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## TRIPURA ELECTRICITY REGULATORY COMMISSION

No.F.25/TERC/239

Dated 16<sup>th</sup> Oct' 2015

### NOTIFICATION

In exercise of powers conferred under Sub-Section (1) of section 181 and clauses (zd), (ze) and(zf) of sub section (2) of section 181, read with sections 61, 62, and 86, of the Electricity Act 2003) and all other powers enabling it in that behalf along with relevant provisions of The National Electricity Policy and Tariff Policy notified by central government, the Tripura Electricity Regulatory Commission hereby makes the following Regulations.

### CHAPTER - 1-PRELIMINARY

#### 1. Short title and commencement.

- I. These regulations shall be called the Tripura Electricity Regulatory Commission Tariff Regulations (**Multi Year Tariff**), 2015.
- II. These regulations shall come into force from the date of their publication in the Official Gazette, and unless reviewed earlier or extended by the Commission, shall remain in force for a period of 5 years from the date of publication or until notification of the revised Regulations whichever is later.
- III. Provided that where a project or a part thereof, has been declared under commercial operation before the date of commencement of these regulations and whose tariff has not been finally determined by the Commission till that date, tariff in respect of such project or such part thereof for the period ending prior to publication of this regulation shall be determined in accordance with the Tripura Electricity Regulatory Commission (Tariff Regulation 2004) as amended from time to time.

#### 2. Scope and extent of application.

These regulations shall apply in all cases where tariff for a generating station or a

- I. unit thereof and a transmission system or an element thereof including communication system used for State transmission of electricity is required to be determined by the Commission under section 62 of the Act read with section 86 thereof.
- II. Further these regulations shall apply for determination of wheeling Tariff and Retail Supply tariff of distribution licensee for multiyear and one year also
- III. These regulations shall not apply for determination of tariff in case of the following:
  - i. Generating stations or transmission systems whose tariff has been discovered through tariff based competitive bidding in accordance with the guidelines issued by the Central/state Government and adopted by the Commission under Section 63 of the Act;
  - ii. Generating stations based on renewable sources of energy whose tariff is determined in accordance with the Tripura Electricity Regulatory Commission (Procurement of Energy from Renewable Sources) Regulations, 2010, as amended from time to time or any subsequent enactment thereof.

### **3. Definitions and Interpretations.-**

In these regulations, unless the context otherwise requires-

(1) ‘**ABT**’ means Availability Based Tariff;

(2) ‘**Act**’ means the Electricity Act, 2003 (36 of 2003);

(3) ‘**Additional Capitalization**’ means the capital expenditure incurred, or projected to be incurred after the date of commercial operation of the project and admitted by the Commission after prudence check, in accordance with provisions of Regulation 16 of these regulations;

(4) “**Applicant**” means a Generating Company or Transmission Licensee or Distribution Licensee who has made an application for determination of Annual Revenue Requirement and Tariff in accordance with the Act and these Regulations and includes a Generating Company or Transmission Licensee or Distribution Licensee whose tariff is the subject of a review by the Commission either on suo-motu basis or on a Petition

(5) “**Aggregate Revenue Requirement**” or “**ARR**” means the costs pertaining to the licensed business which are permitted, in accordance with these regulations, to be recovered from the tariffs and charges determined by the Commission;

**(6) 'Auxiliary Energy Consumption' or 'AUX'** in relation to a period in case of a generating station means the quantum of energy consumed by auxiliary equipment of the generating station, such as the equipment being used for the purpose of operating plant and machinery including switchyard of the generating station and the transformer losses within the generating station, expressed as a percentage of the sum of gross energy generated at the generator terminals of all the units of the generating station:

Provided that auxiliary energy consumption shall not include energy consumed for supply of power to housing colony and other facilities at the generating station and the power consumed for construction works at the generating station;

**(7) "Availability"** in relation to a thermal Generating Station for any period means the average of the daily average declared capacities as certified by State/Regional Load Despatch Centre (SLDC/RLDC) 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, as specified in these Regulations, and shall be computed in accordance with the following formula:

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

Where:

N = number of time blocks in the given period

DC<sub>i</sub> = Average Declared Capacity in MW for the i<sup>th</sup> time block in such period

IC = Installed Capacity of the Generating Station in MW

AUX = Normative Auxiliary Consumption in MW, expressed as a percentage of gross generation

**(8) 'Auditor'** means an auditor appointed by a generating company or a transmission licensee or a Distribution/Supply Licensee, as the case may be, in accordance with the provisions of the Companies Act, 1956 (1 of 1956)], as amended from time to time or Chapter X of the Companies Act, 2013 or any other law for the time being in force;

**(9) "Base Year"** means the financial year immediately preceding first year of the control period and used for the purposes of these regulations;

**(10) "Bank Rate"** means the base rate of interest as specified by the State Bank of India from time to time or any replacement thereof for the time being in effect;

**(11) "Beneficiary"** in relation to a Generating Station means the purchaser of electricity generated at such a Generating Station whose tariff is determined under these Regulations;

(12) **“Beneficiary”** in relation to transmission business means the person who has contracted the transmission capacity on payment of transmission charges.

(13) **“Block”** in relation to a combined cycle thermal generating station includes combustion turbine-generator, associated waste heat recovery boiler, connected steam turbine- generator and auxiliaries;

(14) **“Bulk Power Transmission Agreement”** means an executed Agreement that contains the terms and conditions under which a Transmission System User is entitled to access an intra-State transmission system of a Transmission Licensee;

(15) **“Capacity Charges”** shall have the same meaning as defined in Clause 23(l) of these regulations;

(16) **“Capital Cost”** means the capital cost as determined in accordance with Chapter-4 of these regulations;

(17) **“Change In Law”** means occurrence of any of the following events:

- (a) enactment, bringing into effect or promulgation of any new Indian law; or
- (b) adoption, amendment, modification, repeal or re-enactment of any existing Indian law; or
- (c) change in interpretation or application of any Indian law by a competent court, Tribunal or Indian Governmental Instrumentality which is the final authority under law for such interpretation or application; or
- (d) change by any competent statutory authority in any condition or covenant of any consent or clearances or approval or licence available or obtained for the project; or
- (e) coming into force or change in any bilateral or multilateral agreement/treaty between the Government of India and any other Sovereign Government having implication for the generating station or the transmission system or the Distribution/Supply systems regulated under these Regulations.

(18) **“Commission”** means the Tripura Electricity Regulatory Commission;

(19) **“Communication System”** includes communication system of Power Grid Corporation of India Ltd. and State Transmission Utility covered under Unified Load Dispatch and Communication (ULD&C) scheme, SCADA (supervisory control and data acquisition), Wide Area Measurement (WAMS), Fibre Optic Communication system, Remote Terminal Unit, Private Automatic Branch Exchange, Radio Communication System and auxiliary power supply system etc. used for managing inter-state transmission of electricity;

(20) **“Competitive Bidding”** means a transparent process for procurement of equipment, services and works in which bids are invited by the project developer by open

advertisement covering the scope and specifications of the equipment, services and works required for the project, and the terms and conditions of the proposed contract as well as the criteria by which bids shall be evaluated, and shall include domestic competitive bidding and international competitive bidding;

**(21) “Conduct of Business Regulations”** means the Tripura Electricity Regulatory Commission (Conduct of Business) Regulations, 2004, and subsequent amendments thereof;

**(22) “Contracted Capacity”** means the capacity in MW contracted by long-term Transmission System User as part of its long term power procurement plan through a power purchase agreement and shall be equivalent to the deemed Transmission Capacity Right of a Transmission System User.

**(23) “Control Period”** means a multi-year period comprising of five financial years from the date of publication of this regulation on the Official Gazette and as may be extended by the Commission, for submission of forecast in accordance with these Regulations;

**(24) “Cross Subsidy”** is a mechanism whereby some consumers groups are charged a higher tariff as compared to the cost of supplying power to them. The additional revenue generated from them is used to tide over the revenue shortfall from other consumer groups, who are charged lesser tariff as compared to the cost of supplying power to them. Cross Subsidy shall be such that the tariff of consumer categories is within +/- 20% of the average cost of supply except for the consumers below the poverty line;

**(25) “Cut-off Date”** means 31st March of the year closing after two years of the year of commercial operation of whole or part of the project, and in case the whole or part of the project is declared under commercial operation in the last quarter of a year, the cutoff date shall be 31st March of the year closing after three years of the year of commercial operation:

Provided that the cut-off date may be extended by the Commission if it is proved on the basis of documentary evidence that the capitalization could not be made within the cut-off date for reasons beyond the control of the project developer;

**(26) “Date of Commercial Operation” or “COD”** shall have the same meaning as defined in Clause 4 of these regulations;

**(27) “Day”** means a calendar day consisting of 24 hours period starting at 0000 hour;

**(28) “Declared Capacity” or “DC”** in relation to a generating station means, the capability to deliver ex-bus electricity in MW declared by such generating station in relation to any time-block of the day as defined in the Grid Code or whole of the day, duly taking into account the availability of fuel or water, and subject to further qualification in the relevant regulation;

**Note:**

- I. 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.
- II. Declared capacity however shall be limited to Installed Capacity.
- III. Daily average declared capacity means the sum of capacity declared for every fifteen minutes block during the twenty four hour period divided by ninety six.
- IV. For hydro power Generating Stations, the ex-bus capacity in MW expected to be available from the Generating Station for the ith day of the month, which the station can deliver for at least three (3) hours, as certified by the Concerned Load Dispatch Centre after the day is over, taking into account the availability of water;

**(29) “De-capitalization”**for the purpose of the tariff under these regulations, means reduction in Gross Fixed Assets of the project corresponding to the removal/deletion of assets as admitted by the Commission;

**(30) “De-Commissioning”**means removal from service of a generating station or a unit thereof or transmission/Distribution/Supply system including communication system or element thereof, after it is certified by the Central Electricity Authority or any other authorized agency, either on its own or on an application made by the project developer or the beneficiaries or both, that the project cannot be operated due to non performance of the assets on account of technological obsolescence or uneconomic operation or a combination of these factors;

**(31) “Design Energy”**means the quantum of energy which can be generated in a 90% dependable year with 95% installed capacity of the hydro generating station;

**(32) “Distribution Retail Supply Business”** means the business of sale of electricity by a distribution licensee to the consumers within the area of supply in accordance with the terms of the licence for distribution and retail supply of electricity;

**(33) “Distribution Wheeling Business”** means the business of operating and maintaining a distribution system for wheeling of electricity in the area of supply of the Distribution Licensee;

**(34) “Element”**in respect of a transmission/distribution/supply system shall mean an asset which has been distinctively defined under the scope of the project in the Investment Approval;

**(35) “Energy meter”** means meters as defined by the Central Electricity Authority under the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time;

**(36) “Expected Revenue from Tariff and Charges”** means the revenue estimated to accrue to the Generating Company or Transmission Licensee or Distribution Licensee from the Regulated Business at the prevailing tariff;

**(37) “Existing Generating Unit/Station”** means a Generating Unit/ Station declared under commercial operation prior to the date of effectiveness of these Regulations;

**(38) “Existing Project”** means a project which has been declared under commercial operation on a date prior to the date of effectiveness of these Regulations;

**(39) “Expenditure Incurred”** means the fund, whether the equity or debt or both, actually deployed and paid in cash or cash equivalent, for creation or acquisition of a useful asset and does not include commitments or liabilities for which no payment has been released;

**(40) “Extended Life”** means the life of a generating station or unit thereof or transmission/distribution/supply system or element thereof beyond the period of useful life, as may be determined by the Commission on case to case basis;

**(41) “Financial Year”** means a period commencing on 1st April of a calendar year and ending on 31st March of the subsequent calendar year;

**(42) “Force Majeure”** for the purpose of these regulations means the event or circumstance or combination of events or circumstances including those stated below which partly or fully prevents the generating company or transmission/distribution/supply licensee or to complete the project within the time specified in the Investment Approval, and only if such events or circumstances are not within the control the generating company or transmission/distribution/supply licensee and could not have been avoided, had the generating company or transmission/distribution/supply licensee taken reasonable care or complied with prudent utility practices:

- a. Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or
- b. Any act of war, invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, terrorist or military action and civil disturbance;
- c. Strikes, lockouts, go-slow, bandh or other industrial disturbances not instigated by any party;
- d. Any shutdown or interruption of the grid, which is required or directed by the State or Central Government or by the Commission or the State/Regional Load Despatch Centre; and
- e. Any shut down or interruption, which is required to avoid serious and immediate risks of a significant plant or equipment failure.

**(43) Fuel and Power Purchase Price Adjustment (FPPPA)** shall have the same meaning as defined in TERC, Fuel and Power Purchase Price Adjustment Formula Regulation

,2011

**(44) “Gas-engine based Generating Station”** means generating station which generates power through reciprocating gas engines using natural gas or RLNG(Re-gasified Liquefied Natural Gas) as fuel.

**(45) “Generating Unit”**in relation to a thermal generating station (other than combined cycle thermal generating station) means steam generator, turbine-generator and auxiliaries, or in relation to a combined cycle thermal generating station, means turbine-generator and auxiliaries; and in relation to a hydro generating station means turbine-generator and its auxiliaries;

**(46) “Generation Business”** means the business of production of electricity from a Generating Station for the purpose of (i) giving supply to any premises or enabling a supply to be so given (ii) for the purpose of supply of electricity to any Distribution Licensee in accordance with the Act and the rules and regulations made thereunder and, (iii) subject to the Regulations

**(47) Gross Calorific Value” or “GCV”**in relation to a thermal generating station means the heat produced in kCal by complete combustion of one kilogram of solid fuel or one liter of liquid fuel or one standard cubic meter of gaseous fuel, as the case may be;

**(48) “Gross Station Heat Rate” or “GHR”**means the heat energy input in kCal required to generate one kWh of electrical energy at generator terminals of a thermal generating station;

**(49) “Generating Station”** means any station for generating electricity, including any building and plant with step-up transformer, switch-gear, switch yard, cables or other appurtenant equipment, if any, used for that purpose and the site thereof; a site intended to be used for a generating station, and any building used for housing the operating staff of a generating station, and where electricity is generated by water-power, includes penstocks, head and tail works, main and regulating reservoirs, dams and other hydraulic works, but does not in any case include any sub-station;

**(50) “Infirm Power”** means electricity injected into the grid prior to the commercial operation of a unit or block of the generating station in accordance with this Regulation, 2009 as amended from time to time;

**(51) “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 may be approved by the Commission from time to time;

**(52) “Implementation Agreement”**means the agreement, contract or memorandum of understanding, or any such covenant, entered into (i) between transmission licensee and generating station or (ii) between transmission/distribution/supply licensee and developer of the associated transmission/distribution/supply system for the execution of project in coordinated manner;



**(53) “Intra-State Transmission System (InSTS)”** means any system for conveyance of electricity by transmission lines within the area of the State and includes all transmission lines, sub-stations and associated equipment of Transmission Licensees in the State:

**(54) “Investment Approval”** means approval by the Board of the generating company or the transmission/distribution/supply licensee or Cabinet Committee on Economic Affairs (CCEA) or any other competent authority conveying administrative sanction for the project including funding of the project and the timeline for the implementation of the project.

Provided that the date of Investment Approval shall reckon from the date of the resolution/minutes of the Board/approval by competent authority.

**(55) “Kilowatt-Hour” or “kWh”** means a unit of electrical energy, measured in one kilowatt or one thousand watts of power produced or consumed over a period of one hour;

**(56) “Licence”** means a licence granted under section 14 of the Act;

**(57) “Licensed Business”** means the functions and activities, which the licensee is required to undertake in terms of the licence granted by the Commission or being a deemed licensee under the Act;

**(58) “Licensee”** means a person who has been granted a licence and shall include a deemed licensee;

**(59) “Load Factor”** is the ratio of the average power to the maximum demand. The load factor depends on the interval of time of the maximum demand and the period over which the average is taken.

$$\text{Load Factor} = \frac{\text{Units consumed in a given period}}{\text{Maximum demand} \times \text{No. of hours in the period}}$$

**(60) “Long-Term Transmission Customer”** means a person having a long term transmission service agreement with the transmission licensee including deemed transmission licensee for use of inter-State transmission system by paying transmission charges and the term may be used interchangeably with the term Designated ISTS Customers (DICs);

**(61) “Maximum Continuous Rating” or “MCR”** in relation to a generating unit of the thermal generating station means the maximum continuous output at the generator terminals, guaranteed by the manufacturer at rated parameters, and in relation to a Block of a combined cycle thermal Generating Station means the maximum continuous output at the generator terminals, guaranteed by the manufacturer with water or steam injection (if applicable) and corrected to 50 Hz grid frequency and specified site conditions;

**(62) “New Generating Unit/Station”** means a Generating Unit/Station declared under commercial operation on or after the date of coming into force of these Regulations;

**(63) “New Project”** means the project achieving COD or anticipated to be achieving COD on or after the date of coming into force of these Regulations;

**(64) “Normative Annual Plant Availability Factor” or “NAPAF”** in relation to a generating station means the availability factor as specified in Clause 37 and 38 of these regulations for thermal generating station and hydro generating station respectively;

**(65) “Non-Tariff Income”** means income relating to the licensed business other than from tariff (wheeling and retail supply), and excluding any income from other business, cross-subsidy surcharge and additional surcharge;

**(66) “Operation and Maintenance Expenses” or “O&M expenses”** means the expenditure incurred for operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, repairs, maintenance spares, consumables, insurance and overheads but excludes fuel expenses and water charges;

**(67) “Original Project Cost”** means the capital expenditure incurred by the generating company or the transmission/distribution/supply licensee, as the case may be, within the original scope of the project up to the cut-off date as admitted by the Commission;

**(68) “Other Business”** means any business undertaken by the Generating Company, Transmission Licensee or Distribution Licensee, other than the business regulated by the Commission;

**(69) “Plant Availability Factor” or “(PAF)”** in relation to a generating station for any period means the average of the daily declared capacities (DCs) for all the days during the period expressed as a percentage of the installed capacity in MW less the normative auxiliary energy consumption;

**(70) “Plant Load Factor” or “(PLF)”** in relation to thermal generating station or unit 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:

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

Where,

IC = Installed Capacity of the generating station or unit in MW,  
SG<sub>i</sub> = Scheduled Generation in MW for the i<sup>th</sup> time block of the period,  
N = Number of time blocks during the period, and  
AUX<sub>n</sub> = Normative Auxiliary Energy Consumption as a percentage of gross energy  
generation;

**(71) “Project”** means a generating station or a transmission/distribution system including communication system, as the case may be, and in case of a hydro generating station includes all components of generating facility such as dam, intake water conductorsystem, power generating station and generating units of the scheme, as apportioned to power generation and in case of thermal generating stations does not include mining if it is a pit head project and dedicated captive coal mine;

**(72) “Prudence Check”** means scrutiny of reasonableness of capital expenditure incurred or proposed to be incurred, financing plan, use of efficient technology, cost and time over-run and such other factors as may be considered appropriate by the Commission for determination of tariff. While carrying out the Prudence Check, the Commission shall look into whether the generating company or transmission/distribution licensee has been careful in its judgments and decisions for executing the project or has been careful and vigilant in executing the project;

**(73) ‘Pooled Cost of Power Purchase’** means the weighted average pooled price at which the distribution licensee has purchased the electricity including cost of self-generation, if any, in the previous year from all the long-term and short-term energy suppliers, but excluding those based on renewable energy sources, as the case may be

**(74) ‘Preferential Tariff’** means the tariff fixed by the Appropriate commission for sale of energy from a generating station based on renewable energy sources to a distribution licensee.

