

TNERC (TERMS AND CONDITIONS FOR DETERMINATION OF TARIFF) REGULATIONS - 2005

Preamble

WHEREAS under the Electricity Act 2003 (Central Act 36 of 2003) the State Electricity Regulatory Commission shall specify the terms and conditions for the determination of tariff;

AND WHEREAS the regulations providing for the terms and conditions for determination of tariff shall be subject to prior publication and accordingly undergone previous publication

NOW, THEREFORE, under Section 61 of the said Electricity Act, 2003, read with Section 181 thereof and all other powers enabling in that behalf, the Tamil Nadu Electricity Regulatory Commission hereby makes the following regulations.

CHAPTER I

Preliminary

1. Short Title, Applicability and Commencement

- (1) These Regulations may be called “**Tamil Nadu Electricity Regulatory Commission (Terms and Conditions for the determination of Tariff) Regulations, 2005.**”
- (2) These Regulations supersede “**Tamil Nadu Electricity Regulatory Commission – Tariff Regulations 2002**” published in Notification No. TNERC / TR / 5, dated 19.07.2002.
- (3) They shall come into force on the date of publication in the Tamil Nadu Government Gazette.
- (4) They shall extend to the whole of State of Tamil Nadu.
- (5) They shall be applicable for determination of tariff by the Commission in accordance with Section 62 of the Act.
- (6) They shall not be applicable to co-generation, captive power plants and generation of electricity from renewable sources of energy, which will be covered by a separate regulation to be specified by the Commission under clause (e) of sub-section (1) of Section 86 of the Electricity Act 2003 for promotion of such generation.

2. Definitions

- (1) In these Regulations unless the context otherwise requires
- (a) **'Act'** means the Electricity Act 2003
 - (b) **'Additional Capitalisation'** means the capital expenditure actually incurred after the date of commercial operation of the / generation station / transmission system and admitted by the Commission after prudence check subject to regulation 19;
 - (c) **'Authority'** means Central Electricity Authority referred to in Section 70 of the Act;
 - (d) **'Allotted Transmission Capacity'** means the power transfer in MW between the specified point(s) of injection and point(s) of drawal allowed to a long-term customer on the intra-state transmission system under the normal circumstances and the expression "allotment of transmission capacity" shall be construed accordingly;
 - (e) **'Auxiliary Energy Consumption' or 'AUX'** in relation to a period means the quantum of energy consumed by auxiliary equipment of the Generating Station and transformer losses within the Generating Station, and shall be expressed as a percentage of the sum of gross energy generated at the generator terminals of all the units of the Generating Station;
 - (f) **'Availability'** in relation to a thermal Generating Station for any period means the average of the daily average declared capacities (DCs) for all the days during that period expressed as a percentage of the installed capacity of the Generating Station minus normative auxiliary consumption in MW, and shall be computed in accordance with the following formula:

$$\text{Availability} = 10000 \times \frac{\sum_{i=1}^N \text{DC}_i}{\{ N \times \text{IC} \times (100 - \text{AUX}_n) \}} \%$$

where,

IC = Installed Capacity of the Generating Station in MW,

DC_i = Average declared capacity for the ⁱth day of the period in MW,

N = Number of days during the period, and

AUX_n = Normative Auxiliary Energy Consumption as a percentage of gross generation;

- (g) “**Beneficiary**” in relation to a generating station means the person buying power generated at such a generating station on payment of annual capacity charges;
- (h) “**Block**” in relation to a combined cycle thermal generating station includes combustion turbine – generator(s), associated waste heat recovery boiler(s), connected steam turbine – generator and auxiliaries;
- (i) “**Commission**” means the Tamil Nadu Electricity Regulatory Commission.
- (j) ‘**Capacity Index**’ means the average of the daily capacity indices over one year;
- (k) ‘**Contracted Power**’ means the power in MW which the transmission licensee has agreed to carry or which the transmission licensee is required to carry as per firm allocation from the Generating Station or the long-term agreement between the importing and exporting utility;
- (l) ‘**Cut off Date**’ means the date of first financial year closing after one year of the date of commercial operation of the transmission system.
- (m) ‘**Date of Commercial Operation**’ or ‘**COD**’ in relation to a unit means the date declared by the generator after demonstrating the Maximum Continuous Rating (MCR) or Installed Capacity (IC) through a successful trial run, after notice to the beneficiaries, and in relation to the generating station the date of commercial operation means the date of commercial operation of the last unit of the generating station;
- (n) ‘**Date of Commercial Operation**’ or ‘**COD**’ in relation to **transmission system** means the date of charging the project or part thereof to its rated voltage level or seven days after the date on which it is declared ready for charging by the transmission licensee,

but is not able to be charged for reasons not attributable to the transmission licensee, its suppliers or contractors.

Provided that the date of commercial operation shall not be a date prior to the scheduled date of commercial operation mentioned in the implementation agreement or the transmission service agreement or the investment approval, as the case may be, unless mutually agreed to by all parties.

- (o) **‘Declared Capacity’** or **‘DC’** means the capability of the generating station to deliver ex-bus electricity in MW declared by such Generating Station in relation to any period of the day or whole of the day, duly taking into account the availability of fuel;

Note

In case of a gas turbine Generating Station or a combined cycle Generating Station, the Generating Station shall declare the capacity for units and modules on gas fuel and liquid fuel separately, and these shall be scheduled separately. Total declared capacity and total scheduled generation for the Generating Station shall be the sum of the declared capacity and scheduled generation for gas fuel and liquid fuel for the purpose of computation of availability and Plant Load Factor respectively

- (p) **‘Declared Capacity’** or **‘DC’ relating to hydro generation**
- (a) For run-of-river power station with pondage and storage-type power stations, declared capacity means the ex-bus capacity in MW expected to be available from the generating station over the peaking hours of next day, as declared by the generator, taking into account the availability of water, optimum use of water and availability of machines and for this purpose, the peaking hours shall not be less than 3 hours within 24 hour period, and
- (b) In case of purely run-of–river power stations, declared capacity means the ex-bus capacity in MW expected to be available

from the generating station during the next day, as declared by the generating station, taking into account the availability of water, optimum use of water and availability of machines;

- (q) **'Deemed Generation'** means the energy which a generating station was capable of generating but could not generate due to the conditions of grid or power system, etc. beyond the control of generating station;
- (r) **'Design Energy'** means the quantum of energy which could be generated in a 90% dependable year with 95% installed capacity of the generating station;
- (s) **'Existing Generating Station'** means a generating station declared under commercial operation from a date prior to the notification of these Regulations;
- (t) **'Existing Project'** means the project declared under commercial operation from a date prior to the notification of these Regulations;
- (u) **'Gross Calorific Value'** or **'GCV'** in relation to a thermal power Generating Station means the heat produced in kCal by complete combustion of one kilogram of solid fuel or one litre of liquid fuel or one standard cubic meter of gaseous fuel, as the case may be;
- (v) **'Gross Station Heat Rate'** or **'GHR'** means the heat energy input in kCal required to generate one kWh of electrical energy at generator terminals;
- (w) **"Government"** means the Government of Tamil Nadu.
- (x) **'Infirm Power'** means electricity generated prior to commercial operation of the unit of a Generating Station;
- (y) **'Installed Capacity'** or **'IC'** means the summation of the name plate capacities of all the units of the Generating Station or the capacity of the Generating Station (reckoned at the generator terminals) as approved by the Commission from time to time;
- (z) **'Long-Term Transmission Customer'** means a person availing or intending to avail access to the intra-state transmission system for a period specified in the TNERC Open Access Regulations.

(aa) **'Maximum Available Capacity'** relating to hydel stations means the following:

(a) Run-of-river power station with pondage and storage type power stations

The maximum capacity in MW, the generating station can generate with all units running, under the prevailing conditions of water levels and flows, over the peaking hours of next day,

Explanation

The peaking hours for this purpose shall not be less than 3 hours within a 24 hours period.

(b) Purely run-of-river power stations

The maximum capacity in MW, the generating station can generate with all units running, under the prevailing conditions of water levels and flows over the next day.

(bb) **'Operation and Maintenance Expenses' or 'O&M Expenses'** means the expenditure incurred in operation and maintenance of the generating station, or part thereof, including the expenditure on employee cost, repair & maintenance and administration and general expenses.

(cc) **'Original Project Cost'** means the actual expenditure incurred by the project as per the original scope up to first financial year closing after one year of the date of commercial operation and as admitted by the Commission;

(dd) **'Plant Load Factor' or 'PLF'** for a given period, means the total sent out energy corresponding to scheduled generation during the period, expressed as a percentage of sent out energy corresponding to installed capacity in that period and shall be computed in accordance with the following formula:

$$PLF = 10000 \times \sum_{i=1}^N SG_i / \{ N \times IC \times (100 - AUX_n) \} \%$$

where,

IC = Installed Capacity of the Generating Station in MW,

SG_i = Scheduled Generation in MW for the i^{th} time block of the period,

N = Number of time blocks during the period, and

AUX_n = Normative Auxiliary Energy Consumption as a percentage of gross generation;

- (ee) **'Run-of-river power station'** means a hydro electric power generating station which has no upstream pondage;
- (ff) **'Run –of-river power station with pondage'** means a hydro electric power generating station with sufficient pondage for meeting the daily variation of power demand;
- (gg) **'Storage Type power station'** means a hydro electric power generating station associated with large storage capacity to enable variation of generation of power according to demand;
- (hh) **'Scheduled Energy'** means the quantum of energy to be generated at the generating station over the 24-hour period, as scheduled by the Regional Load Despatch Centre;
- (ii) **'Scheduled Generation' or 'SG'** at any time or for any period or time block means schedule of generation in MW ex-bus given by the State Load Despatch Centre;

Note

For the gas turbine Generating Station or a combined cycle Generating Station if the average frequency for any time block, is below 49.52 Hz but not below 49.02 Hz and the scheduled generation is more than 98.5% of the declared capacity, the scheduled generation shall be deemed to have been reduced to 98.5% of the declared capacity, and if the average frequency for any time block is below 49.02 Hz and the scheduled generation is more than 96.5% of the declared capacity, the scheduled generation shall be deemed to have been reduced to 96.5% of the declared capacity.

- (jj) **'Transmission licensee'**, means a person granted licence for intra-state transmission of electricity and includes STU.

- (kk) '**Transmission System**' means a line with associated sub-stations or a group of lines inter-connected together along with associated sub-stations and the term includes equipment associated with transmission lines and sub-stations;
- (ll) '**Year**' means a financial year.

Words or expressions occurring in these Regulations and not defined herein but defined in other Regulations published by the Commission or the Electricity Act 2003 shall bear the same meaning respectively assigned the terms in the Act / Regulations.

CHAPTER II

Determination of Tariff

3. Power to determine Tariff

- (1) Under Section 62 of the Act, the Commission shall determine tariff and terms and conditions therefor in the following cases:
- (i) Supply of electricity by a Generating Company to a Distribution Licensee:
Provided that the Commission may, in case of shortage of supply of electricity, fix the minimum and maximum ceiling of tariff for purchase or sale of electricity in pursuance of an agreement entered into between the Generating Company and a Licensee or between Licensees for a period not exceeding one year to ensure reasonable price of electricity.
 - (ii) Intra-State transmission of electricity.
 - (iii) Rates, charges and terms and conditions for use of Intervening transmission facilities, if these cannot be mutually agreed upon by the Licensee as provided in Section 36 (1) of the Act.
 - (iv) Wheeling of electricity.
 - (v) Retail sale of electricity.
Provided that in case of distribution of electricity in the same area by two or more distribution Licensees, the Commission

may, for promoting competition among distribution Licensee, fix only maximum ceiling of tariff for retail sale of electricity.

Provided further that the consumers who are allowed open access by the Commission under Section 42 of the Act may enter into an agreement with any person / Licensee for supply or purchase of electricity on such terms and conditions (including tariff) as may be mutually agreed to between them.

- (vi) Surcharge payable by the consumer who is allowed open access in addition to the charges for wheeling under the first proviso to sub-section (2) of section 42 of the Act and in accordance with the TNERC Open Access Regulations.
 - (vii) Additional surcharge on the charges of wheeling payable by a consumer who is allowed open access by the Commission under sub-section (4) of Section 42 of the Act and in accordance with the TNERC Open Access Regulations.
- (2) As provided in sub-section (5) of section 64 of the Act,
 “Notwithstanding anything contained in Part X of the Act, the tariff for any interstate supply, transmission or wheeling of electricity, as the case may be, involving the territories of two States, may, upon an application made to it by the parties intending to undertake such supply, transmission or wheeling, be determined by the Commission in cases where the Licensee intending to distribute electricity and make payment therefor is under the Commission’s jurisdiction.”
- (3) As provided in section 63 of the Act,
 “Notwithstanding anything contained in these Regulations, the Commission shall adopt the tariff if such tariff has been determined through transparent process of bidding in accordance with the guidelines issued by the Central Government.”

