FINAL REPORT

VOLTAGE WISE
COST OF SUPPLY STUDY

Submitted to:

Jharkhand Bijli Vitran Nigam Ltd

Prepared by –

Feedback Infra Pvt. Ltd

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Abbreviations

ARR	: Annual Revenue Requirement
BPL	: Below Poverty Line
CoS	: Cost of Supply / Service
EA	: Electricity Act, 2003
FIPL	: Feedback Infra Pvt. Ltd.
HVDS	: High Voltage Distribution System
JBVNL	: Jharkhand Bijli Vitran Nigam Limited
JSERC	: Jharkhand State Electricity Regulatory Commission
NEP	: National Electricity Policy
NCP	: Non – Coincident Peak
NTP	: National Tariff Policy, 2006
RFP	: Request for Proposal
T&D	: Transmission and Distribution
SERC	: State Electricity Regulatory Commission

Preface

JBVNL (Jharkhand Bijli Vitran Nigam Limited) is the largest distribution utility in the State of Jharkhand, incorporated primarily to carry out distribution of electricity to retail and bulk consumers in Jharkhand. The company started operations on 6th Jan, 2014, after the unbundling of the erstwhile Jharkhand State Electricity Board (JSEB) in the year 2013. The company has a registered consumer base of around 3.20 million and a peak load of around 2,150 MW as of FY 17-18. JBVNL intended to engage Agency to undertake voltage wise cost of supply with FY 2017-18 as base year.

M/s Feedback Infra Private Limited has been appointed as consultant through a competitive bidding process for carrying out Voltage wise cost of supply study. The execution team conducted visited various divisions offices and sub-stations across Jharkhand to collect the relevant data. Based on the data collected and true up data as per the latest tariff order, analysis to estimate the voltage wise cost of supply for 33 kV & above, 11 kV and LT voltage levels was conducted and recorded in a CoS model. The findings of the model are shared in this report.

1. Project Background

1. JBVNL is conducting the Cost of service study which seeks to allocate all the costs of a utility to each of the customer classes it serves. The costs can then be used as an input into tariff design or to determine cross subsidy, if any, existing in tariffs. The determination of cost of service for each of voltage level requires dis-aggregating the utility's costs into functions and services.

2. A basic principle that has been widely accepted in electricity sector regulation is that the tariffs for various categories of customers should be, as far as practicable, equal to the costs imposed by that category of customers on the system. This is what is currently understood as Cost of Service (CoS). The National Tariff Policy also mandates the tariff of a particular category of consumer to be within the range of +/- 20% of cost of service for that particular consumer category.

3. With the focus now shifting to cost- reflective tariffs, it has now become necessary to compute the cost to serve to individual consumer categories and the gradual reduction of the cross subsidies existing between the consumer categories today. A basic principle that has been widely accepted in electricity sector regulation is that the tariffs for various categories of customers should be, as far as practicable, equal to the costs imposed by that category of customers on the system.

1.1 Objectives of the Cost of Supply study: -

a. Formulate a long-term tariff strategy; -
b. Establish cross subsidy reduction path; -
c. Provide right signals for efficient use of energy;
d. Provide price signals for rendering specific services especially in the competitive markets;
e. Facilitate directed and transparent administration of subsidies to the deserving classes;

1.2 Project Context

1.2.1 Statutory and Legal Provisions

The current treatment of cross subsidies by State Electricity Regulatory Commission and other options available to address the cross-subsidy reduction issue have to be inconsonance with the provisions of the ***Electricity Act 2003, the National Electricity Policy 2005, National Tariff Policy 2016 and the Regulations of the State Electricity Regulatory Commission***. In the following sections the various provisions of the Act, Policies, Regulations, Tariff order and the Regulations of the State Electricity Regulatory Commission have been quoted and interpreted in order to develop an understanding of the framework which will form the basis for the development of the Methodology for carrying out Cost to Supply Calculation.

Electricity Act, 2003

Section 62(3) provides for the factors on which the tariffs of the various consumers can be differentiated. Some of these factors like load factor, power factor, voltage, total electricity consumption during any specified period or time or geographical position also affects the cost of supply to the consumer. Due weight-age can be given in the tariffs to these factors to differentiate the tariffs;

As per the ***Section 62 of the EA 2003,*** the SERC is required to determine the retail tariff to be charged by the Distribution Licensees from its consumers. The Commission while determining the tariffs is required to give considerations to the factors (load factor, power factor and 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) listed in ***Section 62(3), 61(c) and 61(e) of the EA 2003,*** which are essentially cost determinants and economically efficient tariffs should consider the cost impact of these factors only without providing for any cross subsidies.

1.2.2 National Tariff Policy, 2016

The National Tariff Policy (NTP) prescribes the principles to be adopted by the Commission for determining tariffs for generation, transmission, distribution and retail consumers. The clauses dealing with the issue of Cost to Supply are given in the table below:

Section 8.3(2) reads-

For achieving the objective that the tariff progressively reflects the cost of supply of electricity, the Appropriate Commission would notify a roadmap such that tariffs are brought 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.

The NTP provides that tariffs is required to reflect efficient costs and gradual reduction of cross subsidy inherent in existing tariffs but consumers below poverty line (BPL) for life line consumption can have cross subsidized tariff rates. Also, a direct subsidy support by the State Government to the other poorer categories of consumers for pre-identified level of consumption is allowed.

1.2.3 National Electricity Policy, 2005

The Commission while discharging its functions as required by the **Electricity Act, 2003** is to be guided by the **National Electricity Policy (NEP).** The NEP provides guidance and clarifications on issues which either have not been or have been inadequately addressed in the EA 2003. The relevant clauses in the context of this study are:

Clause 5.5.1 reads that there is an urgent need for ensuring recovery of cost of service from consumers to make the power sector sustainable;

Clause 5.5.2 stipulates that consumers below poverty line, who consume below a specified level, say 30 units per month, may receive a special support through cross subsidy. Tariffs for such designated group of consumers will be at least 50% of the average cost of supply. This provision will be re-examined after five years;

Further, the National Electricity Policy provides for reducing the cross subsidies progressively and gradually. The gradual reduction is envisaged to avoid tariff shock to the subsidized categories of consumers. It also provides for subsidized tariff for consumers below poverty line for minimum level of support. Cross subsidy for such categories of consumers has to be necessarily provided by the subsidizing consumers.

The thrust of the NEP is that the tariffs should reflect cost and existing cross subsidies should progressively and gradually reduce. However, there can be cross subsidy support for very poor categories of consumers.

1.2.4 JSERC (T&C for Determination of Distribution Tariff) Regulations, 2015

Clause 6.44 of JSERC (Terms and Conditions for Determination of Distribution Tariff) Regulations, 2015 states that "The Licensee shall also propose voltage-wise losses for each year of the Control Period for the determination of voltage-wise cost of supply and determination of voltage-wise Wheeling Tariff.

Also, as per ***Clause 7.11,*** the filings for retail supply tariff shall contain Revenue Gap for various years of the control period and tariff proposal for meeting the revenue gap for each year which should be based on the cost of supply for various consumer categories and cross-subsidy reduction road map.

