a comparison for the cost of serve and the revenue realised from the agricultural consumer category.

Table 5.135 Comparison of Cost to serve and Revenue realisation

Methods	Energy Sold (MU)	Revenue at Current Tariff Rate (Rs cr)	Avg. Realn. (Rs./KWH) at current rates	CoS (Rs./KWH)	Total Cost (Rs cr)	Total Subsidy	Subsidy Recived from Govt	Cross Subsidy
CP Method	4198	470.14	1.12	3.65	1533.06	1062.92	419.62	643.30

5.4 Haryana

Estimation of Cost to Serve for UHBVN[27]

Agricultural Background of the state

The total geographical area of the state is 4.42 m ha, which is 1.4 % of the geographical area of the country. The cultivable area is 3.8 m ha, which is 86 % of the geographical area of the state out of which 3.62 m ha i.e. 96.2 % is under cultivation. The gross cropped area of the state is 6.32m ha and net cropped area is 3.62 m ha with a cropping intensity of 177%.

Haryana is located in the northwest part of the country and the climate is arid to semi arid with average rainfall of 455 mm. The north western part is suitable for Rice, Wheat, Vegetable and temperate fruits and the south western part is suitable for high quality agricultural produce, tropical fruits, exotic vegetables and herbal and medicinal plants.

[27] It is to be noted that load data for the DISCOM was not available for 2007-08. Hence, COS has been computed on the basis of single CP and energy cost divided equally between all categories.

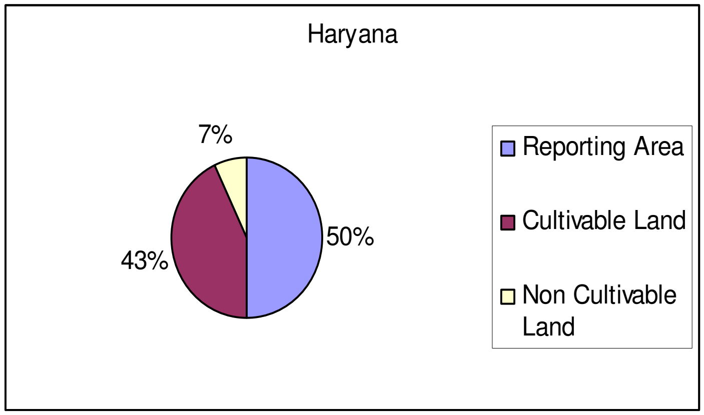


Fig.5.33 Haryana: Reported Area, Cultivable Land and Non-Cultivable Land in India, (2003-2004)

Source: Fertilizer Statistics 2003-04, Ministry of Agriculture

The net irrigated area is 29, 58,000 hectares and gross irrigated area is 53, 43, 000 hectares. The distribution of gross irrigated area based on the various sources of irrigation is as follows:

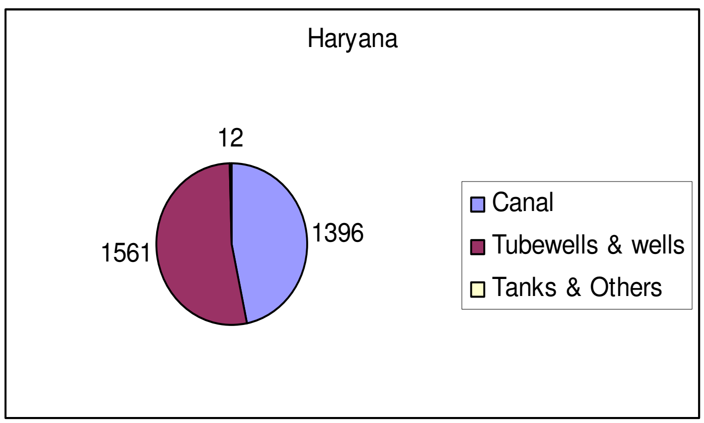


Fig 5.34 Haryana: Irrigation by Source. (Figures in Hectares)

Source: Fertilizer Statistics 2007-08, Ministry of Agriculture

Out of the net irrigated area the above figure indicates that Tube wells and other wells account for majority of irrigation (52%).

Table 5.136 District-wise Tubewells and Pumping Sets in Haryana (2003-2004)

Districts	Diesel Sets	Electric Sets	Total
Ambala	5895	15598	21493
Panchkula	2148	2322	4470
Yamunanagar	9283	18519	27802
Kurukshetra	938	34960	35898

Kaithal	23119	29141	52260
Karnal	14386	52273	66659
Panipat	7105	24257	31362
Sonipat	21016	16641	37657
Rohtak	15239	2213	17452
Jhajjar	29555	5093	34648
Faridabad	18331	13513	31844
Gurgaon	6041	25498	31539
Rewari	6818	22901	29719
Mahendragarh	224	22376	22600
Bhiwani	11397	17784	29181
Jind	18874	20295	39169
Hisar	18459	5069	23528
Fatehabd	12504	17010	29514
Sirsa	21701	18602	40303

Note : Sets Include Both Pumping Sets and Tubewells.
Compiled from the statistics released by : Planning Department, Govt. of Haryana.

There are three canal commands. Yamuna command including Gurgaon and Agra Canal Systems with CCA of 0.288 and 0.158 Million Acres, is the oldest system having CCA of 2.910 Million Acres with Average Irrigated Area as 2.171 Million Acres Bhakra canal command came into existence in 1954 having CCA of 3.565 Million Acres Average Irrigated Area 3.029 Million Acres Lift irrigation system was the pioneer work, an era of providing irrigation water to higher areas having CCA of 1.265 Million Acres Average Irrigated Area 0.167 Million Acres

Total CCA of 7.740 Million Acres and Total Average Irrigated Area 5.347 Million Acres per year (1999-2004). The gross cropped area of the state is 6.32m ha and net cropped area is 3.62 m ha with a cropping intensity of 177%. The north western part is suitable for Rice, Wheat, Vegetable and temperate fruits and the south western part is suitable for high quality agricultural produce, tropical fruits, exotic vegetables and herbal and medicinal plants.

Rainfall

Haryana is located in the northwest part of the country and the climate is arid to semi arid with average rainfall of 455 mm. Around 70 % rainfall is received during the month from July to September and the remaining rainfall is received during Dec. to Feb. There are two agro climatic zones in the state.

Rainfall is varied, with Shivalik Hills region being the wettest and the Aravali Hills region being the driest. About 80% of the rainfall occurs in the monsoon season (July-September) and sometimes causes local flooding. The district-wise average rainfall (mm) during the period from 1998 to 2002 is given below:

Table 5.137 District-wise Average Monthly Normal Rainfall in Haryana (1998-2002)

(In Millimetre)

Districts	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Annual Total
Ambala	25.5	28.5	38.5	19.4	30.8	144.7	365	268.9	165.2	27	1	1.4	1115.5
Panchkula	27.2	33.4	33.4	24.6	59	221.6	340	392.2	183	31.2	0	0.6	1346
Yamunanagar	32.4	40.9	31.1	21.7	41	122	299	259.2	143.4	29.6	0	0.8	1020.8
Kurukshetra	20.5	24.6	14.4	7.6	19.1	78.6	167	124.5	104.7	21.8	3.7	1	587.5
Kaithal	20.9	26.5	9.4	5.8	26	103.4	63.9	85.7	68.9	21.4	0.6	2.3	434.8
Karnal	18.2	17.9	8.7	5.3	20.6	77.5	115	102.4	64.5	22	5.2	0.5	457.6
Panipat	25.5	26	9.6	4.3	12.8	79.6	103	84.5	69.9	19.8	1.6	0.2	436.3
Sonipat	22.3	26.4	15.3	8.5	36.3	59	84.3	111.6	83.7	25.3	0	1.3	474
Rohtak	15.8	21.7	9.9	3.2	38.3	62.2	91.2	112.1	66.8	18.3	0	3	442.5
Jhajjar	7.4	14.5	9.7	4.4	41.3	39	89.1	68.9	48.2	15.8	1	2	341.3
Faridabad	9.3	8.6	2.2	3.9	20.8	42.8	122	147.8	98.3	9.2	0.2	2.3	466.9
Gurgaon	13.5	9.5	6	2.2	29.6	49.4	120	109.4	85.7	15.2	1.4	1.4	443
Rewari	8.9	10.9	6.4	6.2	42.1	59.7	126	103.2	48.8	15.8	1.3	2.8	431.6
Mahendragarh	10.5	10.8	4.3	3.3	23.7	39.1	115	54	32	8.2	1.7	2.4	305.1
Bhiwani	8.4	11	5.6	2.2	33.4	40.7	67.7	55.5	40.6	16.4	0	1.9	283.4
Jind	19.2	22.4	12	11.5	28.8	69.3	146	97.4	79.6	27.3	3	0.5	516.6
Hisar	10.4	13.8	2	2.7	24.1	33	58.2	41.2	30.9	18.5	1.3	0.4	236.5
Fatehabd	12.3	21.5	2.9	5.9	18.3	43.8	60.1	39.7	65.7	27.6	0	2.3	300.1
Sirsa	10	6.5	0.7	1.4	21.8	18.6	77.4	27	20	11.8	0.7	5.7	201.6

Source: Planning Department, Govt. of Haryana.