4. Tariff setting principles

The Commission, while determining the tariff, shall be guided by the following factors:-

- (i) The guidelines outlined in Section 61 of the Act which reads as:

The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:-

- (a) the principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;
 - (b) the generation, transmission, distribution and supply of electricity are conducted on commercial principles;
 - (c) the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;
 - (d) safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;
 - (e) the principles rewarding efficiency in performance;
 - (f) multi year tariff principles;
 - (g) that the tariff progressively reflects the cost of supply of electricity and also, reduces and eliminates cross-subsidies within the period to be specified by the Appropriate Commission;
 - (h) the promotion of co-generation and generation of electricity from renewable sources of energy;
 - (i) the National Electricity Policy and tariff policy:
- (ii) Rationalisation of tariff
 - (iii) Not to give a tariff shock to any category while setting the tariff to progressively reflect the cost.
 - (iv) Consideration of minimum level of support required to make electricity affordable for household of very poor category.
 - (v) In the process of determining tariff to progressively reflect the cost to serve each category, the Commission may endeavour to see that tariff to any category of consumers is not more than 150% of the cost of supply and is not less than 50% of the cost of supply.

- (vi) Adequate payment security arrangements like Letter of credit, escrow of cash flow shall be ensured to Generating Companies.
- (vii) The Generating Companies shall be allowed to sell to other buyers without losing their claim on committed capacity charges in case of under recovery of these charges from alternate sales.

5. Filing of Aggregate Revenue Requirement

- (1) The Distribution / Transmission Licensee shall file the Aggregate Revenue Requirement (ARR) on or before 30th November of each year in the format prescribed, containing the details of the expected aggregate revenue that the Licensee is permitted to recover at the prevailing tariff and the estimated expenditure.
- (2) ARR shall be filed every year even when no application for determination of tariff is made.

6. Procedure for making application for Determination of Tariff

- (1) The Licensee may file the application for determination of tariff in Form 1 in Annexure 1 to the Conduct of Business Regulations. The tariff changes should normally be applied for to take effect from the 1st day of ensuing financial year and hence the application shall be filed before 30th November of Current Year along with Aggregate Revenue Requirement.
- (2) The application shall be accompanied by the fees specified in the TNERC Fees and Fines Regulations and verified by an affidavit in Form 2 specified in Annexure 2 to the TNERC Conduct of Business Regulations.
- (3) The application for determination of tariff for the existing Generating Stations and Transmission System shall be accompanied by information in the respective formats appended to these regulations duly furnishing the figures for the previous year, current year and ensuing year. The application for determination of tariff by Distribution Licensees shall be accompanied by the information in the ARR formats appended to these Regulations. The information for the previous year should be based on the Audited Accounts and in case audited account

of previous year are not available, the audited accounts for the immediately preceding year should be filed along with the unaudited accounts of the previous year.

- (4) If a person holds more than one licence and / or deemed to be Licensee for more than one area of distribution or transmission, he shall submit separate calculation as above in respect of each licence or area of transmission or distribution. The Licensee shall endeavour to separate the accounts function wise. Distribution and Supply shall be treated as separate function.
- (5) A Licensee having a Generating Station shall maintain and submit separate accounts for the licensed business and Generating Station.
- (6) Transmission Licensee and Distribution Licensee engaged in other business for optimum utilisation of their Assets shall maintain separate account for such other business and submit with tariff proposal the proportion of revenue utilised to reduce the transmission / wheeling charges as stipulated in TNERC (Licensing) Regulations.
- (7) In case of Generating Station or the Transmission system declared under commercial operation on or after the date of notification of these Regulations, an application for fixation of tariff shall be made in two stages as below:
 - (i) A Licensee may make an application as per format stipulated by the Commission for determination of tariff in advance of the anticipated date of completion of the projects based on the Capital Expenditure actually incurred upto the date of making of the application or a date prior to making of application, duly audited and the provisional tariff shall be charged from the date of commercial operation of the line or sub-station of the Transmission System.
 - (ii) A Licensee shall make a fresh application in the same format as above, for the determination of final tariff based on actual capital expenditure incurred upto the date of commercial operation of the Generating Station or Transmission system duly audited and certified by the Statutory Auditors.

- (8) In case the Licensee does not initiate tariff filings in time, the Commission shall initiate tariff determination and regulatory scrutiny on suo motu basis.

7. Decision on Application

- (1) The application received in complete shape shall be registered and numbered as provided for in the TNERC Conduct of Business Regulations.
- (2) The applicant shall publish, for the information of public, the contents of the application in an abridged form in English and Tamil newspapers having wide circulation and as per the direction of the Commission in this regard. The copies of Petition and documents filed with the Commission shall also be made available at a nominal price, besides hosting them in the website.
- (3) The applicant shall furnish reply to the objection / suggestion if any received from the public direct to the objector with a copy to the Commission.
- (4) The Commission may conduct its proceedings in accordance with the provisions of the Tamil Nadu Electricity Regulatory Commission – Conduct of Business Regulations, 2004.
- (5) The Commission shall, within one hundred and twenty days from the date of receipt of application, issue tariff order taking all the possible suggestions and objections into consideration.
- (6) The Commission may also reject the application for reasons to be recorded in writing if the application is not in accordance with the provisions of the Act, Codes or Regulations made thereunder or the provision of any other law in force for the time being.

Provided that the applicant shall be given a reasonable opportunity of being heard before rejecting the application.

8. Publication of Tariff Order

- (1) The Licensee shall, within the time specified in the Tariff Order of the Commission, publish the salient features of tariff in two English

Newspapers and two Tamil Newspapers having wide circulation in Tamil Nadu.

- (2) The tariff shall come into force from the date specified in the Tariff Order and shall, unless amended or revoked, continue to be in force for such period as may be specified in the Tariff Order.

9. Communication of the Tariff

- (1) The Commission, shall, within 7 days of making the order, send a copy of the order to the Licensee and Government of Tamil Nadu.
- (2) The Commission shall also make available copies of order to any person on payment of a cost fixed by the Commission.

10. Refund of excess amount

The Licensee shall recover the charges as per the tariff determined by the Commission. If any Licensee recovers the charges exceeding the tariff determined by the Commission, the excess amount shall be refunded to the person who has paid such excess charges along with interest equivalent to the bank rate notified by the Reserve Bank of India.

11. Time- of-the- Day Tariff

- (1) To promote demand side management peak and off-peak tariff may be implemented.
- (2) The time between 0600 hrs and 0900 hrs and between 1800 hrs and 2100 hours shall be treated as peak hour.
- (3) The duration between 2200 hours and 0500 hours shall be off-peak hours.

12. Power Factor

The Commission may direct certain categories of consumers to maintain power factor at a prescribed level and allow incentive / disincentive for maintaining above / below the prescribed level

13. Regulatory Asset

- (1) Any un recovered gap at the beginning must be covered through transition financing arrangement or capital restructuring.

- (2) Wherever the Licensee could not fully recover the cost at the tariff allowed, for the reasons beyond its control under natural calamities and force majeure conditions, the Commission if satisfied with such condition, may allow the Licensee to recover the gap treating it as regulatory asset in subsequent years within a period of three years. The licensee shall intimate the Commission then and there when such contingency arises.

14. Multiyear Tariff

- (1) The Commission may implement multi year tariff for the Transmission and Distribution Licensees for a period to be notified by the Commission.
- (2) The Commission may determine Tariff and revenue for the base year, after proper evaluation and verification of the submission made by the Licensee.
- (3) The Commission may seek expert consultation in the process to determine allowable costs of the Licensees for each of the years of the control period.
- (4) The control period shall be the subsequent years following the previous year.
- (5) All the uncontrollable costs shall be allowed as pass through in tariff and the uncontrollable costs will include the following:
- Cost of fuel;
 - Costs on account of inflation;
 - Taxes and duties
 - Variation in power purchase unit cost from base line level including on account of hydro-thermal mix in case of force majeure and adverse natural events like drought
- (6) The Operation and Maintenance cost which include the following shall be controllable cost and be based on escalation indices or other mode determined during determination of tariff for the base year.
- a) Employees Cost;
 - b) Repair and Maintenance;
 - c) Administration and General Expenses:

- (7) Target for reduction of technical and commercial losses during the control period shall be determined with reference to the loss level determined for the base year and such level shall have the flexibility to accommodate changes due to completion of metering arrangement for accurate measurement of losses. The financial loss if any due to failure to achieve the target shall be borne by the licensee and gain if any shall be shared with the beneficiaries at the rate of 50 : 50.
- (8) At the end of the control period a comprehensive review of the performance may be undertaken.

15. Annual Accounts and Reports, etc.

- (1) Every Licensee shall prepare Annual Statement of Accounts and Annual Report in the form specified in the Licensing Regulations giving an account of their activities during the Current Year and Previous Year and likely to be undertaken in the ensuing year. The report of activities will also indicate targets and achievements in respect of various performance parameters.
- (2) The deemed licensees shall prepare the Annual Statement of Accounts in the form prescribed in the Electricity (Supply) Annual Accounts Rules 1985 until these rules are rescinded or modified as the case may be.
- (3) The Annual Statement of Accounts and other reports shall be furnished (in duplicate) to the Commission before 30th November of every year.

16. Business Plan

The Licensee shall furnish a detailed Business Plan for five years for approval by the Commission. The Business Plan shall contain projections for all activities including loss reduction, effective and tamper proof metering and the criteria for projection.

17. Capital Investment Plan

- (1) The Licensee shall file a detailed Capital Investment Plan every year showing separately, on going projects that will spill into the year under review and new project (along with justification) that will commence but may be completed within or beyond the tariff period.

- (2) The Commission may consider the Licensee's investment plan for approval and for this purpose, may require the Licensees to provide relevant technical and commercial details. The costs corresponding to the approved investment plan of a Licensee for a given year shall normally be considered for its revenue requirement.
- (3) In presenting the justification for new projects, the Licensee shall detail the specific nature of the works and the results to be achieved. The details must be shown in physical parameter (e.g.) new capacity to be added, length of lines to be energised, number of sub-stations / Bays to be added, meters to be added, replaced, etc. so that it is amenable for physical verification. In case of significant shortfall in achieving physical targets, the Commission may require the Licensee to explain the reasons, and may proportionately reduce the provision, including interest and return component made towards revenue requirement, in the next tariff proposal.
- (4) The Licensee may, at any time, during the tariff year, seek provision for additional capital expenditure to meet natural calamities involving substantial investment and the Commission shall examine and review these provisions in the manner as given in this regulation and approve their inclusion in the revenue requirement in the next period.
- (5) The Licensee shall get the Capital Investment Plan approved by the Commission before filing ARR and Application for determination of tariff.

CHAPTER III

General Principles of computing cost and return

18. Capital Cost

- (1) Accurate computation of cost of service including return on investment is essential for determination of cost plus tariff. The Commission shall be guided by the following principles to compute the cost and return.
- (2) Investments made prior to the notification of these Regulations by the Generating Company and Licensees shall be accepted on the basis of audited accounts.

- (3) The actual capital expenditure on the date of commercial operation for the original scope of work based on audited accounts of the Company / Licensee limited to original cost may be considered subject to prudence check by the Commission.
- (4) Wherever Power Purchase Agreement or Agreement for transmission / wheeling provides for a ceiling of capital cost, the capital cost to be considered shall not exceed such ceiling.
- (5) The capital cost may include capitalised initial spares for a maximum of first five years of operation as follows:
 - (i) Upto 2.5% of original capital cost in case of coal based / lignite fired Generating Stations;
 - (ii) Upto 4.0% of original capital cost in case of Gas Turbine / Combined cycle Generating Stations.;
 - (iii) Upto 1.5% of original capital cost in case of Transmission & Distribution Licensees.
- (6) Scrutiny of the cost estimates by the Commission shall be limited to the reasonableness of the capital cost, financing plan, interest during construction stage, use of efficient technology and such other matters, for determination of tariff. In respect of capital cost based projects, a 50% of potential savings, if any, in interest during construction, due to completion of project ahead of schedule, may be allowed to be retained by the Generating Company / Licensee and the balance 50% passed on as a lower tariff.
- (7) Swapping of foreign Debt and Equity shall be permitted, provided the benefit accruing from such swapping is passed on to consumers / beneficiaries in the year following the year of such beneficiaries.
- (8) Restructuring of capital cost in terms of relative share of equity and loan shall be permitted during the tariff period provided it does not affect tariff adversely. Any savings in costs on account of subsequent restructuring shall be shared between the developers / Licensees and the beneficiaries / consumers.

19. Additional Capitalisation

- (1) The following capital expenditure within the original scope of work actually incurred after the date of commencement of operation and upto the cut off date may be admitted by the Commission, subject to prudent check.
- (i) Deferred liabilities
 - (ii) Works deferred for execution
 - (iii) Procurement of initial spares subject to the ceiling specified in Regulation 18.5.
 - (iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court.
 - (v) On account of change of law
 - (vi) Any additional works / services which have become necessary for efficient and successful operation of the Generating Station, but not included in the original project cost.
 - (vii) Deferred works in the original scope of work.