**(75) “Run-of-River generating station”** means a hydro generating station which does not have upstream pondage;

**(76) “Run-of-River generating station with pondage”** means a hydro generating station with sufficient pondage for meeting the diurnal variation of power demand;

**(77) “Rated Voltage”** means the manufacturer’s design voltage at which the transmission/distribution/supply system is designed to operate and includes such lower voltage at which any transmission/distribution/supply line is charged or for the time being charged;

**(78) “Regular Service”** means putting into use a transmission/distribution/supply system or element thereof after successful trial operation and a certificate to that effect has been issued by the concerned State Load Dispatch Centre;

**(79) “Scheduled Energy”** means the quantum of energy scheduled by the concerned

Load Despatch Centre to be injected into the grid by a generating station for a given time period;

**(80) “Scheduled Generation” or “SG”** at any time or for any period or time block means schedule of ex-bus generation in MW or MWh, given by the concerned Load Despatch Centre;

**Note:**

For the open cycle 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. In such an event of reduction of scheduled generation of gas turbine generating station, the corresponding drawal schedule of beneficiaries shall be corrected in proportion to their scheduled drawal with adjustment of transmission losses on post facto basis.

**(81) “Small gas turbine generating station”** means and includes open cycle gas turbine or combined cycle generating station with gas turbines in the capacity range of 50 MW or below;

**(82) “Start Date or Zero Date”** means the date indicated in the Investment Approval for commencement of implementation of the project and where no date has been indicated, the date of investment approval shall be deemed to be Start Date or Zero Date;

**(83) "State Load Dispatch Centre" or "SLDC"** means the centre established by the State Government for purposes of exercising the powers and discharging the functions under Section 31 of the Act;

**(84) “State Transmission Utility”** means the Board or the Government Company specified as such by the State Government under sub-section (1) of Section 39 of the Act;

**(85) “Storage type generating station”** means a hydro generating station associated with large storage capacity to enable variation of generation of electricity according to demand;

**(86) ‘Straight Line Depreciation’** is a method of depreciation allocating a given percentage of the cost of an asset each year for a fixed period

**(87) “Thermal Generating Station”** means a generating station or a unit thereof that generates electricity using fossil fuels such as coal, lignite, gas, liquid fuel or combination of these as its primary source of energy;

**(88) “Time of the Day (TOD) Meter”** means TOD Meter as defined by the Central Electricity Authority under the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time;

**(89) “Transmission Service Agreement”** means the agreement entered into between the transmission licensee and the designated inter-State transmission customers in accordance with the Sharing Regulations and any other agreement between the transmission licensee and the long term transmission customer where the payment of transmission charges are not made through the POC mechanism under Sharing Regulations;

**(90) “Transmission System”** means a line or a group of lines with or without associated substation, and includes equipment associated with transmission lines and sub-stations;

**(91) “Transmission System User”** means a person who has been allotted transmission capacity rights to access an intra-State transmission system pursuant to a Bulk Power Transmission Agreement, except as provided in the Open Access Regulations;

**(92) “Transmission Line”** shall have the same meaning as defined in sub-section (72) of section 2 of the Act;

**(93) “Transmission System”** means a line or a group of lines with or without associated sub-station, equipment associated with transmission lines and sub-stations;

**(94) “Trial Run” or “Trial Operation”** in relation to transmission/distribution system or a generating station shall have the same meaning as specified in Caluse5 of these regulations;

**(95) “Sub-Station”** shall have the same meaning as defined in sub-section (69) of section 2 of the Act;

**(96) “Useful life”** in relation to a unit of a generating station and transmission/distribution/supply system from the COD shall mean the following, namely:

(a) Coal/Lignite based thermal generating station	25 years
(b) Gas/Liquid fuel based thermal generating station	25 years
(c) AC and DC sub-station	25 years
(d) Gas Insulated Substation (GIS)	25 years
(e) Hydro generating station	35 years
(f) Transmission line (including HVAC & HVDC)	35 years
(g) Communication system	15 years
(h) Distribution line-	35 years

Provided further that the extension of life of the projects beyond the completion of their useful life shall be decided by the Commission;

**(97) “Wheeling”** means the operation whereby the distribution system and associated

facilities of a distribution licensee are used by another person for the conveyance of electricity on payment of charges to be determined under clause 23, and in the event where use of the distribution system and associated facilities is by a consumer, on payment of a surcharge in addition to the charges for wheeling as may be determined by the Commission, an additional surcharge on the charges of wheeling, as may be specified by the Commission, if applicable, to meet the fixed cost of such distribution licensee arising out of his obligation to supply;

**(98) “Wheeling Business”** means the business of operating and maintaining a distribution system for conveyance of electricity in the area of supply of the distribution licensee.

**(99) “Wheeling Charges”** shall have the same meaning as defined in Clause 23(II) of these regulations

**(100) “Unscheduled Interchange”** in a time-block for a generating station or a seller means its total actual generation minus its total scheduled generation and for a beneficiary or buyer means its total actual drawal minus its total scheduled drawal.

**(101) “Year”** means a financial year commencing from 1st April and ending 31st March.

The words and expressions used in these regulations and not defined herein but defined in the Act or any other regulation of the Commission or CERC shall have the meaning assigned to them under the Act or any other regulation of the Commission or CERC.

## CHAPTER – 2 GENERAL

4. **Date of Commercial Operation:** The date of commercial operation of a generating station or unit or block thereof or a transmission/distribution/supply system or element thereof shall be determined as under:
- I. Date of commercial operation in case of a generating unit or block of the thermal generating station shall mean the date declared by the generating company after demonstrating the maximum continuous rating (MCR) or the installed capacity (IC) through a successful trial run after seven days notice to the beneficiaries, and in case of the generating station as a whole, the date of commercial operation of the last generating unit or block of the generating station: The scheduling shall commence from 0000 hr after acceptance of the test results by the beneficiaries or within 48 hours after the trial run whichever is earlier:

Provided that

- (i) the generating company shall certify to the effect that the generating station meets the key provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical plants and electric lines) Regulations, 2010 and Grid Code:
  - (ii) the certificate shall be signed by CMD/CEO/MD of the company subsequent to its approval by the Board of Directors in the format enclosed at Annexure-9 and a copy of the certificate shall be submitted to the Member Secretary, (concerned Regional Power Committee) and concerned SLDC/RLDC before declaration of COD:
  - (iii) Provided also that the generating station or unit thereof after being put into commercial operation shall demonstrate the plant availability of not less than the normative plant availability in the month following the date of declaration of commercial operation. If the generating station or unit thereof is not able to demonstrate normative availability, except for the reason beyond the control of generating company, such generating station or the unit is said to be put into commercial service from the month of normative availability.
- II. Date of commercial operation in relation to a generating unit of hydro generating station shall mean the date declared by the generating company from 0000 hour of which, after seven days notice to the beneficiaries, scheduling process in accordance with the Grid code is fully implemented, and in relation to the generating station as a whole, the date declared by the generating company after demonstrating peaking capability corresponding to installed capacity of the generating station through a successful trial run, after seven days notice to the beneficiaries. In relation to the generating station as a whole, the scheduling shall commence from 0000 hr after acceptance of the test results by the beneficiaries or within 48 hours after the trial run whichever is earlier:

Provided that:

- (i) it shall be mandatory for the generating company to obtain certificate from Central Electricity Authority or any agency designated by Authority effect

that the generating station meets all the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical plants and electric lines) Regulations, 2010 and Grid Code

- (ii) the certificate shall be signed by CMD/CEO/MD of the company subsequent to its approval by the Board of Directors in the format enclosed at Annexure-9 and a copy of the certificate shall be submitted to the Member Secretary, (concerned Regional Power Committee) and concerned SLDC/RLDC before declaration of COD:
  - (iii) in case a hydro generating station with pondage or storage is not able to demonstrate peaking capability corresponding to the installed capacity for the reasons of insufficient reservoir or pond level, the date of commercial operation of the last unit of the generating station shall be considered as the date of commercial operation of the generating station as a whole, and it will be mandatory for such hydro generating station to demonstrate peaking capability equivalent to installed capacity of the generating unit or the generating station as and when such reservoir/pond level is achieved:
  - (iv) if a run-of-river hydro generating station or a generating unit thereof is declared under commercial operation during lean inflows period when the water inflow is insufficient for such demonstration of peaking capability, it shall be mandatory for such hydro generating station or generating unit to demonstrate peaking capability equivalent to installed capacity as and when sufficient water inflow is available.
- III. Date of commercial operation in relation to a transmission system shall mean the date declared by the transmission licensee from 0000 hour of which an element of the transmission system is in regular service after successful trial operation for transmitting electricity and communication signal from sending end to receiving end:

Provided that:

- (i) where the transmission line or substation is dedicated for evacuation of power from a particular generating station, the generating company and transmission licensee shall endeavor to commission the generating station and the transmission system simultaneously as far as practicable and shall ensure the same through appropriate Implementation Agreement in accordance with Clause 10(V) of these Regulations :
  - (ii) in case a transmission system or an element thereof is prevented from regular service for reasons not attributable to the transmission licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system, the transmission licensee shall approach the Commission through an appropriate application for approval of the date of commercial operation of such transmission system or an element thereof.
- IV. Date of commercial operation in relation to a communication system or element thereof shall mean the date declared by the transmission licensee from 0000 hour of which a communication system or element is put into service after completion of site acceptance test including transfer of voice and data to respective control centre as certified by the respective RLDC/SLDC.
- V. Date of commercial operation in relation to a distribution system is the date from



which the system is put to use.

5. **Trial Run and Trial Operation.-**

- I. Trial Run in relation to generating station or unit thereof shall mean the successful running of the generating station or unit thereof at maximum continuous rating or installed capacity for continuous period of 72 hours in case of unit of a thermal generating station or unit thereof and 12 hours in case of a unit of a hydro generating station or unit thereof:  
Provided that where the beneficiaries have been tied up for purchasing power from the generating station, the trial run shall commence after seven days notice by the generating company to the beneficiaries.
- II. Trial operation in relation to a transmission system or an element thereof shall mean successful charging of the transmission system or an element thereof for 24 hours at continuous flow of power, and communication signal from sending end to receiving end and with requisite metering system, telemetry and protection system in service enclosing certificate to that effect from concerned RLDC/SLDC.

## CHAPTER – 3-PROCEDURE FOR TARIFF DETERMINATION

### 6. Tariff determination

- I. Tariff in respect of a generating station may be determined for the whole of the generating station or stage or generating unit or block thereof, and tariff in respect of a transmission system may be determined for the whole of the transmission system or transmission line or sub-station or communication system forming part of transmission system.

Provided that:

- (i) where all the generating units of a stage of a generating station or all elements of a transmission system have been declared under commercial operation prior to publication of this regulation on the Official Gazette, the generating company or the transmission licensee, as the case may be, shall file consolidated petition in respect of the entire generating station or transmissions system for the purpose of determination of tariff for the control period:
  - (ii) in case of commercial operation of the generating station or transmission system including communication system on or after publication of this regulation on the Official Gazette, the generating company or transmission licensee shall file a consolidated petition combining all the units of the generating station or file appropriate petition for transmission elements of the transmission system which are likely to be commissioned during next sixmonths from the date of application:
  - (iii) the tariff of the existing communication system forming part of transmission system shall be as per the methodology followed by the Commission prior to publication of this regulation on the Official Gazette
- II. For the purpose of determination of tariff, the capital cost of a project may be broken up into stages, blocks, units, transmission lines and sub-stations, forming part of the project, if required:  
Provided that where break-up of the capital cost of the project for different stages or units or blocks and for transmission lines or sub-stations is not available and in case of on-going projects, the common facilities shall be apportioned on the basis of the installed capacity of the units, line length and number of bays:
  - III. Where only a part of the generation capacity of a generating station is tied up for supplying power to the beneficiaries through long term power purchase agreement and the balance part of the generation capacity have not been tied up for supplying power to the beneficiaries, the tariff of the generating station shall be determined with reference to the capital cost of the entire project, but the tariff so determined shall be applicable corresponding to the capacity contracted for supply to the beneficiaries.
  - IV. Tariff in respect of Distribution system shall be determined for Distribution Wires Business and Retail Supply Business and shall be based on A detailed Business Plan based on the Operational Norms and trajectories of performance parameters specified in this Regulation.
  - V. The Licensee or generating company shall provide to the Commission all details as given below and any other details that may be necessary for the purpose of computation of tariff and charges. The details provided needs to be duly verified and authenticated by person/authority submitting the petition.
    - a. The details to be furnished are for 3 years i.e. ensuing year ( year for which

tariff and charge is to be determined), current year (year immediately prior to ensuing year) for which Annual Performance Review will be done as per Caluse-9 of this regulation, and previous year (year immediately prior to current year) for True-up based on audited accounts as per Clause-10 of this regulation.

- b. Details of approved business plan as per clause 7 of this regulation
- c. Copies of relevant requirements for the period as per Annexure-1.
- d. Statement of current tariff rates and applicable terms and conditions of the expected revenue for the ensuing year based on the current tariff rates as in Annexure-2.
- e. Statement of the proposed tariff rates and proposed terms and conditions and expected revenue for the ensuing year based on the proposed tariff rates as in Annexure-3.
- f. Detailed plan for reduction of energy loss in generation, transmission and distribution both short term and long term.
  - i. Details of energy audit conducted, if any, along with result to be submitted.
  - ii. Details of energy conservation measures adopted.
- g. Details of transmission and distribution losses may be given as in Annexure-4.
- h. The method and system of determining the losses and basis of bifurcation between technical losses and other than technical losses be suitably explained in detail.
- i. Performance measurement details to be given as per Annexure-5.
- j. Cash flow statement as per Annexure-6.lk
- k. Statement showing flow details of subsidies received and receivable, if any, to the Consumers to whom it is directed and the way in which such subsidies is proposed to be reflected for the proposed tariff applicable to these consumers.
- l. Details of allocation of ARR into various categories and sub-categories of consumers, basis and justification of such allocation, determination of cost based tariff for each category including sub-category. The details of cost subsidies for the existing and proposed tariff.
- m. Audited Accounts of last 3 years along with audited report and reply of the Management.
- n. Performa A to E in Cost Accounting Records (Electrical Industry), Rules to the extent applicable.
- o. Operational result of training activities, if any with a Note.
- p. Draft gist of the tariff application for publication. The Commission reserves the right to ask for additional information.
- q. A consolidated annual report on Standard of Performance Compliance as per TERC, Standard of Performance Regulation, 2004 and subsequent amendments to the same, to be submitted by Distribution Licensee.
- r. A consolidated annual report of operational Forum for Redressal of Grievances to be submitted by Distribution Licensee.

Provided, failure to submit complete and required information, data, figures, documents etc. in required manner, may entail rejection of the petition

- VI. The tariff shall be revised ordinarily only once in a year except for adjustment on account of Fuel and Power Purchase and as per the formula. However, no reimbursement of fuel and power cost shall be allowed on any excess beyond permissible (a) Technical and commercial loss and (b) Self-consumption of electricity under the formula.

- VII. The tariff shall normally be revised from the prospective date with due notice except for adjustment of FPPCA unless there is a compelling reason to revise the same from the retrospective date in which case detailed justification will be given in writing by the Commission.
- VIII. The Commission may differentiate the tariff based on following factors or on the basis of combination of following factors
- a. Load Factor
  - b. Power Factor
  - c. Voltage
  - d. Total consumption of electricity during any specified period or time
  - e. Nature of supply
  - f. Purpose for which supply is being taken

Accordingly, the commission can come out with telescopic tariff, Time of Day tariff or any other suitable tariff design as may be deemed fit by commission from time to time.

- IX. The Commission, depending on the factors/available data/information, or any other material which it may consider appropriate, may either fix separate rate or by any other method impose extra charges, incentives, penalty etc. on the basic tariff keeping in view the interest of the Consumers, Licensee, Generating company or the sector as a whole.