Area, Irrigation and Crops

Haryana contributed significantly to the Green Revolution in India in the 1970s that made the country self-sufficient in food production. The state has also significantly contributed to the field of agricultural education in the country. Haryana is primarily an agricultural state. About 70% of residents are engaged in agriculture. Wheat and rice are the major crops. Haryana is self-sufficient in food production and the second largest contributor to India's central pool of food grains. The main crops of Haryana are wheat, rice, sugarcane, cotton, oilseeds, gram, barley, corn, millet etc. There are two main types of crops in Haryana: Rabi and Kharif. The major Kharif crops of Haryana are rice, jowar, bajra, maize, cotton, jute, sugarcane, sesame and groundnut. For these crops the ground is prepared in April and May and the seeds are sown at the commencement of rains in June. The crops are ready for harvesting by the beginning of November. The major Rabi crops are wheat, tobacco, gram, linseed, rapeseed and mustard. The ground is prepared by the end of October or the beginning of November and the crops are harvested by March.

Table 5.138 Area, Production and Average Yield of Major Crops in Haryana (2004-2005)

(Area in ' 000 Hectare; Production in ' 000 Tonne; Average Yield in Kg./Ha.)

Crops	Area	Production	Average Yield
	2004-05	2004-05	2004-05
Kharif Foodgrains	**1770**	**3890**	**2198**

Rice	1028	3023	2941
Bajra	569	749	1316
Maize	16	40	2500
Jowar	96	26	271
Kharif Pulses	61	52	852
Rabi Foodgrains	**2455**	**9198**	**3747**
Wheat	2322	9058	3901
Barley	25	67	2680
Gram	107	91	850
Other Rabi Pulses	7	6	833
Rabi Oilseeds	**702**	**826**	**1177**
Sugarcane (Gur)	130	7101	54623
Cotton (Lint)	621	2075	568

Abbr. : P : Provisional.

Compiled from the statistics released by : The Fertiliser Association of India.

About 86% of the area is arable, and of that 96% is cultivated. About 75% of the area is irrigated, through tubewells and an extensive system of canals. Major crops irrigated is given in the following table:

Table 5.139 District-wise Irrigated Area under Food Crops in Haryana - Part I (2004-2005)

(In Hectare)

	Cereals (Food Crops)											
	Rice		Jowar or Cholum							Other Cereals and Millets		Total Cereals and Millets
District	Autumn	Total	Kharif	Rabi	Total	Bajra or Cumbu	Maize	Wheat	Barley	Kharif	Total	
Ambala	73449	73449	-	-	-	-	55	80359	10	-	-	153873
Bhiwani	11369	11369	3767	-	3767	18838	41	126341	4006	-	-	164362
Faridabad	28255	28255	10642	-	10642	5291	227	135706	1327	-	-	181448
Fatehbad	65365	65365	-	-	-	8085	18	177200	2494	-	-	253162
Gurgaon	5687	5687	3107	-	3107	18303	6	110478	1655	-	-	139236
Hissar	28281	28281	8	-	8	32494	78	202401	3709	-	-	266971
Jhajjer	13362	13362	18473	-	18473	10754	65	82454	906	-	-	126014
Jind	90894	90894	507	-	507	22366	-	206752	791	-	-	321310
Kaithal	152637	152637	34	-	34	10419	99	174257	33	-	-	337479
Karnal	167405	167405	-	-	-	1028	148	170667	106	149	149	339503
Kurkshetra	121844	121844	-	-	-	51	208	113851	11	-	-	235965
Mahendra Garh	-	-	60	-	60	12499	-	40575	439	-	-	53573
Panchkula	6621	6621	-	-	-	-	30	11502	4	-	-	18157
Panipat	72281	72281	28	-	28	700	10	83827	48	-	-	156894
Rewari	475	475	977	-	977	21760	-	44854	-	-	-	68066
Rohtak	15006	15006	20759	-	20759	5418	40	87100	881	-	-	129204
Sirsa	45459	45459	-	-	-	2825	1	247155	3807	-	-	299247
Sonepat	65954	65954	12246	-	12246	4985	434	131430	484	-	-	215533
Yamuna Nagar	58050	58050	-	-	-	14	133	68631	10	-	-	126838
Haryana	**1022394**	**1022394**	**70608**	**-**	**70608**	**175830**	**1593**	**2295540**	**20721**	**149**	**149**	**3586835**

Note : - : Not Reported/Not Available or Reported Zero. Compiled from the statistics released by : Ministry of Agriculture, Govt. of India.

Energy characteristics of Haryana[28]

HPGCL meets the total requirements of power of distribution licensees UHBVN and DHBVN out of generation from own sources, allocation from NTPC, NHPC, NPC , shared projects such as BBMB and IPGCL, new sources, short term and bilateral trading as shown in table 5.140.

Table 5.140 - Power Purchase volume for FY 2007-08 (MUs)

Source of Power	HERC approved values (MU)
NTPC	
Singrauli STPS	1849
Rihand I	699
Rihand II	664
Unchhahar I	173
Unchhahar II	280
Unchhahar III	95
Anta CCGT	264
Auraiya CCGT	376
Dadri CCGT	342
Faridabad CCGT #	2910
NHPC	
Salal	540
Bairasiul	235
Tanakpur	23
Chamera I	347
Chamera II	180
Dhauliganga	88
Dhulhasti	175
Uri	123
Parbati II	30
Sewa II	20
New Sources	
SJVNL	307
Tehri (THDC)	260
Koteshwar HEP	15
Kahalgaon I	25
Kahalgaon II	250
Tala (displacement)	45
NPC	
NAPP	103
RAPP (3-4)	367
HPGCL #	**10058**

[28] Source : HERC's Order on "Annual Review Report for Bulk Supply Business for FY 2007-08, Trading Margin & Bulk Supply Tariff dated 8th May, 2007

Source of Power	**HERC approved values (MU)**
Shared Projects	
BBMB	3200
IPGCL	228
Others	
Malana (PTC)	100
Ch. Devilal Sugar Mill #	2
Short Term & Bilateral	2000
TOTAL	**26,372**

N.B. Sources of power marked (#) represents energy generated within the state & volume totals to 12970 MUs. The balance energy amounting to 13402 MUs (26,372 – 12,970) is from out of state sources. The approved rates and source wise cost of power purchase is given in Table 5.141.

Table 5.141 Approved Power Purchase Rates & Cost (FY 2007 – 08)

Source of Power	**HERC Approval**		
	Volume (MU)	Rate (Rs/kWh)	Cost (Rs. Mln)
NTPC			
Singrauli STPS	1849	1.18	2189
Rihand I	699	1.64	1147
Rihand II	664	1.59	1056
Unchhahar I	173	1.80	312
Unchhahar II	280	1.93	539
Unchhahar III	95	2.20	209
Anta CCGT	264	2.09	551
Auraiya CCGT	376	2.40	903
Dadri CCGT	342	2.76	944
Faridabad CCGT #	2910	2.24	6518
NHPC			
Salal	540	0.69	373
Bairasiul	235	0.95	224
Tanakpur	23	1.33	31
Chamera I	347	1.21	420
Chamera II	180	2.34	422
Dhauliganga	88	2.05	179
Dhulhasti	175	3.00	525
Uri	123	2.40	295
Parbati II	30	3.85	116
Sewa II	20	3.00	60
New Sources			
SJVNL	307	3.23	992
Tehri (THDC)	260	3.43	892
Koteshwar HEP	15	2.50	38
Kahalgaon I	25	2.50	63
Kahalgaon II	250	3.00	750
Tala (displacement)	45	1.88	85

Source of Power	**HERC Approval**		
	Volume (MU)	Rate (Rs/kWh)	Cost (Rs. Min)
NPC			
NAPP	103	2.45	252
RAPP (3-4)	367	2.95	1082
HPGCL #	**10058**	**2.798966**	**28152**
Shared Projects			
BBMB	3200	0.1120	358
IPGCL	228	3.12	711
Others			
Malana (PTC)	100	2.88	288
Ch. Devilal Sugar Mill #	2	2.5	5
Short Term & Bilateral	2000	3.77	7540
Wheeling & Other Charges			
Wheeling PGCIL			1184
Wheeling HPSEB			5
Wheeling PSEB			10
Wheeling UPSEB			5
Wheeling BBMB			1
LC Charges			8
ULDC Charges			56
Open Access			488
TOTAL	**26,372**		**59,977**

Wheeling Charges

HPGCL pays wheeling charges to the Power Grid Cooperation of India (PGCIL) for wheeling power from the generating sections of NTPC, NHPC, NPC & other sources to its boundary. In addition to this, additional wheeling charges are paid to the State Grids through which power from sources like Salal, Bairasiul and ER power is wheeled. With the grant of 'Open Access' and 'Trading License' by the CERC and the fact that HPGCL is buying short-term power from the licensed traders, open access charges have become a reality. These are legitimate cost of bulk supply business and are therefore allowed by the Commission as per table 5.141 above.