Note: The list is illustrative and not exhaustive.

- (2) Any expenditure on minor items / assets like normal tools and tackles, personal computers, furniture, air conditioners, etc. bought after the cut off date shall not be considered for additional capitalisation for determination of tariff.
- (3) The impact of additional capitalisation in tariff revision may be considered by the Commission twice in a tariff period, including revision of tariff after the cut off date.

Note:

1. *Any expenditure admitted on account of committed liabilities within the original scope of work and the expenditure deferred on techno-economic grounds but falling within the original scope of work shall be serviced in the normative debt equity ratio specified in Regulation 21.*
2. *Any expenditure incurred on replacement of old assets shall be considered after writing off the gross value of the original assets from the original capital cost except the minor assets brought after*

cut off date and not considered for additional capitalisation vide clause 2 of this Regulation.

3. *Any expenditure admitted by the Commission for determination of tariff on account of new works not in the original scope of work shall be serviced in the normative debt equity ratio specified in regulation 21.*
4. *Any expenditure admitted by the Commission for determination of tariff on renovation and modernisation and life extension shall be serviced on normative debt equity ratio specified in regulation 21. after writing off the original amount of the replaced assets from the original project cost*

20. Revenue / charges during trial stage (prior to COD)

- (1) The cost incurred during trial upto COD shall be treated as capital cost
- (2) The revenue earned from sale of power (infirm power) shall be treated as reduction in capital cost.
- (3) Cost of infirm power shall be the lowest fuel cost applicable to the existing similar type of station.

21. Debt-Equity Ratio

For the purpose of determination of tariff, debt-equity ratio as on the date of commercial operation of Generating Station and transmission projects, sub-station, distribution lines or capacity expanded after the notification of these Regulations shall be 70:30. Where equity employed is more than 30% the amount of equity shall be limited to 30% and the balance amount shall be considered as loans, advanced at the weighted average rate of interest and for weighted average tenor of the long term debt component of the investment.

Provided that in case of a Generating Company or other Licensees, where actual equity employed is less than 30%, the actual debt and equity shall be considered for determination of return on equity in tariff computation..

22. Return on Equity

- (1) Return on equity shall be computed on the equity base determined in accordance with regulation 21 @ 14% per annum. The return shall be allowed post tax.

Provided that equity invested in foreign currency shall be allowed a return upto the prescribed limit in the same currency and payment on this account shall be made in Indian Rupees based on the exchange rate prevailing on the due date of billing.

Provided that the deemed licensees shall adopt the rate of reasonable return prescribed in the Electricity (Supply) Annual Accounts Rules 1985 till these rules are rescinded or modified.

- (2) The premium raised by the Generating Company or the Licensee while issuing capital and investment of internal resources created out of free reserve, if any, for funding of a project shall also be reckoned as paid up capital for the purpose of computing return on equity, provided such premium amount and internal resources are actually utilised for meeting capital expenditure of the project.

23. Interest and Finance Charges on (debt) Loan Capital

- (1) Interest on loan capital including the amount of equity above 30% treated as loan shall be computed on the outstanding loans duly taking into account the schedule of repayment, as per the terms and conditions of relevant agreement of loan, bonds or debentures.
- (2) The Generating Company or the Licensee shall put in every effort to swap the loan as long as it results in net benefit to the beneficiaries. The cost associated with such swapping shall be borne by the beneficiaries.
- (3) The changes to the loan terms and conditions shall be reflected from the date of such swapping and benefit passed on to the beneficiaries.
- (4) The Generating Company and the Licensee shall not make any profit on account of swapping of loan and interest on loans.
- (5) Interest on Security Deposit, if any, with the Generating Company or the Licensee shall be considered at the rate specified by the Commission from time to time.

- (6) In case any moratorium period is availed by the Generating Company or the Licensees, depreciation provided for in the tariff during the years of moratorium shall be treated as repayment during those years and interest on loan capital shall be calculated accordingly.
- (7) Saving in costs on account of subsequent restructuring of debt shall be shared between the consumers and the Generating Company / Licensees
- (8) The future agreements with lenders may have a provision for refixation of interest rate after every three years to reduce the interest commitment.

24. Depreciation

For the purpose of tariff, depreciation shall be computed in the following manners:

- (i) The value base for the purpose of depreciation shall be historical cost of the asset.
- (ii) The depreciation shall be calculated at the rates as per the Annexure to these Regulations.
- (iii) The residual value of assets shall be considered as 10% and depreciation shall be allowed upto maximum of 90% of the estimated cost of the Asset.
- (iv) Land is not a depreciable asset and its cost shall be excluded from the capital cost while computing 90% of the historical cost of the asset.
- (v) The historical cost of the asset shall include additional capitalisation.
- (vi) Depreciation shall be chargeable from the first year of operation. In case of operation of the asset for part of the year, depreciation shall be charged on pro-rata basis.
- (vii) After the assets are fully depreciated the benefit of reduced tariff shall be made available to the consumer.

Note: The Electricity (Supply) Annual Accounts Rules 1985 made under Section 69 of the Electricity (Supply) Act 1948 shall continue to have

effect until these rules are rescinded or modified as the case may be and depreciation shall be allowed accordingly.

25. Operation and Maintenance Expenses

- (1) Operation and Maintenance or O & M expenses include the following:
 - Repair & Maintenance Expenses (R & M)
 - Employees Cost
 - Administrative and General Expenses
- (2) The Commission may endeavor to fix Operation and Maintenance Expenditure on normative basis and these shall be recognised at actuals or as may be allowed by the Commission for the period of review.
- (3) The O & M expenses allowed at the commencement of the tariff period may be escalated by 4% per annum.
- (4) In case of considerable variation between the normative expenses and actual expenses, the Commission may allow the Generating Company or the Licensee to achieve the normative level over a period of time.
- (5) Increase in O & M expenses due to force majeure conditions like war, insurgency, change in law, may be considered by the Commission.
- (6) Any savings achieved by Generating Company or the Licensee shall be allowed to be retained by them. When they exceed the normative expenses they shall bear the loss.

26. Bad and Doubtful Debt

The Commission may consider and allow a provision upto 0.25% of receivables for writing off of bad and doubtful debts. The Licensee or Generating Company shall write off the Bad & Doubtful debts as per the procedure laid down by them.

27. Insurance

The Generating Company and Licensee may adopt the practice of Self Insurance and a provision upto 0.5 of the capital cost shall be allowed by the Commission in their revenue requirement. The reserves shall be utilised to replace the assets lost due to accident, fire, flood, cyclone and other force majeure conditions.

28. Contingency Reserve

The Generating Companies and the Licensees shall provide and maintain a contingency reserve upto 0.5% of the value of assets at the beginning of the year and the provision made for the year will be allowed in their Revenue Requirement. This reserve will be utilised to meet any contingent liability or unforeseen revenue losses.

29. Interest on Working Capital

The rate of interest on working capital shall be on normative basis and shall be equivalent to the short term primary lending rate of State Bank of India as on 1st April of the relevant year. The computation of working capital shall be as provided in these regulations subsequently.

30. Foreign Exchange Rate Variation

- (1) Extra rupee liability towards interest payment and loan repayment corresponding to the actual foreign debt in the relevant year shall be permissible provided the entire rupee liability directly arises out of Foreign Exchange Rate variation and is not attributable to the Generation Company / Licensee or their suppliers or contractors.
- (2) Generating Companies shall be allowed reasonable cost of hedging subject to a ceiling of 1 % of the foreign exchange component to take care of foreign exchange variation.

31. Income Tax

- (1) Tax on Income stream of the Generating Company or the Transmission Licensee or the Distribution Licensee as the case may be from Core / Licensed business shall be computed as expenses and shall be recovered as pass through from the beneficiaries.
- (2) Under recovery or over recovery of any amount from the beneficiaries or the consumers on account of such tax having been passed on to them shall be adjusted every year on the basis of income tax assessment under the Income Tax Act 1961 as certified by the Statutory Auditors.

Provided that tax on income from business other than the Core / licenced business shall not constitute a pass through component in

tariff and the tax on such income shall be borne by the Generating Company or the Licensees as the case may be.

32. Provisional assessment of Income Tax and Foreign Exchange Rate variation

Income tax and Foreign Exchange Rate variation shall be provisionally estimated by the Commission with reference to the ARR and application of the Generating Company or the Licensee for the purpose of determining tariff and shall be subject to adjustment as per actuals.

CHAPTER IV

Thermal Power Generating Station

33. Application for Determination of Tariff

- (1) The Generating Company may file application for determination of tariff in the manner specified in Chapter II of these Regulations.
- (2) In respect of existing Generating Companies covered under PPAs already entered, the tariff and norms shall be as per the terms agreed to. However, modification to the existing PPAs may be undertaken through mutual discussion between the parties to the agreement to explore possibilities of reducing costs and aligning the PPAs with the new market structure.
- (3) For new Generating Stations, a significant part of the capacity shall be made available (as free capacity) to be sold through trading markets and the remaining capacity only shall be contracted through Power Purchase Agreement.
- (4) The new PPAs shall have appropriate clauses to ensure that the contracts can be modified to align them with the emerging market structures.
- (5) The linkage of PPAs terms to loan tenor shall be progressively de-emphasized as the electricity markets and trading arrangements provide alternate avenues to developers for selling their output.

34. Components of Tariff

- (1) The tariff for sale of power by the Generating Companies shall be of two part namely the Fixed Charges (recovery of annual capacity charges) and variable (energy) charges.
- (2) The Fixed (annual capacity) charges shall consist of the following elements:
 - (a) Interest on Loan Capital;
 - (b) Depreciation
 - (c) Return on Equity;
 - (d) Operation and Maintenance expenses; and
 - (e) Interest on Working Capital:
- (3) The energy (variable) charges shall cover fuel cost.

35. Norms of Operation

The norms of operation for the Thermal Generating Stations shall be as under:

(i) Target availability for recovery of full capacity (fixed) charges

- | | |
|---|------------|
| (a) All Thermal Generation in Tamil Nadu except Ennore Power Station | 80% |
| (b) Ennore Thermal Power Station
(Till R & M works in all units are completed) | 50% |
| (c) In respect of Generating Stations of IPPs | As per PPA |
| (d) New Thermal Stations | 80% |

(ii) Target availability for generation to meet the demand

- | | |
|--|------------|
| (a) All Thermal Stations except ETPS | 90% |
| (b) ETPS | 49% |
| (c) In respect of Generating Stations of IPPs..... | As per PPA |
| (d) New Thermal Stations | 80% |

(iii) Target Plant Load Factor for incentive

- | | |
|---|------------------|
| (a) All the Thermal Power Generating Stations except the existing Stations of Independent Power Producers covered under PPA | 85% |
| (b) Power Stations of IPPS covered under existing PPAs | As per PPA |

(iv) Gross Station Heat Rate**(a) Norms for the existing Coal-based Thermal Power Generating Stations**

Station	Heat Rate
1. ETPS	3200 kcal/kwh
2. TTPS	2453 “
3. MTPS	2500 “
4. NCTPS	2393 “

(b) Norms for the new Thermal Power Generating Stations

	200/210/250 MW sets	500 MW and above sets
During Stabilisation period	2600 KCal/kWh	2500 Kcal/kWh
Subsequent period	2500 KCal/kWh	2450 Kcal/kWh

Note 1

In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the heat rate of 40 kCal/kWh shall be reduced from the Generating Station heat rate indicated above.

Note 2

For Generating Stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross Generating Station heat rate shall be the weighted average Generating Station heat rate of various sets.

(c) Lignite-fired thermal power Generating Stations

The station heat rate specified in clause (b) above for coal based Thermal Power Generating Station shall be corrected, using multiplying factors as given below:

- (i) For lignite having 50% moisture: Multiplying factor of 1.10
- (ii) For lignite having 40% moisture: Multiplying factor of 1.07
- (iii) For lignite having 30% moisture: Multiplying factor of 1.04

- (iv) For other values of moisture content, multiplying factor shall be pro-rated for moisture content between 30-40 and 40-50 depending upon the rated values of multiplying factor for the respective range given under sub-clauses (i) to (iii) above.

(d) Gas-Turbine / combined cycle Generating Stations

	Advanced class machine	E/.EA/EC/E2 class machine
Open Cycle	2685 Kcal / kWh	2830 Kcal / kWh
Combined cycle	1850 Kcal/ kWh	1950 Kcal / kWh

(v) Secondary fuel oil consumption

- (a) Coal-based Generating Stations:

During stabilization period	:	4.5 ml/kWh
Subsequent period (except ETPS)	:	2.0 ml/kWh
ETPS	:	4.ml/kWh

- (b) Lignite fired Generating Stations:

During stabilization period	:	5.0 ml/kWh
Subsequent period (except ETPS)	:	3.0 ml/kWh

(vi) Auxiliary Energy Consumption

- (a) Coal-based Generating Stations:

(i) With cooling towers	:	9%
(ii) Without cooling towers	:	8.5%

- (b) Gas-based and Naphtha-based Generating Stations:

(i) Combined cycle	:	3%
(ii) Open cycle	:	1%

- (c) Lignite fired Thermal Power Station

The auxiliary consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms for coal based Generating Stations indicated in a (i) and (ii) above.