## **7. Business Plan**

- I. The Generating Company, Transmission licensee, and Distribution Licensee for Distribution Wires Business and Retail Supply Business, shall file for the Commission's approval, not less than 180 days before the commencement of the first year of the Control Period or such other date as may be directed by the Commission, a Long Term Business Plan prepared in accordance with these regulations. The Business Plan shall be for the entire Control Period and shall, inter alia, contain but not be limited to:
- a. Sales/Demand Forecast for each consumer category and sub-categories for each year of the Business Plan;  
Provided that
    - Metered sales shall be treated as an uncontrollable parameter;
    - Open access transactions shall not form part of the sales;
    - Forecast shall be based on past trends in each of the slabs of consumer categories. The compounded annual growth rate (CAGR) of past 2 to 3 years of sales within each of the slabs of a consumer category as per audited books of account shall be used to forecast up to short and medium (5 years) time range. Provided also that in case of following occurrences, prudent adjustment of forecasted metered sales shall be carried out:
      - Abnormal variation in consumer mix in any given area (on the basis of proposed city plan, tax holidays, Government incentives for industrial establishments, migration of consumers due to open access, etc.)
      - Inflection point in economic cycle (boom, slowdown, recession or expansion)
      - Variations in weather conditions
      - Materially significant findings during audit check

- In cases where slab-wise sales to each consumer category are not available in audited books of accounts and only consolidated sales are available, the Distribution Licensee shall include the slab-wise sales in annexure to its Annual Report from next year onwards;
  - Till the time 100% metering of electricity consumers is achieved in area of operation of Distribution Licensee, an independent study shall be conducted by the Distribution Licensee to assess actual consumption of power by un-metered consumer segment. For this Distribution Licensee will carry a sample survey(Stratified random sampling) for three years and submit the month-wise, taluka-wise details of study conducted to the Commission. Based on the results of study conducted and prudence check by commission, baseline norms shall be established as per the results of study for first year which shall be revised/fine-tuned in the remaining two subsequent years. After three years of annual study leading to streamlining of processes, study shall be conducted on alternate year basis. The Distribution licensee shall adjust the projection for the unmetered sales based on result of the study.
  - On similar lines as above for unmetered category, a sample study for establishing the agricultural unmetered consumption based on readings of the meters installed at each DTs supplying to agricultural consumers in the sample area, shall be conducted to establish the unmetered consumption of agricultural consumers.  
 Provided, where agricultural feeders are segregated, commercial losses in each of the agriculture feeder based on difference of the feeder meter consumption and billing of agriculture consumers connected to the feeder and proposed technical losses, shall be worked out and submitted to commission on yearly basis.  
 Provided that the Distribution licensee shall adjust the projection for the unmetered sales to agricultural category based on result of the study.
- b. AT&C loss, distribution loss and Transmission Loss reduction trajectory and collection efficiency for distribution licensee for each year of the Business Plan;
- c. Power Procurement Plan of the distribution licensee for each year of the business plan period, taking into consideration the following
- The quantum of power purchase for the ensuing financial year shall be estimated on the basis of actual purchase made during the previous financial year(s) and actual to the extent available for the current year and any projections for the balance period of the current year with appropriate adjustments for any abnormal variations during the period. The licensee through appropriate documentation shall justify all the abnormal deviations. Such estimate should also consider the Quantum of Renewable Purchase Obligation (RPO) and the target set, if any, for Energy Efficiency (EE) and Demand Side Management (DSM) schemes. Also, such estimate shall include special consideration for any abnormal addition of consumers envisaged (like under RGGVY).
- Provided that the forecasts/estimates shall take into account factors such as overall economic growth, consumption growth of electricity-intensive sectors, advent of competition in the electricity industry, impact of loss reduction initiatives and other relevant factors.
- Based on the above guideline, the licensee should prepare a long term

- power procurement plan and submit the same to commission every year.
- Such power procurement plan shall be based on merit order dispatch.
  - This power purchase plan will be evaluated by Commission based on
    - (a) The submission made by licensee
    - (b) Guideline set by commission for power purchase
    - (c) Power purchase agreements
    - (d) Bulk supply tariff
    - (e) Trends in captive power consumption
    - (f) Need to promote co-generation and generation of electricity from renewable sources of energy.
    - (g) Availability (or expected availability) of capacity in the intra-State transmission system for evacuation and supply of power procured under the agreement/arrangement;
  - Commission based on its evaluation can revise the power procurement plan of the licensee. Provided that the revised power procurement plan shall be made available to Distribution licensee every year.
  - The Commission shall review the power procurement plan of the Distribution Licensee for its prudence for determination of ARR.
  - In case of direct procurement of power by the distribution licensees from generators/other sources in order to optimize the cost of power procured by utilities, the same should be based on the Merit Order Dispatch principles of all Generating Stations considered for power purchase. While approving these direct purchase, the Commission may consider the following:
    - (a) Load profiles during various seasons
    - (b) Technical constraints
    - (c) Avoidable costs (whether from own generation or power purchase) after giving due consideration to valid contractual obligations.
  - In the regime of Availability Based Tariff (ABT), the licensee shall be allowed to retain incentive of over drawl of power under higher frequency and likewise absorb the loss for drawl of power under lower frequency.
  - An automatic fuel cost revision shall be provided based on the monthly energy charge rate and fuel price adjustment of secondary fuel determined for generating stations. The licensee shall be required to compute changes in the fuel costs, and appropriately claim or refund the same in tariffs, on quarterly basis according to an automatic fuel cost revision provision. The fuel cost revision shall include fuel related expenses including variations in mix of power purchases.
- d. The Capital Investment Plan separately showing year wise details of,
- i. On-going projects that will spill into the control period under review
  - ii. New projects that will commence within the control period and will be completed within the control period
  - iii. New projects that will commence within the control period but may be completed within or beyond the control period.
  - iv. Relevant commercial and technical details along with cost benefit analysis for each of the major item proposed under capital investment plan.
- v. Underlying assumptions for the projected capital cost and additional

capital expenditure, wherever applicable

- e. The appropriate capital structure and cost of financing (interest on debt) and return on equity, terms of the existing loan agreements, etc;
  - f. The Operation and Maintenance (O&M) costs estimated for the Base Year and two years prior to the Base Year with complete details, together with the forecast for each year of the Business Plan Period based on the proposed efficiency in operating costs, norms for O&M cost allowance including indexation and other appropriate mechanism;
  - g. Details of depreciation
  - h. A set of targets proposed for other controllable items such as working capital, quality of supply targets, etc. The targets shall be consistent with the capital investment plan proposed by the Licensee;
  - i. Proposals for other items such as external parameters used for indexation (inflation, etc);
- II. The licensee or the Generating Company shall, before incurring any capital expenditure which does not fall within the capital expenditure programme as approved by the Commission under business plan and which exceeds, in any one financial year or in more than one financial year, a sum of Rs.5.0 crores or 1% of the gross Fixed Assets whichever is less for one individual/head of item, take the approval of the Commission before incurring the same for the purpose of tariff. The overall annual limit for incurring capital expenditure on all such unapproved capital items shall not exceed Rs.25.0 crores or 2% of the opening balance of gross fixed assets whichever is lower.
- Provided that in case of emergency or emergent circumstances due to its impact on the safety of the assets, life, system or smooth supply or such similar reasons, the licensee or the generating company may incur the necessary expenditure without taking the prior approval of the Commission, but shall intimate the same to the Commission along with the circumstances due to which it was not possible to take prior approval.
- Provided further that in case the Commission neither refuses nor gives its consent for incurring of such expenditure within 10 working days from its filing, with all the relevant documents, the licensee / generating company may presume that the Commission has no objection for the inclusion of the same for fixing the tariff.
- III. The filings in addition to the Business Plan period shall also contain the data for the cost and revenue parameters for the previous five year period.
- IV. The Commission will broadly classify costs incurred by generating company or the licensee as controllable and non-controllable. For all controllable costs, the Commission may set the targets for each year under review in the approved Business Plan. These targets shall be used for computing revenue requirement.
- V. All non-controllable costs as checked by the Commission with due diligence and prudence shall be treated as pass-through.
- VI. Provided that the performance parameters, whose trajectories have been specified in the Regulations, shall form the basis of projection of these performance parameters in the Business Plan.
- VII. Annual review of performance shall be conducted based on the actual vis-à-vis the approved forecast and categorization of variations in performance into controllable factors and uncontrollable factors;
- VIII. The Commission shall make periodic reviews of the licensee's performance during the control period to address any practical issues, concerns or unexpected outcomes that may arise.

## **8. Application for determination of tariff:**

- I. The generating company may make an application for determination of tariff for new generating station or unit thereof in accordance with this Regulation, in respect of the generating station or generating units thereof within 120 days of the anticipated date of commercial operation.
- II. The transmission licensee may make an application for determination of tariff for new transmission system including communication system or element thereof as the case may be in accordance with this Regulation, in respect of the transmission system or elements thereof anticipated to be commissioned within 120 days from the date of filing of the petition.
- III. In case of an existing generating station or transmission system including communication system or element thereof, the application shall be made not later than 120 days from the date of notification of these regulations or by November 30<sup>th</sup> (whichever is later) based on admitted capital cost including any additional capital expenditure already admitted up to date publication of this regulation on the Official Gazette (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure as per approved business plan for the respective years of the tariff control period.  
Provided that the application of the generating company or the transmission licensee, as the case may be, shall be as per Annexure-7 of these regulations.
- IV. The distribution licensee shall submit the application for Retail Supply Tariff and Wheeling Tariff, not later than 120 days from the date of notification of these regulations or by November 30<sup>th</sup> (whichever is later) based on admitted capital cost including any additional capital expenditure already admitted up to the date publication of this regulation on the Official Gazette (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure as per approved business plan for the respective years of the tariff control period.
- V. If the petition is inadequate in any respect as required under these regulations, the application shall be returned to the applicant, for resubmission of the petition within one month after rectifying the deficiencies as may be pointed out by the staff of the Commission.
- VI. If the information furnished in the petition is in accordance with the regulations and is adequate for carrying out prudence check of the claims made, The commission shall accept the petition within 14 days of the submission of petition and within 21 days of submission of petition shall publish the approved gist of study, tariff publication in such form or manner as prescribed by commission from time to time. The Commission shall invite objections from respondents giving a period of 30 days from publication. The Commission shall consider the suggestions and objections, if any, received from the respondents and any other person including the consumers or consumer associations and subsequently, The Commission shall issue the tariff order within 120 days of the submission of petition, after hearing the petitioner, the respondents and any other person specifically permitted by the Commission.
- VII. In case of the new projects, the generating company or the transmission licensee, as the case may be, may be allowed tariff by the Commission based on the projected capital expenditure from the anticipated COD in accordance with Chapter 4 of this regulation:

Provided that :

- (i) the Commission may grant tariff upto 90% of the annual fixed charges claimed in based on the management certificate regarding the capital cost for the purpose



- of determination of tariff:
- (ii) if the date of commercial operation is delayed beyond 120 days from the date of issue of tariff order, the tariff granted shall be deemed to have been withdrawn and the generating company or the transmission licensee shall be required to file a fresh application for determination of tariff after the date of commercial operation of the project:
  - (iii) where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure exceeds the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall refund to the beneficiaries, the excess tariff recovered corresponding to excess capital cost, as approved by the Commission alongwith interest at 1.20 times of the bank rate as prevalent on 1st April of respective year:
  - (iv) where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure falls short of the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall be entitled to recover from the beneficiaries, the shortfall in tariff corresponding to reduction in capital cost, as approved by the Commission alongwith interest at 0.80 times of bank rate as prevalent on 1st April of respective year.
- VIII. In case of the existing projects, the generating company or the transmission licensee, as the case may be, may be allowed tariff by the Commission based on the admitted capital cost as on publication of this regulation on the Official Gazette and projected additional capital expenditure for the respective years of the tariff control period in accordance with the Chapter 4:

Provided that:

- (i) the generating company or the transmission licensee, as the case may be, shall continue to bill the beneficiaries at the tariff approved by the Commission and applicable as on 31.3.2015 for the period starting from 1.4.2015 till approval of tariff by the Commission in accordance with these regulations:
  - (ii) where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure submitted by the generating company or the transmission licensee, as the case may be, exceeds the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall refund to the beneficiaries, the excess tariff recovered corresponding to excess capital cost, as approved by the Commission along with interest at 1.20 times of the bank rate as prevalent on April 1 of respective year:
  - (iii) where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure submitted by the generating company or the transmission licensee, as the case may be, falls short of the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall be entitled to recover from the beneficiaries, the shortfall in tariff corresponding to reduction in capital cost, as approved by the Commission along with interest at 0.80 times of bank rate as prevalent on April 1 of respective year.
- IX. With regard to determination of tariff for wheeling of electricity in a distribution system, the principles as enumerated in clause 23 of these Regulations for determination of wheeling charges in respect of a distribution system shall be made applicable in

addition to the nine principles as laid down in Section 61(a) to 61(i) of the Act:

Provided that the commission reserves the right to determine Wheeling Charges of the Distribution Licensee on the basis of segregated accounts the Licensed business into Distribution Wires Business and Retail Supply Business.

Provided further that where the Distribution Licensee is not able to submit audited and certified separate accounts for Distribution Wires Business and Retail Supply Business, the Commission shall determine allocation matrix in the following manner:

- The Licensee shall prepare an “allocation matrix” for the control period showing apportionment of costs and revenues to Distribution Wires Business and Retail Supply Business. The statement shall be supported with an explanation of the methodology used for such allocations. The Allocation Statement should be consistent over the Control Period, as approved by the Managing Director/CEO of the Licensee.
- The Commission shall review the “allocation matrix” submitted by the Licensee and based on the prudence check shall finalize the “allocation matrix” for each year of the control period.

Provided further 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 Licensees, fix only maximum ceiling of tariff for retail sale of electricity.

X. The annual filings for Wheeling Tariff shall contain the following:

- (i) The Distribution system or network usage forecast for the year consistent with the Business Plan;
- (ii) Computation of Non-Tariff Income with item-wise description and details;
- (iii) Computation of income from Other Businesses like Consultancy Services, Training Facilities, etc;
- (iv) Computation of tariffs for Wheeling of electricity for the year, including the losses and the procedure thereof;

XI. The annual filings for Retail Supply Tariff shall contain the following:

- (i) Licensee shall submit proposal for retail sale of electricity for the consumers pertaining to Retail Supply Business, which shall include tariffs for each consumer category, slab-wise and voltage wise. The proposed tariff shall also contain energy charges, demand charges, minimum fixed charges, etc along with the tariff rationalization measures. The tariff proposals of the Licensee should demonstrate that the tariffs are progressively reflecting the cost of supply;
- (ii) Computation of Non-Tariff Income with item-wise description and details;
- (iii) Computation of income from Other Businesses like Consultancy Services, Training Facilities, etc;
- (iv) Expected Revenue from the proposed Retail Supply Tariff, and other matters considered appropriate by the Distribution Licensee, including incentive schemes to consumers, cross subsidy surcharge, etc.

XII. Where tariff has been determined through the process of bidding in accordance with the guidelines issued by the Central Government, the Commission shall adopt such tariff in accordance with the provisions of the Act.

- XIII. The Generating Company or the Transmission or the Distribution Licensees as the case may be, in the ARR filing for the ensuing financial year shall indicate the manner in which the gap, if any, between the charges which it is permitted to recover and the expected revenue calculated shall be filled up.
- XIV. The Generating Company or the Transmission or the Distribution Licensees as the case may be, shall along with the aforesaid petition submit a statement on the status of compliance of directives, if any, issued by the Commission in its last tariff order.
- XV. A Tariff Order shall continue to be in force for such period as may be indicated in the said order unless amended or revoked earlier.
- XVI. The commission reserve the right to suo-moto ask the Generating companies or the Transmission or the Distribution licensees to file such an application for variation in tariff and other charges which shall be filed as per TERC Conduct of Business Regulation, 2004 and subsequent amendments from time to time.
- XVII. All the application for determination/revision of tariff shall be accompanied by appropriate fee as per TERC Regulation(Miscellaneous Provisions Relating to Petition Fee Regulation, 2005) and subsequent amendments to the same.
- XVIII. Appeal for review, interim order, review of the decisions, directions and orders, proceedings after death, publication of petition and other conditions shall be as per TERC Conduct of Business Regulation, 2004 and subsequent amendments to the same.
- XIX. The tariff for any inter State supply, transmission or wheeling of electricity, as the case may be involved the territories of two States may upon application made to it by the licensees intending to undertake such supply, transmission or wheeling shall be determined by the Commission who intends to distribute electricity and make payment in the area of jurisdiction of Tripura Electricity Regulatory Commission. As per provision 64(5) of the Act provided further that where open access is permitted the category of consumers under section-42.  
The Commission shall determine only the wheeling charges and surcharge thereon if any, for the said categories of consumers.  
Provided, further if the open access permitted to certain consumer by the Commission under section-42, such consumers may enter into an agreement with any person for supply or purchase of electricity on such terms and conditions (including tariff) as may be agreed upon by them. Notwithstanding the provision contained in clause (d) of Sub-section-(1) of Section-62 of the Act.
- XX. The Commission shall within 7(seven) days of making order, send a copy of the order to the State Government, the Central Electricity Authority and the concerned applicant.

## **9. Annual Performance Review**

The Commission shall carry out Annual Performance Review along with the tariff petition filed for the next tariff period. Annual review of performance shall be conducted based on the actual vis-à-vis the approved forecast and categorization of variations in performance into controllable factors and uncontrollable factors;

## **10. Truing up**

- I. The Generating Company or the Transmission or the Distribution Licensee as the case may be, may file an application each year for truing up along with the tariff petition filed for the next tariff period and the Commission shall carry out truing up exercise along with the tariff petition filed for the next tariff period:
- II. Truing-up shall be carried out, on the basis of expense estimates made in the

beginning of the year under consideration, actual expenses booked in the audited books of account of the Licensee for the year and prudence check by the Commission: Provided that true up for any period shall be governed by the provisions of the regulation under which the tariff for that year was determined:

Provided that if such variations are large, and it is not feasible to recover in one year alone, the Commission may take a view to create a regulatory asset.

- III. The Commission shall have the discretion of providing regulatory assets. Regulatory assets shall be created only in case of the Licensee incurring losses on account of force majeure or cost variations due to uncontrollable factors or avoiding major tariff shocks because of these reasons:

Provided that the amortization schedule corresponding to the regulatory asset shall be prepared and put in effect along with creation of regulatory asset:

Provided that the carrying cost of the regulatory shall be determined by commission from time to time taking into account the State Bank Base Rate for the tenure for which regulatory asset has been created.

- IV. The generating station shall carry out truing up of tariff of generating station based on the performance of following Controllable and uncontrollable parameters:

- (i) Controllable Parameters :
  - (a) Station Heat Rate;
  - (b) Secondary Fuel Oil Consumption;
  - (c) Auxiliary Energy Consumption; and
  - (d) Re-financing of Loan.
- (ii) Uncontrollable parameters:
  - (a) Force Majeure;
  - (b) Change in Law; and
  - (c) Primary Fuel Cost.

- V. The Transmission Licensee shall carry out truing up of tariff of transmission system based on the controllable parameter of Re-Financing of loans and Uncontrollable parameters of Force Majeure and Change in Law.