2. Approach & Methodology

2.1 Definition

Cost of Supply can be defined as:

"A process used to assign or allocate a fair share of total cost or revenue requirement of a utility to the various customer classes or Voltage level"

It is a prerequisite for further studies / analyses like

- *ANALYSIS* of prevailing tariff structures
- *COST RECOVERY* through design of per unit rate attributable to different categories of consumers

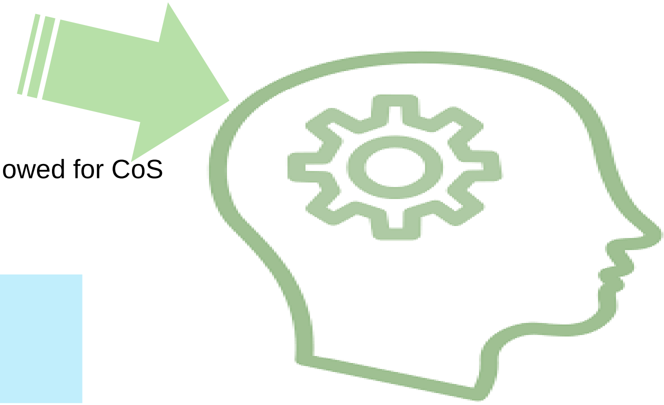
Traditionally, in the Indian context, tariffs for domestic and agricultural consumers have been heavily subsidized either by the state through subsidies and subventions or through cross subsidization by other consumer categories, primarily the consumers using electricity at high voltages.

A basic principle that has been widely accepted in electricity sector regulation is that the tariffs for various categories of customers should be, as far as practicable, equal to the costs imposed by that category of customers on the system. This is what is currently understood as **Cost of Service (CoS).**

Therefore, the Study of Cost needs to be carried out for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to the utility;
- To provide a comparison of the allocated costs with revenues from existing tariff;
- To illustrate the Extent of existing cross-subsidization between consumer categories;

2.2 Key Methodology



There are 3 broad and distinct methodologies prominently followed for CoS studies:

- **Average CoS Study**
- **Embedded CoS Study**
- **Marginal CoS Study**

Average CoS Study

- Calculated as the ratio of total revenue requirement to total units sold
- Simple and easy to compute
- Doesn't differentiate between CoS at HT and LT consumers and hence has limitations with respect to targeted economic indicators.

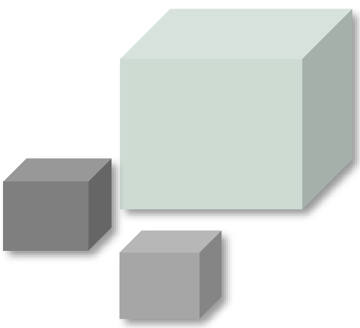
Embedded CoS Study

- Based on money actually spent for plant and operating expenses and its allocation amongst categories of consumers
- Reflects actual cost being incurred and provides a much better economic signal
- Data intensive, requires accurate data and based on quality of assumptions

Marginal CoS Study

- Based on cost incurred to supply every additional unit of energy
- Highly data intensive and requires greater data accuracy compared to Embedded CoS study
- Applicable in situations of equilibrium and perfect competition where MR = MC

FIGURE 1: COS METHODOLOGIES



Average Cost of Supply Method

The average method is the simplest CoS method that is very convenient to use but lacks usability.

Focus of Study	• It is CoS allocation model that only focuses on the average revenue requirements of the utility & its impact on the overall cost of service.
Key Usage	• Its usage is limited to rough estimates on the cost of service and consequent comparison of tariff levels • It is used where the utilities don't have sufficient load research data available
Key Limitations	• The study is highly limited in a sense it does not deal with the allocation of costs to various consumer categories based on rational economic means

Embedded Cost of Supply Method

The embedded CoS method focuses on the allocation of the total revenue requirement to various consumer categories:

Focus of Study	•This is a cost allocation method based on known historical costs that are accounted and hence verifiable. The key steps involved in the study are: •Functionalization – Splitting total costs in generation, transmission & distribution •Classification – Demand, energy and consumer related •Allocation – to the various consumer categories
Key Usage	•The embedded CoS study allocates known costs and hence provides a direct reconciliation to the ARR approved by relevant regulators •The study can be easily applied in markets where there is lack of perfect competition
Key Limitations	•The study has to be tweaked in order to get understanding of future costs. •Certain Assumptions have to be made in order to arrive at the desired results. This can be avoided by provision of real time data.
Critical Success Factors	•Presence of audited and approved historical costs •Load Pattern Data in digitized format. • Reliable and accurate data.