- (d) During stabilization period, normative auxiliary consumption shall be reckoned at 0.5 percentage point more than the norms indicated at (a), (b) and (c) above.

(vii) Stabilization period

The stabilization period of a unit shall be reckoned commencing from the date of commercial operation of that unit as follows:

- | | |
|--|-----------|
| (a) coal-based and lignite-fired Generating Stations | -180 days |
| (b) Gas turbine / combined Generating Stations | - 90 days |

36. Capital Cost and sale of infirm power

- (1) The capital cost of a Generating Company shall be worked out in accordance with the provisions of regulation 18 and 19.
- (2) Any revenue other than the recovery of fuel cost earned by the Generating Company from the sale of infirm power shall be taken as reduction in capital cost as provided in regulation 20.

37. Operation and Maintenance Expenses

- (1) The operation and maintenance expenses, shall be derived on the basis of actual operation and maintenance expenses for the past five years previous to current year based on the audited Annual Accounts excluding abnormal operation and maintenance expenses, if any, after prudence check by the Commission.
- (2) The average of such normative operation and maintenance expenses after prudence check shall be escalated at the rate of 4% per annum to arrive at operation and maintenance expenses for current year i.e. base year and ensuing year.
- (3) The base operation and maintenance expenses so determined shall be escalated further at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant years of tariff period.
- (4) In case of the thermal power Generating Stations, which have not been in existence for a period of five years the operation and maintenance

expenses shall be fixed at 1.0% of the capital cost (as admitted by the Commission) and shall be escalated at the rate of 4% per annum from the subsequent year to arrive at base operation and maintenance expenses. The base operation and maintenance expenses shall be further escalated at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant year.

- (5) In case of the thermal power generating stations declared under commercial operation on or after the notification of these Regulations, the base operation and maintenance expenses shall be fixed at 1.0% of the actual capital cost (as admitted by the Commission), in the year of commissioning and shall be subject to an annual escalation of 4% per annum for the subsequent years.

38. Working Capital

- (1) The Commission may conduct lead-lag studies for determination of Working Capital requirement for various types of Generating Stations to arrive at a formulaic dispensation to accommodate improvement on norms mutually agreed to between the generators and purchasers.
- (2) Till such a formula is evolved, the norms for Working Capital shall be as below:

(a) For Coal based / Lignite fired Generating Stations

- (i) Cost of coal or lignite for 2 months corresponding to the target availability;
- (ii) Cost of secondary fuel oil for two months corresponding to the target availability;
- (iii) Operation and Maintenance expenses for one month;
- (iv) Maintenance spares @ 1% of the historical cost escalated @ 4% per annum from the date of commercial operation; and
- (v) Receivables equivalent to two months of fixed and variable charges for sale of electricity calculated on "target availability".

(b) For Gas Turbine combined cycle Generating Stations

- (i) Fuel cost for one month corresponding to the target availability duly taking into account the mode of operation of the Generating Station on gas fuel and liquid fuel;

- (ii) Liquid fuel stock for ½ month;
- (iii) Operation & Maintenance expenses for one month;
- (iv) Maintenance spares @ 1% of the historical cost escalated @ 4% per annum from the date of commercial operation; and
- (v) Receivables equivalent to two months of fixed and variable charges for sale of electricity calculated on target availability.

Note

- (i) *Norms of operation specified in these regulations are the ceiling norms and the Generating Company and the user may agree for improved norms. In such a case, the improved norms on the basis of their agreement shall be considered for the purpose of tariff determination.*
- (ii) *In respect of the Generating Companies covered under Power Purchase Agreements the norms in the Power Purchase Agreements will be applicable till the expiry of the contract.*

39. SLDC and Transmission Charges

SLDC charges as determined by the Commission shall be considered as expenses. SLDC and Transmission charges paid for the energy sold outside the State shall not be considered as expenses for determining generation tariff.

40. Other Income

Income other than income from sale of electricity including UI charges shall be grouped as other income.

41. Computation of Capacity (Fixed) Charges

- (1) The total annual Fixed Charges of a Generating Company consisting the elements detailed in clause 2 of Regulation 34 shall be worked out on the basis of the principles outlined in Chapter III and also in accordance with the norms allowed in these Regulations.
- (2) The annual capacity charges recoverable by the Generating Company shall be worked out by deducting other income as per Regulation 40 from the total annual expenses and return worked out under clause (1) above

42. Recovery of Capacity Charges

- (1) Full capacity charges (Fixed Charges) shall be recoverable at target availability specified in clause (1) of Regulation 35.
- (2) Recovery of capacity charges below the level of target availability will be on pro rata basis. At zero availability, no capacity charges shall be payable.
- (3) Payment of capacity charges (Fixed Charges) shall be on monthly basis in proportion to allocated / contracted capacity.
- (4) Capacity (Fixed) charges per kWh in the month shall be worked out by dividing the capacity charges recoverable for the month by the quantum of ex-bus energy sent out in the month.

43. Energy (Variable) Charges

The energy charges shall cover fuel costs and shall be computed as follows:

(i) **Generating Stations covered under ABT**

The Energy (variable) Charges shall be worked out on the basis of ex-bus energy scheduled to be sent out from the Generating Station as per the following formula:

$$\text{Energy Charges (Rs)} = \text{Rate of Energy Charges in Rs/kWh} \times \text{Scheduled Energy (ex-bus) for the month in kWh corresponding to scheduled generation.}$$

(ii) **Generating Stations other than those covered under ABT**

The Energy (variable) charges shall be worked out on the basis of ex-bus energy delivered / sent out from the Generating Station as per the following formula:

$$\text{Energy Charges (Rs)} = \text{Rate of Energy Charges in Rs/kWh} \times \text{Energy delivered (ex-bus) for the months in kWh}$$

Where,

Rate of Energy Charges (REC) shall be the sum of the cost of normative quantities of primary and secondary fuel for delivering ex-bus one kWh of electricity in Rs/kWh and shall be computed as under:

$$\text{REC} = \frac{100 \{P_p \times (Q_p)_n + P_s \times (Q_s)_n\}}{(100 - (\text{AUX}_n))} \quad (\text{Rs/kWh})$$

Where,

P_p = Price of primary fuel namely coal or Lignite or Gas or liquid fuel in Rs/Kg or Rs/cum or Rs./litre as the case may be.

$(Q_p)_n$ = Quantity of primary fuel required for generation of one kWh of electricity at generator terminals in Kg or litre or cum as the case may be, and shall be computed on the basis of Gross station Heat Rate (less heat contributed by secondary fuel oil for coal/lignite based Generating Stations) and gross calorific value of coal/lignite or gas or liquid fuel actually fired.

P_s = Price of Secondary fuel oil in Rs./ml,

$(Q_s)_n$ = Normative Quantity of Secondary fuel oil/kwh as per clause v of Regulation 35.

(iii) **Adjustment of rate of energy charge (REC) on account of variation in price or heat value of fuels**

- (a) Initially, Gross Calorific Value of coal/lignite or gas or liquid fuel shall be taken as per actuals of the preceding three months. Any variation shall be adjusted on a month to month basis on the basis of average Gross Calorific Value of coal/lignite or gas or liquid received and burnt and weighted average landed cost incurred by the Generating Company for procurement of coal/lignite, oil, or gas or liquid fuel, as the case may be for a Power Station.
- (b) In its bills, Generating Company shall indicate rate of energy charges at base price of primary and secondary fuel specified by the Commission and the fuel price adjustment to it separately.
- (c) No separate petition need to be filed with the Commission for fuel price adjustment.

(iv) **Landed Cost of Coal**

The landed cost of fuel shall include the following:

- (a) Base cost of coal / lignite / oil / naphtha / gas

- (b) Royalty
- (c) Tax and duties
- (d) Transport cost by rail / ocean / road / gas pipeline or any other means.

For the purpose of computing energy charges, Landed Cost of coal / lignite shall be arrived at after considering normative transit and handling loss of 0.8% on the quantity of fuel despatched by the fuel supplier.

- (v) The capacity (fixed) charges per KWh and the energy charges per KWh shall be the generation tariff
- (vi) In respect of power generated in the stations owned by the distribution licensee and distributed by the licensee himself in his area of supply, the generation tariff of the station shall be considered as the transfer price to the distribution licensee which will be determined in the licensee's tariff petition itself.

44. Incentive

Incentive shall be payable at a flat rate of 25 paise / kWh for ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to target Plant Load Factor.

45. Unscheduled Interchange(UI) Charges applicable to stations covered under ABT

- (1) Variation in actual generation or actual drawal and scheduled generation or scheduled drawal shall be accounted for through Unscheduled Interchange (UI)Charges.
- (2) UI for a Generating Station shall be equal to its actual generation minus its scheduled generation.
- (3) UI for beneficiary shall be equal to its total actual drawal minus its total scheduled drawal.
- (4) UI shall be worked out for each 15 minute time block.
- (5) Charges for all UI transactions shall be based on average frequency of the time block and the following rates shall apply:
- (6)

Average Frequency of time block		UI Rate (paise per unit kWh)
Below	Not below	
-	50.50	0.0
50.50	50.48	6.0
50.48	50.46	12.00
-	-	-
-	-	-
49.84	49.82	204.0
49.82	49.80	210.0
49.80	49.78	219.0
49.78	49.76	228.0
-	-	-
-	-	-
49.04	49.02	561.0
49.02	-	570.0

(Each 0.02 Hz step is equivalent to 6.00 paise /kWh in the 50.5 – 49.8 HZ frequency range and to 9.0 paise / kWh in the 49.8 – 49.0 HZ frequency range)

Note

- (1) *The above average frequency range and UI rates are subject to change through a separate notification by the Commission from time to time.*
- (2) (i) *Any Generation upto 105% of the declared capacity in any time block of 15 minutes and averaging upto 101% of the average declared capacity over a day shall not be construed as foul play, and the generator shall be entitled to UI charges for such excess generation above the scheduled generation (SG).*
- (ii) *For any generation beyond the prescribed limits, the State Load Despatch Centre shall investigate so as to ensure that there is no foul play, and if foul play is found by the State Load Despatch Centre, the corresponding UI charges due to the Generating Station on account of such extra generation shall be reduced to zero and the amount shall be adjusted in UI account of beneficiaries in the ratio of their capacity share in the Generating Station.*

46. Rebate

For payment of bills of capacity charges and energy charges through a Letter of Credit, a rebate of 2% shall be allowed. If the payments are made by a mode other than Letter of Credit but within a period of one month of

presentation of bills by a Generating Company, a rebate of 1% shall be allowed.

47. Late Payment Surcharge

In case payment of capacity charges and energy charges by the beneficiary is delayed, beyond a period of 60 days from the date of billing, a late payment surcharge at the rate of 1.25% per month shall be levied by the Generating Company.

48. Scheduling:

Read with the provisions of Tamil Nadu Electricity Grid Code, the methodology of scheduling and calculating availability shall be as under:

- (i) The generator shall make an advance declaration of capability of its generating station. The declaration shall be for that capability which can be actually made available.
The declaration shall be for the capability of the generating station to deliver ex-bus MW for the next day either as one figure for the whole day or as different figures for different periods of the day. The capability as declared by the generator, also referred to as the declared capacity, shall form the basis of generation scheduling.
- (ii) While making or revising its declaration of capability, the generator shall ensure that the declared capability during peak hours is not less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronisation of units as a result of forced outage of units.
- (iii) Generation scheduling shall be done in accordance with the operating procedure stipulated in the Tamil Nadu Electricity Grid Code.
- (iv) Based on the declaration of the generator, the State Load Dispatch Centre shall communicate their shares to the beneficiaries out of which they shall give their requisitions.
- (v) Based on the requisitions given by the beneficiaries and taking into account technical limitations on varying the generation and also taking into account transmission system constraints, if any, the

State Load Dispatch Centre shall prepare the economically optimal generation schedules and drawal schedules and communicate the same to the generator and the beneficiaries.

The State Load Dispatch Centre shall also formulate the procedure for meeting contingencies both in the long run and in the short run (Daily scheduling).

- (vi) The scheduled generation and actual generation shall be ex-bus at the generating station. For beneficiaries, the scheduled and actual net drawals shall be at their respective receiving points.
- (vii) For calculating the net drawal schedules of beneficiaries, the transmission losses shall be apportioned to their drawal schedules for the time being.

Provided that a refinement may be specified by the Commission in future depending on the preparedness of the respective State Load Dispatch Centre.