- VI. The distribution company shall carry out truing up of tariff based on the performance of following Controllable and uncontrollable parameters:

- (i) Controllable Parameters :
  - (a) Variations in capitalization on account of time and/or cost overruns/ efficiencies in the implementation of a capital expenditure project not attributable to an approved change in scope of such project, change in statutory levies or force majeure events;
  - (b) Variation in Interest and Finance Charges, Return on Equity, and Depreciation on account of variation in capitalization, as specified in clause (a) above;
  - (c) Variations in Aggregate Technical & Commercial (AT&C) losses which shall be measured as the difference between the units input into the distribution system and the units realized (units billed and collected) wherein the units realized shall be equal to the product of units billed and collection efficiency (where Collection Efficiency shall be measured as ratio of total revenue realized to the total revenue billed for the same year);  
Detailed methodology for computation of AT&C loss has been indicated in Annexure-10 to these regulations;

- (d) Variations in performance parameters;
  - (e) Variation in approved parameters for T&D loss. In case of actual T&D loss being higher than approved value, power purchase cost proportionate to difference between actual purchase and purchase arrived based on actual sales and approved T&D loss shall be disallowed.
  - (f) Variations in working capital requirements;
  - (g) Failure to meet the standards specified by the Regulatory Commission (Standard of Performance Regulations-2004) except where exempted in accordance with those Regulations;
  - (h) Variations in labour productivity;
  - (i) Variation in operation & maintenance expenses;
  - (j) Variation in Wires Availability.
  - (ii) Uncontrollable parameters:
    - (a) Force Majeure;
    - (b) Change in Law; and
    - (c) Variation in the price of fuel and/ or price of power purchase according to the FPPPA formula approved by the Commission from time to time;
    - (d) Variation in the number or mix of consumers or quantities of electricity supplied to consumers;
    - (e) Transmission Loss;
    - (f) Variation in market interest rates;
    - (g) Taxes and Statutory levies;
    - (h) Taxes on Income
- VII. The financial gains by a generating company or the Transmission or the Distribution licensee, on account of controllable parameters shall be shared between generating company or the Transmission or the Distribution licensee and the beneficiaries on monthly basis with annual reconciliation. The financial gains computed shall be shared in the ratio of 60:40 between generating company or the Transmission or the Distribution licensee as the case may be, and the beneficiaries
- VIII. The financial gains and losses by a generating company or the Transmission or the Distribution licensee, as the case may be, on account of uncontrollable parameters shall be passed on to beneficiaries.
- IX. Where after the truing up, the tariff recovered exceeds the tariff approved by the Commission under these regulations, the generating company or the Transmission or the Distribution licensee, shall refund to the beneficiaries, the excess amount so recovered.
- X. Where after the truing up, the tariff recovered is less than the tariff approved by the Commission under these regulations, the generating company or the Transmission or the Distribution licensee shall recover from the beneficiaries.
- XI. The amount under-recovered or over-recovered, along with simple interest at the rate equal to the bank rate as on 1st April of the respective year, shall be recovered or refunded by the generating company or the Distribution/Transmission licensee, as the case may be, in six equal monthly installments starting within three months from the date of the tariff order issued by the Commission.

## CHAPTER – 4-COMPUTATION OF CAPITALCOST AND CAPITAL STRUCTURE

### 11. Capital Cost:

- I. The Capital cost as determined by the Commission after prudence check in accordance with this regulation shall form the basis of determination of tariff for existing and new projects.
- II. The Capital Cost of a new project shall include the following:
  - (i) the expenditure incurred or projected to be incurred up to the date of commercial operation of the project;
  - (ii) Interest during construction and financing charges, on the loans (i) being equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event of the actual equity less than 30% of the funds deployed;
  - (iii) Increase in cost in contract packages as approved by the Commission;
  - (iv) Interest during construction and incidental expenditure during construction as computed in accordance with Clause 13 of these regulations;
  - (v) Capitalized Initial spares subject to the ceiling rates specified in Clause 15 of these regulations;
  - (vi) Expenditure on account of additional capitalization and de-capitalisation determined in accordance with Clause 16 of these regulations;
  - (vii) Adjustment of revenue due to sale of infirm power in excess of fuel cost prior to the COD as specified under Clause 20 of these regulations; and
  - (viii) Adjustment of any revenue earned by the generating company or the transmission/distribution licensee by using the assets before COD.
- III. The Capital cost of an existing project shall include the following:
  - (i) the capital cost admitted by the Commission prior to publication of this regulation on the Official Gazette duly tried up by excluding liability, if any, as on the date of publication of this regulation on the Official Gazette;
  - (ii) additional capitalization and de-capitalization for the respective year of tariff as determined in accordance with Clause 16; and
  - (iii) expenditure on account of renovation and modernization as admitted by this Commission in accordance with Clause 17.
- IV. The capital cost in case of existing/new hydro generating station shall also include:
  - (i) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and
  - (ii) cost of the developer's 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) project in the affected area.
- V. The capital cost with respect to thermal generating station, incurred or projected to be incurred on account of the Perform, Achieve and Trade (PAT) scheme of Government of India will be considered by the Commission on case to case basis and shall include:
  - (i) cost of plan proposed by developer in conformity with norms of PAT Scheme; and
  - (ii) sharing of the benefits accrued on account of PAT Scheme.

- VI. The following shall be excluded or removed from the capital cost of the existing and new project:
- (i) The assets forming part of the project, but not in use;
  - (ii) De-capitalization of Asset;
  - (iii) In case of hydro generating station any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State government by following a two stage transparent process of bidding; and
  - (iv) the proportionate cost of land which is being used for generating power from generating station based on renewable energy;
  - (v) Provided that any grant received from the Central or State Government or any statutory body or authority for the execution of the project which does not carry any liability of repayment shall be excluded from the Capital Cost for the purpose of computation of interest on loan, return on equity and depreciation;
- VII. The Capital cost of the Distribution Licensee shall be as per proposed capital investment plan by licensee in its filing. The plan must separately show ongoing projects that will spill into the year under review, and new projects that will commence but may be completed within or beyond the tariff period. For the new projects, the filing must provide the justification as stipulated under relevant investment guidelines of the Commission.
- VIII. In addition to the approved capital investment plan, the distribution licensee can seek provision for additional capital expenditure anytime during the tariff year to meet natural calamities involving substantial investments. The Commission shall examine and if satisfied shall approve the corresponding costs for inclusion in revenue requirement in the next period.
- IX. The Capital investment plan of Distribution Licensee shall be circle-wise/scheme-wise and with respect to each circle/scheme, shall include:
- (a) Purpose of investment (i.e. replacement of existing assets, meeting load growth, technical loss reduction, non-technical loss reduction, meeting reactive energy requirements, customer service improvement, improvement in quality and reliability of supply, etc)
  - (b) Capital Structure;
  - (c) Capitalization Schedule;
  - (d) Financing Plan;
  - (e) Cost-benefit analysis;
  - (f) Performance improvement envisaged in the Control Period.
- X. While presenting the justification for new projects, the Distribution licensee shall detail the specific nature of the works, and outcome sought to be achieved. The detail must be shown in the form of physical parameters, e.g., new capacity added, to be added, meters replaced, customer service centres set up etc, so that it is amenable for physical verification. This is necessary to ensure that the approved investment plans are implemented and the licensee does not derive improper financial benefit by delaying or neglecting to make the proposed investment.
- XI. The Generation Company/Licensee shall quarterly submit the details of the scheme-wise asset capitalization along with receipt of the Electrical Inspector certificate (wherever applicable) and other documents as may be prescribed by the CEA and Commission from time to time for allowing Depreciation.

- XII. In case of any significant shortfall in physical implementation, the Commission shall require the Generation Company/licensee to explain the reasons, and may proportionately reduce the provision, including the interest and the return component, made towards revenue requirement, in the next period.

**12. Prudence Check of Capital Expenditure:**

- I. The following principles shall be adopted for prudence check of capital cost of the existing or new projects:
- (i) In case of the thermal generating station, and the transmission or Distribution system, prudence check of capital cost may be carried out taking into consideration the benchmark norms specified/to be specified by the Commission from time to time:  
Provided that in cases where benchmark norms have not been specified, prudence check may include scrutiny of the capital expenditure, financing plan, interest during construction, incidental expenditure during construction for its reasonableness, use of efficient technology, cost over-run and time over-run, competitive bidding for procurement and such other matters as may be considered appropriate by the Commission for determination of tariff:  
Provided further that in cases where benchmark norms have been specified, the generating company or transmission licensee shall submit the reasons for exceeding the capital cost from benchmark norms to the satisfaction of the Commission for allowing cost above benchmark norms.
  - (ii) For the prudence check of proposed capital investment plan of distribution licensee, the Commission shall review the licensee's investment plan for approval, and for this purpose may require the licensee to provide relevant technical and commercial details. The costs corresponding to the approved investment plan of a licensee for a given year will, normally be considered for its revenue requirement.  
Prudence check may include scrutiny of the capital expenditure, financing plan, interest during construction, incidental expenditure during construction for its reasonableness, use of efficient technology, cost over-run and time over-run, competitive bidding for procurement and such other matters as may be considered appropriate by the Commission for determination of tariff:  
Provided that in cases where benchmark norms have been specified, the distribution licensee shall submit the reasons for exceeding the capital cost from benchmark norms to the satisfaction of the Commission for allowing cost above benchmark norms.
  - (iii) The Commission may issue new guidelines or revise the existing guidelines for vetting of capital cost of hydro-electric projects by an independent agency or an expert and in that event the capital cost as vetted by such agency or expert may be considered by the Commission while determining the tariff for the hydro generating station.
  - (iv) The Commission may issue new guidelines or revise the existing guidelines for scrutiny and approval of commissioning schedule of the hydro-electric projects in accordance with the tariff policy issued by the Central Government under section 3 of the Act from time to time which shall be considered for prudence check.
  - (v) Where the power purchase agreement entered into between the generating company and the beneficiaries provides for ceiling of actual capital expenditure, the Commission shall take into consideration such



ceiling for determination of tariff for prudence check of capital cost.

**13. Interest during construction (IDC), Incidental Expenditure during Construction (IEDC)**

**(A) Interest during Construction (IDC):**

- II. Interest during construction shall be computed corresponding to the loan from the date of infusion of debt fund, and after taking into account the prudent phasing of funds upto scheduled COD.
- III. In case of additional costs on account of IDC due to delay in achieving the scheduled COD, the generating company or the transmission/distribution licensee as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds:  
Provided that if the delay is not attributable to the generating company or the transmission/distribution licensee as the case may be, and is due to uncontrollable factors as specified in Clause 10 of these regulations, IDC may be allowed after due prudence check.  
Provided further that only IDC on actual loan may be allowed beyond the scheduled COD to the extent, the delay is found beyond the control of generating company or the transmission/distribution licensee, as the case may be, after due prudence and taking into account prudent phasing of funds.

**(B) Incidental Expenditure during Construction (IEDC):**

- I. Incidental expenditure during construction shall be computed from the zero date and after taking into account pre-operative expenses upto scheduled COD:  
Provided that any revenue earned during construction period up to scheduled COD on account of interest on deposits or advances, or any other receipts may be taken into account for reduction in incidental expenditure during construction.
- II. In case of additional costs on account of IEDC due to delay in achieving the scheduled COD, the generating company or the transmission/distribution licensee as the case may be, shall be required to furnish detailed justification with supporting documents for such delay including the details of incidental expenditure during the period of delay and liquidated damages recovered or recoverable corresponding to the delay:  
Provided that if the delay is not attributable to the generating company or the transmission/distribution licensee, as the case may be, and is due to uncontrollable factors as specified in Clause 10, IEDC may be allowed after due prudence check:  
Provided further that where the delay is attributable to an agency or contractor or supplier engaged by the generating company or the transmission/distribution licensee, the liquidated damages recovered from such agency or contractor or supplier shall be taken into account for computation of capital cost.
- III. In case the time over-run beyond scheduled COD is not admissible after due prudence, the increase of capital cost on account of cost variation corresponding to the period of time over run may be excluded from capitalization irrespective of price variation provisions in the contracts with supplier or contractor of the generating company or the transmission/distribution licensee.

**14. Controllable and Uncontrollable factors:**

- I. The following shall be considered as controllable and uncontrollable factors leading to cost escalation impacting Contract Prices, IDC and IEDC of the project :

- (i) The “controllable factors” shall include but shall not be limited to the following:
  - (a) Variations in capital expenditure on account of time and/or cost over-runs on account of land acquisition issues;
  - (b) Efficiency in the implementation of the project not involving approved change in scope of such project, change in statutory levies or force majeure events; and
  - (c) Delay in execution of the project on account of contractor, supplier or agency of the generating company or transmission/distribution licensee.
- (ii) The “uncontrollable factors” shall include but shall not be limited to the following:
  - (a) Force Majeure events.; and
  - (b) Change in law.

Provided that no additional impact of time overrun or cost over-run shall be allowed on account of non-commissioning of the generating station or associated transmission/distribution system by scheduled COD, as the same should be recovered through Implementation Agreement between the generating company and the transmission/distribution licensee:

Provided further that if the generating station is not commissioned on the scheduled COD of the associated transmission system, the generating company shall bear the IDC or transmission charges if the transmission system is declared under commercial operation by the Commission till the generating station is commissioned:

Provided also that if the transmission system is not commissioned on scheduled COD of the generating station, the transmission licensee shall arrange the evacuation from the generating station at its own arrangement and cost till the associated transmission system is commissioned.

### **15. Initial Spares:**

- I. Initial spares shall be capitalized as a percentage of the Plant and Machinery cost upto cut-off date, subject to following ceiling norms:
  - (a) Coal-based/lignite-fired thermal generating stations - 4.0%
  - (b) Gas Turbine/Combined Cycle thermal generating stations - 4.0%
  - (c) Hydro generating stations - 4.0%
  - (d) Transmission/distribution system
    - (i) Transmission/Distribution line/network - 1.00%
    - (ii) Transmission/Distribution Sub-station (Green Field) - 4.00%
    - (iii) Transmission/Distribution Sub-station (Brown Field) - 6.00%
    - (iv) Series Compensation devices and HVDC Station - 4.00%
    - (v) Gas Insulated Sub-station (GIS) - 5.00%
    - (vi) Communication system - 3.5%
    - (vii) Transmission and Distribution system- 1.5%

(others not covered under point (i) to (vi))

Provided that:

- (i) where the benchmark norms for initial spares have been published as part of the benchmark norms for capital cost by the Commission, such norms shall apply to the exclusion of the norms specified above:
- (ii) where the generating station has any transmission equipment forming part of the generation project, the ceiling norms for initial spares for such equipment shall be as per the ceiling norms specified for transmission system under these regulations:
- (iii) once the transmission project is commissioned, the cost of initial spares shall be restricted on the basis of plant and machinery cost corresponding to the transmission project at the time of truing up:
- (iv) for the purpose of computing the cost of initial spares, plant and machinery cost shall be considered as project cost as on cut-off date excluding IDC, IEDC, Land Cost and cost of civil works. The transmission licensee shall submit the break up of head wise IDC & IEDC in its tariff application.

**16. Additional Capitalisation and De-capitalisation:**

- I. The capital expenditure in respect of the new project or an existing project incurred or projected to be incurred, on the following counts within the original scope of work, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check:
  - (i) Undischarged liabilities recognized to be payable at a future date;
  - (ii) Works deferred for execution;
  - (iii) Procurement of initial capital spares within the original scope of work, in accordance with the provisions of Clause 15;
  - (iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law; and
  - (v) Change in law or compliance of any existing law:

Provided that the details of works asset wise/work wise included in the original scope of work along with estimates of expenditure, liabilities recognized to be payable at a future date and the works deferred for execution shall be submitted along with the application for determination of tariff.

- II. The capital expenditure incurred or projected to be incurred in respect of the new project on the following counts within the original scope of work after the cut-off date may be admitted by the Commission, subject to prudence check:
  - (i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;
  - (ii) Change in law or compliance of any existing law;
  - (iii) Deferred works relating to ash pond or ash handling system in the original scope of work; and
  - (iv) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.
- III. The capital expenditure, in respect of existing generating station or the transmission/distribution system including communication system, incurred or projected to be incurred on the following counts after the cut-off date, may be admitted by the Commission, subject to prudence check:

- (i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;
- (ii) Change in law or compliance of any existing law;
- (iii) Any expenses to be incurred on account of need for higher security and safety of the plant/premise as advised or directed by appropriate Government Agencies of statutory authorities responsible for national security/internal security;
- (iv) Deferred works relating to ash pond or ash handling system in the original scope of work;
- (v) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.;
- (vi) Any liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments;
- (vii) Any additional capital expenditure which has become necessary for efficient operation of generating station other than coal/lignite based stations or transmission/distribution system as the case may be. The claim shall be substantiated with the technical justification duly supported by the documentary evidence like test results carried out by an independent agency in case of deterioration of assets, report of an independent agency in case of damage caused by natural calamities, obsolescence of technology, up-gradation of capacity for the technical reason such as increase in fault level;
- (viii) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) and due to geological reasons after adjusting the proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation;
- (ix) In case of transmission system, any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement due to obsolescence of technology, replacement of switchyard equipment due to increase of fault level, tower strengthening, communication equipment, emergency restoration system, insulators cleaning infrastructure, replacement of porcelain insulator with polymer insulators, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system; and
- (x) Any capital expenditure found justified after prudence check necessitated on account of modifications required or done in fuel receiving system arising due to non-materialization of coal supply corresponding to full coal linkage in respect of thermal generating station as result of
- (xi) Provided that any expenditure on acquiring the minor items or the assets including tools and tackles, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, computers, fans, washing machines, heat convectors, mattresses, carpets etc. brought after the cut-off date shall not be considered for additional capitalization for determination of tariff w.e.f. the date of publication of this regulation on the Official Gazette:

Provided further that any capital expenditure other than that of the nature specified

above in (i) to (iv) in case of coal/lignite based station shall be met out of compensation allowance:

Provided also that if any expenditure has been claimed under Renovation and Modernization (R&M), repairs and maintenance under (O&M) expenses and Compensation Allowance, same expenditure cannot be claimed under this regulation.

- IV. In case of de-capitalization of assets of a generating company or the transmission/distribution licensee, as the case may be, the original cost of such asset as on the date of de-capitalization shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalization takes place, duly taking into consideration the year in which it was capitalized.

#### **17. Renovation and Modernization:**

- I. The generating company or the transmission/distribution licensee, as the case may be, for meeting the expenditure on renovation and modernization (R&M) for the purpose of extension of life beyond the originally recognized useful life for the purpose of tariff of the generating station or a unit thereof or the transmission/distribution system or an element thereof, shall make an application before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee.
- II. Where the generating company or the transmission/distribution licensee, as the case may be, makes an application for approval of its proposal for renovation and modernization, the approval shall be granted after due consideration of reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.
- III. In case of gas/ liquid fuel based open/ combined cycle thermal generating station, any expenditure which has become necessary for renovation of gas turbines/steam turbine after 25 years of operation from its COD and an expenditure necessary due to obsolesce or non-availability of spares for efficient operation of the stations shall be allowed :  
Provided that any expenditure included in the R&M on consumables and cost of components and spares which is generally covered in the O&M expenses during the major overhaul of gas turbine shall be suitably deducted after due prudence from the R&M expenditure to be allowed.
- IV. Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

#### **18. Special Allowance for Coal-based/Lignite fired Thermal Generating station:**

- I. In case of coal-based/lignite fired thermal generating station, the generating company, instead of availing R&M may opt to avail a „special allowance“ in accordance with the norms specified in this regulation, as compensation for meeting the requirement of expenses including renovation and modernization beyond the useful life of the generating station or a unit thereof, and in such an event, revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the

special allowance shall be included in the annual fixed cost:

Provided that such option shall not be available for a generating station or unit for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.