FIGURE 2: EMBEDDED COST OF SUPPLY

Embedded Cost of Supply Method- Illustration

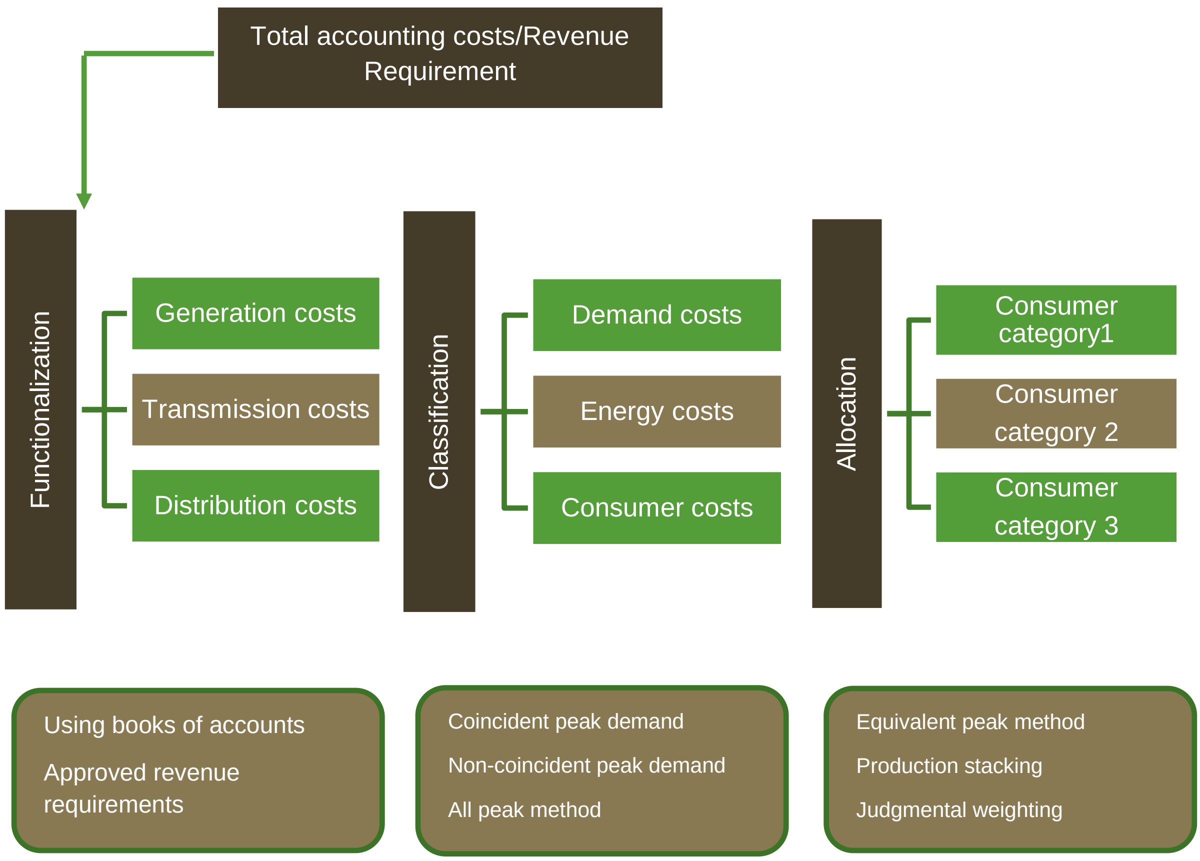


FIGURE 3: EMBEDDED COS ILLUSTRATION

Marginal Cost of Supply Method

The marginal CoS method, though more advanced, requires significant development of both system and data

Focus of Study

- Marginal cost of supply study concentrates on the incremental cost incurred for each unit of output to serve the increase in demand.
- The additional costs that will be incurred include –
- One kW of demand (Demand related)
- One kWh of energy (Energy related)
- One number of consumer (Consumer related)

Key Usage

- For determination of future costs, especially while redesigning the tariff structures / categories

Key Limitations

- No direct reconciliation with the aggregate revenue requirement of the utility
- Except in case of Generation function, the Marginal CoS study for Transmission and Distribution function is difficult and less precise and it is difficult to justify the benefits

Critical Success Factors

- Presence of a perfectly competitive market where the marginal cost can be equated to marginal revenue (MR = MC)
- Absence of constrained demand and restricted supply. A situation where there is abundant demand to meet the supply

FIGURE 4: MARGINAL COS

2.3 Comparative Review

	Embedded CoS	*Marginal CoS*
Market environment	Used in markets with both perfect and imperfect competition	Used in markets with perfect competition
Primary objective	Revenue Allocation Utility “entitled” to recover embedded costs	Rate Design Better indicator price signals and thus rate design
Methodology	Top down, allocation of costs	Bottom-up, development of costs
Joint and Common Costs	Joint and common costs are allocated either in the overall ratio of these costs or by series of allocators which best reflect cost causation principles	Fewer joint and common costs because many costs do not vary with change in production. The presence of these costs contribute to the inequality between totals obtained from study and the revenue requirement based on test year costs
Study based on	Historic accounts –which have been verified and audited	Forward-looking - estimated costs

TABLE 1: COMPARATIVE REVIEW

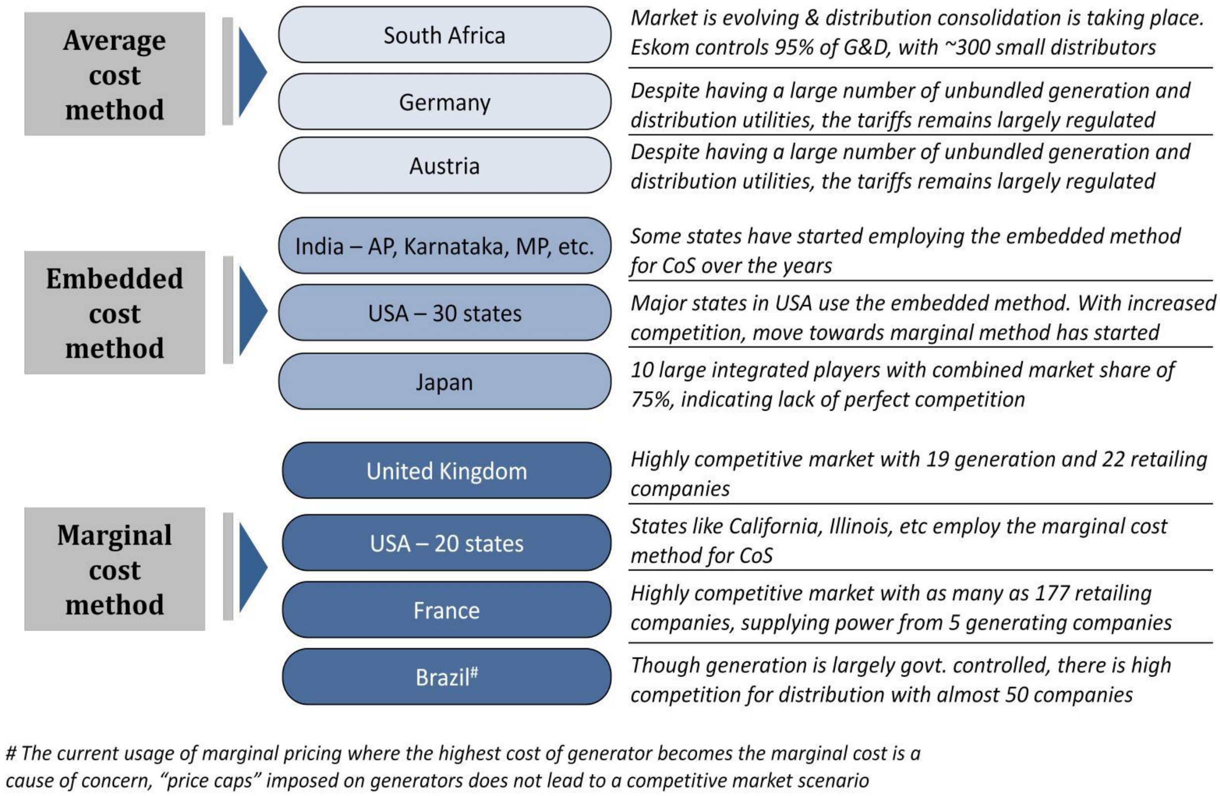


FIGURE 5: APPLICATION OF CoS IN DIFFERENT COUNTRIES

The cost of supply to consumer categories can be determined either on the **Embedded (Historical) cost or Marginal cost approach basis**. Usually, the approach adopted by many SERC's and utilities is to consider the average cost of supply method to calculate the Cross Subsidy as the data required to calculate the cost of supply category wise and voltage wise is not available. However, the average cost of supply is not the efficient way of determination of cost of supply.

Based on above comparative analysis, the **Embedded Cost Method** of calculating cost of service is suitable methodology for implementation of this study. A complete dummy model shall be prepared and submitted. The model is capable of running various embedded cost analysis using various methods like Coincident Peak, Average and Excess, All Monthly Peak, etc.