- (viii) In case of forced outage of a unit, the State Load Dispatch Centre shall revise the schedules on the basis of revised declared capability. The revised declared capability and the revised schedules shall become effective from the 4th time block, counting the time block in which the revision is advised by the generator to be the first one.
- (ix) In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, associated switchyard and sub-stations owned by the State Transmission Utility or any other transmission licensee involved in intra-state transmission (as certified by the State Load Dispatch Centre) necessitating reduction in generation, the State Load Dispatch Centre shall revise the schedules which shall become effective from the 4th time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. Also, during the first, second and third time blocks of such an event, the scheduled generation of the generating station shall be deemed to have been revised to be equal to actual generation, and

the scheduled drawals of the beneficiaries shall be deemed to have been revised to be equal to their actual drawals.

- (x) In case of any grid disturbance, scheduled generation of all the generating stations and scheduled drawal of all the beneficiaries shall be deemed to have been revised to be equal to their actual generation/drawal for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the State Load Dispatch Centre.
- (xi) Revision of declared capability by the generator(s) and requisition by beneficiary(ies) for the remaining period of the day shall also be permitted with advance notice. Revised schedules/declared capability in such cases shall become effective from the 6th time block, counting the time block in which the request for revision has been received in the State Load Dispatch Centre to be the first one.
- (xii) If, at any point of time, the State Load Dispatch Centre observes that there is need for revision of the schedules in the interest of better system operation, it may do so on its own, and in such cases, the revised schedules shall become effective from the 4th time block, counting the time block in which the revised schedule is issued by the State Load Dispatch Centre to be the first one.
- (xiii) Generation schedules and drawal schedules issued/revised by the State Load Dispatch Centre shall become effective from designated time block irrespective of communication success.
- (xiv) For any revision of scheduled generation, including post facto deemed revision, there shall be a corresponding revision of scheduled drawals of the beneficiaries.
- (xv) A procedure for recording the communication regarding changes to schedules duly taking into account the time factor shall be evolved by the State Transmission Utility in consultation with SLDC as well as other stakeholders and it shall be to the extent possible in line with the prevailing practices at the national level

Note

In case of a generating station, contracting to supply power to two or more States, the scheduling, metering and energy accounting shall be carried out by the Regional Load Dispatch Centre.

49. Demonstration of Declared Capability:

- (1) The generating company may be required to demonstrate the declared capability of its generating station as and when asked by the State Load Dispatch Centre of the state. In the event of the generating company failing to demonstrate the declared capability, the capacity charges due to the generator shall be reduced as a measure of penalty.
- (2) The quantum of penalty for the first mis-declaration for any duration/block in a day shall be the charges corresponding to two days fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in the geometrical progression.
- (3) The operating log books of the generating station shall be available for review by the SLDC. These books shall keep record of machine operation and maintenance.

50. Metering and Accounting:

Metering arrangements, including installation, testing and operation and maintenance of meters and collection, transportation and processing of data required for accounting of energy exchanges and average frequency on 15 minute time block basis shall be organised by the State Transmission Utility/State Load Dispatch Centres. All concerned entities (in whose premises the special energy meters are installed), shall fully cooperate with the State Transmission Utility/State Load Dispatch Centre and extend the necessary assistance by taking weekly meter readings and transmitting them to the State Load Dispatch Centre.

Further SLDC will forward the necessary data / schedules to regional level in line with regulations formulated by Central Electricity Regulatory Commission. UI accounting procedures shall be governed by the orders of the Commission.

Note

In case of a generating station, contracting to supply power to two or more States, the scheduling, metering and energy accounting shall be carried out by the Regional Load Dispatch Centre.

51. Billing and Payment of Capacity Charges:

Billing and payment of capacity charges shall be done on a monthly basis in the following manner:

- (i) Each beneficiary shall pay the capacity charges in proportion to its percentage share in Installed Capacity of the generating station.

The beneficiaries could be the various distribution licensees or the trading companies.

Note:

If any capacity remains un-requisitioned during day-to-day operation, the State Load Dispatch Centre shall advise all beneficiaries in the region and the other State Load Dispatch Centres so that such capacity may be requisitioned through bilateral arrangements either with the concerned generating company or with the concerned beneficiary(ies) under intimation to the State Load Dispatch Centre.

The information regarding un-requisitioned capacity shall also be made available by the State Load Dispatch Centres through their respective websites.

- (ii) The capacity charges shall be paid by the beneficiary(ies) to the generating company every month in accordance with the following formulas:

(a) Total Capacity charges payable to the thermal power generating company for the:

$$1^{\text{st}} \text{ month} = (1 \times \text{ACC1}) / 12$$

$$\begin{aligned}
2^{\text{nd}} \text{ month} &= (2XACC2 - 1XACC1)/12 \\
3^{\text{rd}} \text{ month} &= (3xACC3 - 2XACC2)/12 \\
4^{\text{th}} \text{ month} &= (4xACC4 - 3xACC3)/12 \\
5^{\text{th}} \text{ month} &= (5XACC5 - 4xACC4)/12 \\
6^{\text{th}} \text{ month} &= (6XACC5 - 5xACC5)/12 \\
7^{\text{th}} \text{ month} &= (7XACC7 - 6xACC6)/12 \\
8^{\text{th}} \text{ month} &= (8xACC8 - 7xACC7)/12 \\
9^{\text{th}} \text{ month} &= (9xACC9 - 8xACC8)/12 \\
10^{\text{th}} \text{ month} &= (10xACC10 - 9xACC9)/12 \\
11^{\text{th}} \text{ month} &= (11xACC11 - 10xACC10)/12 \\
12^{\text{th}} \text{ month} &= (12xACC12 - 11xACC11)/12
\end{aligned}$$

(b) Each beneficiary having firm allocation in capacity of the generating station shall pay for the :

$$\begin{aligned}
1^{\text{st}} \text{ month} &= [ACC1 x WB1]/1200 \\
2^{\text{nd}} \text{ month} &= [2XACC2 x WB2 - 1XACC1x WB1]/1200 \\
3^{\text{rd}} \text{ month} &= (3xACC3 x WB3 - 2XACC2 x WB2)/1200 \\
4^{\text{th}} \text{ month} &= (4xACC4 x WB4 - 3xACC3 x WB3]/1200 \\
5^{\text{th}} \text{ month} &= (5XACC5 x WB5 - 4xACC4 x WB4]/1200 \\
6^{\text{th}} \text{ month} &= (6XACC5 x WB6 - 5xACC5 x WB5]/1200 \\
7^{\text{th}} \text{ month} &= (7XACC7 x WB7 - 6xACC6 x WB6]/1200 \\
8^{\text{th}} \text{ month} &= (8xACC8 x WB8 - 7xACC7 x WB7]/1200 \\
9^{\text{th}} \text{ month} &= (9xACC9 x WB9 - 8xACC8 x WB8]/1200 \\
10^{\text{th}} \text{ month} &= (10xACC10 x WB10- 9xACC9 x WB9]/1200 \\
11^{\text{th}} \text{ month} &= (11xACC11 x WB11- 10xACC10x WB10]/1200 \\
12^{\text{th}} \text{ month} &= (12xACC12 x WB12- 11xACC11x WB 11]/1200
\end{aligned}$$

Where,

ACC1, ACC2, ACC3, ACC4, ACC5 ACC6, ACC7, ACC8, ACC9, ACC10, ACC11 and ACC12 are the amount of Annual Capacity Charge corresponding to 'Availability' for the cumulative period up to the end of 1st, 2nd 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th months respectively.

And, WB1, WB2, WB3, WB4, WB5, WB6, WB7, WB8, WB9, WB10, WB11 and WB12 are the weighted average of percentage allocated capacity share of the beneficiary during the cumulative period up to 1st, 2nd, 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th month respectively.

CHAPTER V

Hydro Power Generating Stations

52. Application for determination of tariff

The provisions of Regulation 33 shall apply mutatis mutandis, to an Application for determination of tariff of Hydro Generating Stations.

53. Components of tariff

Tariff for sale of electricity from a Hydro Power Generating Station shall comprise of two parts, namely, the recovery of annual capacity charges and energy charges to be worked out in the manner provided hereinafter.

54. Norms of operation

The norms of operation shall be as follows:-

- (1) Normative capacity index for recovery of full capacity charges
 - (a) During first year of commercial operation of the Generating Station

(i) Purely Run-of-river Power Stations	- 85%
(ii) Storage type and Run of river Power Stations with pondage	- 90%
 - (b) After first year of commercial operation of the Generating Station

(i) Purely Run-of-river Power Stations	- 90%
(ii) Storage type and Run-of-River Power Stations with pondage	- 85%
 - (c) There shall be prorata recovery of capacity charges in case the Generating Station achieves capacity index below the prescribed normative levels. At Zero capacity index, no capacity charges shall be payable to the Generating Station.
- (2) Auxiliary Energy Consumption:

- (a) Surface hydro electric Power Generating Stations with rotating exciters mounted on the generator shaft 0.2% of energy generated
 - (b) Surface hydro electric Power Generating Stations with static excitation system - 0.5% of energy generated
 - (c) Pumped storage hydro stations – energy consumed for pumping
- (3) Transmission Losses
From generation voltage to transmission voltage – 0.5% of energy generated

55. Capital Cost and sale of infirm power

- (1) Capital Cost of Hydro Power Generating Station, including the complete hydro power generating facility covering all components such as dam, intake, water conductor system, power generating station and generating units of the scheme as apportioned to power generation, shall be determined in accordance with Chapter III of these Regulations.
- (2) Any revenue earned by the Generating Company from sale of infirm power, shall be taken as reduction in capital cost of the Generating Station and shall not be treated as revenue. The rate for infirm power shall be same as the energy rate of the Generating Stations.

56. Operation and Maintenance Expenses

- (1) The operation and maintenance expenses, shall be derived on the basis of actual operation and maintenance expenses for the past five years previous to current year based on the audited Annual Accounts excluding abnormal operation and maintenance expenses, if any, after prudence check by the Commission.

The average of such normative operation and maintenance expenses after prudence check shall be escalated at the rate of 4% per annum to arrive at operation and maintenance expenses for current year i.e. base year and ensuing year.

The base operation and maintenance expenses so determined shall be escalated further at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant years of tariff period.

- (2) In case of the hydro electro Generating Stations, which have not been in existence for a period of five years, the operation and maintenance expenses shall be fixed at 1.0% of the capital cost as admitted by the Commission and shall be escalated at the rate of 4% per annum from the subsequent year to arrive at base operation and maintenance expenses. The base operation and maintenance expenses shall be further escalated at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant year.
- (3) In case of the hydro electric generating stations declared under commercial operation on or after the notification of these Regulations, the base operation and maintenance expenses shall be fixed at 1.0% of the actual capital cost as admitted by the Commission, in the year of commissioning and shall be subject to an annual escalation of 4% per annum for the subsequent years.

57. Working Capital

The working Capital shall cover:

- (i) Operation and Maintenance expenses for one month;
- (ii) Maintenance spares @ 1% of the historical cost escalated @ 4% per annum from the date of commercial operation; and
- (iii) Receivables equivalent to two months of fixed charges for sale of electricity, calculated on normative capacity index.

58. SLDC and transmission charges

SLDC charges as determined by the Commission shall be considered as expenses. SLDC and Transmission Charges paid for energy sold under bilateral agreements out side the State shall not be considered as expenses to determine generation tariff.

59. Computation of Annual Energy Charges

- (1) The two part tariff for sale of electricity from a hydro power generating station shall comprise a recovery of annual capacity (fixed) charges and primary energy charges.
- (2) The annual capacity (fixed charges shall consist of the following and shall be computed as per the principles in Chapter III.
 - (a) Interest on Loan Capital
 - (b) Depreciation including advance against depreciation
 - (c) Return on equity
 - (d) Operation and Maintenance expenses excluding operating expenses like water charges, lubricants, consumables and station supplies.
 - (e) Interest on Working Capital
- (3) Primary Energy Charges shall be the operating expenses like cost of water, lubricants, consumables and station supplies

60. Energy Rate

Energy charges per kWh shall be arrived at as below:

$$\text{Energy rate} = \frac{\text{Annual Capacity Charges} + \text{Annual Primary Energy Charges}}{\text{Saleable Energy}}$$

61. Incentive

- (1) Incentive shall be payable in case of all the Generating Stations, including new Generating Stations in the first year of operation, when the capacity index (CI) exceeds 90% for purely run-of-river power generating stations and 85% for run-of-river power station with pondage or storage type power generating stations and incentive shall accrue upto a maximum capacity index of 100%.
- (2) Incentive shall be payable to the Generating Company in accordance with the following formula:

$$\text{Incentive} = 0.65 \times \text{Annual Charge} \times (CI_A - CI_N) / 100$$
 (If incentive is negative, it shall be set to zero)

Where, CI_A is the Capacity Index achieved and CI_N is the normative capacity index whose values are 90% for purely run of the river hydro stations and 85% for pondage / storage type hydro Generating Stations.