Transmission losses

The Commission vide its order on Annual Revenue Report for Transmission Business & SLDC for FY 2007-08 & Transmission Tariff and SLDC charges (Case No. HERC/PRO – 6 of 2006) dated 8th May 2007 has pegged the inter-state transmission losses at 4% and intra-state transmission losses of 2.6% in FY 2007-08. Resultantly, the net units available for sale to the Discoms work out to 25,164 million units. The details are presented in table 5.142.

Table 5.142 Energy available for sale to distribution business (FY 2007-08)

Description		HERC Approval
Gross Energy Procured from out of state sources (MU)	1	13402
Inter state transmission loss %	2	4%
Inter state transmission loss (MU)	3=1*2	536
Net energy available from out of state sources (MU)	4=1-3	12866
Add energy generated within the state (MU)	5	12970
Net energy available for use in Haryana	6=4+5	25836
Intra – State transmission loss (%)	7	2.60%
Intra – State transmission loss (MU)	8=6*7	672
Energy available for sale to distribution licensee	9=6-8	25164

Load Curve Analysis for Haryana

Load curve Analysis for UHBVN

The Load Curve Analysis for Haryana and Load curve Analysis for UHBVN could not be carried out as we have not been able to obtain SLDC load data such as hourly schedule drawl, actual drawl, frequency, UI charges inspite of multiple visits to SLDC at Panipat and discussions with SE(SLDC Operation), Panchkula and XCN (LD and PC), HVPN, Sewah, Panipat In fact, seeing that we were not able to get the SLDC data from SLDC Haryana, we had requested FOIR to use their good offices and help in obtaining the aforesaid data. FOIR had been kind enough to send letter ref 16/4(8)/2008-FOIR/STUDY/COS-Agri dated 25th August, 2009 (enclosed as Annexure-I to SE(SLDC Operation), HVPN, Panchkula with copy to XCN (LD and PC), HVPN, Sewah, Panipat requesting for the aforesaid data to be made available to TERI's representative. However, the data was not made available to us.

Estimation of Cost to Serve for UHBVN based on sample load data for FY 2007-08

Team Identification

For the study, Mr RK Gupta, GM, UHBVN was nominated as the Nodal officer. Subsequently, Mr Chandan Singh, Dy Director, UHBVN was nominated as the Nodal officer. Detailed discussions were held with the UHBVN officers about the scope of work and the data requirement. Theses officials include:

Officials of UHBVN:
Mr Tandon (Director Technical)
Mr R K Gupta, (GM/SO, UHBVN)
Mr Chandan Singh (Dy Director, Technical)
Mr M L Gupta (SE, Commercial)

Mr Anil Kumar (Xen,Operations)
Mr Arun Goel (Xen, Operations)
Mr S C Gupta (SE, Commercial)
Mr Pathania (Xen, Commercial)
Mr Tandon (Xen, Commercial)

Officials of Haryana SLDC:
Mr Naresh Kumar Makkad (Xen)
Mr Kaushik (Xen

Sampling

For the feeder data analysis, 15 feeders were selected which have predominantly i.e 80% of the agricultural load. However, data was received for 8 feeders only. Table 5.143 presents the circle wise list of selected feeders.

Table 5.143 Sample Feeders selected across various circle

Name of the Circle	No of Sample Feeders
11kV Padla	1
11 KV Baba Sita Giri	1
11 KV Padla Village	1
11 KV Kartarpur	1
11 KV Bherian	1
11 KV Usmanapur	1
11 KV Bateri	1
11 KV Nanakpur	1
Total	**8**

19 days uniformly spread across the year were selected to collect the load details of the selected feeder. This captured the seasonality factor in the agricultural power consumption. Load details of selected feeder are also collected for the peak day of the utility. The selected days are presented in table 5.144.

Table 5.144 days Selected for collection of load data from sample feeders

4/6/2007	Summer
4/22/2007	Summer
5/2/2007	Summer
5/19/2007	Summer
3/14/2008	Monsoon
7/15/2007	Monsoon
7/25/2007	Monsoon
8/15/2007	Monsoon
9/4/2007	Monsoon
9/23/2007	Monsoon
9/26/2007	Winter
10/8/2007	Winter
11/18/2007	Winter
12/11/2007	Winter

12/25/2007	Winter
1/12/2008	Winter
1/14/2008	Winter
2/20/2008	Summer
3/13/2008	Summer

Analysis of the sample feeder data

Figure 5.35 presents the load curves aggregated for 18 selected feeders across different selected days.

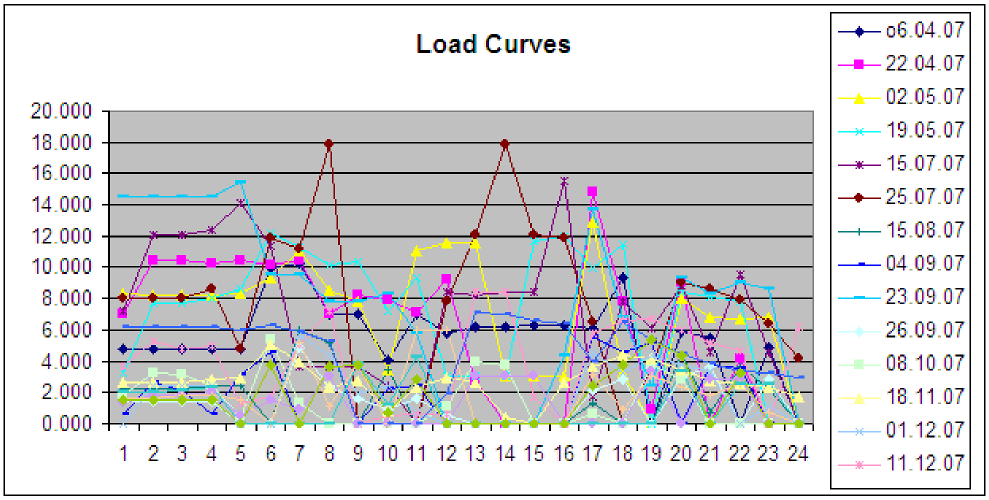


Figure 5.35 Agricultural Feeder Data Analysis

Table 5.145 gives the Load factor, load loss factor and coincident factor of the agricultural feeder data.

Table 5.145 Feeder Data Analysis

Calculation of class load factor		
Average (MW)		**3.88**
Max (MW)		**17.90**
Load factor (%)		**21.7%**
Calculation of load loss factor		
Formula	(0.3 *LF +0.7 (LF)^2	**9.8%**
Calculation of CF		**48.32%**

Model Process

This section details out the process for calculating the cost of service of power to the agricultural consumers and the analysis of the results derived.

Step 1: Functionalisation

As per UHBVN's annual accounts for 2007/08, a summary of costs incurred by the utility as functionalised into power purchase, transmission and distribution related is presented in table 5.146.

Table 5.146 Functionalised Cost of UHBVN

	PP cost	Tr. Charges	Distribution	Total UHBVN
	Rs Cr	Rs Cr	Rs Cr	Rs Cr
Purchase of Power	3366.51			3366.51
Transmission Charges		289.38		289.38
Repairs & Maintenance			31.66	31.66
Employee Costs			322.29	322.29
Administration & General expense			32.69	32.69
Depreciation & Related			108.13	108.13
Interest & Financial Charges			230.97	230.97
Interest on working capital			0.62	0.62
Interest on consumer security deposit			11.06	11.06
Provison for Tax			0.58	0.58
Rate of Return			0	0
SUB-TOTAL	**3366.51**	**289.38**	**738**	**4,393.89**
Less				
Expenses capitalised			108.61	108.61
NET TOTAL EXPENSES	**3366.51**	**289.38**	**628.80**	**4,284.69**
Other Debits(Including bad debts)			8.4	
Net prior period Charges/credits			36.82	
Total ARR	**3366.51**	**289.38**	**674.6**	**4330.49**

Source : Annual Accounts, UHBVN, 2007/08

Discussions with UHBVN revealed that the power purchase cost of Rs 3655.89 cr is combined cost which is inclusive of the transmission charges. Thus, this power purchase cost is functionalised into power purchase and transmission charges based on the ratio of transmission charges in total power purchase as approved by the Haryana Electricity Regulatory Commission (HERC) for the tariff determination for 2007/08.