2.4 Key Project steps

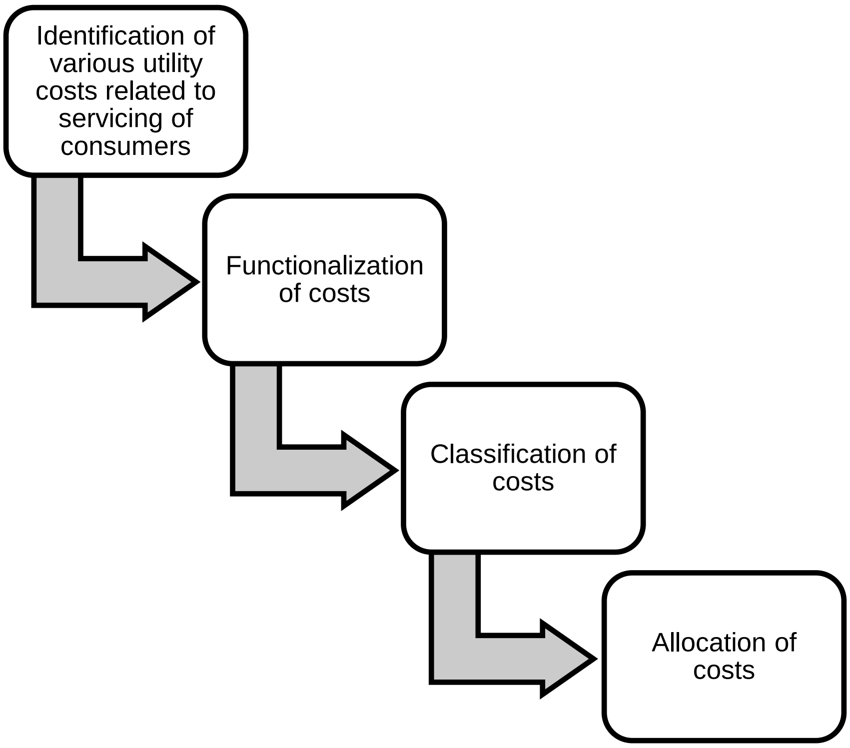


FIGURE 6: KEY PROJECT STEPS

Cost Classification and Functionalisation:

Cost Classification	Explanation	Functions	Cost Classification
Demand	Triggered by peak demands and Fixed in nature	**Power Purchase**	Demand Related Energy Related
Energy	Vary with volume of energy increased	**Transmission**	Demand Related
Customer	Depend on number and type of consumer served	**Distribution**	Demand Related Consumer Related

TABLE 2: COST CLASSIFICATION AND FUNCTIONALIZATION

3. Data Collection and Digitization

3.1 Selection of Feeders

The feeders were randomly selected based on log book data availability and representation of feeder to the voltage class.

The feeders were categorized into the following categories:

1. 33 KV and above feeders –
    a. Incoming feeders: Feeders which are supplying power from either Grid Substations / Power Substations
    b. Outgoing Feeders: Outgoing feeders from the concerned PSS to 33/11 KV PSS
    c. HT Feeders: Feeders supplying power to one or more 33 kV HT consumers only
    d. Dedicated HT Feeders: Feeders supplying dedicatedly to a single 33 kV HT Consumer
2. 11 KV feeders
    a. Distribution Feeders: Feeders supplying power to Distribution transformers
    b. Mixed Feeders: Feeders supplying power to Distribution transformers and 11 kV HT Consumers
    c. HT feeders: Feeders supplying power to one or more 11 kV HT consumers only
    d. Dedicated HT Feeders: Feeders supplying dedicatedly to a single 11 kV HT Consumer

In case the data available is less than 12 months the current over the year has been taken on average basis over the available time period instead on hourly load data for a full year. The following feeders were selected based on data availability and relevance:

1. 33 KV outgoing feeders supplying power predominately to 33 KV consumers.
2. 11 KV outgoing feeders supplying power predominately to 11 KV consumers.
3. 11 KV outgoing feeders supplying power predominately to distribution transformers.

The Sample data selected is attached as per Annexure A.

3.2 Collection of Power Substation / Feeder data

After selection of the sample feeders, PSS log book data for the feeders was collected and digitized for analysis and calculation. The feeder data collected was as follows:

1. Type of conductor of sampled feeders
2. Length of the conductors
3. Log books / metered data of the sample feeders
4. No of power transformers installed and their rated capacity.
5. Rated Copper and Iron losses of the Power transformers as per their capacity.

3.3 Collection of Commercial Data

Collection of Commercial data such as:

1. Details of no. of Consumers
2. Power purchase data
3. Revenue statement
4. Administrative and Operative costs
5. Details of energy sales as per consumer category / voltage

4. Functionalization, Classification and Allocation of Costs

The Embedded Cost Basis was adopted in the development of COS Framework for JBVNL. This approach determines the apportionment of accounting-based revenue requirement using the functionalization, classification and allocation processes with the ultimate goal of rate setting.

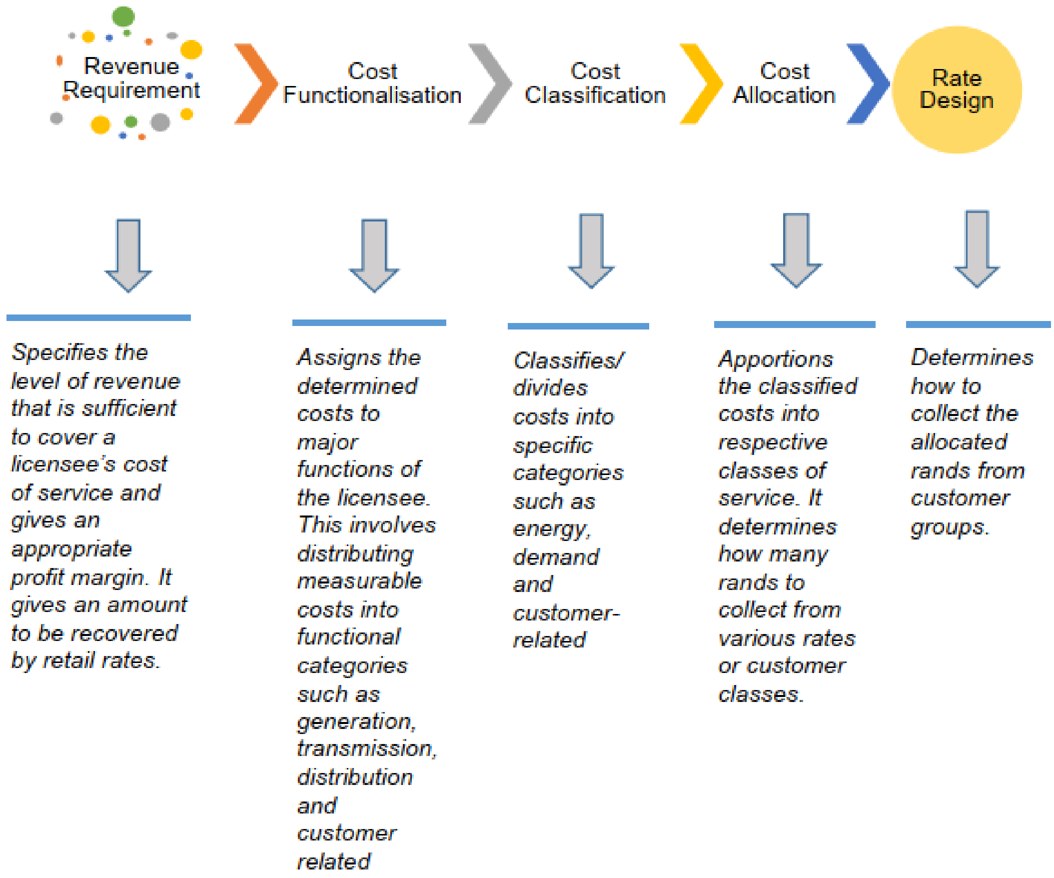


FIGURE 7: COS RATE DESIGN

4.1 Functionalization of costs

Electricity production costs are functionalized into -

1. **Generation Costs**: Costs related to the production of electricity such as the Cost of Power procurement. This also includes variable costs such as fuel, UI charges, RPO obligations, banking of power and electricity trading costs. Generation Costs have been functionalized as:
   a. Power Purchase from DVC
   b. Power Purchase from other sources