- (3) The total incentive payment calculated on annual basis shall be shared by the beneficiaries based on the allocated capacity.
- (4) **Incentive for completion of hydro electric power Generating Stations ahead of schedule.**

In case of commissioning of a hydro electric power generating station or part thereof ahead of schedule, the Generating Station shall become eligible for incentive for an amount equal to pro rata reduction in interest during construction, achieved on commissioning ahead of the schedule. The incentive shall be recovered through tariff in twelve equal monthly instalments during the first year of operation of the Generating station. In case of delay in commissioning, interest during construction for the period of delay shall not be allowed to be capitalised for determination of tariff, unless the delay is on account of natural calamities or geological surprises.

62. Deemed Generation

- (1) In case of reduced generation due to the reasons beyond the control of Generating Company or on account of non-availability of Board's transmission licensee's transmission lines or on receipt of backing down instructions from the concerned State Load Despatch Centre resulting in spillage of water, the energy equivalent on account of such spillage at the same rate of energy charges shall be payable to the Generating Company. Apportionment of energy charges for such spillage among the beneficiaries shall be in proportion of their shares in saleable capacity of the respective Generating Station.
- (2) Energy Charges on the above account shall not be admissible if the energy generated during the year is equal to or more than the design energy.

63. Scheduling:

Read with the provisions of Tamil Nadu Electricity Grid Code, the methodology of scheduling and calculating capacity index shall be as under:

- (i) The generator shall make an advance declaration of capacity of its generating station. The declaration shall be for that capacity which can be actually made available for a period of time not less than 3 hours within a 24 hours period for pondage and storage type of stations and for the entire day for purely run-of-river type stations.
- (ii) The generator shall intimate the declared capacity (MW), for the next day, either as one figure for the whole day or different figures for different periods of the day along with maximum available capacity (MW) and total energy (MWh) ex-bus to the State Load Dispatch Centre.

The declaration should also include limitation on generation during specific time periods, if any, on account of restriction(s) on water use due to irrigation, drinking water, industrial, environmental considerations etc.

- (iii) While making or revising his declaration of capability, the generator shall ensure that the declared capacity during peak hours is not less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronisation of units as a result of forced outage of units.
- (iv) Generation scheduling shall be done in accordance with the operating procedure, as stipulated in the Tamil Nadu Electricity Grid Code.
- (v) Based on the declaration of the generator, the State Load Dispatch Centre shall communicate their shares to the beneficiaries out of which they shall give their requisitions.
- (vi) Based on the requisitions given by the beneficiaries and taking into account technical limitations on varying the generation and also taking into account transmission system constraints, if any, the State Load Dispatch Centre shall prepare the economically optimal generation schedules and drawal schedules and communicate the same to the generator and the beneficiaries.

The State Load Dispatch Centre shall also formulate the procedure for meeting contingencies both in the long run and in the short run (Daily scheduling).

- (vii) The scheduled generation and actual generation shall be ex-bus at the generating station. For beneficiaries, the scheduled and actual net drawals shall be at their respective receiving points.
- (viii) For calculating the net drawal schedules of beneficiaries, the transmission losses shall be apportioned to their drawal schedule for the time being. However, a refinement may be specified by the Commission in future, depending upon the preparedness of the respective State Load Dispatch Centre.
- (ix) In case of forced outage of a unit, the State Load Dispatch Centre shall revise the schedules on the basis of revised declared capability. The revised declared capability and the revised schedules shall become effective from the 4th time block, counting the time block in which the revision is advised by the generator to be the first one.
- (x) In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, associated switchyard and sub- stations owned by the State Transmission Utility or any other transmission licensee involved in inter-state transmission (as certified by the State Load Dispatch Centre) necessitating reduction in generation, the Regional Load Dispatch Centre shall revise the schedules which shall become effective from the 4th time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. Also, during the first, second and third time blocks of such an event, the scheduled generation of the generating station shall be deemed to have been revised to be equal to actual generation, and the scheduled drawals of the beneficiaries shall be deemed to have been revised to be equal to their actual drawals.
- (xi) In case of any grid disturbance, scheduled generation of all the generating stations and scheduled drawal of all the beneficiaries shall be deemed to have been revised to be equal to their actual generation/drawal for all the time blocks affected by the grid

disturbance. Certification of grid disturbance and its duration shall be done by the State Load Dispatch Centre.

- (xii) Revision of declared capability by the generator(s) and requisition by beneficiary(ies) for the remaining period of the day shall also be permitted with advance notice. Revised schedules/declared capability in such cases shall become effective from the 6th time block, counting the time block in which the request for revision has been received in the State Load Dispatch Centre to be the first one.
- (xiii) If, at any point of time, the State Load Dispatch Centre observes that there is need for revision of the schedules in the interest of better system operation, it may do so on its own and in such cases, the revised schedules shall become effective from the 4th time block, counting the time block in which the revised schedule is issued by the State Load Dispatch Centre to be the first one.
- (xiv) Generation schedules and drawal schedules issued/ revised by the Regional Load Dispatch Centre shall become effective from designated time block irrespective of communication success.
- (xv) For any revision of scheduled generation, including post facto deemed revision, there shall be a corresponding revision of scheduled drawals of the beneficiaries.
- (xvi) A procedure for recording the communication regarding changes to schedules duly taking into account the time factor shall be evolved by the State Transmission Utility.
- (xvii) Purely run-of-river power stations
 - Since variation of generation in such stations may lead to spillage, these shall be treated as must run stations. The maximum available capacity, duly taking into account the over load capability, must be equal to or greater than that required to make full use of the available water.
- (xviii) Run-of-river power station with pondage and storage type power stations
 - These hydro stations are designed to operate during peak hours to meet system peak demand. Maximum available capacity of the station declared for the day shall be equal to the installed

capacity including overload capability, minus auxiliary consumption and transformation losses, corrected for the reservoir level. The Regional Load Dispatch Centres shall ensure that generation schedules of such type of stations are prepared and the stations dispatched for optimum utilization of available hydro energy except in the event of specific system requirements/constraints.

64. Demonstration of Declared Capability:

- (1) The generating company may be required to demonstrate the declared capacity of its generating station as and when asked by the State Load Dispatch Centre of the region in which the generating station is situated. In the event of the generating company failing to demonstrate the declared capacity, within the tolerance as specified by the Central Transmission Utility, the capacity charges due to the generating station shall be reduced as a measure of penalty.
- (2) The quantum of penalty for the first mis-declaration for any duration or block in a day shall be the charges corresponding to two days fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in the geometrical progression.
- (3) The operating log books of the generating station shall be available for review by the State Load Dispatch Centre. These books keep record of machine operation and maintenance, reservoir level and spillway gate operation.

65. Metering and Accounting:

Metering arrangements, including installation, testing and operation and maintenance of meters and collection, transportation and processing of data required for accounting of energy exchanges and average frequency on 15 minute time block basis shall be organised by the State Transmission Utility/State Load Dispatch Centres. All concerned entities (in whose premises the special energy meters are installed), shall fully cooperate with the State Transmission Utility/State Load Dispatch Centre and extend the

necessary assistance by taking weekly meter readings and transmitting them to the State Load Dispatch Centre.

Further SLDC will forward the necessary data / schedules to regional level in line with regulations formulated by Central Electricity Regulatory Commission. UI accounting procedures shall be governed by the orders of the Commission.

66. Billing and Payment of Capacity Charges: Billing and payment of capacity charges shall be done on a monthly basis in the following manner:

- (i) Each beneficiary shall pay the capacity charges in proportion to its percentage share in total saleable capacity of the generating station. Saleable capacity shall mean total capacity minus free capacity to the state, if any.
- (ii) The beneficiaries could be the present SEB continuing or the various distribution licensees or the trading companies. As per the Transfer Scheme, for GEB successor entities, the Board shall continue to be the beneficiary.
- (iii) If any capacity remains un-requisitioned during day-to-day operation, the State Load Dispatch Centre shall advise all beneficiaries in the region and the other State Load Dispatch Centres so that such capacity may be requisitioned through bilateral arrangements either with the concerned generating company or the concerned beneficiary(ies) under intimation to the State Load Dispatch Centre.

The information regarding un-requisitioned capacity shall also be made available by the State Load Dispatch Centres through their respective websites.

- (iv) The capacity charges shall be paid by the beneficiary(ies) including those outside the region to the generating company every month in accordance with the following formulas and in proportion to their respective shares in the concerned generating station:

$$ACC_1 = AFC - (SPE_1 + DE_{2nd\ to\ 12th\ months}) * Primary\ Energy\ Rate$$

$$ACC_2 = AFC - (SPE_2 + DE_{3rd\ to\ 12th\ months}) * Primary\ Energy\ Rate$$

$$ACC_3 = AFC - (SPE_3 + DE_{4th\ to\ 12th\ months}) * Primary\ Energy\ Rate$$

$$ACC_4 = AFC - (SPE_4 + DE_{5th\ to\ 12th\ months}) * Primary\ Energy\ Rate$$

$$\begin{aligned} \text{ACC}_5 &= \text{AFC} - (\text{SPE}_5 + \text{DE}_{6\text{th to 12th months}}) * \text{Primary Energy Rate} \\ \text{ACC}_6 &= \text{AFC} - (\text{SPE}_6 + \text{DE}_{7\text{th to 12th months}}) * \text{Primary Energy Rate} \\ \text{ACC}_7 &= \text{AFC} - (\text{SPE}_7 + \text{DE}_{8\text{th to 12th months}}) * \text{Primary Energy Rate} \\ \text{ACC}_8 &= \text{AFC} - (\text{SPE}_8 + \text{DE}_{9\text{th to 12th months}}) * \text{Primary Energy Rate} \\ \text{ACC}_9 &= \text{AFC} - (\text{SPE}_9 + \text{DE}_{10\text{th to 12th months}}) * \text{Primary Energy Rate} \\ \text{ACC}_{10} &= \text{AFC} - (\text{SPE}_{10} + \text{DE}_{11\text{th to 12th months}}) * \text{Primary Energy Rate} \\ \text{ACC}_{11} &= \text{AFC} - (\text{SPE}_{11} + \text{DE}_{12\text{th month}}) * \text{Primary Energy Rate} \\ \text{ACC}_{12} &= (\text{AFC} - \text{SPE}_{12}) * \text{Primary Energy Rate} \end{aligned}$$

Where,

AFC = Annual Fixed Charges

ACC₁, ACC₂, ACC₃, ACC₄, ACC₅, ACC₆, ACC₇, ACC₈, ACC₉, ACC₁₀, ACC₁₁ and ACC₁₂ are the amount of Annual Capacity Charge for the cumulative period up to the end of 1st, 2nd, 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th months respectively.

SPE₁, SPE₂, SPE₃,..... SPE₁₂ are the ex-bus scheduled primary energy values up to 1st, 2nd, 3rd12th months of the year respectively.

$$\begin{aligned} \text{CC1} &= \text{ACC}_1 \times \frac{\text{DE1}}{\text{DE}} \\ \text{CC2} &= \text{ACC}_2 \times \frac{\text{DE2}}{\text{DE}} \\ \text{CC3} &= \text{ACC}_3 \times \frac{\text{DE3}}{\text{DE}} \\ \text{CC4} &= \text{ACC}_4 \times \frac{\text{DE4}}{\text{DE}} \\ \text{CC5} &= \text{ACC}_5 \times \frac{\text{DE5}}{\text{DE}} \\ \text{CC6} &= \text{ACC}_6 \times \frac{\text{DE6}}{\text{DE}} \\ \text{CC7} &= \text{ACC}_7 \times \frac{\text{DE7}}{\text{DE}} \\ \text{CC8} &= \text{ACC}_8 \times \frac{\text{DE8}}{\text{DE}} \end{aligned}$$

$$\begin{aligned} & \text{DE} \\ \text{CC9} & = \text{ACC}_9 \times \underline{\text{DE9}} \\ & \text{DE} \\ \text{CC10} & = \text{ACC}_{10} \times \underline{\text{DE10}} \\ & \text{DE} \\ \text{CC11} & = \text{ACC}_{11} \times \underline{\text{DE11}} \\ & \text{DE} \\ \text{CC12} & = \text{ACC}_{12} \times \underline{\text{DE12}} \\ & \text{DE} \end{aligned}$$

Where,

CC1, CC2, CC3,.....CC12 is the monthly capacity charge up to 1st, 2nd, 3rd12th months of the year respectively.

DE = Annual Design Energy

DE1, DE2, DE3,DE12 are the ex-bus design energy values up to 1st, 2nd, 3rd12th months of the year respectively.