Step 2: Classification

Details of fixed Assets have been captured and segregation of assets in to various voltage classes have been made based on the discussion with then UHBVN officials. Table 5.147 & 5.148 presents the classification of the fixed assets into different voltage classes and their further segregation into demand, energy and customer category.

Table 5.147 Classification of fixed assets voltage wise

Description	Amount in Rs Crores	Apportionment of Fixed Assets (in %)*					Apportionment of Fixed Assets amount (In Rs)				
		33 KV	11KV	LT network	Retail supply	Total	33 KV	11KV	LT network	Retail supply	Total
Land	34.16	5.00%	5.00%	15.00%	75.00%	100.00%	3.49	3.49	10.47	52.37	69.82
Buildings & Civil Structure	69.82	5.00%	5.00%	15.00%	75.00%	100.00%	89.31	89.31	267.93	1339.66	1786.21

Description	Amount in Rs Crores	Apportionment of Fixed Assets (in %)*					Apportionment of Fixed Assets amount (In Rs)				
		33 KV	11KV	LT network	Retail supply	Total	33 KV	11KV	LT network	Retail supply	Total
Transmission/ Distribution System (Plant & Machinery)	1786.21	40.00%	30.00%	30.00%	0.00%	100.00%	4.20	3.15	3.15	0.00	10.50
Vehicles	10.50	0.00%	5.00%	15.00%	80.00%	100.00%	0.00	0.38	1.13	6.02	7.53
Furniture & Fixtures	7.53	0.00%	5.00%	15.00%	80.00%	100.00%	0.00	95.41	286.23	1526.58	1908.22
Total Fixed Assets	**1908.22**						**97.00**	**191.74**	**568.92**	**2924.63**	**3782.29**

Table 5.148 Classification of Fixed assets into demand, energy and customer related costs

Description	Amount in Rs Crores	Fixed Assets classification (In %)			33 KV Fixed Assets classification (In Rs)				11 KV Fixed Assets classification				LT net work Fixed Assets classification				Retail supply Fixed Assets classification			
		Demand	Energy	Customer	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Land	34.16	50%	0%	50%	0.85	0.00	0.85	1.71	0.85	0.00	0.85	1.71	2.56	0.00	2.56	5.12	12.81	0.00	12.81	25.62
Buildings & Civil Structure	69.82	50%	0%	50%	1.75	0.00	1.75	3.49	1.75	0.00	1.75	3.49	5.24	0.00	5.24	10.47	26.18	0.00	26.18	52.37
Trans-mission/ Distribution System (Plant & Machinery)	1786.21	80%	0%	20%	571.59	0.00	142.90	714.49	428.69	0.00	107.17	535.86	428.69	0.00	107.17	535.86	0.00	0.00	0.00	0.00
Vehicles	10.50	50%	0%	50%	0	0	0	0	0.26	0.00	0.26	0.52	0.79	0.00	0.79	1.57	4.20	0.00	4.20	8.40
Furniture & Fixtures	7.53	50%	0%	50%	0	0	0	0	0.19	0.00	0.19	0.38	0.56	0.00	0.56	1.13	3.01	0.00	3.01	6.02
Total Fixed Assets	1908.22	0	0	0	0	0	0	0	431.74	0.00	110.22	541.96	437.84	0.00	116.32	554.17	46.20	0.00	46.20	92.41

The functionalised cost is classified into demand, energy and customer related cost. Table 5.149 presents the classification of power purchase cost and transmission cost into demand, energy and customer related costs.

Table 5.149 Classification of Power Purchase and Transmission Charges

Particulars	Demand	Energy	Customer
Generation /Power Purchase	31.07%	68.93%	0%
Transmission	100%	0%	0%

Power purchase cost has both energy and demand related component as the utility maintains its power system to supply energy across the year and to meet the peak demand as well. The power purchase cost is classified into demand and energy related component in the ratio of fixed and variable cost in total power purchase cost as approved by the Haryana Electricity Regulatory Commission (HERC) for the tariff determination for 2007/08. Transmission charges are incurred to supply energy across the year and thus transmission charges are classified as demand related.

Classification of distribution cost is carried out at two levels wherein at first level, distribution costs are classified at different voltage level of 11KV, LT Network and Retail Supply as presented in table 5.150.

Table 5.150 Classification of Distribution Cost- Voltage level wise

Particulars	Distribution (%)					Distribution (Rs Cr)				
	33 kV	11 KV	LT Network	Retail Supply	Total	33 kV	11 KV	LT Network	Retail Supply	Total
Repairs & Maintenance	37.7%	28.5%	29.1%	4.7%	100.0%	11.94	9.01	9.21	1.50	31.66
Employee cost	10.0%	10.0%	20.0%	60.0%	100.0%	32.23	32.23	64.46	193.37	322.29
Administration & General expense	7%	20%	37%	37%	100%	2.29	6.54	11.93	11.93	32.69
Depreciation & Related	38%	28%	29%	5%	100%	41	31	31	5	108
Interest & Financial Charges	38%	28%	29%	5%	100%	87	66	67	11	230.97
Interest on WC	0%	0%	0%	100%	100%	0.00	0.00	0.00	0.62	0.62
Interest on con.security deposits	20%	20%	20%	40%	100%	2.21	2.21	2.21	4.42	11.06

Particulars	Distribution (%)					Distribution (Rs Cr)				
	33 kV	11 KV	LT Network	Retail Supply	Total	33 kV	11 KV	LT Network	Retail Supply	Total
Intt Finance charges & other expenses capitalised	38%	28%	29%	5%	100%	-40.96	-30.85	-31.54	-5.26	-108.61
Other Debits (incl. Bad debts)	20%	20%	20%	40%	100%	1.68	1.68	1.68	3.36	8.40
Net Prior Period Charges/Credits	10%	10%	10%	70%	100%	3.68	3.68	3.68	25.77	36.82
Income Tax	0%	0%	0%	100%	100%	0.00	0.00	0.00	0.58	0.58

Again, second level classification of each voltage specific distribution cost is carried wherein the costs are classified into demand, energy and customer related cost depending on its intrinsic nature. Table 5.151 presents the classification of the voltage wise distribution cost.

Table 5.151 Second Level Classification of Distribution Cost

Distribution	Distribution- 33 KV			Distribution- 11 KV			Distribution- LT net work			Retail supply			Distribution-Total		
	Demand	Energy	Consumer	Demand	Energy	Cus.	Demand	Energy	Cus.	Demand	Energy	Cus.	Demand	Energy	Cus.
Revenue Requirement Classification															
R&M	100%	0%	0%	80%	10%	10%	51%	10%	41%	3%	0%	13%	76%	6%	18%
Employee Costs	40%	0%	60%	40%	0%	60%	40%	0%	60%	40%	0%	60%	40%	0%	60%
A&G expenses	50%	0%	50%	50%	0%	50%	50%	0%	50%	50%	0%	50%	50%	0%	50%
Depreciation	80%	0%	20%	80%	0%	20%	79%	0%	21%	50%	0%	50%	78%	0%	22%
Interest & Financial Charges	80%	0%	20%	80%	0%	20%	79%	0%	21%	50%	0%	50%	78%	0%	22%

Based on the above table, the costs at each voltage level are then classified into demand, energy and customers as indicated in table 5.152.

Table 5.152. Second Level Classification (Rs Cr)

Description	Distribution 33KV			Distribution 11KV			Distribution LT network			Retail supply		
	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Repairs & Maintenance	11.94	-	-	7.21	0.90	0.90	4.60	0.92	3.68	0.30	-	1.20
Employee Costs	12.89	-	19.34	12.89	-	19.34	25.78	-	38.67	77.35	-	116.02
Administration & General expense	1.14	-	1.14	3.27	-	3.27	5.97	-	5.97	5.97	-	5.97
Depreciation & Related	32.54	-	8.24	24.47	-	6.25	24.81	-	6.59	2.62	-	2.62
Interest & Financial Charges	69.50	-	17.61	52.26	-	13.34	53.00	-	14.08	5.59	-	5.59
Interest on working capital	-	-	-	-	-	-	-	-	-	-	0.62	-
Interest on con.security deposits	-	-	2.21	-	-	2.21	-	-	2.21	-	-	4.42
Intt Finance charges & other expenses capitalised	(32.68)	-	(8.28)	(24.61)	-	(6.27)	(24.92)	-	(6.62)	(2.63)	-	(2.63)
Other Debits (incl. Bad debts)	-	-	1.68	-	-	1.68	-	-	1.68	-	-	3.36
Net Prior Period Charges/Credits	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	1.23	8.58	8.58	8.58
Income Tax	-	-	-	-	-	-	-	-	-	-	-	0.58

Step 3: Allocation

Once the costs are classified into demand, energy and customer related cost, they are then finally allocated to the agricultural consumer category in manner as explained in Chapter [1]4.