- II. The Special Allowance shall be @ Rs. 8 lakh/MW/year for the first year of control period and thereafter escalated @ 6.35% every year during the tariff control period, unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:

Provided that in respect of a unit in commercial operation for more than 25 years as on the date of publication of this regulation on the Official Gazette, this allowance shall be admissible from the year 2015-16:

Provided further that the special allowance for the generating stations, which, in its discretion, has already availed of a „special allowance“ in accordance with the norms specified by Central Electricity Regulatory Commission, shall be allowed Special Allowance by escalating the special allowance allowed for the year 2014-15 @ 6.35% every year during the tariff period 2015-16 to 2019-20.

- III. In the event of granting special allowance by the Commission, the expenditure incurred or utilized from special allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure.

#### **19. Compensation Allowance:**

- I. In case of coal-based or lignite-fired thermal generating station or a unit thereof, a separate compensation allowance shall be admissible to meet expenses on new assets of capital nature which are not admissible under Clause 16 of these regulations, and in such an event, revision of the capital cost shall not be allowed on account of compensation allowance but the compensation allowance shall be allowed to be recovered separately.
- II. The Compensation Allowance shall be allowed in the following manner from the year following the year of completion of 10, 15, or 20 years of useful life:

Years of Operation	Compensation Allowance (Rs lakh/MW/year)
0-10	Nil
11-15	0.20
16-20	0.50
21-25	1.00

#### **20. Sale of Infirm Power:**

- I. Supply of infirm power shall be accounted as deviation and shall be paid for from the regional deviation settlement fund accounts in accordance with the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations, 2014, as amended from time to time or any subsequent re-enactment thereof:

Provided that any revenue earned by the generating company from supply of infirm power after accounting for the fuel expenses shall be applied in adjusting the capital cost accordingly.

## **21. Debt-Equity Ratio:**

- I. For a project declared under commercial operation on or after the date of publication of this regulation on the Official Gazette, the debt-equity ratio would be considered as 70:30 as on COD. If the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan:

Provided that:

- (i) where equity actually deployed is less than 30% of the capital cost, actual equity shall be considered for determination of tariff:
- (ii) the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment:
- (iii) any grant obtained for the execution of the project shall not be considered as a part of capital structure for the purpose of debt : equity ratio.

**Explanation.-**The premium, if any, raised by the generating company or the transmission/distribution licensee, as the case may be, while issuing share capital and investment of internal resources created out of its free reserve, for the funding of the project, shall be reckoned as paid up capital for the purpose of computing return on equity, only if such premium amount and internal resources are actually utilized for meeting the capital expenditure of the generating station or the transmission/distribution system.

- II. The generating company or the transmission/distribution licensee shall submit the resolution of the Board of the company or approval from Cabinet Committee on Economic Affairs (CCEA) regarding infusion of fund from internal resources in support of the utilization made or proposed to be made to meet the capital expenditure of the generating station or the transmission/distribution system including communication system, as the case may be.
- III. In case of the generating station and the transmission/distribution system including communication system declared under commercial operation prior to the date of publication of this regulation on the Official Gazette, debt-equity ratio allowed by the Commission for determination of tariff for the period ending the year before the date of publication of this regulation on the Official Gazette shall be considered.
- IV. In case of the generating station and the transmission/distribution system including communication system declared under commercial operation prior to the date of publication of this regulation on the Official Gazette, but where debt: equity ratio has not been determined by the Commission for determination of tariff for the period ending the year before the date of publication of this regulation on the Official Gazette, the Commission shall approve the debt:equity ratio based on actual information provided by the generating company or the transmission/distribution licensee as the case may be.
- V. Any expenditure incurred or projected to be incurred on or after the date of publication of this regulation on the Official Gazette as may be admitted by the Commission as additional capital expenditure for determination of tariff, and renovation and modernization expenditure for life extension shall be serviced in the manner specified in clause (1) of this regulation.

## CHAPTER – 5 TARIFF STRUCTURE

### **22. Components of Tariff:**

- I. The tariff for supply of electricity from a thermal generating station shall comprise two parts, namely, capacity charge (for recovery of annual fixed cost consisting of the components as specified in Clause 23 of these regulations) and energy charge (for recovery of primary and secondary fuel cost and limestone cost where applicable).
- II. The tariff for supply of electricity from a hydro generating station shall comprise capacity charge and energy charge to be derived in the manner specified in Clause 33 of these regulations, for recovery of annual fixed cost (consisting of the components referred to in Clause 23) through the two charges.
- III. The tariff for transmission of electricity shall comprise transmission charge (inclusive of incentive) for recovery of annual fixed cost consisting of the components specified in Clause 23 of these regulations.
- IV. The tariff for wheeling of electricity shall comprise wheeling charge (inclusive of incentive) for recovery of annual revenue requirement consisting of the components specified in Clause 23 of these regulations.
- V. The tariff for Retail Supply of electricity shall comprise retail supply tariff for recovery of annual revenue requirement consisting of the components specified in Clause 23 of these regulations.

### **23. Capacity Charges:**

- I. The Capacity charges shall be derived on the basis of annual fixed cost. The annual fixed cost (AFC) of a generating station or a transmission system including communication system shall consist of the following components:
  - a. Return on equity;
  - b. Interest on loan capital;
  - c. Depreciation;
  - d. Interest on working capital;
  - e. Operation and maintenance expenses;
  - f. Recovery of fee for tariff petition filing; and
  - g. Minus Non tariff income
  - h. Provided that special allowance in lieu of R&M where opted in accordance to Clause 18 and/or separate compensation allowance in accordance to Clause 19, wherever applicable shall be recovered separately and shall not be considered for computation of working capital.
- II. The wheeling charges for Distribution Wheeling Business of the Distribution Licensee shall provide for the recovery of the Aggregate Revenue Requirement, as provided in this regulation and shall comprise the following:
  - a. Return on Equity Capital;
  - b. Interest on Loan Capital;
  - c. Depreciation;
  - d. Operation and maintenance expenses;
  - e. Interest on working capital and deposits from consumers and Distribution System Users; and
  - f. Provision for Bad and doubtful debts.
  - g. minus: Non-tariff income; and Income from Other Business, to the extent specified in these Regulations, and Receipts on account of additional surcharge on charges of wheeling.
- III. The Wheeling Charges may be denominated in terms of Rupees/kWh or



Rupees/kW/month, for the purpose of recovery from the Distribution System User, or any such denomination, as stipulated by the Commission from time to time.

- IV. The tariff for retail supply by a Distribution Licensee shall provide for recovery of the aggregate revenue requirement of the Distribution Licensee for each year of the Control Period, as approved by the Commission and comprising the following
- a. Return on Equity Capital;
  - b. Interest on Loan Capital;
  - c. Depreciation;
  - d. Cost of own power generation /power purchase expenses;
  - e. Transmission charges;
  - f. Operation and Maintenance expenses;
  - g. Recovery of fee for tariff petition filing;
  - h. Interest on working capital and on consumer security deposits; and
  - i. Provision for Bad and doubtful debts.
  - j. minus: Non-tariff income and Income from Other Business, to extent specified in these Regulations;
  - k. minus: Receipts on account of cross-subsidy surcharge.

**24. Energy Charges:**

- I. Energy charges shall be derived on the basis of the landed fuelcost (LFC) of a generating station (excluding hydro) and shall consist of the following cost:
  - a. Landed Fuel Cost of primary fuel; and
  - b. Cost of secondary fuel oil consumption:

Provided that any refund of taxes and duties along with any amount received on account of penalties from fuel supplier shall have to be adjusted in fuel cost.

**25. Landed Fuel Cost for Tariff Determination:**

- I. The landed fuel cost of primary fuel and secondary fuel for tariff determination shall be based on actual weighted average cost of primary fuel and secondary fuel of the three preceding months, and in the absence of landed costs for the three preceding months, latest procurement price of primary fuel and secondary fuel for the generating station, before the start of the tariff period for existing stations and immediately preceding three months in case of new generating stations shall be taken into account.

## CHAPTER – 6 COMPUTATION OF ANNUAL FIXED COST

### **26. Return on Equity:**

- I. Return on equity shall be computed in rupee terms, on the equity base determined in accordance with Clause 21.
- II. Return on equity shall be computed at the base rate of 15.50% for thermal generating stations, transmission/distribution system including communication system and run of the river hydro generating station, and at the base rate of 16.50% for the storage type hydro generating stations and run of river generating station with pondage:

Provided that:

- (i) in case of projects commissioned on or after 1st April, 2015, an additional return of 0.50 % shall be allowed, if such projects are completed within the timeline specified in Annexure-7:
- (ii) the additional return of 0.5% shall not be admissible if the project is not completed within the timeline specified above for reasons whatsoever:
- (iii) additional RoE of 0.50% may be allowed if any element of the transmission project is completed within the specified timeline and it is certified by the Regional Power Committee/National Power Committee that commissioning of the particular element will benefit the system operation in the regional/national grid:
- (iv) the rate of return of a new project shall be reduced by 1% for such period as may be decided by the Commission, if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO)/ Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system:
- (v) as and when any of the above requirements are found lacking in a generating station based on the report submitted by the respective SLDC/RLDC, RoE shall be reduced by 1% for the period for which the deficiency continues:
- (vi) additional RoE shall not be admissible for transmission line having length of less than 50 kilometers.

### **27. Tax on Return on Equity:**

- I. The base rate of return on equity as allowed by the Commission under Clause 26 shall be grossed up with the effective tax rate of the respective financial year. For this purpose, the effective tax rate shall be considered on the basis of actual tax paid in the respect of the financial year in line with the provisions of the relevant Finance Acts by the concerned generating company or the transmission/distribution licensee, as the case may be. The actual tax income on other income stream (i.e., income of non generation or non transmission/distribution business, as the case may be) shall not be considered for the calculation of “effective tax rate” computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)

Where “t” is the effective tax rate in accordance with Clause (I) of this regulation and shall be calculated at the beginning of every financial year based on the estimated profit and tax to be paid estimated in line with the provisions of the relevant Finance Act applicable for that financial year to the company on pro-rata basis by excluding the income of non-generation or non-transmission/distribution business, as the case may be, and the corresponding tax thereon. In case of generating company or the

Transmission or the Distribution licensee paying Minimum Alternate Tax (MAT), “t” shall be considered as MAT rate including surcharge and cess.

**Illustration.-**

- (i) In case of the generating company or the transmission/distribution licensee paying Minimum Alternate Tax (MAT) @ 20.96% including surcharge and cess:  
Rate of return on equity =  $15.50/(1-0.2096) = 19.610\%$
  - (ii) In case of generating company or the transmission/distribution licensee paying normal corporate tax including surcharge and cess:  
Estimated Gross Income from generation or transmission/distribution business for FY 2015-16 is Rs 1000 crore.  
Estimated Advance Tax for the year on above is Rs 240 crore.  
Effective Tax Rate for the year 2015-16 =  $\text{Rs } 240 \text{ Crore} / \text{Rs } 1000 \text{ Crore} = 24\%$   
Rate of return on equity =  $15.50 / (1-0.24) = 20.395\%$
- II. The generating company or the Transmission or the Distribution licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year based on actual tax paid together with any additional tax demand including interest thereon, duly adjusted for any refund of tax including interest received from the income tax authorities pertaining to the tariff period 2015-16 to 2019-20 on actual gross income of any financial year. However, penalty, if any, arising on account of delay in deposit or short deposit of tax amount shall not be claimed by the generating company or the transmission/distribution licensee as the case may be. Any under-recovery or over-recovery of grossed up rate on return on equity after trueing up, shall be recovered or refunded to beneficiaries on year to year basis.

**28. Interest on loan capital:**

- I. The loans arrived at in the manner indicated in Clause 21 shall be considered as gross normative loan for calculation of interest on loan.
- II. The normative loan outstanding as on the date of publication of this regulation on the Official Gazette shall be worked out by deducting the cumulative repayment as admitted by the Commission up to the date of publication of this regulation on the Official Gazette from the gross normative loan.
- III. The repayment for each of the year of the tariff control period shall be deemed to be equal to the depreciation allowed for the corresponding year/period. In case of de-capitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment on a pro rata basis and the adjustment should not exceed cumulative depreciation recovered upto the date of de-capitalization of such asset.
- IV. Notwithstanding any moratorium period availed by the generating company or the transmission/distribution licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the depreciation allowed for the year or part of the year.
- V. The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after providing appropriate accounting adjustment for interest capitalized:  
Provided that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest shall be considered:  
Provided further that if the generating station or the transmission/distribution system, as the case may be, does not have actual loan, then the weighted average rate of

- interest of the generating company or the transmission/distribution licensee as a whole shall be considered.
- VI. The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest.
  - VII. The generating company or the transmission/distribution licensee, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and the generating company or the transmission/distribution licensee, as the case may be, in the ratio of 2:1.
  - VIII. The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.
  - IX. In case of dispute, any of the parties may make an application to the commission in accordance with the Conduct of Business) Regulations 2004, as amended from time to time, including statutory re-enactment thereof for settlement of the dispute:  
Provided that the beneficiaries shall not withhold any payment on account of the interest claimed by the generating company or the Transmission or the Distribution licensee during the pendency of any dispute arising out of re-financing of loan.

**29. Depreciation:**

- I. Depreciation shall be computed from the date of commercial operation of a generating station or unit thereof or a transmission/distribution system including communication system or element thereof. In case of the tariff of all the units of a generating station or all elements of a transmission system including communication system for which a single tariff needs to be determined, the depreciation shall be computed from the effective date of commercial operation of the generating station or the transmission system taking into consideration the depreciation of individual units or elements thereof.  
Provided that effective date of commercial operation shall be worked out by considering the actual date of commercial operation and installed capacity of all the units of the generating station or capital cost of all elements of the transmission system, for which single tariff needs to be determined.
- II. The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission. In case of multiple units of a generating station or multiple elements of transmission system, weighted average life for the generating station of the transmission system shall be applied. Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the year, depreciation shall be charged on pro rata basis.
- III. The salvage value of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the capital cost of the asset:  
Provided that in case of hydro generating station, the salvage value shall be as provided in the agreement signed by the developers with the State Government for development of the Plant:  
Provided further that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciated value shall correspond to the percentage of sale of electricity under long-term power purchase agreement at regulated tariff:  
Provided also that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life and the extended life.
- IV. Land other than the land held under lease and the land for reservoir in case of hydro generating station shall not be a depreciable asset and its cost shall be excluded from

- the capital cost while computing depreciable value of the asset.
- V. Depreciation shall be calculated annually based on Straight Line Method and at rates specified in Annexure-8 of these regulations for the assets of the generating station and transmission/distribution system. However, a higher rate of depreciation may be permitted by the Commission, in case of inadequacy of cash for debt repayment. The Commission may also consider allowing advance against depreciation subject to the following constraints:
- (i) In any year, the Advance against depreciation and depreciation together do not exceed 1/12th of the original loan amount.
  - (ii) Provided that Advance Against Depreciation shall be permitted only if the cumulative repayment up to a particular year exceeds the cumulative depreciation up to that year;
  - (iii) Provided further that Advance Against Depreciation in a year shall be restricted to the extent of difference between cumulative repayment and cumulative depreciation up to that year.
  - (iv) Total depreciation allowed during the life of the project shall not exceed 90% of the original project cost.
- VI. Depreciation shall not be allowed on assets funded by consumer contribution (i.e., any receipts from consumers that are not treated as revenue) and capital subsidies/ grants.
- VII. In case of the existing projects, the balance depreciable value as on the date of publication of this regulation on the Official Gazette shall be worked out by deducting the cumulative depreciation as admitted by the Commission upto such date from the gross depreciable value of the assets.
- VIII. The generating company or the transmission/distribution license, as the case may be, shall submit the details of proposed capital expenditure during the fag end of the project (five years before the useful life) alongwith justification and proposed life extension. The Commission based on prudence check of such submissions shall approve the depreciation on capital expenditure during the fag end of the project.
- IX. In case of de-capitalization of assets in respect of generating station or unit thereof or transmission/distribution system or element thereof, the cumulative depreciation shall be adjusted by taking into account the depreciation recovered in tariff by the de-capitalized asset during its useful services.  
Provided that assets shall normally be not retired before completion of the useful life and the Licensee shall take prior approval of the Commission in case of retiring any asset before its useful life  
Provided further that the Licensee shall submit year-wise details of the assets which have completed its useful life.

### **30. Interest on Working Capital :**

- I. The working capital shall cover:
  - a. Coal-based/lignite-fired thermal generating stations
    - i. Cost of coal or lignite and limestone towards stock, if applicable, for 15 days for pit-head generating stations and 30 days for non-pit-head

- generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower;
- ii. Cost of coal or lignite and limestone for 30 days for generation corresponding to the normative annual plant availability factor;
- iii. Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil;
- iv. Maintenance spares @ 20% of operation and maintenance expenses specified in Clause 31;
- v. Receivables equivalent to two months of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor; and
- vi. Operation and maintenance expenses for one month.
- b. Open-cycle Gas Turbine/Combined Cycle thermal generating stations
  - i. Fuel cost for 30 days corresponding to the normative annual plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel;
  - ii. Liquid fuel stock for 15 days corresponding to the normative annual plant availability factor, and in case of use of more than one liquid fuel, cost of main liquid fuel duly taking into account mode of operation of the generating stations of gas fuel and liquid fuel;
  - iii. Maintenance spares @ 30% of operation and maintenance expenses specified in Clause 31;
  - iv. Receivables equivalent to two months of capacity charge and energy charge for sale of electricity calculated on normative plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel; and
  - v. Operation and maintenance expenses for one month.
- c. Hydro generating station and transmission system including communication system:
  - i. Receivables equivalent to two months of fixed cost;
  - ii. Maintenance spares @ 15% of operation and maintenance expenses specified in Clause 31; and
  - iii. Operation and maintenance expenses for one month.
- d. Transmission/Distribution Licensee
  - i. Receivables equivalent to two months of fixed cost;
  - ii. Maintenance spares @ 15% of operation and maintenance expenses specified in Clause 31; and
  - iii. Operation and maintenance expenses for one month.
- II. The cost of fuel in cases covered under sub-clauses (a) and (b) of clause (I) of this regulation shall be based on the landed cost incurred (taking into account normative transit and handling losses) by the generating company and gross calorific value of the fuel as per actual for the three months preceding the first month for which tariff is to be determined or preceding three months and no fuel price escalation shall be provided during the tariff period.
- III. The rate of interest for working capital shall be Rate of interest on working capital shall be on normative basis and shall be equal to the SBI Base Rate plus 300 basis points as on 1st April of the year for which tariff is determined.
- IV. Interest on working capital shall be payable on normative basis notwithstanding that

the generating company or the transmission/distribution licensee has not taken loan for working capital from any outside agency.