Total capacity charges payable to the generator for the:

$$\begin{aligned} 1^{\text{st}} \text{ month} & = (\text{CC1}) \\ 2^{\text{nd}} \text{ month} & = (\text{CC2} - \text{CC1}) \\ 3^{\text{rd}} \text{ month} & = (\text{CC3} - \text{CC2}) \\ 4^{\text{th}} \text{ month} & = (\text{CC4} - \text{CC3}) \\ 5^{\text{th}} \text{ month} & = (\text{CC5} - \text{CC4}) \\ 6^{\text{th}} \text{ month} & = (\text{CC6} - \text{CC5}) \\ 7^{\text{th}} \text{ month} & = (\text{CC7} - \text{CC6}) \\ 8^{\text{th}} \text{ month} & = (\text{CC8} - \text{CC7}) \\ 9^{\text{th}} \text{ month} & = (\text{CC9} - \text{CC8}) \\ 10^{\text{th}} \text{ month} & = (\text{CC10} - \text{CC9}) \\ 11^{\text{th}} \text{ month} & = (\text{CC11} - \text{CC10}) \\ 12^{\text{th}} \text{ month} & = (\text{CC12} - \text{CC11}) \end{aligned}$$

and, each beneficiary having firm allocation in capacity of the generating station shall pay for the :

$$1^{\text{st}} \text{ month} = [\text{CC1} \times \text{WB1}] / 100$$

$$2^{\text{nd}} \text{ month} = [\text{CC2} \times \text{WB2} - \text{CC1} \times \text{WB1}] / 100$$

$$3^{\text{rd}} \text{ month} = (\text{CC3} \times \text{WB3} - \text{CC2} \times \text{WB2}) / 100$$

$$4^{\text{th}} \text{ month} = (\text{CC4} \times \text{WB4} - \text{CC3} \times \text{WB3}) / 100$$

$$5^{\text{th}} \text{ month} = (\text{CC5} \times \text{WB5} - \text{CC4} \times \text{WB4}) / 100$$

$$6^{\text{th}} \text{ month} = (\text{CC6} \times \text{WB6} - \text{CC5} \times \text{WB5}) / 100$$

$$7^{\text{th}} \text{ month} = (\text{CC7} \times \text{WB7} - \text{CC6} \times \text{WB6}) / 100$$

$$8^{\text{th}} \text{ month} = (\text{CC8} \times \text{WB8} - \text{CC7} \times \text{WB7}) / 100$$

$$9^{\text{th}} \text{ month} = (\text{CC9} \times \text{WB9} - \text{CC8} \times \text{WB8}) / 100$$

$$10^{\text{th}} \text{ month} = (\text{CC10} \times \text{WB10} - \text{CC9} \times \text{WB9}) / 100$$

$$11^{\text{th}} \text{ month} = (\text{CC11} \times \text{WB11} - \text{CC10} \times \text{WB10}) / 100$$

$$12^{\text{th}} \text{ month} = (\text{CC12} \times \text{WB12} - \text{CC11} \times \text{WB11}) / 100$$

Where,

And, WB1, WB2, WB3, WB4, WB5, WB6, WB7, WB8, WB9, WB10, WB11 and WB12 are the weighted average of percentage allocated capacity share of the beneficiary during the cumulative period up to 1st, 2nd, 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th month respectively.

CHAPTER VI

Transmission Tariff

67. Application for determination of tariff

The STU / Transmission Licensee shall make application for determination of transmission tariff in the manner indicated in regulation 6 along with Aggregate Revenue Requirement.

68. Norms of operation

The norms of operation of transmission system subject to modification thereof from time to time shall be as under:

(a) Auxiliary Power consumption in the sub-station

The charges for auxiliary consumption in the sub-station for the purpose of air conditioning, lighting, technical consumption, etc.

shall be considered as part of its normative operation and maintenance expenses.

(b) Target availability for recovery of full transmission charges

The normative availability of transmission system shall be 98%.

(c) Operation and maintenance expenses

The operation and maintenance expenditure for the base year (i.e.) for the current year for which tariff is applied for, shall be computed based on actuals for the previous 5 years any abnormal O & M expenses during these periods, if any will have to be excluded. The O & M charges computed for the base year shall be escalated at 4%. In respect of the transmission system declared under commercial operation on or after notification of these regulations the base operation and maintenance expenses shall be fixed at 1% of the capital cost (as admitted by the Commission), in the year of commissioning and shall be subject to an annual escalation of 4% per annum for the subsequent years.

69. Norms for Working Capital

Working Capital shall cover:

- (a) Operation and Maintenance Expenses for one month;
- (b) Maintenance spares @ 1% of the historical cost of the transmission asset;
- (c) Receivables equivalent to two months transmission charges calculated on target availability level.

70. Transmission Tariff Charges

The tariff for transmission of electricity by a transmission system shall comprise recovery of annual transmission charges consisting of the following computed as per the principles outlined in Chapter III of these Regulations.

- (i) Interest on Loan Capital;
- (ii) Depreciation including Advance Against Depreciation;
- (iii) Operation and Maintenance Expenses;
- (iv) Return on equity; and
- (v) Interest on Working Capital at normative availability power:

The annual transmission charges computed as per this regulation shall be total annual revenue requirement of the STU / Transmission Licensee. The following shall be deducted from the total revenue requirement.

- (a) Transmission charges collected from the short term intra state open access consumers, captive power plant and generating stations using Non Conventional Energy Sources.
- (b) Income from other business to the extent of portion to be passed on to the beneficiaries.
- (c) Reactive Energy Charges and Transmission charges received from CTU for use of facilities of the licensee / STU

Till such time a common transmission tariff is evolved to maintain consistency in transmission pricing framework in inter state and in the state transmission system the monthly transmission charges payable by the Distribution Licensees and other long term intra state open access consumers shall be based on the capacity allocated to each beneficiaries as detailed below:

$$\sum \frac{TC}{12} - (a + b + c) \times \frac{CL}{SCL}$$

- Where TC = Annual Transmission Charges
- a = Total transmission charges by the short term open access consumers
 - b = Income from other business to the extent of portion to be passed on to the beneficiaries.
 - c = Reactive Energy Charges and Transmission charges received from CTU for use of facilities of the licensee / STU
 - CL = Allotted capacity to the long term transmission customers
 - SCL = Sum of allocated Transmission capacity to all the long term transmission customers of the intra state transmission system.

The transmission charges shall be determined after following the procedure outlined in chapter II.

71. Variable Charges

The transmission loss shall be allocated to the users of the transmission system in proportion to the energy drawn through the system. .

72. Payment of transmission charges

Full annual transmission charges shall be recoverable at the target availability of 98%. Payment of transmission charges below the target availability shall be on prorata basis.

73. Unbundling Transmission Charges

- (1) The transmission licensee / STU shall endeavour to maintain separate function wise accounts for transmission system and furnish the revenue requirement line wise, bay wise and for load dispatch centerwise.
- (2) The tariff for the transmission services shall be unbundled to reflect the cost of various activities associated with provision of transmission service once the data as per clause (1) are made available
- (3) The components of transmission tariff are:

a. Charges for use of network

This component of transmission tariff shall be distance sensitive and would reflect cost of capital investment in and maintenance and operation of, a transmission system to transfer bulk power to and from different locations. The revenue from this component of transmission tariff will meet the annual revenue requirement of transmission entity in respect of owning the transmission asset. The charges for use of network would be worked out on distance slabs to reflect the distance travelled by the energy transmitted.

b. System Operation Charges

This component of transmission tariff shall reflect the cost associated with operating the load dispatch center. The cost, among other things, shall include the cost of owning and maintaining load dispatch center. This system operation charges shall be charged as SLDC charges to users of such services, based on total energy of transactions.

c. Reactive Power Charges

This component of transmission charges would be a variable charge reflecting voltage related drawal of reactive power. Reactive power drawals by beneficiaries are to be priced as follows

- i. The beneficiary pays for reactive power drawal when voltage at the metering point is below 97%
- ii. The beneficiary gets paid for reactive power return when voltage is below 97%
- iii. The beneficiary gets paid for reactive power drawal when voltage is above 103%
- iv. The beneficiary pays for reactive power return when voltage is above 103%
- v. The charges for reactive energy shall be as decided by the Commission.

74. Incentive

The Transmission Licensee shall be entitled to incentive @ 1% of equity for each percentage point of increase in annual availability beyond the target availability prescribed under regulation 60 (b) in accordance with the following formula.

$$\text{Incentive} = \text{Equity} \times (\text{Annual Availability achieved} - \text{Target availability}) / 100$$

The incentive shall be shared by the long term customers in the ratio of their average allotted capacity.

75. Rebate

For payment of bills of transmission charge through Letter of Credit on presentation, a rebate of 2% shall be allowed. Where payments are made within a period of one month of presentation of bills by the Transmission Licensee a rebate of 1% shall be allowed.

76. Late Payment Surcharge

In case the payment of bills of the transmission charges by the beneficiary or beneficiaries is delayed beyond a period of 60 days from the

date of billing, late payment surcharge at the rate of 1.25% per month shall be levied by the Transmission Licensee.

77. Transmission Charges for Open Access

Under clause (d) of sub-section (7) of section 39 of the Act, the STU / Transmission Licensee shall provide non-discriminatory open access for use by other Licensee, Generating Company or any consumer on payment of transmission charges.

This transmission charges payable for use of the facility under open access shall be as per Regulation 62 with reference to the capacity permitted to be used.

78. Surcharge

The consumer who uses the transmission system under open access is liable to pay a surcharge in addition to the transmission charges.

79. Principle for computing the surcharge

- (1) In case a consumer / person who is in the area of local distribution licensee with consumers contributing cross subsidy for subsidising the tariff to other category of consumer opts to procure power from other sources / other Distribution Licensee, he shall pay surcharge to compensate the cross-subsidy to the existing Distribution Licensee in addition to the transmission / wheeling charges.
- (2) The amount of such surcharge shall be based on the quantum of cross subsidy that is being contributed under the existing Distribution Licensee.
- (3) The cross subsidy component shall be determined by the Commission based on the tariff to the category of the consumer, the cost to serve etc..
- (4) The quantum of surcharge recoverable shall be as per the TNERC Open Access Regulations.
- (5) The surcharge collected shall be utilised to meet the current level of cross subsidy.
- (6) The surcharge shall be collected till the cross subsidy is eliminated.

- (7) Surcharge shall not be collected in case of open access provided to captive power plants for carrying the power to the destination for their own use.

CHAPTER VII

Tariff for Distribution Licensees

80. Component of tariff for supply of electricity

- (1) The charges for the electricity supplied by the Distribution Licensee may include:-
- (a) a fixed charges / Demand Charges;
 - (b) Charges for actual electricity supplied;
 - (c) a rent or other charge in respect of electro meter or electrical plant provided by the Distribution Licensee;
- (2) Rent for meter provided by the Licensee and other charges are treated as non-tariff charges and shall be determined by the Commission in accordance with the provision of TNE Supply Code and Distribution Code.
- (3) Charges for actual electricity supplied and fixed charges are tariff related charges and the Commission shall determine these charges on an application from the Distribution Licensee.

81. Application for determination of tariff

- (1) The Distribution Licensee shall file application for determination of tariff for retail distribution of electricity along with ARR in accordance with the procedure outlined in regulation 6.
- (2) The application for determination of tariff by the Distribution Licensee shall be accompanied with following information besides Aggregate Annual Revenue Requirement:-
- (a) A statement showing current tariff and applicable terms and conditions of tariff.
 - (b) A statement showing Demand / Sales projection for different categories of consumers including slabwise consumption with a

note on the method adopted to arrive at the projected growth rate.

- (c) The Distribution Licensee shall furnish the energy requirement detail with Aggregate Technical and Commercial loss and sources of procurement of power.
- (d) A statement containing detail of expected revenue at the current tariff for the ensuing year or the period for which tariff is to be determined and revenue gap, if any to be matched with additional revenue from revised tariff.
- (e) A statement showing cost to serve each category of consumer at different voltage level with the allocation of T & D loss and consumer wise cross subsidy at the existing tariff.
- (f) A statement showing the subsidy received / receivable from Government at the existing tariff.
- (g) A statement showing the changes in tariff proposed for each category of consumer and the estimated revenue at the revised tariff.
- (h) A statement showing cross subsidy at revised tariff and subsidy committed by the Government, if any.
- (i) Any other information that the Commission may require.

82. The Aggregate Revenue Requirement of Distribution Licensee

- (1) The Aggregate Revenue Requirement of Distribution Licensee consists of the following:-
 - (i) Cost of Power Purchase
 - (ii) Operation and Maintenance expenses
 - (iii) Depreciation including Advance Against Depreciation
 - (iv) Interest and cost of finance
 - (v) Income Tax
 - (vi) Provision for Bad & Doubtful Debts
 - (vii) Provision for Insurance
 - (viii) Provision for contingency reserve
 - (ix) other expenses
 - (x) Return on equity / Reasonable rate of return

(2) Sales Forecast

- (i) The accurate projection of category-wise sales is very essential for the assessment of energy input requirement so as to determine the quantum of generation and quantum of energy to be purchased for the correct assessment of revenue requirement for generation and power purchase.
- (ii) The Utility / Distribution Licensee shall formulate the long term demand forecast as stipulated in sub-clause (4) of clause 6 of the TNE Distribution Code and get the forecast approved by the Commission.
- (iii) The Licensee may adopt a suitable methodology like CAGR to arrive at the category wise sales for the base year i.e. for the current year.
- (iv) The Licensee shall forecast demand and sale of electricity for different categories of consumers in his area of supply for ensuing year, and for a period of 3 years taking into account the long term demand forecast already approved and also subsequent changes in situation, if any. Wherever different rates are proposed for different slabs of consumption, forecast for slabwise consumption shall also be furnished.
- (v) The Commission shall examine the forecast for reasonableness based on growth in number of consumers and consumption of electricity in the previous years and anticipated growth in the next year and any other factor that the Commission may consider relevant and approve sale of electricity to consumers with such modification as deemed fit.
- (vi) The Licensee shall also furnish the categorywise open access consumers and the demand and energy wheeled for them. The details may be furnished separately for the supply within the area of the Distribution Licensee and to the supply outside the area of supply of the Distribution Licensee.
- (vii) The details of bulk supply of electricity, if any to electricity traders may also be furnished.