For allocation of cost to agricultural consumers, coincident peak have been used. Table 5.153 indicates the coincident and non coincident peak for the agricultural consumer category of UHBVN .

[1] In case of UHBVN, allocation of energy component of power purchase is done on the basis of share of agricultural consumption in total consumption and not on the basis of block approach due to non availability of adequate data.

Table 5.153 Coincident peak

Description	Load factor (as per sample feeders)	LLF	CF	No. of Consumers	Consumer weightage	No of equivalent Consumers	Consumption (MU)	Allocation of Total Loss -MU	Consumption + Total Loss (MU)	Loss MW	NCP MW (without loss)	NCP MW+ Loss	CP-MW
Agricultural Consumer	21.70%	9.80%	48.32%	267,417.00	1.00	267,417.00	4,573.97	1,900.00	6,473.97	999.69	2406	3406	1646.06
Total NO of Consumers In UHBVN	-	-	-	2,305,898.00	-	-	-	-	-	-	-	-	-
Total Consumption	-	-	-	-	-	-	9,223.47	3,687.57	12,911.04	-	-	-	-
Share of agricultural consumers and consumption in Total	-	-	-	11.6%	-	-	49.6%		50.1%	-	-	-	-
System Peak	-	-	-	-	-	-	-	-	-	-	-	-	2,415.57

Table 5.154 presents the allocation of the costs to the agricultural category using the coincident Peak Method.

Table 5.154 Allocation of cost – CP Method

Description	PP cost			Transmission charges			Distribution Total			Total Cost
	Rs Cr	Rs Cr	Rs Cr	if	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr
	Demand	Energy	Cust	Demand	Energy	Cust	Demand	Energy	Cust	
Total UHBVN Cost	1046.12	2320.39		289.38			361.51	14.70	298.33	4330.42
Allocation of Cost to Agricultural Consumer Category	712.87	1163.51		197.19			246.34	7.37	34.60	2361.88
Per Unit alloacted Cost (Rs/Kwh)	1.56	2.54	0.00	0.43	0.00	0.00	0.54	0.02	0.08	5.16

From the above table, it appears that Cost of Supply to agriculture is Rs 5.16 per kWh. An analysis of the results presented in table 5.154 reveals that although consumption is agriculture is 4574 MU out of a total of 9223.5 MU ie 49.6%, the load factor is only 21.70 % and Load Loss Factor is 9.8% . This gives NCP of Agricultural category as 4619 MW whereas the system peak is only 2415.57 MW. From the above, it can be inferred that that the there is a data mismatch. If the load factor is only 21.7% the agriculture consumption cannot be 4574 MU or if the agriculture consumption is 4574 MU, the load factor cannot be as low as 21.&%.

The above results were discussed with UHBVN and as the result did not appear to be satisfactory, UHBVN provided TERI's team with load data for FY 2008-09 which was available with them as they were using it for a separate study. Further, UHBVN officials felt that load characteristics, consumption pattern and financials have not changed much between 2007-08 and 2008-09. Hence, the load data of 2008-09 can be applied to 2007-08 financial data to obtain Cost of Supply.

Estimation of Cost to Serve for UHBVN based on sample load data for FY 2008-09

Sampling

For the feeder data analysis, 39 feeders were selected which have predominantly i.e 80% of the agricultural load. Table 5.155 presents the circle wise list of selected feeders.

Table 5.155 Sample Feeders selected across various circle

Circle	No of feeders in Circle	Feeder Name
Yamunanagar	3	Gudiana
		Bangera
		Doiwala
Jind	3	Dhamtan Kharal Road T
		Rasidan T/Well
		11 KV Rampura road.
Kurukshetra	22	K.D.B.
		Udarsi
		Narkatari
		Ram Nagar
		Bhadurpura
		Hathira
		Sahani Farm
		Kasital
		Jogi Majra
		Chhalondi
		Behlolpur
		Jainpur
		Gadli
		Barondi
		Sonti
		Bartoli
		Mohan Pur
		Malik Pur (kalsana)
		N.S.Majra
		Salpani
		Malikpur (shahbad)
		Rishi Markanda
Sonipat	2	11 KV O/G MUKINPUR
		11 KV O/G KISSAN
Ambala	5	Malik Pur
		Rajauli
		Mulana Old
		Kalyana

Circle	No of feeders in Circle	Feeder Name
		Mohari
Jhajjar	4	11KV KHORDA
		11KV JHARLI
		11KV SASROLI
		11KV MALIAWAS

Sample days uniformly spread across the year were selected to collect the load details of the selected feeder. This captured the seasonality factor in the agricultural power consumption. Load details of selected feeder are also collected for the peak day of the utility. The selected days are presented in table 5.156.

Table 5.156 days Selected for collection of load data from sample feeders

Date	Season	Date	Season	Date	Season
06/04/2008	Summer	20.07.2008	Monsoon	09.10.2008	Winter
07/04/2008	Summer	23.07.2008	Monsoon	10.10.2008	Winter
08/04/2008	Summer	24.07.2008	Monsoon	12.10.2008	Winter
09/04/2008	Summer	25.07.2008	Monsoon	14.10.2008	Winter
13/04/2008	Summer	27.07.2008	Monsoon	19.10.2008	Winter
14/04/2008	Summer	15.08.2008	Monsoon	28.10.2008	Winter
11/05/2008	Summer	24.08.2008	Monsoon	13.11.2008	Winter
12/05/2008	Summer	25.08.2008	Monsoon	16.11.2008	Winter
13/05/2008	Summer	29.08.2008	Monsoon	17.11.2008	Winter
15/05/2008	Summer	31.08.2009	Monsoon	18.11.2008	Winter
18/05/2008	Summer	03.09.2008	Monsoon	21.11.2008	Winter
20/05/2008	Summer	04.09.2008	Monsoon	25.11.2008	Winter
08/06/2008	Summer	05.09.2009	Monsoon	14.12.2008	Winter
15/06/2008	Summer	07.09.2008	Monsoon	21.12.2008	Winter
16.06.2008	Summer	14.09.2008	Monsoon	22.12.2008	Winter
17.06.2008	Summer	16.09.2008	Monsoon	23.12.2008	Winter
18.06.2008	Summer			24.12.2008	Winter
19.06.2008	Summer			25.12.2008	Winter
08.03.2009	Summer			14.01.2009	Winter
11.03.2009	Summer			25.01.2009	Winter
12.03.2009	Summer			28.01.2009	Winter
13.03.2009	Summer			29.01.2009	Winter
15.03.2009	Summer			30.01.2009	Winter
17.03.2009	Summer			06.02.2009	Winter
				08.02.2009	Winter
				12.02.2009	Winter
				15.02.2009	Winter
				23.02.2009	Winter

Analysis of the sample feeder data

Figure 5.36 presents the load curves aggregated for 18 selected feeders across different selected days.