**31. Operation and Maintenance Expenses:**

- I. Normative Operation and Maintenance expenses of thermal generating stations shall be as follows:
  - a. Coal based and lignite fired (including those based on Circulating Fluidized Bed Combustion (CFBC) technology) generating stations:

(in Rs Lakh/MW)

Year	200/210/250 MW Sets	300/330/350 MW Sets	500 MW Sets	600 MW Sets and above
FY 2015-16	25.40	21.21	17.01	15.31
FY 2016-17	27.00	22.54	18.08	16.27
FY 2017-18	28.70	23.96	19.22	17.30
FY 2018-19	30.51	25.47	20.43	18.38
FY 2019-20	32.43	27.07	21.72	19.54

Provided that the norms shall be multiplied by the following factors for arriving at norms of O&M expenses for additional units in respective unit sizes for the units whose COD occurs on or after the date of publication of this regulation on the Official Gazette in the same station:

200/210/250 MW	Additional 5 <sup>th</sup> & 6 <sup>th</sup> units	0.90
	Additional 7 <sup>th</sup> & more units	0.85
300/330/350 MW	Additional 4 <sup>th</sup> & 5 <sup>th</sup> units	0.90
	Additional 6 <sup>th</sup> & more units	0.85
500 MW and above	Additional 3 <sup>rd</sup> & 4 <sup>th</sup> units	0.90
	Additional 5 <sup>th</sup> & above units	0.85

- b. Open Cycle Gas Turbine/Combined Cycle generating stations:

Year	Gas Turbine/ Combined Cycle generating stations other than small gas turbine power generating stations	Small gas turbine power generating stations	Baramura Gas Thermal Project and Rokhia Gas Thermal Project (below 25MW units)	Advance F Class Machin es

FY 2015-16	15.59	35.70	44.14	28.36
FY 2016-17	16.57	38.13	47.14	30.29
FY 2017-18	17.61	40.73	50.35	32.35
FY 2018-19	18.72	43.50	53.78	34.56
FY 2019-20	19.90	46.46	57.44	36.91

c. Lignite-fired generating stations (in Rs Lakh/MW)

Year	125 MW Sets
FY 2015-16	30.94
FY 2016-17	32.88
FY 2017-18	34.95
FY 2018-19	37.15
FY 2019-20	39.49

d. Generating Stations based on coal rejects : (in Rs Lakh/MW)

Year	O&M Expenses
FY 2015-16	30.94
FY 2016-17	32.88
FY 2017-18	34.95
FY 2018-19	37.15
FY 2019-20	39.49

II. The Water Charges and capital spares for thermal generating stations shall be allowed separately:

Provided that water charges shall be allowed based on water consumption depending upon type of plant, type of cooling water system etc., subject to prudence check. The details regarding the same shall be furnished along with the petition:

Provided that the generating station shall submit the details of year wise actual capital spares consumed at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not funded through compensatory allowance or special allowance or claimed as a part of additional capitalization or consumption of stores and spares and renovation and modernization.

III. Hydro Generating Station

a. Following operations and maintenance expense norms shall be applicable for hydro generating stations (in Rs lakh)

i. The operation and maintenance expenses shall be derived on the basis of actual operation and maintenance expenses for the years 2009-10 to 2013-14, based on the audited balance sheets, excluding abnormal operation and maintenance expenses, if any, after prudence check by the Commission.

ii. The normalized operation and maintenance expenses after prudence check, for the years 2009-10 to 2013-14, shall be escalated at the rate of 6.04% to arrive at the normalized operation and maintenance expenses at the 2013-14 price level respectively and then



averaged to arrive at normalized average operation and maintenance expenses for the 2009-10 to 2013-14 at 2013-14 price level. The average normalized operation and maintenance expenses at 2013-14 price level shall be escalated at the rate of 6.64% to arrive at the operation and maintenance expenses for year 2014-15 and thereafter escalated at the rate of 6.64% p.a., to arrive at the O&M expenses for the control period.

- iii. In case of the hydro generating stations, which have not been in commercial operation for a period of three years as on 1.4.2015, operation and maintenance expenses shall be fixed at 2% of the original project cost (excluding cost of rehabilitation and resettlement works) for the first year of commercial operation. Further, in such case, operation and maintenance expenses in first year of commercial operation shall be escalated @6.04% per annum up to the year 2013-14 and then averaged to arrive at the O&M expenses at 2013-14 price level. The average operation and maintenance expenses at 2013-14 price level shall be escalated at the rate of 6.64% to arrive at the operation and maintenance expenses for year 2014-15 and thereafter escalated at the rate of 6.64% p.a., to arrive at the O&M expenses for the control period.
- iv. In case of the hydro generating stations declared under commercial operation on or after 1.4.2015, operation and maintenance expenses shall be fixed at 4% and 2.50% of the original project cost (excluding cost of rehabilitation & resettlement works) for first year of commercial operation for stations less than 200 MW projects and for stations more than 200 MW respectively and shall be subject to annual escalation of 6.64% per annum for the subsequent years.

IV. Transmission system

- a. The following normative operation and maintenance expenses shall be admissible for the transmission system :

<b>Norms for sub-stations (in Rs Lakh per bay)</b>	<b>2015-16</b>	<b>2016-17</b>	<b>2017-18</b>	<b>2018-19</b>	<b>2019-20</b>
765 kV	87.22	90.12	93.11	96.2	99.28
400 kV	62.3	64.37	66.51	68.71	70.91
220 kV	43.61	45.06	46.55	48.1	49.64
132 kV and below	31.15	32.18	33.25	34.36	35.46
400 kV Gas Insulated Substation	53.25	55.02	56.84	58.73	60.61
<b>Norms for AC and HVDC lines (in Rs Lakh per km)</b>					
Single Circuit (Bundled Conductor with six or more sub-conductors)	0.731	0.755	0.78	0.806	0.832
Single Circuit (Bundled Conductor with four sub-conductors)	0.627	0.647	0.669	0.691	0.713
Single Circuit (Twin & Triple Conductor)	0.418	0.432	0.446	0.461	0.476
Single Circuit (Single Conductor)	0.209	0.216	0.223	0.23	0.237
Double Circuit (Bundled conductor with four or more sub-conductors)	1.097	1.133	1.171	1.21	1.249

<b>Norms for sub-stations (in Rs Lakh per bay)</b>	<b>2015-16</b>	<b>2016-17</b>	<b>2017-18</b>	<b>2018-19</b>	<b>2019-20</b>
Double Circuit (Twin & Triple Conductor)	0.731	0.755	0.78	0.806	0.832
Double Circuit (Single Conductor)	0.313	0.324	0.334	0.346	0.357
Multi Circuit (Bundled conductor with four or more sub-conductors)	1.925	1.989	2.055	2.123	2.191
Multi Circuit (Twin & Triple Conductor)	1.282	1.324	1.368	1.413	1.458
<b>Norms for HVDC Stations</b>					
HVDC Back-to-back stations (Rs. Lakh per 500 MW)	627	679	736	797	862

Provided further that the O&M expenses norms for HVDC bi-pole line shall be considered as Single Circuit quad AC line.

Provided further that each expense shall be escalated at the similar escalation rate used for 5 years to arrive at O&M expense rate of future year till the revision of this regulation.

- b. The total allowable operation and maintenance expenses for the transmission system shall be calculated by multiplying the number of bays and kms of line length with the applicable norms for the operation and maintenance expenses per bay and per km respectively.
- c. The operation and maintenance expenses of communication system forming part of inter-state transmission system shall be derived on the basis of the actual O&M expenses for the period of 2009-10 to 2013-14 based on audited accounts excluding abnormal variations if any after prudence check by the Commission. The normalized operation and maintenance expenses after prudence check, for the years 2009-10 to 2013-14, shall be escalated at the rate of 3.02% to arrive at the normalized operation and maintenance expenses at the 2013-14 price level respectively and then averaged to arrive at normalized average operation and maintenance expenses for the 2009-10 to 2013-14 at 2013-14 price level. The average normalized operation and maintenance expenses at 2013-14 price level shall be escalated at the rate of 3.32% to arrive at the operation and maintenance expenses for year 2014-15 and thereafter escalated at the rate of 3.32% p.a., to arrive at the O&M expenses for the control period.

#### V. Distribution system

- a. The Commission shall stipulate a separate trajectory of norms for each of the components of O&M expenses viz., Employee cost, R&M expense and A&G expense.

- o Employee Cost

Employee cost shall be escalated by consumer price index (CPI), adjusted by provisions for expenses beyond the control of the Distribution Licensee and one time expected expenses, such as recovery/adjustment of terminal benefits, implications of pay commission, arrears and Interim Relief, governed by the following formula:

$$EMP_n = (EMP_b * CPI \text{ inflation}) + Provision$$

Where:

EMP<sub>n</sub>: Employee expense for the year n

EMP<sub>b</sub>: Employee expense in base year, which shall be recognized at actual or as allowed by the Commission, whichever is lower, for the first period of review and shall be taken as base values.

CPI inflation: is the average increase in the Consumer Price Index (CPI) for immediately preceding three years

Provision: Provision for expenses beyond control of the Distribution Licensee and expected one-time expenses as specified above

○ Repairs and Maintenance Expense

Repairs and Maintenance expense shall be calculated as percentage (as per the norm defined) of Opening Gross Fixed Assets for the year governed by following formula:  $R\&M_n = K_b * GFA_n$

Where:

R&M<sub>n</sub>: Repairs & Maintenance expense for nth year

GFA<sub>n</sub>: Opening Gross Fixed Assets for n<sup>th</sup> year

K<sub>b</sub>: is a constant specified by the Commission in %. Value of K for each year of the control period shall be determined by the Commission in the MYT Tariff order based on licensee's filing, benchmarking of repair and maintenance expenses, approved repair and maintenance expenses vis-à-vis GFA approved by the Commission in past and any other factor considered appropriate by the Commission;

○ Administrative and General Expense

A&G expense shall be escalated by wholesale price index (WPI) and adjusted by provisions for confirmed initiatives (IT etc. initiatives as proposed by the Distribution Licensee and validated by the Commission) or other expected one-time expenses, and shall be governed by following formula:

$A\&G_n = (A\&G_b * WPI \text{ inflation}) + \text{Provision}$

Where:

A&G<sub>n</sub>: A&G expense for the year n

A&G<sub>b</sub>: A&G expense in base year, which shall be recognized at actual or as allowed by the Commission, whichever is lower, for the first period of review and shall be taken as base values.

WPI inflation: is the average increase in the Wholesale Price Index (WPI) for immediately preceding three years

Provision: Cost for initiatives or other one-time expenses as proposed by the Distribution Licensee and validated by the Commission.

Provided that such norms may be specified for a specific Distribution Licensee or a class of Distribution Licensees.

## CHAPTER – 7

### COMPUTATION OF CAPACITY CHARGES AND ENERGY CHARGES

#### 32. Computation and Payment of Capacity Charge and Energy Charge for Thermal

##### Generating Stations:

- I. The fixed cost of a thermal generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share / allocation in the capacity of the generating station.
- II. The capacity charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:

$$CC1 = (AFC/12) ( PAF1 / NAF ) \text{ subject to ceiling of } (AFC/12)$$

$$CC2 = ((AFC/6) ( PAF2 / NAF ) \text{ subject to ceiling of } (AFC/6)) - CC1$$

$$CC3 = ((AFC/4) ( PAF3 / NAF ) \text{ subject to ceiling of } (AFC/4)) - (CC1+CC2)$$

$$CC4 = ((AFC/3) ( PAF4 / NAF ) \text{ subject to ceiling of } (AFC/3)) - (CC1+CC2+CC3)$$

$$CC5 = ((AFC \times 5/12) ( PAF5 / NAF ) \text{ subject to ceiling of } (AFC \times 5/12)) - (CC1+CC2 +CC3 +CC4)$$

$$CC6 = ((AFC/2) ( PAF6 / NAF ) \text{ subject to ceiling of } (AFC/2)) - (CC1+CC2+CC3+CC4 + CC5)$$

$$CC7 = ((AFC \times 7/12) ( PAF7 / NAF ) \text{ subject to ceiling of } (AFC \times 7/12)) - (CC1+CC2 +CC3 +CC4 + CC5 + CC6)$$

$$CC8 = ((AFC \times 2/3) ( PAF8 / NAF ) \text{ subject to ceiling of } (AFC \times 2/3)) - (CC1+CC2 +CC3 +CC4 + CC5 + CC6 + CC7)$$

$$CC9 = ((AFC \times 3/4) ( PAF9 / NAF ) \text{ subject to ceiling of } (AFC \times 3/4)) - (CC1+CC2 +CC3 +CC4 + CC5 + CC6 + CC7+ CC8)$$

$$CC10 = ((AFC \times 5/6) ( PAF10 / NAF ) \text{ subject to ceiling of } (AFC \times 5/6)) - (CC1+CC2 +CC3 +CC4 + CC5 + CC6 + CC7 + CC8 + CC9)$$

$$CC11 = ((AFC \times 11/12) ( PAF11 / NAF ) \text{ subject to ceiling of } (AFC \times 11/12)) - (CC1+CC2+CC3 +CC4 + CC5 + CC6 + CC7 + CC8 + CC9 + CC10)$$

$$CC12 = ((AFC) ( PAFY / NAF ) \text{ subject to ceiling of } (AFC)) - (CC1+CC2 +CC3+CC4 + CC5 + CC6 + CC7 + CC8 + CC9 + CC10 + CC11)$$

Provided that in case of generating station or unit thereof or transmission system or an element thereof, as the case may be, under shutdown due to Renovation and Modernization, the generating company or the transmission licensee shall be allowed to recover part of AFC which shall include O&M expenses and interest on loan only. Where,

AFC = Annual fixed cost specified for the year, in Rupees.

NAPAF = Normative annual plant availability factor in percentage.

PAFN =Percent Plant availability factor achieved upto the end of the nth month.

PAFY =Percent Plant availability factor achieved during the Year

CC1, CC2, CC3, CC4, CC5, CC6, CC7, CC8, CC9, CC10, CC11 and CC12 are the Capacity Charges of 1st, 2nd, 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th months respectively.

- III. The PAFM upto the end of a particular month and PAFY shall be computed in accordance with the following formula:

$$\text{PAFM or PAFY} = 10000 \times \sum_{i=1}^N \text{DC}_i / \{ N \times \text{IC} \times (100 - \text{AUX}) \} \%$$

Where,

AUX=Normative auxiliary energy consumption in percentage.

DC<sub>i</sub> = Average declared capacity (in ex-bus MW), for the ith day of the period i.e. the month or the year as the case may be, as certified by the concerned load dispatch centre after the day is over.

IC = Installed Capacity (in MW) of the generating station

N= Number of days during the period.

Note: DC<sub>i</sub> and IC shall exclude the capacity of generating units not declared under commercial operation. In case of a change in IC during the concerned period, its average value shall be taken.

- IV. Incentive to a generating station or unit thereof shall be payable at a flat rate of 50 paise/kWh for ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) as specified in Clause 37 (B).
- V. The energy charge shall cover the primary and secondary fuel cost and limestone consumption cost (where applicable), and shall be payable by every beneficiary for the total energy scheduled to be supplied to such beneficiary during the calendar month on ex-power plant basis, at the energy charge rate of the month (with fuel and limestone price adjustment). Total Energy charge payable to the generating company for a month shall be:  
(Energy charge rate in Rs./kWh) x {Scheduled energy (ex-bus) for the month in kWh.}
- VI. Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis shall

be determined to three decimal places in accordance with the following formulae:

- (a) For coal based and lignite fired stations  
$$ECR = \frac{\{(GHR - SFC \times CVSF) \times LPPF / CVPF + SFC \times LPSFi + LC \times LPL\} \times 100}{100 - AUX}$$
- (b) For gas and liquid fuel based stations  
$$ECR = GHR \times LPPF \times 100 / \{CVPF \times (100 - AUX)\}$$
  
Where,  
AUX = Normative auxiliary energy consumption in percentage.  
CVPF =
- (a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal based stations
- (b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per liter or per standard cubic meter, as applicable for lignite, gas and liquid fuel based stations.
- (c) In case of blending of fuel from different sources, the weighted average Gross calorific value of primary fuel shall be arrived in proportion to blending ratio.
- CVSF = Calorific value of secondary fuel, in kCal per ml.  
ECR = Energy charge rate, in Rupees per kWh sent out.  
GHR = Gross station heat rate, in kCal per kWh.  
LC = Normative limestone consumption in kg per kWh.  
LPL = Weighted average landed price of limestone in Rupees per kg.  
LPPF = Weighted average landed price of primary fuel, in Rupees per kg, per litre or per standard cubic metre, as applicable, during the month. (In case of blending of fuel from different sources, the weighted average landed price of primary fuel shall be arrived in proportion to blending ratio)  
SFC = Normative Specific fuel oil consumption, in ml per kWh.  
LPSFi = Weighted Average Landed Price of Secondary Fuel in Rs./ml during the month  
Provided that energy charge rate for a gas/liquid fuel based station shall be adjusted for open cycle operation based on certification of Member Secretary of respective Regional Power Committee for the open cycle operation during the month.

VII. The generating company shall provide to the beneficiaries of the generating station the details of parameters of GCV and price of fuel i.e. domestic coal, imported coal, e-auction coal, lignite, natural gas, RLNG, liquid fuel etc., as per the forms prescribed at Annexure-I to these regulations:

Provided that the details of blending ratio of the imported coal with domestic coal, proportion of e-auction coal and the weighted average GCV of the fuels as received shall also be provided separately, along with the bills of the respective month:

VIII. The landed cost of fuel for the month shall include price of fuel corresponding to the grade and quality of fuel inclusive of royalty, taxes and duties as applicable, transportation cost by rail / road or any other means, and, for the purpose of computation of energy charge, and in case of coal/lignite shall be arrived at after considering normative transit and handling losses as percentage of the quantity of coal or lignite dispatched by the coal or lignite supply company during the month as given below:

Pithead generating stations : 0.2%

Non-pithead generating stations : 0.8%

Provided that in case of pit head stations if coal or lignite is procured from sources other than the pit head mines which is transported to the station through rail, transit loss of 0.8% shall be applicable:

Provided further that in case of imported coal, the transit and handling losses shall be 0.2%.

IX. The landed price of limestone shall be taken based on procurement price of limestone for the generating station, inclusive of royalty, taxes and duties as applicable and transportation cost.

X. In case of part or full use of alternative source of fuel supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power purchase agreement for supply of contracted power on account of shortage of fuel or optimization of economical operation through blending, the use of alternative source of fuel supply shall be permitted to generating station: Provided that in such case, prior permission from beneficiaries shall not be a pre-condition, unless otherwise agreed specifically in the power purchase agreement: Provided further that the weighted average price of use of alternative source of fuel shall not exceed 30% of base price of fuel computed as per clause (XI) of this regulation:

Provided also that where the energy charge rate based on weighted average price of use of fuel including alternative source of fuel exceeds 30% of base energy charge rate as approved by the Commission for that year or energy charge rate based on weighted average price of use of fuel including alternative sources of fuel exceeds 20% of energy charge rate based on based on weighted average fuel price for the previous month, whichever is lower shall be considered and in that event, prior consultation with beneficiary shall be made not later than three days in advance.