2. **Transmission Costs:** These includes the cost paid by distribution utility to the central and state transmission utility. These are predominately fixed cost and are associated with the transmitting of the energy from the generating plant to the distribution facilities. These have been functionalized as:
   a. **Annual Bill of PGCIL**
   b. **Annual Bill of JUSNL**

3. **Distribution Costs**: Costs associated with plant, equipment, maintenance and operation required to move the energy from the transmission system to the customer's premises. Affected primarily by demand and number of customers these may be functionalized as follow.

S. No	Particular
1	Annual Repairs & Maintenance Cost
2	Annual Employees Salary Expenditure
3	Administrative & general expenses
4	Depreciation & related debits
5	Interest & finance charges
6	Other costs and taxes

4.2 Classification of Costs

The objective of cost classification is to arrange costs into groups that bear a relationship to a measurable cost-defining characteristic of the service being rendered. Once the functionalized costs are so arranged, i.e. classified, they can be allocated to the services on an appropriate basis.

Functionalized costs are classified as:

1. Demand related;
2. Energy related, or;
3. Customer related.

The Demand classification relates to providing capacity to serve portions or all of system load requirements. The Energy related classification consists of those expenses that generally vary with changes in the unit consumption of kilowatt-hours, such as purchased power energy charges. The Customer related classification is related directly to each electric user and varies by the number and type of customers served. Customer costs include the minimum service, metering, accounting and other expenses necessary to connect a new customer to the system. These costs typically vary by the type of customer served, with large industrial customers being the most expensive group of users to connect to the system. Costs classified as energy related are often associated with the generation function. Therefore, no distribution costs are assigned to the energy function

4.2.1 Classification of Generation Cost

Generation cost can be classified into either demand related or energy related based on the source of power generation. Energy purchased through DVC is considered to be 100% energy dependent as the quantum of energy is fixed. The classification of the cost is done as below:

S. No	Particular	Demand related	Energy related	Consumer related
1	Power Purchase through DVC		PP cost * 100%	

S. No	Particular	Demand related	Energy related	Consumer related
2	Other Power purchase	PP Cost * (1-System load factor)	PP Cost * System load factor	

4.2.2 Classification of Transmission Cost

Transmission system is reflective of the maximum demand that needs to be catered and is thus considered to be 100% demand dependent.

S. No	Particular	Demand related	Energy related	Consumer related
1	PGCIL Annual Bill	100% * Cost		
2	JUSNL Annual Bill	100% * cost		

4.2.3 Classification of Distribution Cost

Distribution cost can be classified into either demand related or consumer related based on the functionality of the operation conducted. The classification of the cost is done as below:

S. No	Particular	Classification
1	Annual Repairs & Maintenance Cost	Demand related
2	Annual Employees Salary Expenditure	Consumer related
3	Administrative & general expenses	Consumer related
4	Depreciation & related debits	Demand related
5	Interest & finance charges	Demand related
6	Other costs and taxes	Consumer related

4.3 Allocation of Cost

The final step in developing an allocated cost of service is to allocate classified demand and customer expenses to each tariff customer class on an equitable and fairly apportioned basis.

4.3.1 Demand Allocation method

Customers take service at different voltage levels, and the assumption in the model is that only those customers which utilize a component of the distribution system are to be allocated a portion of the cost related to these facilities. Therefore, customers who take service at a higher voltage (transmission) level should be excluded from lower voltage (distribution) demand allocators entirely. Likewise, those groups taking service at the primary level should only be allocated primary demand costs. Only customers taking service at secondary voltage levels should be allocated a portion of the entire distribution system costs. Primary distribution facilities are allocated to customers using the customer-class non-coincident peak demand (NCP 1) method which is the default allocator used in the model. This method apportions the diversity benefits without regard to the group contribution to the system coincident peak loads.

Costs can also be allocated using methods more typically applied to the transmission system. Two of these methods are the coincidental peak responsibility (CP) method and the average and excess method. Generally, the NCP method is used to allocate primary distribution costs because customer class peaks are typically the main drivers to capacity requirements in a distribution system.

4.3.2 Customer Allocation Method

In most cases, expenses classified as customer costs should be allocated based upon the number of customers by tariff class or customers adjusted for weighting factors. Since the study focuses on the voltage wise classification of customers rather than classification of customers as per their tariff category, the classification should be done based on the same.

4.3.3 Energy Allocation Method

Energy allocation is done based on the total energy consumption by a particular voltage class. In the absence of metered data / energy audit data, the recommended method for estimation of energy consumption by each voltage class is to estimate the energy sales data and distribution losses at each voltage level. Generally, energy allocation is worked under the assumption that the commercial losses of the utility are technical in nature and no commercial losses are observed towards billing. However, it was observed that large loss could be attributed to commercial losses and thus it was desirable to work under the assumption that all the commercial losses occur at LT side of the business and take the losses into account towards the LT cost of supply.

5. Estimation of Distribution Losses

For Calculation of Energy losses, we must first understand the energy input, energy sale and feeder losses. By principles of energy audit, energy input may be defined as follows

Energy Input (X) = (Mn –Mo) x MC

X = *Energy input to the feeder from the substation*
Mn = *Final meter reading of current month*
Mo = *Initial meter reading of current month*
MC = *Meter constant*

If additional energy is imported to the feeder from other sources, then the imported energy (P) is added into the energy input to calculate the net energy input to the feeder

Final energy Input to the feeder (Y) = Energy input (X) + Energy imported (P)

The energy consumed (Z) is available from the monthly bills of the consumers (both high tension (HT) and low tension (LT) consumers) associated with the feeder. The difference between the energy input and energy consumed gives the energy loss (R) in the network, if the feeder is supplying to the consumers in the same sub-division.

Energy Loss (R) = Energy Input(X) – Energy Consumed (Z)
Energy Loss (R) = [Energy Input(X) – Energy exported (Q)] – Energy Consumed (Z)

For energy allocation estimation of distribution losses is a must.

5.1 Estimation of losses for 33 KV voltage class

The losses incurred by supply of power to 33 KV consumers can be classified as Technical Losses in 33 KV feeders. The primary losses incurred by the 33 KV voltage class occur can be classified as

- Transmission losses incurred upstream
- I^2R losses in 33 KV incoming and outgoing feeders.

Since the losses are not flowed through the 33/11 KV Transformer, Transformer losses would not be considered.