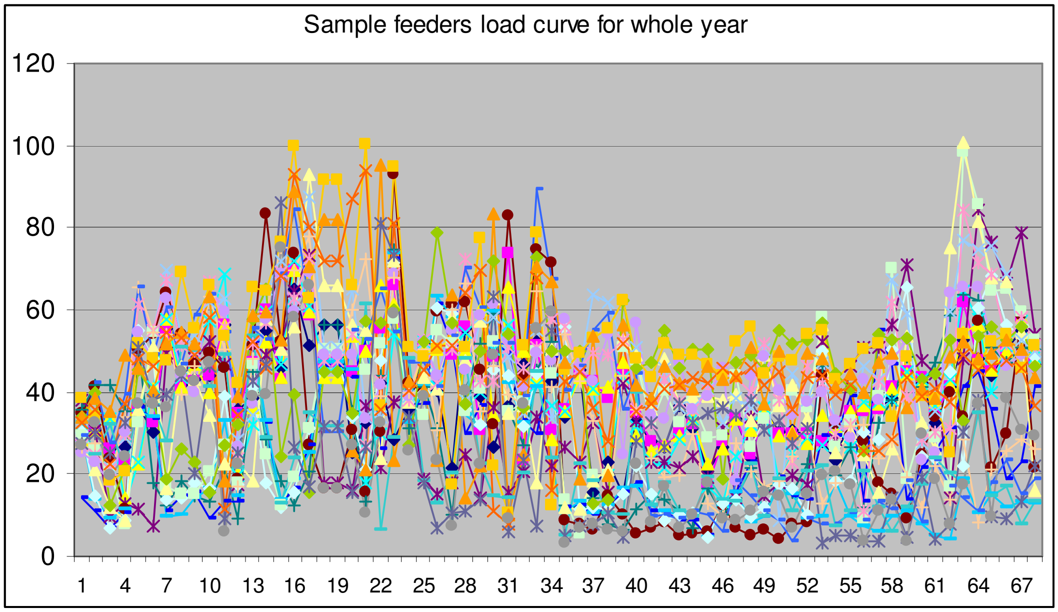


Figure 5.36 Sample feeders load curve - for whole year

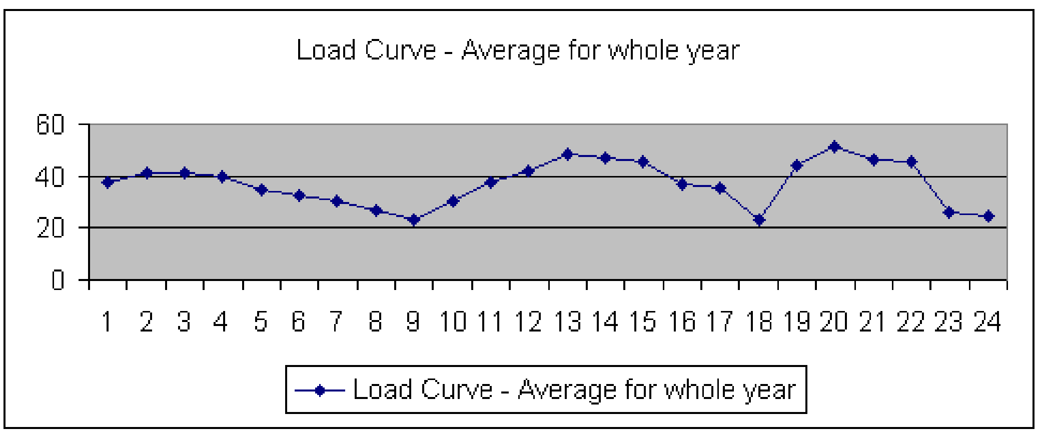


Figure 5.37 Sample feeders load curve - average for whole year

From the above load curves – Figure 5.36 and 5.37 depicting load curve for all sample feeders and the load curve of average of all the sample feeders, it is evident that there are three peak timings in agriculture – one between 2:00 AM to 4:00 AM , the second between 12:00 Noon to 2:00 PM and the third between 8:00 PM to 10:00 PM. The state peak of 4791 MW had occurred on 28.07.08 at 9:45 PM and the DISCOM peak had occurred on 27.07.08 at 5:45 AM. It does appear that Agriculture load contributed to the state peak. This is all the more significant in view of the fact that agriculture consumption is 49.5 % of the total consumption. The load curve for July 2008 (Figure 5.38) does not show high consumption in agriculture at around 5:45 AM but the load curve for August 2008 (Figure 5.39) shows peak consumption in agriculture around 5:45AM. As 27th July is towards the end of July, the load curve for August appears to be more representative of the consumption agriculture. As such, it can be inferred that agriculture consumption is contributing significantly to the peak demand of the DISCOM.

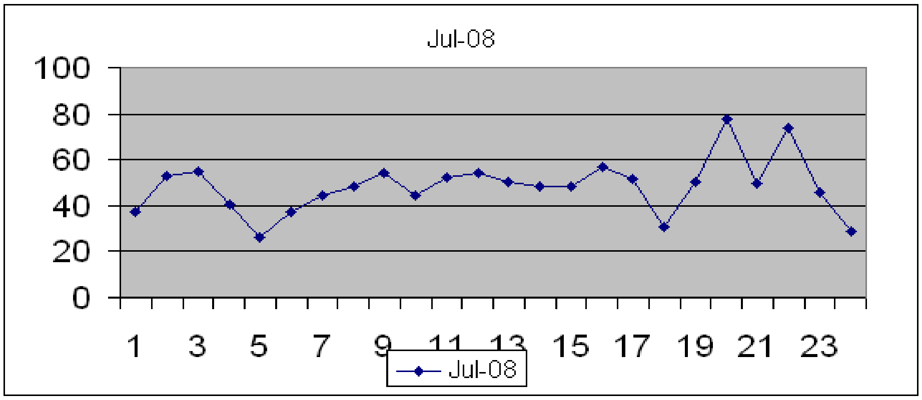


Figure 5.38 Sample feeders Load Curve for July 2008

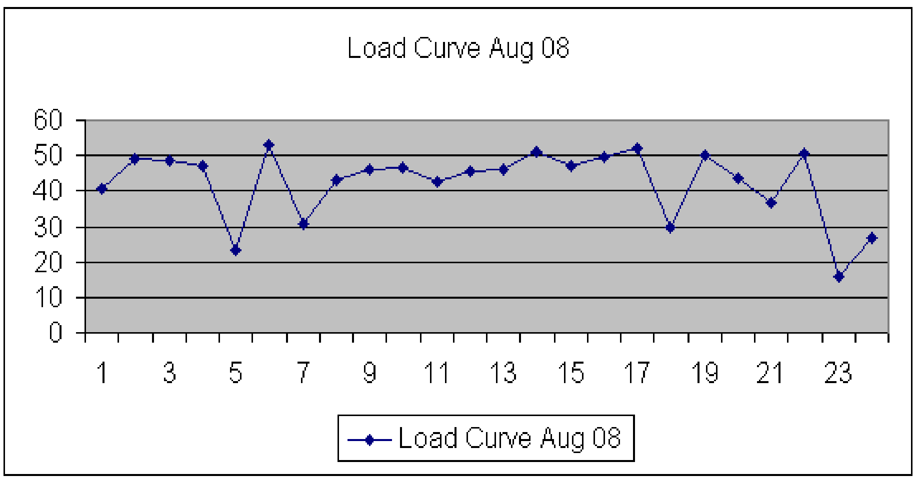


Fig 5.39 Sample feeders Load Curve for Aug 2008

Table 5.157 gives the Load factor, load loss factor and coincident factor of the agricultural feeder data.

Table 5.157 Feeder Data Analysis

Calculation of class load factor		
Average		**36.85**
Max		**100.86**
Load factor (%)		**36.85%**
Calculation of load loss factor		
Formula	(0.3 *LF +0.7 (LF)^2	**20.56%**
Calculation of CF		**92.31%**

Table 5.158 gives details of the computation of NCP and CP of agriculture category.

Table 5 158 Sample feeder data for FY 2008-09

	Load factor (as per sample feeders)	LLF	CF	No. of Consumers	Consumer weightage	No. of equivalent consumers	Consumption (MU)	Allocation of Total Loss - MU	Consumption + Total Loss (MU)	Loss MW	NCP MW (without loss)	NCP MW+ Loss	CP-MW
Agricultural Consumer	36.85%	20.56%	92.31%	267417	1	267417	4573.971	1900.00	6473.97	1055.02	588.62	1417.03	1851.36
Total NO of Consumers In UHBVN				2305898									
Total Consumption							9223.469	3687.57	12911.04				
Share of agricultural in Total				11.60%		11.60%	49.59%	51.52%	50.14%				
System Peak													2591

Table 5.159 presents the allocation of the costs to the agricultural category using the Coincident Peak Method.

Table 5 159 Allocation of cost to agriculture category using coincident peak method

	PP cost			**Transmission charges**			**Distribution Total**			**Total Cost**
	Rs Cr	**Rs Cr**	**Rs Cr**	**Rs Cr**	**Rs Cr**	**Rs Cr**	**Rs Cr**	**Rs Cr**	**Rs Cr**	**Rs Cr**
Description	**Demand**	**Energy**	**Customer**	**Demand**	**Energy**	**Customer**	**Demand**	**Energy**	**Customer**	**-**
Total Cost	1046.12	2320.39		289.38			361.51	14.70	298.33	4330.42
Allocation of Cost to Agricultural Consumer Category	747.49	1163.51		206.77			258.31	7.37	34.60	2418.05
Per Unit alloacted Cost (Rs/Kwh)	1.63	2.54	0.00	0.45	0.00	0.00	0.56	0.02	0.08	5.29
Avg Cost as per Annual Report (Rs/Kwh)										4.70

Final Results of Model

The cost of supplying power to agricultural consumers is in the range of Rs 5.29/Kwh. This cost is quite high (around 25% higher) when compare to the average cost of supplying power to all consumer categories of the UHBVN as a whole which is about Rs 4.70/Kwh.