XI. The Commission through the specific tariff orders to be issued for each generating station shall approve the energy charge rate at the start of the tariff period. The energy charge so approved shall be the base energy charge rate at the start of the tariff period. The base energy charge rate for subsequent years shall be the energy charge computed after escalating the base energy charge rate approved at the start of the tariff period by escalation rates for payment purposes as notified by the Commission from time to time for under competitive bidding guidelines.

### **33.Computation and Payment of Capacity charge and Energy Charge for Hydro**

#### **Generating Stations:**

The fixed cost of a hydro generating station shall be computed on annual basis,based on norms specified under these regulations, and shall be recovered on monthly basis under capacity charge (inclusive of incentive) and energy charge, which shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station, i.e., in the capacity excluding the free power to the home State:

Provided that during the period between the date of commercial operation of the first

unit of the generating station and the date of commercial operation of the generating station, the annual fixed cost shall provisionally be worked out based on the latest estimate of the completion cost for the generating station, for the purpose of determining the capacity charge and energy charge payment during such period.

- I. The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month shall be :

$$\text{AFC} \times 0.5 \times \text{NDM} / \text{NDY} \times (\text{PAFM} / \text{NAPAF}) \text{ (in Rupees)}$$

Where,

AFC = Annual fixed cost specified for the year, in Rupees

NAPAF = Normative plant availability factor in percentage

NDM = Number of days in the month

NDY = Number of days in the year

PAFM = Plant availability factor achieved during the month, in percentage

- II. The PAFM shall be computed in accordance with the following formula :

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

Where

AUX = Normative auxiliary energy consumption in percentage

DC<sub>i</sub> = Declared capacity (in ex-bus MW) for the i<sup>th</sup> day of the month which the station can deliver for at least three (3) hours, as certified by the nodal load dispatch centre after the day is over.

IC= Installed capacity (in MW) of the complete generating station

N = Number of days in the month

- III. The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary, excluding free energy, if any, during the calendar month, on ex power plant basis, at the computed energy charge rate. Total Energy charge payable to the generating company for a month shall be:



(Energy charge rate in Rs. / kWh) x {Scheduled energy (ex-bus) for the month in kWh} x (100 - FEHS) / 100

- IV. Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis, for a hydro generating station, shall be determined up to three decimal places based on the following formula, subject to the provisions of clause (VI):

$$\text{ECR} = \text{AFC} \times 0.5 \times 10 / \{ \text{DE} \times (100 - \text{AUX}) \times (100 - \text{FEHS}) \}$$

Where,

DE = Annual design energy specified for the hydro generating station, in MWh, subject to the provision in clause (V) below.

FEHS = Free energy for home State, in per cent, as defined in clause 43 of this regulation.

- V. In case the actual total energy generated by a hydro generating station during a year is less than the design energy for reasons beyond the control of the generating station, the following treatment shall be applied on a rolling basis on an application filed by the generating company:

- (a) In case the energy shortfall occurs within ten years from the date of commercial operation of a generating station, the ECR for the year following the year of energy shortfall shall be computed based on the formula specified in clause (IV) with the modification that the DE for the year shall be considered as equal to the actual energy generated during the year of the shortfall, till the energy charge shortfall of the previous year has been made up, after which normal ECR shall be applicable:

Provided that in case actual generation from a hydro generating station is less than the design energy for a continuous period of 4 years on account of hydrology factor, the generating station shall approach CEA with relevant hydrology data for revision of design energy of the station.

- (b) In case the energy shortfall occurs after ten years from the date of commercial operation of a generating station, the following shall apply.

Explanation : Suppose the specified annual design energy for the station is DE MWh, and the actual energy generated during the concerned (first) and the following (second) financial years is A1 and A2 MWh respectively, A1 being less than DE. Then, the design energy to be considered in the formula in clause (IV) of these regulations for calculating the ECR for the third financial year shall be moderated as (A1 + A2 - DE) MWh, subject to a maximum of DE MWh and a minimum of A1 MWh.

- (c) Actual energy generated (e.g. A1, A2) shall be arrived at by multiplying the net metered energy sent out from the station by 100 / (100 - AUX).

- VI. In case the energy charge rate (ECR) for a hydro generating station, computed as per clause (IV) of this regulation exceeds ninety paise per kWh, and the actual saleable energy in a year exceeds { DE x (100 - AUX) x (100 - FEHS) / 10000 } MWh, the Energy charge for the energy in excess of the above shall be billed at ninety paise per kWh only:

Provided that in a year following a year in which total energy generated was less than the design energy for reasons beyond the control of the generating company, the energy charge rate shall be reduced to ninety paise per kWh after the energy charge shortfall of the previous year has been made up.

### 34. Computation and Payment of Transmission Charge

- I. The fixed cost of the transmission system or communication system forming part of transmission system shall be computed on annual basis, in accordance with norms contained in these regulations, aggregated as appropriate, and recovered on monthly basis as transmission charge from the users, who shall share these charges in the manner specified in Clause 44.
- II. The Transmission charge (inclusive of incentive) payable for a calendar month for transmission system or part shall be

#### For AC system:

- a) For TAFM < 98%  
 $AFC \times (NDM/NDY) \times (TAFM/98\%)$
- b) For TAFM: 98% < TAFM < 98.5%  
 $AFC \times (NDM/NDY) \times (1)$
- c) For TAFM: 98.5% < TAFM < 99.75%  
 $AFC \times (NDM/NDY) \times (TAFM/98.5\%)$
- d) For TAFM > 99.75%  
 $AFC \times (NDM/NDY) \times (99.75\%/98.5\%)$

#### For HVDC bi-pole links and HVDC back-to-back Stations:

- a) For TAFM < 95%  
 $AFC \times (NDM/NDY) \times (TAFM/95\%)$
- b) For TAFM: 95% < TAFM < 96%  
 $AFC \times (NDM/NDY) \times (1)$
- c) For TAFM: 96% < TAFM < 99.75%  
 $AFC \times (NDM/NDY) \times (TAFM/96\%)$
- d) For TAFM > 99.75%  
 $AFC \times (NDM/NDY) \times (99.75\%/96\%)$

Where,

AFC = Annual Fixed Cost specified for the year in Rupees

NATAF = Normative annual Transmission availability factor, in per cent

NDM = Number of days in the month

NDY = Number of days in the year

TAFM = Transmission System availability factor for the month, in percent computed in accordance with CERC Regulation.

- III. The transmission charges shall be calculated separately for part of the transmission system having different NATAF, and aggregated thereafter, according to their sharing by the long term transmission customers/DICs.

### 35. Deviation Charges:

- I. Variations between actual net injection and scheduled net injection for the generating stations, and variations between actual net drawal and scheduled net drawal for the beneficiaries shall be treated as their respective deviations and charges for such deviations shall be governed by the Central Electricity Regulatory Commission

(Deviation Settlement Mechanism and Related matters) Regulations, 2014, as amended from time to time or any subsequent re-enactment thereof.

- II. Actual net deviation of every Generating Stations and Beneficiaries shall be metered on its periphery through special energy meters (SEMs) installed by the State/Central Transmission Utility (CTU), and computed in MWh for each 15-minute time block by the concerned State/Regional Load Despatch Centre.

## CHAPTER – 8 NORMS OF OPERATION

### 36. Recovery of capacity charge, energy charge, transmission charge and incentive

by the generating company and the transmission licensee shall be based on the achievement of the operational norms specified in the clause 37 to 40 of this regulation.

The Commission may on its own revise the norms of Station Heat Rate specified in clause 37 of this regulation in respect of any of the generating stations for which relaxed norms have been specified.

### 37. Norms of operation for thermal generating station

I. The norms of operation as given hereunder shall apply to thermal generating stations:

#### (A) Normative Annual Plant Availability Factor (NAPAF)

a) All thermal generating stations, except those covered under clauses (b)-85%

Provided that in view of shortage of coal and uncertainty of assured coal supply on sustained basis experienced by the generating stations, the NAPAF for recovery of fixed charges shall be 83% till the same is reviewed.

b) Lignite fired Generating Stations using Circulatory Fluidized Bed Combustion (CFBC) Technology and Generating stations based on coal rejects

1. First Three years from COD – 75%
2. For next year after completion of three years of COD – 80%

#### (B) Normative Annual Plant Load Factor (NAPLF) for Incentive

a) All thermal generating stations- 85%

#### (C) Gross Station Heat Rate

a) Existing Thermal Generating Station

1. Existing Coal-based Thermal Generating Station :

200/210/250 MW Sets	500 MW Sets (Sub-critical)
2450 kCal/kWh	2375 kCal/kWh

#### Note 1

In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the gross station heat rate shall be 40 kCal/kWh lower than the gross station heat rate specified above.

## Note 2

For the generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average gross station heat rate of the combinations.

2. Lignite-fired Thermal Generating Stations :the gross station heat rates specified under sub-clause (1) for coal-based thermal generating stations shall be applied with correction, using multiplying factors as given below:

- (a) For lignite having 50% moisture: 1.10
- (b) For lignite having 40% moisture: 1.07
- (c) For lignite having 30% moisture: 1.04
- (d) For other values of moisture content, multiplying factor shall be pro-rated for moisture content between therated values of multiplying factor for the respective range given under sub-clauses (a) to (c) above.

3. Gas Turbine/Combined Cycle generating stations except for plants mentioned in point 4 below:

- (a) Open cycle - 2830 kCal/kWh
- (b) Combined cycle - 1950 kCal/kWh

4. Baramura Gas Thermal Project and Rokhia Gas Thermal Project

- (a) Open cycle - 3700 kCal/kWh

**b) New Thermal Generating Station achieving COD on or after the date of publication of this regulation on the Official Gazette**

1. Coal-based and lignite-fired Thermal Generating Stations

$$= 1.045 \times \text{Design Heat Rate (kCal/kWh)}$$

Where the Design Heat Rate of a generating unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR, zero percent make up, design coal and design cooling water temperature/back pressure.

Provided that the design heat rate shall not exceed the following maximum design unit heat rates depending upon the pressure and temperature ratings of the units:

Pressure Rating (Kg/cm <sup>2</sup> )	150	170	170	247
SHT/RHT (°C)	535/535	537/537	537/565	565/593
Type of BFP	Electric Driven	Turbine Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1955	1950	1935	1850
Min. Boiler Efficiency				

Sub-Bituminous Indian Coal	0.86	0.86	0.86	0.86
Bituminous Imported Coal	0.89	0.89	0.89	0.89
<b>Max Design Unit Heat Rate (kCal/kWh)</b>				
Sub-Bituminous Indian Coal	2273	2267	2250	2151
Bituminous Imported Coal	2197	2191	2174	2078

Provided further that in case pressure and temperature parameters of a unit are different from above ratings, the maximum design unit heat rate of the nearest class shall be taken:

Provided also that where unit heat rate has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers, the unit design heat rate shall be arrived at by using guaranteed turbine cycle heat rate and boiler efficiency:

Provided also that where the boiler efficiency is below 86% for Sub-bituminous Indian coal and 89% for bituminous imported coal, the same shall be considered as 86% and 89% respectively for Sub-bituminous Indian coal and bituminous imported coal for computation of station heat rate:

Provided also that maximum turbine cycle heat rate shall be adjusted for type of dry cooling system:

Provided also that if one or more generating units were declared under commercial operation prior to the date of publication of this regulation on the Official Gazette, the heat rate norms for those generating units as well as generating units declared under commercial operation on or after the date of publication of this regulation on the Official Gazette shall be lower of the heat rate norms arrived at by above methodology and the norms as per the clause 37(C)(a)(1) of this regulation:

Provided also that in case of lignite-fired generating stations (including stations based on CFBC technology), maximum design heat rates shall be increased using factor for moisture content given in sub-clause 37(C)(a)(2) of this regulation:

Provided also that for Generating stations based on coal rejects, the Commission will approve the Design Heat Rate on case to case basis.

Note: In respect of generating units where the boiler feed pumps are electrically operated, the maximum design unit heat rate shall be 40 kCal/kWh lower than the maximum design unit heat rate specified above with turbine driven BFP.

2. Gas-based / Liquid-based thermal generating unit(s)/ block(s)

= 1.05 X Design Heat Rate of the unit/block for Natural Gas and RLNG (kCal/kWh)

= 1.071 X Design Heat Rate of the unit/block for Liquid Fuel (kCal/kWh)

Where the Design Heat Rate of a unit shall mean the guaranteed heat rate for a unit at 100% MCR and at site ambient conditions; and the Design Heat Rate of a block shall mean the guaranteed heat rate for a block at 100% MCR, site ambient conditions, zero percent make up, design cooling water temperature/back pressure:

**(D) Secondary fuel oil consumption**

- a) Coal-based generating stations: 0.50 ml/kWh
- b) Lignite-fired generating stations except stations based on CFBC technology: 2ml/kWh
- c) Lignite-fired generating stations based on CFBC Technology: 1.00ml/kWh
- d) Generating Stations based on Coal Rejects : 2 ml/kWh

**(E) Auxiliary Energy Consumption :**

- a) Coal-based generating stations With Natural Draft cooling tower or without cooling tower
  - (i) 200 MW series - 8.5%
  - (ii) 300/330/350/500 MW and above
    - Steam driven boiler feed pumps - 5.25%
    - Electrically driven boiler feed pumps - 7.75%

Provided further that for thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%:

Provided also that Additional Auxiliary Energy Consumption as follows may be allowed for plants with Dry Cooling Systems:

Type of Dry Cooling System	(% of gross generation )
Direct cooling air cooled condensers with mechanical draft fans	1%
Indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower	0.5%

- b) Gas Turbine /Combined Cycle generating stations:
  - (i) Combined Cycle : 2.5%
  - (ii) Open Cycle : 1.0%
- c) Lignite-fired thermal generating stations:

(i) All generating stations with 200 MW sets and above: The auxiliary energy consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (E) (a) above.

Provided that for the lignite fired stations using CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at

(E) (a) above.

- (ii) Lime stone consumption for lignite-based generating station using CFBC technology:

Limestone consumption (kg/kWh) = 0.056 x normative specific lignite consumption (kg/kWh) x Savg(%)

Where: Savg = Weighted Average inorganic Sulphur content in lignite

- d) Generating Stations based on coal rejects : 10%

### **38. Norms of operation for hydro generating stations:**

- I. The following Normative annual plant availability factor (NAPAF) shall apply to hydro generating station:
  - (a) Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8%, and where plant availability is not affected by silt : 90%
  - (b) In case of storage and pondage type plants with head variation between full reservoir level and minimum draw down level is more than 8% and when plant availability is not affected by silt, the month wise peaking capability as provided by the project authorities in the DPR (approved by CEA or the State Government) shall form basis of fixation of NAPAF.
  - (c) Pondage type plants where plant availability is significantly affected by silt: 85%.
  - (d) Run-of-river type plants: NAPAF to be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant.
- II. A further allowance may be made by the Commission in NAPAF determination under special circumstances, e.g. abnormal silt problem or other operating conditions, and known plant limitations.
- III. A further allowance of 5% may be allowed for geographical difficulties in North East Region as per discretion of the commission.
- IV. Auxiliary Energy Consumption (AUX):
  - (a) Surface hydro generating stations
    - (i) with rotating exciters mounted on the generator shaft : 0.7%
    - (ii) with static excitation system : 1.00%



- (b) Underground hydro generating stations
  - (i) with rotating exciters mounted on the generator shaft : 0.9%
  - (ii) with static excitation system: 1.2%

### 39. Norms of operation for transmission system

- I. Normative Annual Transmission System Availability Factor (NATAF): shall be as under:
  - For recovery of Annual Fixed Charges:
    - (1) AC system: 98%
    - (2) HVDC bi-pole links and HVDC back-to-back stations: 95%
  - For incentive consideration:
    - (1) AC system: 98.50%
    - (2) HVDC bi-pole links and HVDC back-to-back Stations: 96%

Provided that for new HVDC stations, NATAF shall be considered as 95% for first three years of operations for the purpose of incentive:

Provided further that no incentive shall be payable for availability beyond 99.75%:

Provided also that for AC system, two trippings per year shall be allowed. After two trippings in a year, additional 12 hours outage shall be considered in addition to the actual outage:

Provided also that in case of outage of a transmission element affecting evacuation of power from a generating station, outage hour shall be multiplied by a factor of 2.

- II. Auxiliary Energy Consumption in the sub-station:

- (a) AC System

The charges for auxiliary energy consumption in the AC sub-station for the purpose of air-conditioning, lighting and consumption in other equipment shall be borne by the transmission licensee and included in the normative operation and maintenance expenses.

- (b) HVDC sub-station

For auxiliary energy consumption in HVDC sub-stations, the State Government may allocate an appropriate share from one or more Generating Stations. The charges for such power shall be borne by the transmission licensee from the normative operation and maintenance expenses.

### 40. Target availability for Distribution System

- I. Recovery of the Annual Revenue Requirement determined as per the norms under these regulations shall be based on achievement of the target availability index as under:

The Availability index shall be computed for both Wheeling Business and Supply Business of the Distribution Licensee on yearly basis as per following:

- (a) For Wheeling Business:

Wheeling Network Availability Index (%) =  $(1 - (\text{SAIDI}/8760)) \times 100$  Where,  
SAIDI = Sum of all customer interruption durations/Total number of consumers Served

- (b) For Supply Business:

The Supply Availability shall be measured on the basis of power contracted by the Distribution Licensee on a long-term basis as per the power procurement plan under following heads:

Base Load Supply Availability =  $\frac{((\text{Actual Contracted Base Load Supply (MW)} \times (\text{Number of Off-Peak hours}))}{((\text{Base Load in MW}) \times (\text{Number of Off-Peak hours}))} \times \text{Peak}$

Load Supply Availability = ((Actual Contracted Peak Load Supply (MW)) X (Number of Peak hours)) / ((Peak Load in MW) X (Number of Peak hours))  
Supply Availability Index = 75% of Base Load Supply Availability + 25% of Peak Load Supply Availability

- II. The Distribution Licensee shall maintain data on planned maintenance outages, load shedding, force majeure outages and trippings.
- III. The incentive/disincentive shall exclude the circumstances when the actual supply differs from the contracted supply due to force majeure situations, weather conditions, extreme monsoon failure, station outages, etc. which are beyond the control of the Distribution Licensee.
- IV. The Commission shall specify progressively increasing normative levels of Availability for Wires and Supply Business of the Distribution Licensee on the basis of past performance over the control period.
- V. Provided that the Availability of Supply Business shall not be lower than 90% and shall gradually increase to 95% or 98% in no less than three years.
- VI. The additional ARR shall be considered as +/- 0.2% of ARR for every percentage point increase/decrease in Availability vis-à-vis the normative levels of availability.
- VII. Provided that the maximum additional return that can be earned/reduced shall be +/- 2% of ROE

## CHAPTER – 9-SCHEDULING, ACCOUNTING AND BILLING

### 41. Scheduling:

- I. The methodology for scheduling and dispatch for the generating station shall be as specified in the Grid Code.