Considering the high voltage and low length of such feeders the losses incurred are quite small in comparison to other voltage class levels.

5.2 Estimation of losses for 11 KV voltage class

The losses incurred by supply of power to 11 V consumers can be segregated as Transmission losses upstream, technical losses in 33 KV incoming feeders, technical losses in 11 KV feeders and 33/11 KV transformer losses.

5.2.1 Transformer losses

Copper losses: Copper loss or I2R loss occurs because of heat dissipation due to current passing through the windings of the transformer and the internal resistance offered by the windings. The copper loss is variable loss and depend upon the variation in the current due to change in load.

Iron Losses: Iron loss occurs in the core of the transformer and depends upon the magnetic properties of the core material. Iron loss is constant as it does not change with the load.

The technical loss in PTRs, both copper and iron loss, is calculated based on the number of hours PTRs were in service, peak load, power factor, number, and capacity of DTs.

Total iron loss (kWh) =I x N x t/1000
Total copper loss (kWh) = C x N x (DTL) 2 x LLF x t/1000

Here,
I = Rated Iron loss of the transformer
C= Rated Copper loss of the transformer
N = Number of transformers connected to the feeder
DTL= Loading on the transformer calculated as
Peak load (KVA)/Total connected load (KVA)
t= Number of hours the transformer was working in the year
LLF = Loss load factor

For sake of simplification it was assumed that the transformers were working round the clock (8760 hours) as the demand for power would be present irrespective of the maintenance cycle of the transformers.

Technical loss in PTR = Total iron loss (kWh) + Total copper loss (kWh)

5.2.2 11 KV Feeder losses

The primary reason for 11 KV feeder losses is the energy lost as heat represented as I^2R losses in the conductor. The resistance of the conductor is a function of the resistivity, length and cross section area of the conductor. The resistivity and the length of the conductor would depend on the type of the conductor while the length represent the ckt. km that a feeder would traverse. Based on the sample data the cumulative current passing through the conductor is obtained. With data collection activity on remaining variables (length and type of conductor), the resistance of the sample feeder can be calculated. On multiplication of the same with the multiplication factor (as used for NCP calculation) the net I^2R feeder losses have been calculated.

5.3 Estimation of losses for LT voltage class

The losses incurred by supply of power to LT consumers can be segregated as

1. Upstream transmission Losses
2. 33 KV Incoming feeder Losses
3. 33/11 KV Power Transformer Losses
4. Losses in 11 KV feeders
5. Losses in LT lines
6. Losses in DTR

5.3.1 Power Transformer Losses

Copper losses: Copper loss or I2R loss occurs because of heat dissipation due to current passing through the windings of the transformer and the internal resistance offered by the windings. The copper loss is variable loss and depend upon the variation in the current due to change in load.

Iron Losses: Iron loss occurs in the core of the transformer and depends upon the magnetic properties of the core material. Iron loss is constant as it does not change with the load.

The technical loss in PTRs, both copper and iron loss, is calculated based on the number of hours PTRs were in service, peak load, power factor, number, and capacity of DTs.

Total iron loss (kWh) =I x N x t/1000
Total copper loss (kWh) = C x N x (DTL) 2 x LLF x t/1000

Here,
I = Rated Iron loss of the transformer
C= Rated Copper loss of the transformer
N = Number of transformers connected to the feeder
DTL= Loading on the transformer calculated as
Peak load (KVA)/Total connected load (KVA)
t= Number of hours the transformer was working in the year
LLF = Loss load factor

For sake of simplification it was assumed that the transformers were working round the clock (8760 hours) as the demand for power would be present irrespective of the maintenance cycle of the transformers.

Technical loss in PTR = Total iron loss (kWh) + Total copper loss (kWh)

The power transformer losses are common for both 11 KV voltage class and LT voltage class, Hence they be allocated based on the NCP of the respective voltage class.

5.3.2 Losses in 11 KV feeders

Calculation of 11 KV feeder losses can be done based on I^2R Losses as calculated from the hourly load data of the 11 KV feeders feeding LT consumers.

5.3.3 Losses in LT Lines and DTR

The losses in LT Line and Distribution transformer can simply be calculated by subtraction of the above all losses from the total T&D loss of the system.

Allocation of T&D losses for a Distribution system			
Particular	33 KV and above	11 KV	LT

Allocation of T&D losses for a Distribution system			
PGCIL Losses (in MU)	**As per PGCIL Loss Data**		
Transmission losses (in MU)	**As per load flow analysis**		
Copper Losses in 33/11 KV Transformer	-	Total Rated copper loss * (NCP_11KV (in MVA)/ Total Load (in MVA))^2 *8760* LLF	Total Rated copper loss * (NCP_LT (in MVA)/ Total Load (in MVA))^2 *8760* LLF
Iron Losses in 33/11 KV Transformer	-	Rated Iron Losses Segregated as NCP	Rated Iron Losses Segregated as NCP
Incoming 33 KV Feeder losses	As per I sq. loss of sample incoming 33 KV feeders		
Outgoing 33 KV Feeder losses	As per I sq. loss of sample 33 KV feeders (supplying 33 kV HT feeders)	-	-
Outgoing 11 KV Feeder to 11 KV consumers	-	As per I sq. loss of sample 11 KV feeders (supplying 11 kV HT feeders)	-
Outgoing 11 KV Feeder to DTR	-	-	As per I sq. loss of sample 11 KV feeders (suppling DTRs)
Distribution Transformer Loss	-	-	Total T&D losses - Sum of all above losses
LT Line Loss	-	-	

TABLE 3: ALLOCATION OF T&D LOSS

6. Estimation of Transmission losses

6.1 Estimation of losses by Central Transmission Utility

PoC Charging method is the methodology adopted for of computation and sharing of ISTS Charges and Losses among Designated ISTS Customers (DICs) which depends on location and sensitive to distance and direction of the node in the grid. Charges would be computed for each node of DICs based on Hybrid Method.

For the purpose of estimation of Transmission losses, both the injection and withdrawal charges are considered.

w is the Withdrawal PoC losses (average in %)

is the Injection PoC losses (average in %)

x is the Power Purchased (in MU)