At the present tariff which is charged from the agricultural consumers is very low . Only about 4.43% of cost of supplying power is recovered which leads to large quantum of cross subsidies to this consumer category. The table 5.160 presents a comparison for the cost of serve and the revenue realised from the agricultural consumer category as well as extent of Cross subsidy amount and subsidy.

Table 5.160 Comparison of Cost to serve and Revenue realisation

Consumer Category	Energy Sold (MU)	Revenue at current tariff (Rs Crore)	Avg. Realn. (Rs./KWH)	CoS (Rs./KWH)	Revenue at CoS rate(Rs Cr)	Cross subsidy amount +subsidizing (subsidized) Rs. In Crs	Cost coverage at current rates(%)
Agriculture	4573.97	119.58	0.26	5.29	2418.05	2298.46	4.95%

Computation of Cost to serve after excluding cost of traded power:

The power purchase approved by HERC for Haryana State (which includes both UHBVN and DHBVN) from different sources as well as the source wise rate and cost of power purchase have been provided at Table 5.161. The details of power purchase approved by HERC for FY 2007-08 for UHBVN is given in table 5.161

Table 5.161 Approved Power Purchase Rates & Cost (FY 2007 – 08) for UHBVN as per Tariff Order for FY 2007-08

Item	Unit	Amount
Total Power purchase	MU	12192
Power purchase Cost	Rs crores	2901.6
Trading margin	Rs crores	24.38
Transmission charges	Rs crores	284.41
SLDC Charges	Rs crores	4.97
Total cost of power purchase	Rs crores	3215.36
Average cost of power	Rs/kWh	2.64
Power purchase excluding short term bilateral and PTC (Malana)	MU	10092
Power purchase excluding short term bilateral and PTC (Malana)	Rs Cr	2359.192

Item	Unit	Amount
Average cost of power purchase excluding short term bilateral and PTC(Malana)	Rs/kWh	**2.34**
Percent reduction in power purchase cost when short term bilateral and PTC(Malana) is excluded	%	**11.36%**

From the above table, it is clear that power purchase approved for UHBVN, vide Tariff Order for FY 2007-08 amounts to 12192 MU at a cost of Rs 2901.60 Crores and an additional amount of Rs 24.38 crores has been allowed as trading margin. Also Rs 284.41 crores has been allowed as transmission charges and Rs 4.97 crores has been allowed as SLDC charges. Hence for power purchase of 12192 MU a total cost of Rs 3215.36 crores have been approved giving an average cost of Rs 2.64 per kWh for power purchase. This compares quite well with the actual average cost of power purchase which is Rs 2.61 per kWh.

Given the fact that agriculture is a priority as well as subsidized sector, a case can be made out that high cost traded power and power from UI is not made available to agriculture. In such a case the power purchase through bilateral trade and power purchase from PTC(Malana) can be excluded and the average cost of power purchase for agriculture comes down to Rs 2.34 per kWh from Rs 2.61 per kWh ie a reduction of 11.36%. Using this reduced cost of power purchase for considering supply to agriculture, the Cost of Supply is computed to be Rs 4.81 per kWh.

Table 5 162 Allocation of cost to agriculture category using coincident peak method after excluding cost of traded power

	PP cost			Transmission charges			Distribution Total		Total Cost
	Rs Cr	Rs Cr	Rs Cr	RsCr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr	Rs Cr
Description	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	-
Total UHBVN Cost	1046.12	2320.39		289.38			361.51	14.70	298.33	4330.42
Allocation of Cost to Agricultural Consumer Category excluding cost of traded power	662.58	1031.33	0.00	206.77	0.00	0.00	258.31	7.37	34.60	2200.96
Per Unit alloacted Cost (Rs/Kwh)	1.45	2.25	0.00	0.45	0.00	0.00	0.56	0.02	0.08	4.81

Final results of Model

The cost of supplying power to agricultural consumers has reduced from of Rs 5.29/Kwh to Rs 4.81/Kwh. This cost 14.6 5is higher than average CoS as compared to 25.6% when CoS is computed considering all power purchase (traded power also).

At the present tariff which is charged from the agricultural consumers is very low . Only about 4.85 % of cost of supplying power is recovered which leads to large quantum of cross subsidies to this consumer category. The table 5.163 presents a comparison for the cost of serve and the revenue realised from the agricultural consumer category as well as extent of Cross subsidy amount and subsidy.

Table 5.163 Comparison of Cost to serve and Revenue realisation

Consumer Category	Energy Sold (MU)	Revenue at current tariff (Rs Crore)	Avg. Realn. (Rs./KWH)	CoS (Rs./KWH)	Revenue at CoS rate(Rs Cr)	Cross subsidy amount +subsidizing (subsidized) Rs. In Crs	Cost coverage at current rates(%)
Agriculture CoS excluding cost of traded power	4573.97	119.58	0.26	4.81	2200.96	2081.37	5.43%

5.5 Uttar Pradesh:

PVVNL and PuVVNL had been selected for study of CoS. No analysis has been presented as TERI's team was not able to get any data from either PVVNL or PuVVNL inspite of multiple visits to the DISCOM's offices, discussions with the nodal officers of the DISCOM's, discussions with senior officers of the DISCOM's and requests by nodal officer of UPERC as well as requests by FOIR.

CHAPTER 6: Important issues in assessment of Cost to serve

The above Cost of Supply study has thrown up important issues some of which are enumerated below:

1. There is a clear need to move out of Average Cost of Supply to Actual Cost of Supply as this represents actual economic value of the product and services being supplied. Further, there is a strong need for educating consumers about the actual cost of supply vis a vis the tariff they are paying.
2. The data used in the CoS study comprises data culled from Annual Report of DISCOMs , other data supplied by the DISCOMs and feeder data supplied by DISCOMs. DISCOM load data as well as State load data obtained from SLDC of the respective states. These data have not been independently verified for their accuracy.
3. It is very important to have correct understanding of different category of loads – its almost archaic to assume feeder level data (amps reading– this distorts the load data as the voltage profile need not be same and hence the load in MW could be wrong). Better would be to put in meters at randomly selected consumer base or DTR and use the meter dump to study the category profile[1]. This is extremely important as the Load Factor, Load Loss Factor, Coincident Factor and the ratio of category peak to DISCOM Peak which are critical in arriving at the allocation of costs are all based on the sample feeder load data.
4. It is important to have a proper record of voltage level wise technical and commercial losses as such data will help in improving assumptions regarding allocation of technical and commercial losses to different categories and the resultant CoS study.
5. As there are certain consumer category which receive restrictive power supply i.e not all consumer category would have "voluntary" consumption. Hence the peak stack or the peak curve is quite an induced administrative one. Also, agricultural consumer category is serviced during odd hours when most of the other loads like non-process industries, commercial etc are not consuming. It can be argued that had the agriculture category access to uninterrupted quality of supply for the entire year (24 hrs in a year), then the consumption

[1] This is like the empanelment of consumers for Market Research like TV programme rating, Consumer goods satisfaction etc

curve could have been different. Given this, it has been felt that the single "peak" may be imposing a higher burden on this category. Hence, usage of average if monthly peak is suggested as an alternative to use of single peak so that no single category is disadvantaged

6. When the variable charge of power purchase is averaged out for entire utility and allocated to all the categories, it is assumed that the energy consumed by various categories are pooled from the portfolio of generation assets handled by a utility. However, there faster growing consumer categories which poses higher requirement of supply expansion or purchase through spot or bilateral arrangements to meet the demand. In this case, categories such as agriculture which receives administered power supply and thus do not consume as per their requirement should not be penalised with higher 'average rate'
7. Regulators should reflect the cross-subsidy picture based on actual cost of supply, so that the consumer categories understand their incidence of costs and the benefits enjoyed/ penalties levied on them. This would also help the Regulator to set up the cross-subsidy management programme, as envisaged in the EA 2003
8. Correlation of rainfall/ ground water extraction and area under cultivation – needs large database and the utility may not be the right place to start. This requires an interdisciplinary approach from variety of Government agencies – this can lead to a comprehensive policy to be created for utilization of the most difficult asset of all viz. water. Also, level of rainfall affects the CoS as paucity of rain increases the demand for electricity and reduces the availability of electricity (reduced hydel generation) thus having a cascading effect on the short term traded power cost.
9. Just like Industries, even farming sector need ToD, Seasonality in their tariff structure– to encourage better use of electricity. Since the sector is almost treated as 'free supply', there's hardly any proper energy accounting (except for certain studies done in the past on sample basis, in fixing up energy per farmer, per HP etc. There is no objective methodology and availability of reliable data for fixing the consumption to this category)
10. Even though agricultural loads are meant to serviced in roster, there's again no clear trail to prove that the energy pumped into these feeders are as stated and it is 'No More or No Less'