83. Monitoring of sale of electricity to consumers

- (1) On the basis of approved sale forecast, the Licensee shall work out the monthly sales requirement to different categories of consumers taking into account the seasonal variation in demand during the year.
- (2) The Licensee shall monitor sales to different consumer categories and ensure that sales to any category are not unduly restricted.
- (3) The Licensee shall make necessary arrangement to capture the data every month and furnish monthly reports to the Commission comparing the actual sale for the month with the forecast for the month and reasons for wide variation if any.
- (4) The Licensee shall get approval of the Commission for any extraordinary variation in sales in any month.

84. Transmission and Distribution Loss

- (1) The Distribution Licensee shall have proper metering arrangements for accurate measurement of transmission loss.
- (2) Appropriate sample study with the approval of the Commission shall be conducted to estimate the consumption in unmetered services so that distribution losses are estimated fairly accurate
- (3) The Licensee shall compute and furnish loss levels at every supply voltage level.
- (4) The Distribution Licensee shall furnish the T & D losses during the previous year and the proposed target for the Current and Ensuing Year as well as for the next three years with the details of measures proposed to achieve the target in each year.
- (5) The Commission shall fix target for reduction of losses in the next three years.

85. Estimate of Energy input requirement

- (1) The Distribution Licensee shall compute the quantum of energy to meet the estimated sales after the loss levels are arrived at and taking into account, the generation and auxiliary consumption in Distribution Licensees own generating stations at normative PLF levels.

- (2) The Commission shall scrutinise and approve the power purchase requirement with some modification as deemed fit for the tariff period and ensuing year.

86. Cost of Power Purchase

- (1) The Distribution Licensee shall procure power on least cost basis and strictly on merit order despatch and shall have flexibility to procure power from any source in the country.

A two-part tariff structure shall be adopted for all long term contracts to facilitate merit order dispatch.

- (2) They shall procure power through arrangement other than long term contracts progressively in an increasing proportion.
- (3) The cost of power purchased from Central Generating Company shall be worked out based on tariff determined by the Central Electricity Regulatory Commission.
- (4) The cost of power purchased from IPPs shall be considered based on Power Purchase Agreement.
- (5) In case of power purchased from Captive Generators and other non conventional energy sources, the cost shall be worked out as per the policy approved by the Commission.
- (6) The cost of power generated in the Generating Companies / Units owned by the Licensee shall be worked out based on the transfer price determined by the Commission.
- (7) In case of short term power shortage, the Licensee may procure power from any source at a tariff not exceeding the highest rate approved by the Commission.
- (8) All power purchases shall be made under tariff based bidding following the guidelines issued except in cases where tariff based bidding may not be cost defective.

87. Variation in Power Purchase

- (1) Any financial loss or gain on account of variation in quantum of power purchase for the reasons beyond the control of the Licensees like charges in thermal – hydro mix due to natural calamities shall be

allowed to be carried forward and adjusted in the next years revenue requirement and tariff allowed accordingly.

- (2) Any financial gain / loss on account of variation in power purchase not covered under sub clause (1) above shall be to the account of the licensee in the year itself.

88. Transmission Charges

The transmission and wheeling charges payable by the Distribution Licensees to the CTU and STU shall be considered as expenses and included in the power purchase cost.

89. SLDC Charges

SLDC charges if paid separately in addition to charges for usage of Network (instead of bundled transmission charges) shall be considered as expenses and included in power purchase cost for the purpose of determination of tariff.

90. Operation and Maintenance expenses

The O & M expenses for the base year may be fixed on the basis of average increase in the past 2 years for which audited accounts are made available and for the ensuing years with the same rate of increase. Where the Commission desires to fix multi year tariff, a formula based on CPI and WPI shall be prescribed.

91. Norms for working capital

- (i) Operation and Maintenance expenses for one month
- (ii) Maintenance spares for 2 months based on annual requirement considered at 1% of the gross fixed cost at the beginning of the year.
- (iii) Receivable equivalent to 60 days consumption charges.

92. Interest and Finance Charges

The expenses on interest for purpose of annual revenue requirement of the Distribution Licensee shall include interest payable on Security Deposit received from the consumer.

93. Annual Revenue Requirement

- (1) The total annual expenses and return for the year referred in Regulation 82 shall be worked out based on guidelines in chapter III of these regulations.
- (2) The total annual revenue requirement of the Licensee shall be worked out by deducting the following from the total expenses:
 - (i) Amount of other income as per regulation 80.2.
 - (ii) Income from surcharge and additional surcharge from open access conditions.
 - (iii) Wheeling charges recovered from the open access consumers
 - (iv) Authorised portion of Income from other business engaged by the Licensees for optimum utilisation of assets.
 - (v) Any revenue grant received from Government (other than subsidy)

94. Determination of tariff

The Commission shall determine the tariff for supply of electricity by the Distribution Licensee to meet the annual revenue requirement into after following the procedure mentioned in Chapter II of these Regulations.

95. Tariff Income

Income from supply of electricity to consumers shall be assessed based on the tariff applicable to different category of consumers and the quantity of electricity estimated to be sold to them.

96. Profit sharing

In case, the Licensee recover more income than its annual revenue requirement in any year, the Commission may allow the Licensee to treat the profit beyond the approved reasonable return, in the following manner:-

- (i) One third of the amount may be retained by the Licensee to be treated as part of equity or may be paid as dividend to the shareholders.
- (ii) One-third amount may be passed on to the consumers by way of reduction in to revenue requirement for the next year. In case the Distribution Licensee seeks for tariff revision after a gap of

more than one year, one third of all the incremental earnings, during such period shall be reduced from future annual revenue requirement.

- (iii) One third amount may be kept as tariff balance reserve to be used for reducing ARR in future years.

97. Cost of supply to various categories of consumers

- (1) The Licensee shall conduct a study to prepare a model to work out voltage level cost to serve each category of consumer and furnish the details to the Commission.
- (2) The Licensee shall furnish the details along with the tariff application as required in regulation 81.2 and also along with Annual Accounts.
- (3) The Commission shall consider and approve the cost to serve with modifications if any required.
- (4) The cost to serve a category to consumer and realisation of revenue at the tariff from each category of consumer shall form the basis for estimating the cross subsidy.

98. Cross subsidy, reduction and elimination

- (1) The difference between the cost to serve and the revenue realized from the consumer category at the approved tariff level is the cross subsidy. The consumer paying more than the cost to serve is subsidizing consumer and the consumer paying less than the cost to serve is the subsidized consumer.
- (2) The Commission may endeavour to hold the tariff of the subsidising categories at the nominal rates until the tariff to subsidized categories approaches the cost to serve such categories
- (3) The Commission may endeavour to reduce and eliminate the gross subsidy progressively and the licensee shall prepare a road map towards this object and get it approved.
- (4) In view of the necessity to make electricity affordable for households of very poor category, the domestic consumers including hut dwellers consuming 30 kWh per month may be designated as lifeline categories

requiring minimum level of supply. The tariff for such category may be pegged at 50% of the cost to serve domestic consumers.

- (5) However, if the Government requires grant of any subsidy to any consumer or class of consumers in the tariff determined by the Commission, the State Government shall pay the amount to compensate the Licensee in advance as may be ordered by the Commission.

99. Wheeling Charges

- (1) The Distribution Licensee shall provide open access to any consumer within the area of the supply on payment of wheeling charges.
- (2) The wheeling charges for a consumer category shall be based on costs of Distribution Licensee for its pure "wire business". Thus all items of revenue requirement of the Distribution Licensee excluding cost of power purchase and interest on Security Deposit from consumers shall be the cost of Distribution Licensee for his wire business.
- (3) The wheeling charges shall be computed taking into account the projected units sold and wheeled (input and quantity) through Distribution Licensee and with in the ensuing tariff period.
- (4) The normative distribution system loss at the voltage at which the open access transaction is undertaken shall be borne by the consumer in kind.

100. Surcharge

- (1) Till such time the cross subsidy is eliminated, the open access consumer shall pay surcharge in addition to the wheeling charges.
- (2) The surcharge shall be computed as per Regulation 79.

101. Additional Surcharge

When the Commission permits a consumer or class of consumers to receive supply of electricity from a person other than the Distribution Licensee of his area of supply, such consumer shall pay additional surcharge to meet the fixed charges.

CHAPTER VIII MISCELLANEOUS

102. Power to remove difficulty

If any difficulty arises in giving effect to any of the regulation, the Commission, may, of its own motion or otherwise, by an order and after giving a reasonable opportunity to those likely to be affected by such order, make such provisions, not inconsistent with these regulations, as may appear to be necessary for removing difficulties.

103. Power to relax / amend

The Commission, for reasons to be recorded in writing, may vary, amend any of the provisions of these Regulations on its own motion or an application made before it by the Commission.

104. Review of Regulations

The Commission shall undertake the comprehensive review of these regulations and the norms prescribed herein with the object of analyzing implementation of long-term principles and making modifications or improvement in the principles, procedures and methodologies.

Annexure

DEPRECIATION SCHEDULE
(Referred to in Regulation 24 (ii))

Description of Assets	Revised	
	Fair Life (Years)	Depreciation (Straight Line)
A. Land owned under full title	Infinity	
B. Land held under lease		
(a) For investment in the land	The period of lease or the period remaining unexpired on the assignment of the lease	
(b) For cost of clearing site	The period of lease remaining unexpired at the date of clearing site.	
C. Assets purchased new		
(a) Plant and machinery in generating stations including plant foundations		
(i) Hydro-electric	35	3.40
(ii) Steam-electric NHRS & Waste Heat Recovery Boilers/Plants	25	7.84
(iii) Diesel-electric & gas plant	15	8.24
(b) Cooling towers and circulating water systems	25	7.84
(c) Hydraulic works forming part of hydro-electric system including:-		
(i) Dams, Spilways weirs, canals reinforced concrete flumes & syphons	50	1.95
ii) Reinforced concrete pipelines and surge tanks, steel pipelines, sluice gates, steel surge (tanks) hydraulic control valves and other hydraulic works.	35	3.40
(d) Building & civil engineering works of a permanent character, not mentioned above:-		
(i) Offices & showrooms	50	3.02
(ii) Containing thermo-electric generating plant	25	7.84
iii) Containing hydro-electric generating plant	35	3.40
(iv) Temporary erection such as wooden structures	5	33.40
(v) Roads other than kutchra roads	50	3.02
(vi) Others	50	3.02
(e) Transformers, transformer (Kiosk) sub-station equipment & other fixed apparatus (including plant foundations)		
(i) Transformers (including foundations) having a rating of 100 kilo volt amperes and over	25	7.84

Description of Assets	Revised	
	Fair Life (Years)	Depreciation (Straight Line)
(ii)Others	25	7.84
(f) Switchgear, including cable connections	25	7.84
(g) Lightning arrestors:		
(i) Station type	25	7.84
(ii) Pole type	15	12.7
(iii) Synchronous condensor	35	5.27
(h) Batteries:	5	33.40
(i) Underground Cable including joint boxes and disconnected boxes	35	5.27
(ii) Cable duct system	50	3.02
(l) Overhead lines including supports:		
(l) Lines on fabricated steel operating at nominal voltages higher than 66 KV	35	5.27
(ii) Lines on steel supports operating at nominal voltages higher than 13.2 kilo volts but not exceeding 66 kilo volts	25	7.84
(iii) Lines on steel or reinforced concrete supports	25	7.84
(iv) Lines on treated wood supports	25	7.84
(j) Meters	15	12.77
(k) Self propelled vehicles	15	33.40
(l) Air conditioning plants:		
(i) Static	15	12.77
(ii) Portable	5	33.40
(m) (i) Office furniture and fittings	15	12.77
(ii) Office equipments:	15	12.77
(iii) Internal wiring including fittings and apparatus	15	12.77
(iv) Street light fittings	15	12.77
(o) Apparatus let on hire:		
(i) Other than motors	5	33.40
(ii) Motors	15	12.77
(p) Communication equipment:		
(i) Radio and higher frequency carrier system	15	12.77
(ii) Telephone lines and telephones	15	12.77
(q) Assets purchased second hand and assets not otherwise provided for in the schedule.	Such reasonable period as the competent Government determines in each case having regard to the nature, age and condition of the assets at the time of its acquisition by the owner.	