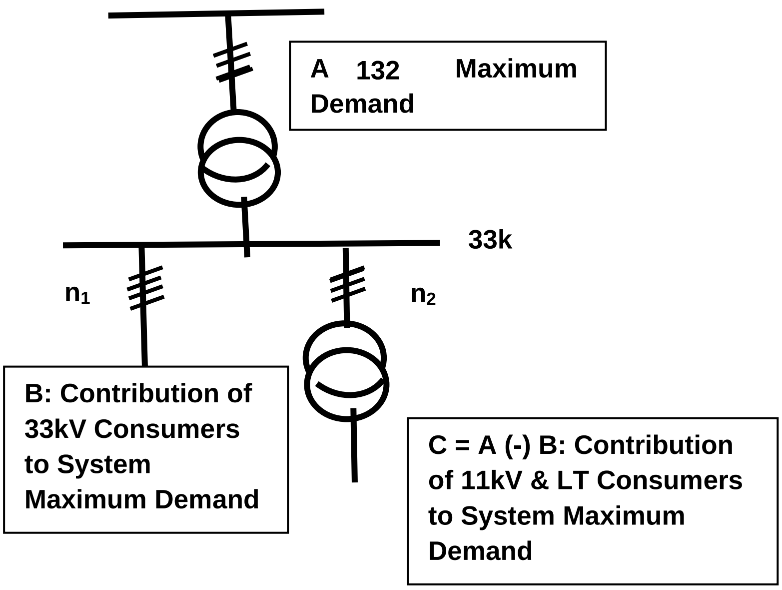
y is the Net Input energy (at state periphery)

$$\text{PGCIL Loss (in \%)} = \frac{(i * x) + (w * y)}{x}$$

$$= \frac{(i * x) + ((1-i) * x * w)}{x}$$

$$= i + (1-i) * w$$

6.2 Methodology for Determining Technical Losses in Sub-Transmission Network



DIAGRAMATIC REPRESENTATION OF SUB- TRANSMISSION NETWORK

The maximum demand JBVNL for FY 2017-18 system is 2150 MW and annual energy consumption of the network (input energy) is 11940x10^6 kWh and load factor of 0.68. The demand is served at four voltage levels – at 132 KV, 33kV, 11kV and 240/415 V. For sake of simplicity 132 KV Voltage class and 33 KV voltage class are clubbed together as 33 KV and above voltage class. This is due to low no. of 132 KV consumers.

Technical loss will be determined in the following manner:

1. The contribution to maximum demand of 11kV and LT consumers (C) will be determined by the difference between the system maximum demand (A) and the contribution of 33kV consumers (B).
2. The contribution of 33kV consumers to the maximum demand (B) will be determined by multiplying the system maximum demand by the ratio of the energy served at 33kV and the input energy fed into the system, i.e.,

$$B = \text{System Maximum Demand (A)} \quad \times \quad \frac{\text{Energy Served at 33kV}}{\text{Total Energy Input to the Network}}$$

3. The contribution of 11kV and LT consumers to the maximum demand (C) will be taken as the difference between the system maximum demand (A) and the contribution of 33kV consumers to the maximum demand (B):

C = A (-) B

4. The coincident maximum demand i.e., the contribution to maximum demand under system maximum demand condition of **each direct 33kV feeder** will be taken as equal to C divided by the number of direct 33kV feeders (n_1): $\mathbf{P_{33kV}(direct) = B \div n_1}$, where n_1 is the number of 33kV direct feeders in the network.
5. Coincident maximum demand of each 33kV feeder supplying 33/11kV transformer will be taken as $\mathbf{P_{33kV}(substation) = C \div n_2}$ where n_2 is the number of 33kV feeders to 33/11kV transformers in the network.
6. Keeping in view that the maximum demand of a feeder/ transformer will, in general, be different and higher than its demand under the system coincident maximum demand condition, the loss must be determined by multiplying the respective coincident maximum demands, $\mathbf{P_{33kV}(direct)}$ **and** $\mathbf{P_{33kV}(substation)}$ by the diversity factor**,** $\mathbf{K_d}$**,**

$$[P_{33kV}(direct)]_{max} = [P_{33kV}(direct)]_{max\ (coincident)}$$

$$[P_{33kV}(substation)]_{max} = [P_{33kV}(substation)]_{max\ (coincident)}$$

These values of active power (P) will be used as input data in the load flow study, and I^2R losses will be determined accordingly.

7. For estimation of the losses the system diagram is plotted on a dynamic simulation software for load flow analysis. Load flow analysis would yield the result closer to an losses that would be present in the system, however doesn't take into account the Computer Load flow results give power loss figures corresponding to peak demand. To account for the fact that demand of any feeder does not stay at the peak level throughout 24 hours in a day and in 365 days in a year, the technical loss (I^2R loss) calculated at peak demand must be multiplied by load loss factor (LLF).

   I^2R Loss (annual) = I^2R_{max} * LLF * 8760 kWh (I is in Amperes)

   LLF is given by: LLF = 0.2*LF + 0.8*LF^2 (LF = Load factor = 0.68 in the JBVNL network).

Given the fact that the underlying assumption that all feeders at a given voltage are equally loaded results in the least losses and uneven sharing of load between feeders causes losses to increase, the I^2R losses should be multiplied by a factor in the range 1.2 – 1.5 to arrive at an estimate of I^2R loss in the system.

7. Estimation of Cost of Supply

7.1 Estimation of T&D losses

7.1.1 Power Transformer Asset Details

No. of Power Transformers (Capacity in MVA)					Total
Power Transformer Rating	10 MVA	7.15 MVA	5 MVA	3.15 MVA	
No of Transformers	159	12	554	165	890
Iron Loss (in KW)	8	7	6	4.15	5365
Copper Loss (in KW)	50	40	34	23	31061
Total PTR rating (in MVA)	1590	86	2770	520	4966

TABLE 4: PTR ASSET DETAILS

7.1.2 Allocation of T&D losses

Allocation of T&D losses for a Distribution system				
	33 KV and above	**11 KV**	**LT**	**Total**
PGCIL Losses (in MU)	9	12	54	74
Transmission losses (in MU)	18	24	110	152
Copper Losses in 33/11 KV Transformer (in kwh)	-	5,53,588	2,26,72,992	2,32,26,580
Iron Losses in 33/11 KV Transformer (in kwh)	-	58,50,292	4,11,44,918	4,69,95,210
Outgoing 33 KV Feeder losses (in kwh)	1,54,31,152			1,54,31,152
Outgoing 11 KV Feeder to 11 KV consumers (in kwh)	-	4,84,96,610		4,84,96,610
Outgoing 11 KV Feeder to DTR (in kwh)	-	-	45,90,27,978	45,90,27,978
Distribution Transformer Loss (in kwh)	-	-	2,44,54,05,875	2,44,54,05,875

Allocation of T&D losses for a Distribution system				
LT Line Loss (in Kwh)	-	-		
Voltage wise Distribution Losses (in kwh)	1,54,31,152	5,49,00,490	2,96,82,51,762	3,03,85,83,405
Voltage wise Distribution Losses (in MU)	15.43	54.90	2,968.25	3,039
Total Voltage wise T&D Losses (in MU)	41.66	90.53	3,132.22	3,264
Losses %	3.60%	5.63%	30.97%	25.35%
∆ PTR Loss at peak load (in KVA) (instantaneous at peak Load)	0	5,449	9,545	14,994

TABLE 5: ALLOCATION OF T&D LOSS AS PER MODEL

7.2 Estimation of Non – Coincident peak

The Model uses the NCP Demand allocation method as its default. The advantage of this method of allocation is the reduced level of information required for the model to work. Under the NCP Demand allocation method, the required information is the Non – Coincident Peak demand which can be computed from the load data as collected and digitized. The Maximum demand over a period of year across the hourly load of the sample consumers of the voltage class is the peak demand of the consumer. The log book data from the sample feeders as detailed in Annexure A was collected. The sample feeders were so selected such as to be representative of their voltage class.