11. State Regulators should appreciate the cost of procuring that ‘minimum peak loads’ at high cost and devise adjustment to the price (For E.g.. a 3% additional energy requirement translates into 7% of the total cost). Further, this needs to be tagged on to specific categories that are causing them (if its agriculture, then the State Governments should be aware that their decision to supply this category at these rates are adding to their overall subsidy regime)
12. Alternate methods of subsidy regime can bring in changed approach to the sector – for if the subsidy is reached directly to the consumer and the utility bills the consumer at the correct cost (of course, as approved by Regulator), then there would be more incentive for utilities to come out with proper energy accounting and cost identification to service this category
13. As long as there’s shortage of cash inter-se Discoms (requiring cross-subsidisation between Discoms) and uniform Retail supply tariffs, there would be distortions in terms of cost allocations between utilities (this would also force the single buyer model to continue in guise of power committee co-ordinating the State’s supply and drawal programme)
14. Proper ‘Activity Based Costing’ approach to be adopted, so that the 20% in the cost chain (80% goes for Power purchase), can be properly allocated to Wires and Supply businesses. This can help in fixing in proper costs for ‘Distribution Open access’ charges. As dealt in the case of Provision for Bad and Doubtful debts in the case of CPDCL, it would be improper to allocate all costs as single line items and ignore the finesse that can make a change to those costs. Even in power purchase, a detailed study would ensure that categories causing large strain on the system are properly identified and such costs are allocated to them, rather than penalizing all categories.

CHAPTER 7: Conclusion

From a study of five DISCOM namely NPDCL and CPDCL from AP, BESCOM from Karnataka and UGVCL and PGVCL from Gujarat, the following conclusions emerge regarding assessment of cost of serve to agriculture category:

Move towards the actual cost to serve pricing principle

The EA 2003, NEP and Tariff Policy, all require that each category of consumer should pay the cost to serve for that consumer. Hence, it is imperative that tariff of agriculture be determined as per cost to serve and this cost to serve be computed judiciously taking into account not only accounting costs, but also hours of supply and quality of power.

Move towards the actual cost to serve pricing principle is required to introduce transparency in rate designing and subsequent assessment in subsidy requirement. The actual cost to serve being higher then the average cost to serve would result in higher subsidy requirements from the Government, which would be even more unsustainable in the long run. However, this move would convey the real picture to the Government, and help them strategise their policies on agriculture tariffs.

Special attention in allocation of power purchase

In Distribution value chain ~75% to 85% of the costs is Power purchase (PP) related. PP consists of fixed cost and Variable costs. Fixed costs (also called as Capacity charges) can vary between 20% to 50% of the total PP cost (depending on the vintage of the plant vis-à-vis the way competitive tariffs are structured and bid for IPPs). Distribution wires costs are the costs incurred for setting up of the network, and includes costs such as repairs and maintenance, employee costs, depreciation, administration and general, finance charges, returns etc. This ranges from 15 % to 25 % of the total costs. Usually such costs are also termed as 'fixed costs or wheeling charges' to be recovered based on the overall availability of these wires. Consumer related costs cover employees, repairs and maintenance (of meters), administration , finance charge (for working capital), provision for bad and doubtful debts etc., and are based on the segregation of costs according to the businesses. From the above, it is evident that allocations of power purchase costs have the maximum effect on the cost of supply to a category of consumer and hence its allocation to consumer category needs special attention.

Cost of serve to agriculture category to reflect reliability of supply (timing & availability)

Agriculture consumers throughout the country are always given restricted supply during certain numbers of hours during the day. Often, agriculture supply is at odd hours of the day when demand from other significant load is low. Many State Load Dispatch Centres do load management whereby agriculture (due to low billing or free nature) load is interrupted first, rather than other paying categories. They service this load, when the supply costs are lowest in their merit ordering and surplus power is available in the inter-regional ABT system. Anecdotal evidence points out that the energy sourced during this period (own as well as through ABT) is low enough to justify in servicing this agriculture load. Even the hours of supply are erratic in nature. They are normally not notified in advance. However, there are some states where power supply to agriculture is regulated, e.g. in Gujarat the total agriculture load has been divided in blocks of feeders and each block of feeder is provided uninterrupted eight hours supply. Also, the supply hours to each block of feeders are notified well in advance. The eight hours of uninterrupted supply are considered to be sufficient to meet their requirement of water.

Hence there is a case for differential treatment to agricultural consumers. Where the agricultural consumer category is not pre notified about the hours of power supply to them, then in that case, certain discount should be given to the cost of serve determined by the model described above in view of the inconvenience caused to the agricultural consumer category. Also, such power will have very little contribution to coincident peak and as such demand charges of power which comprise the lowest cost as per the merit order should be considered.

However, where the hours are regulated and notified well in advance, then agriculture supply cannot be said to have been discriminated. Thus the cost of serve should not be discounted. Hence, for these supplies the full cost of power purchase including UI charges and cost of traded power should be included while allocating to the agricultural consumer category.

Cost of serve to agriculture category to reflect quality of supply

Poor quality of power supply (voltage and frequency excursions) beyond the permissible limits affects the performance of the system. Often it has been observed that quality issues are ignored in agriculture supply. Agriculture consumers get power with poor quality of power supply (poor voltage regulation, unbalanced voltage in three phase supply, large flickers, sags or surges etc.) leading to motor burnouts due to higher current drawals in the case of motors, higher system losses, etc.

Supply of poor quality power is against the spirit of the Act and the Standards of Performance Regulations. Hence, it is important to link the total cost of power purchase incidental to agriculture consumption with the quality of power supply made available to agriculture consumers. This issue could be addressed in following two ways:

1. Modify the total cost of power purchase on account of agriculture consumers considering the average voltage deviations beyond permissible limit

Since, feeder-wise voltage variation is not reported to SERCs, it would be advisable to select sample predominantly feeders and suitable metering, which can provide the details of the quality of power supply to agriculture feeders. This information along with the permissible limits of deviations can be used in moderating the total power purchase cost on account of agriculture consumption.

2. Aggregating the penalty levied on licensees due to poor quality supply and, thereby, moderating the power purchase cost

Wherever, SERCs have already defined the nature and amount of penalty to be borne by the licensee on account of its poor power supply, such penalties need to be aggregated and discounted from the power purchase cost for the agriculture consumers.

Use of appropriate load curves

The accuracy of any Cost of Supply study depends upon the accuracy of the Load Curves. For this purpose, feeder selected should be such that more than 80% of the load belongs to the selected category. Appropriate level of metering linked to a central computer is required to have accurate load curves which can be used subsequently. Also, it is important to carry out load research so as to appropriately assess the demand of each category of consumer.

Capturing seasonal diversity

Agriculture demand widely varies across the year on account of different seasons, cropping and rainfall pattern. At the same time, availability and mix of supply also varies leading to different cost of power purchase. Therefore, it is essential to capture the diversity in agriculture demand for arriving co-incident peak by studying the behaviour of agriculture demand on significant number of days widely dispersed over the year or study period.

Use of average monthly peak

As there are certain consumer category which receive restrictive power supply i.e not all consumer category would have "voluntary" consumption. Hence the peak stack or the peak curve is quite an induced administrative one. Also, agricultural consumer category is serviced during odd hours when most of the other loads like non-process industries, commercial etc are not consuming. It can be argued that had the agriculture category access to uninterrupted quality of supply for the entire year (24 hrs in a year), then the consumption curve could have been different. Given this, it has been felt that the single "peak" may be imposing a higher burden on this category. Hence, usage of average if monthly peak is suggested as an alternative to use of single peak so that no single category is disadvantaged

Need to change the assets/expenditure accounting practices

It is seen that the total distribution expenditure is a bundled expenditure and presently they do not segregate the assets and expenditure as per voltage wise and as per the fixed and variable nature of costs. In order to compute the Cost of Supply with a greater degree of certainty, it is necessary that a policy be evolved and accounting of expenditure be done in a manner which makes it amenable to identify voltage wise and function wise costs.

CHAPTER 8: Road Ahead

The CoS study is a very important tool in the hands of Regulators in determining the actual cost incurred for each category of consumer as this provides a realistic basis for computation of subsidy and cross subsidy. It also brings to the fore the need for better and more accurate data capture and storage by utilities and SLDC so as to aid in proper computation of CoS study. Also CoS study should not be restricted to a particular category alone . It should be carried out for all category of consumers as such a study helps in understanding the linkages of peak load , demand , allocation of losses and all costs between the different consumer categories. Hence, it is felt that the CoS study should be carried out by all SERCs at least once in three/five years (coinciding with the control period of MYT) to assist it in better finalising the MYT parameters as well as provide assistance in annual performance review.