For the model to the following assumptions were taken into consideration.

a) Voltage regulation has not been considered
b) A Load distribution factor of Unity has been adopted for 33 kV feeders, 1.3 for 11 KV Feeders and 1.5 for 11 KV feeders feeding LT consumers.
c) A power factor of 0.85 has been adopted

Particulars	33 KV and above Voltage Class	11 kV voltage Class	LT voltage Class	Total
Energy (in MU) (inclusive of loss)	1131.64	1553.00	9535.30	12219.94
No of Sample Feeders Selected	8	12	21	41
Assumed power factor	0.85	0.85	0.85	0.85
Peak Power Sampled (in MW)	33.15	11,433	41,263	-
Energy Sampled (in MU)	222.02	72.48	230.28	-

Particulars	33 KV and above Voltage Class	11 kV voltage Class	LT voltage Class	Total
Multiplication factor	5.10	21.43	41.41	-
NCP (Peak Power Scaled up (in MW))	169	245	1709	2,123
Load Distribution Factor considered	1.00	1.30	1.50	-
I^2 R Loss (apportioned in %)	1.33%[1]	2.32%[2]	3.03%[3]	2.78%
I^2 R Loss (apportioned in MU)	15.08	36.04	288.54	339.66
Load Factor	76.46%	72.37%	63.71%	68.38%
NCP at 11 KV level (in MW)	169	245	1709	2,123
NCP at 33 KV level (in MW)	169	250	1717	2,135
∆ 33 KV incoming feeder Loss at peak load (in MVA) (instantaneous at peak Load)	5	7	38	50
∆ 132 KV incoming feeder Loss at peak load (in MVA) (instantaneous at peak Load)	3	4	20	28
∆ 132 KV incoming feeder Loss at peak load (in MVA) (instantaneous at peak Load)	2	3	14	19
NCP (in MW)	179	264	1789	2232

TABLE 6: NCP AT POWER SUBSTATION

[1] I^2 R Loss in 33 KV feeders due to 33 KV HT load
[2] I^2 R Loss in 11 KV feeders only due to 11 KV HT load
[3] I^2 R Loss in 11 KV feeders only due to LT load

7.3 Functionalization of Costs as per Model

Functionalisation of cost					
All costs are in Rs. Crores		Total Cost (as per true up order 2017-18)	Energy Dependent	Demand Dependent	Customer Dependent
Cost of Generation	Other Power Purchase	2,804	1,917	887	-
	DVC Power Purchase	2,439	2,439	-	
Cost of Transmission	Annual bill of PGCIL	138	-	138	-
	Annual bill of JUSNL	204	-	204	-
Cost of Distribution	Annual Repairs & Maintenance Cost	55	-	55	-
	Annual Employees Salary Expenditure	216	-	-	216
	Administrative & general expenses	76	-	-	76
	Depreciation & related debits	170	-	170	-
	Interest & finance charges	189	-	189	-
	Other costs and taxes	-	-	-	-
	Total	**6,290**	**4,356**	**1,642**	**292**

TABLE 7: FUNCTIONALIZATION OF COSTS AS PER MODEL

7.4 Classification of Cost as per Model

Classification of Cost					
All costs are in Rs. Crores		Total Cost	Energy Dependent	Demand Dependent	Customer Dependent
Cost of Generation	33 KV and Above	477	400	71	-
	11 KV	664	555	105	-
	LT	4,102	3,490	711	-
	Total	**5,243**	**4,356**	**887**	**-**
		Total Cost	**Energy Dependent**	**Demand Dependent**	**Customer Dependent**

Classification of Cost					
Cost of Transmission	33 KV and Above	27	-	27	-
	11 KV	40	-	40	-
	LT	274	-	274	-
	Total	**342**	**-**	**342**	**-**
		Total Cost	**Energy Dependent**	**Demand Dependent**	**Customer Dependent**
Cost of Distribution	33 KV and Above	33	-	33	0
	11 KV	49	-	49	0
	LT	623	-	331	292
	Total	**705**	**-**	**413**	**292**

TABLE 8: CLASSIFICATION OF COST AS PER MODEL

7.5 Allocation of Costs as per Model

Allocation of Cost				
Allocation of Energy Cost				
Total Energy Cost (Generation) (in Rs. Crore)	**4,356**			
	33 KV and above	**11 KV**	**LT**	**Total**
Power Purchase (in MU)				12,878.14
Energy Available for Sale (in MU)				12,515.60
Energy Sales (in MU)	1,116.56	1,516.96	6,980.21	9,613.73
T&D Losses (in MU)	83.66	135.79	3,044.96	3,264.41
Total Energy Consumed (in MU)	1,200.23	1,652.74	10,025.17	12,878.14
Voltage wise Energy Component Cost of Generation (in Rs. Crore)	406	559	3,391	4,356
Allocation of Consumer Cost				
Total Consumer Cost (Distribution) (in Rs. Crore)	292			

Allocation of Cost				
	33 KV and above	11 KV	LT	Total
No of Consumers	131	1,533	31,94,147	31,95,811
Voltage wise Demand Component Cost of Distribution (in Rs. Crore)	0.01	0.14	291.69	291.84
Allocation of Demand Cost				
Total Demand Cost (Generation) (in Rs. Crore)	887			
Total Demand Cost (Transmission) (in Rs. Crore)	342			
Total Demand Cost (Distribution) (in Rs. Crore)	413			
	33 KV and above	11 KV	LT	Total
Apportioned Non - Coincident peak (NCP) (sample) (in MW)	179	264	1789	2,232
Voltage wise Demand Component Cost of Generation (in Rs. Crore)	71	105	711	887
Voltage wise Demand Component Cost of Transmission (in Rs. Crore)	27	40	274	342
Voltage wise Demand Component Cost of Distribution (in Rs. Crore)	33	49	331	413
Voltage wise Total Demand Cost (in Rs. Crore)	132	194	1,316	1,642

TABLE 9: ALLOCATION OF COSTS AS PER MODEL

7.6 Estimation of Cost of supply in Rs./ kWh

Estimation of Cost of Supply					
		Total Cost	Energy Dependent	Demand Dependent	Customer Dependent
Total Cost (in Rs. Crore)	33 KV and Above (a)	538	406	132	0
	11 KV (b)	754	559	194	0

Estimation of Cost of Supply					
	LT (c)	4,998	3,391	1,316	292
	Total (a)+(b)+(c)	6,290	4,356	1,642	292
	Voltage wise Energy Sales				
Energy Sales (in MU)	33 KV and Above (p)	1,116.56[4]			
	11 KV (q)	1,516.96			
	LT (r)	6,980.21			
	Total (p)+(q)+(r)	9,613.73			
		Total Cost	**Energy Dependent**	**Demand Dependent**	**Customer Dependent**
Total Cost of Supply (in Rs / Kwh)	33 KV and Above (a*10/p)	4.82			
	11 KV (b*10/q)	4.97			
	LT (c*10/r)	7.16			
	Total (in Rs/kwh)	6.54			

TABLE 10: ESTIMATION OF COS IN /KWH

[4] The total HT energy sales have been segregated as per the connected load of 33 kV and above consumers and 11 kV consumers

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