42. **Metering and Accounting:** The provisions of the Grid Code shall be applicable.

### 43. Billing and Payment of charges:

- I. Bills shall be raised for capacity charge, energy charge and the transmission charge on monthly basis by the generating company and the transmission licensee in accordance with these regulations, and payments shall be made by the beneficiaries directly to the generating company or the transmission licensee, as the case may be.
- II. Payment of the capacity charge for a thermal generating station shall be shared by the beneficiaries of the generating station as per their percentage shares for the month (inclusive of any allocation out of the unallocated capacity) in the installed capacity of the generating station. Payment of capacity charge and energy charge for a hydro generating station shall be shared by the beneficiaries of the generating station in proportion to their shares (inclusive of any allocation out of the unallocated capacity) in the saleable capacity (to be determined after deducting the capacity corresponding to free energy to home State as per Note 3 herein).

#### Note 1

Shares / allocations of each beneficiary in the total capacity of State/Central sector generating stations shall be as determined by the Central Government, inclusive of any allocation made out of the unallocated capacity. The shares shall be applied in percentages of installed capacity and shall normally remain constant during a month. Based on the decision of the Central Government the changes in allocation shall be communicated by the Member-Secretary, Regional Power Committee in advance, at least three days prior to beginning of a calendar month, except in case of an emergency calling for an urgent change in allocations out of unallocated capacity. The total capacity share of a beneficiary would be sum of its capacity share plus allocation out of the unallocated portion. In the absence of any specific allocation of unallocated power by the Central Government, the unallocated power shall be added to the allocated shares in the same proportion as the allocated shares.

#### Note 2

The beneficiaries may propose surrendering part of their allocated firm share to other beneficiaries within / outside the region. In such cases, depending upon the technical feasibility of power transfer and specific agreements reached by the generating company with other States within/ outside the region for such transfers, the shares of the beneficiaries may be prospectively re-allocated by the State/Central Government for a specific period (in complete months) from the beginning of a calendar month. When such re-allocations are made, the beneficiaries who surrender the share shall not be liable to pay capacity charges for the surrendered share. The capacity charges for the capacity surrendered and reallocated as above shall be paid by the State(s)/Beneficiary to whom the surrendered capacity is allocated. Except for the period of reallocation of capacity as above, the beneficiaries of the generating station

shall continue to pay the full capacity charges as per allocated capacity shares. Any such reallocation and its reversion shall be communicated to all concerned by the Member Secretary, Regional Power Committee in advance, at least three days prior to such reallocation or reversion taking effect.

**Note 3**

FEHS = Free energy for home State, in percent and shall be taken as 13% or actual whichever is less.

Provided that in cases where the site of a hydro project is awarded to a developer, by the State Government by following a two stage transparent process of bidding, the “free energy” shall be taken as 13%, in addition to energy corresponding to 100 units of electricity to be provided free of cost every month to every project affected family for a period of 10 years from the date of commercial operation of the generating station:

Provided further that the generating company shall submit detailed quantification of energy corresponding to 100 units of electricity to be provided free of cost every month to every month to every project affected family for a period of 10 years from the date of commercial operation.

**44. Sharing of Transmission Charges:**

- I. The sharing of transmission charges shall be governed by the Sharing Regulations.
- II. The charges determined in this regulation in relation to communication system forming part of transmission system shall be shared by the beneficiaries or long term transmission customers in proportion to the capital cost belonging to respective beneficiaries.

**45. Rebate.**

- I. For payment of bills of the generating company and the transmission licensee through letter of credit on presentation or through NEFT/RTGS within a period of 2 days of presentation of bills by the generating company or the transmission licensee, a rebate of 2% shall be allowed.
- II. Where payments are made on any day after 2 days and within a period of 30 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1% shall be allowed.

**46. Late payment surcharge:**

- I. In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary, beyond a period of 60 days from the date of billing, a late payment surcharge at the rate of 1.50% per month shall be levied by the generating company or the transmission licensee, as the case may be.

## CHAPTER – 10 SUBSIDY, CROSS SUBSIDY AND TARIFF DESIGN

### 47. Subsidy

- I. The Commission shall determine the ARR and Tariff without considering subsidy. Provided that if the State Government declares subsidy for the categories of consumers after notification of Tariff Order, the licensee shall incorporate the same in the tariff and intimate the Commission with the revised Tariff Schedule that shall be charged if the subsidy is received in advance:
- II. Provided further that in case the State Government declares subsidy in advance or during tariff filing proceedings and the licensee incorporates the subsidy in the petition, the Commission shall notify two tariff schedules, one with subsidy and the other without subsidy:
- III. Provided also that the Government's subsidy provided for or declared shall be supported by documentary evidence of time schedule of payment, mode of the payment of the subsidy and categorization of the subsidy amount into subsidized consumer categories:
- IV. The Commission may clarify in the tariff order, post the declaration from the Government, the quantum of Government's subsidy as applicable to the fuel cost adjustment along with the range (%) of variable cost upto which the fuel adjustment cost shall not be passed to the consumers, category wise classification, mode of payment and schedule of payment etc.
- V. the State Government shall notwithstanding any direction which may be given under Section 108 of the Act, pay, in advance by a separate Account Payee Cheque in favour of the Licensee or such other person to implement the subsidy.
- VI. In case of no disbursement or delayed disbursement of subsidy by the Government, the licensee shall charge consumers as per the tariff schedule which is approved by the Commission without consideration of subsidy.

### 48. Cross Subsidy, Allocation of Cost to Serve and Tariff Design

- I. The Commission shall notify a roadmap for reduction of cross subsidies within six months from the notification of these Regulations. The road map shall also have intermediate milestones, based on the approach of a gradual reduction in cross subsidy.
- II. The Distribution Licensee shall compute the consumer category-wise cost of supply as per the methodology elaborated below.
- III. Allocation of Cost: The Cost to serve shall be allocated to the consumer categories in the following manner:

**Step 1: Functionalization of Cost** - Total cost shall be divided on the basis of functions performed such as power purchase, distribution etc.

**Step 2: Classification of Cost** –Each of the functionalized costs shall be further classified, based on its intrinsic nature into Demand related cost, Energy related cost and Customer related cost. Demand related costs shall generally be of fixed nature, related to capacity creation and shall include interest on capital borrowing, depreciation etc. Energy cost shall be related to quantum of electricity consumption of consumer, such as fuel cost, interest on working capital, etc. Customer related cost shall include operating expenses associated with meter reading, billing and accounting.

### **Step 3: Allocation of Cost**

**i. Allocation of Demand Costs:** Demand costs of all three functions shall be allocated among consumer categories on the basis of average coincident peak demand of the tariff categories (average of past 12 months). To facilitate determination of average coincident peak demand for the various tariff categories, load research shall be made an integral part of the operations of the DISCOMs and systematic load research exercises shall be initiated.

**ii. Allocation of Energy Costs:** Energy related costs of Distribution functions shall be allocated to consumer categories on the basis of ratio of electricity consumption of each consumer category to the total electricity consumption under the purview of the Distribution Licensee. Energy related costs of Power purchase shall be allocated to various tariff categories on the basis of block approach on merit order dispatch and incremental principle, where each tariff category shall be allocated the incremental (energy related) power purchase cost on the basis of their respective share in the incremental power purchase. For the purpose of operationalizing the block approach and incremental principle, the Commission shall identify and notify a suitable year as the "base year". .

**iii. Allocation of Customer Costs:** Customer related costs shall be allocated to consumer categories on the basis of the ratio of number of consumers in each category to total number of consumers under the purview of the Distribution Licensee.

IV. Summation of allocated Demand cost, Energy cost and Customer cost across functions shall be total Cost to serve for respective consumer categories. Cost to serve reduced by revenue from a consumer category shall give total subsidy for that category. Total subsidy for a consumer category reduced by Government subsidy, if any, shall be cross-subsidy for that consumer category.

V. The consumers below poverty line who consume power below a specified level, say 30 units per month, shall receive a special support through cross subsidy.

VI. Provided till such time the utility is able to determine consumer category wise cost of supply, voltage wise cost of supply as per the methodology prescribed by Honorable APTEL in its order dated 10<sup>th</sup> May 2012 in the matter of BERC Vs BSEB.

#### **49. Cross-subsidy surcharge and additional surcharge in Open Access**

I. The amount received or to be received by the licensee on account of cross subsidy surcharge and additional surcharge, as approved by the Commission from time to time in accordance with the Regulations specified by the Commission, shall be shown separately against the consumer category that is permitted open access as per the phasing plan.

II. Cross-subsidy surcharge and additional surcharge shall be shown as revenue from the tariff from the consumer categories who have been permitted open access and such amount shall be utilized to meet the cross-subsidy requirements of subsidized categories and fixed costs of the Distribution Licensee arising out of his obligation to supply.

III. Provided that the licensee shall provide such details in its annual filings.

#### **50. Tariff Design**

- I. The Commission shall be guided by the objective that the tariff progressively reflects the efficient and prudent cost of supply of electricity.
- II. After the costs have been allocated based on the method specified in clauses 48 above, tariffs for different consumer categories shall be designed with due regard to factors provided under section 62(3) of the Act.
- III. The time of day tariff would be structured across three time slabs to denote normal, peak and off-peak periods. The time-periods would vary according to different seasons of the year i.e. summer, winter and the monsoon season. The peak tariff would be 40% higher than the normal tariff and the off-peak tariff would be priced 40% lower than the normal tariff.
- IV. The peak and off-peak hours during seasons shall be as notified by the State Load Despatch Centers in advance.
- V. Time of Day tariff shall be introduced in a phased manner, wherein in phase-1 it would be compulsory for HT Consumers, in phase 2 – compulsory for LT consumers consuming more than 25 KW and in phase 3 compulsory for LT consumers consuming more than 10 KW.

## CHAPTER – 11 MISCELLANEOUS PROVISIONS

### **51. Sharing of Clean Development Mechanism (CDM) Benefits:**

The proceeds of carbon credit from approved Clean Development Mechanism (CDM) project shall be shared in the following manner-

- I. 100% of the gross proceeds on account of Clean Development Mechanism (CDM) to be retained by the project developer in the first year after the date of commercial operation of the generating station or the transmission/distribution licensee, as the case may be;
- II. In the second year, the share of the beneficiaries shall be 10% which shall be progressively increased by 10% every year till it reaches 50%, whereafter the proceeds shall be shared in equal proportion, by the generating company or the transmission/distribution licensee, as the case may be, and the beneficiaries.

### **52. Norms to be ceiling norms:**

Norms specified in these regulations are the ceiling norms and shall not preclude the generating company or the transmission/distribution licensee, as the case may be, and the beneficiaries from agreeing to the improved norms and in case the improved norms are agreed to, such improved norms shall be applicable for determination of tariff.

### **53. Deviation from norms:**

- I. Tariff for sale of electricity by the generating company or for transmission/distribution charges of the transmission/distribution licensee, as the case may be, may also be determined in deviation of the norms specified in these regulations subject to the conditions that :
  - i. The levelised tariff over the useful life of the project on the basis of the norms in deviation does not exceed the levelised tariff calculated on the basis of the norms specified in these regulations and upon submission of complete workings with assumptions to be provided by the generator or the transmission licensee at the time of filing of the application;

Provided that For the purpose of calculating the levelised tariff, the discounting factor shall be as notified by the Commission from time to time.

- ii. Any deviation shall come into effect only after approval by the Commission, for which an application shall be made by the generating company or the transmission/distribution licensee, as the case may be.

### **54. Deferred Tax liability with respect to previous tariff period:**

The deferred tax Liability shall be recovered from the beneficiaries, as and when the same gets materialized.

### **55. Foreign Exchange Rate Variation:**

- I. The generating company or the transmission/distribution licensee, as the case may be, may hedge foreign exchange exposure in respect of the interest on foreign currency loan and repayment of foreign loan acquired for the generating station or the transmission/.distribution system, in part or in full in the discretion of the generating company or the transmission/distribution licensee.
- II. As and when the petitioner enters into any hedging based on its approved hedging policy, the petitioner should communicate to the beneficiaries concerned about its



- hedging decision within thirty days of entering into such hedging transaction(s).
- III. Every generating company and transmission/distribution licensee shall recover the cost of hedging of foreign exchange rate variation corresponding to the normative foreign debt, in the relevant year on year-to-year basis as expense in the period in which it arises and extra rupee liability corresponding to such foreign exchange rate variation shall not be allowed against the hedged foreign debt.
  - IV. To the extent the generating company or the transmission/distribution licensee is not able to hedge the foreign exchange exposure, the extra rupee liability towards interest payment and loan repayment corresponding to the normative foreign currency loan in the relevant year shall be permissible provided it is not attributable to the generating company or the transmission/distribution licensee or its suppliers or contractors.
  - V. Every generating company and the transmission/distribution licensee shall recover the cost of hedging and foreign exchange rate variation on year-to-year basis as income or expense in the period in which it arises.

**56. Recovery of cost of hedging or Foreign Exchange Rate Variation:**

- I. Recovery of cost of hedging or foreign exchange rate variation shall be made directly by the generating company or the transmission/distribution licensee, as the case may be, from the beneficiaries, without making any application before the Commission:
- II. Provided that in case of any objections by the beneficiaries, to the amounts claimed on account of cost of hedging or foreign exchange rate variation, the generating company or the transmission/distribution licensee, as the case may be, may make an appropriate application before the Commission for its decision expenses shall be reimbursed directly by the beneficiary.

**57. Other Fee**

- I. The application filing fee and the expenses incurred on publication of notices in the application for approval of tariff, may in the discretion of the Commission, be allowed to be recovered by the generating company or the transmission/distribution licensee, as the case may be, directly from the beneficiaries:
- II. The following fees and charges shall be reimbursed directly by the beneficiaries in proportion of their allocation in the generating stations or by the long term transmission customers in proportion to their share in the State transmission systems;
  - a. Fees and charges paid to SLDC/RLDC;
  - b. Licence fees paid by the licensee;
- III. The Commission may, for the reasons to be recorded in writing and after hearing the affected parties allow reimbursement of any fee or expenses, as may be considered necessary.

**58. Power to Relax.**

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

**59. Power to amend**

The Commission may, at anytime, amend any provisions of these Regulations.

**60. Power to remove difficulties**

If any difficulty arises in giving effect to the provisions of these Regulations, the Commission may, by general or specific order, make such provisions not inconsistent with the provisions of the Act, as may appear to be necessary for removing the difficulty.

## 61. Repeal and savings

- (a) Save as otherwise provided in these Regulations, the TERC (Tariff Procedure) Regulations, 2004, are hereby repealed.
- (b) Notwithstanding such repeal, any proceedings before the Commission pertaining to the period prior to the commencement of the Control Period, including Petitions for True up of expenses, annual performance review, etc. shall be governed by TERC (Tariff Procedure) Regulations, 2004.

By Order of the Commission



(Er. H.K.Das)  
Secretary

**T.E.R.C.**

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## ANNEXURE-I.

### 1. REVENUE REQUIREMENT FORM

Terms used are to be read as per the meanings assigned to the same under the Act and Regulations. All financial figures, unless mentioned otherwise, are to be in rupees lakhs. The figures should be based on audited accounts for previous year, estimated for current year and projected for next year. The figures as allowed by the Commission for previous year and current year may also be given.

- a. Original cost of fixed assets available for use and necessary for the purpose of the business to be provided as follows
- (1) Generation Assets (station wise) as per Form-B
  - (2) Transmission Assets(voltage class wise)
  - (3) Distribution Assets(Voltage class wise) less Contribution from consumers including advance from them
  - (4) Other Assets, if any.

#### Notes :

- (1) Generation assets will include assets up to Station Bus bar as per Section 2(72) of the Act.
- (2) Distribution assets will be assets as per Section 2(19) of the Act.
- (3) Details of capital expenditure proposed to be made during the ensuing year(whether included in fixed assets or capital work-in-progress) is to be submitted for assets individually costing more than 0.1% of overall net fixed assets as standing at the end of the previous year, along with complete details and justifications from the angle of the utility and consumer. All capital expenditure more than Rs.100 lakhs for any individual item will be supported with DPR or detailed techno-economic analysis unless already approved by the Commission.
- (4) The value of the assets, if any, retired or not available for use is not to be included in revenue requirement. Figures for ensuing year, current year and previous year of the assets so retired/likely to be retired/not available for use are to be submitted.
- (5) Period during which the units of the operational power stations were scheduled to be under planned repairs and maintenance or were under major repairs other than the above, as contained in Form-A may be submitted.
- (6) In case the cost of any assets has been revalued, or purchased on revalued cost basis, the details thereof, along with the year of revaluation are to be submitted.
- (7) Foreign exchange variation charged/adjusted, in capital cost in any period, if any, is to be separately indicated.
- (8) Figures for capital expenditure for projects under construction

are to be separately indicated along with the sanctions required if any and the DPR.

b. Cost of intangible assets including expenses on account of new capital issues.

1. Details of items included in this item valuing Rs. 5 lakhs & above are to be submitted.

c. Original cost of works in progress.

1. The notes under 1(a) are also applicable and relevant details and documents needs to be submitted.
2. Interest during construction(to be charged and actually charged) may be indicated separately along with basis for calculation.
3. The break-up of major capital works in progress at the beginning of the year, proposed expenditure for the year and balance to be incurred needs to be provided. The physical status in brief along with estimated date of completion and capitalization. The variations from the projections of earlier years needs to be suitably explained.

d. Investments.

1. Details of investments made along with date and amount, nature, period, income from such investments and the entity in which the investment has been made are to be given. Also the source of funds for such investments.

e. Working capital

1. Supporting proof of State Bank Base Rate considered and related calculation needs to be provided
2. Calculation supporting Working capital requirements as per Clause-30 of this regulation.
3. Working Capital is subtotal of 1(a) to (e)

f. Depreciation

1. The amount written off or set aside on account of depreciation on fixed assets and amount written off in respect of intangible assets needs to be provided.
2. Category-wise details, along with the rates of depreciation charged on assets and total of accumulated depreciation at the

beginning and end of the year is required to be submitted.

3. Details of depreciation chargeable to revenue account for the year to be given as in Form-B.
4. The closing balance of a particular year should match with opening balance of next year
5. Withdrawals from depreciation fund, if any, to be separately indicated.
6. Details of amount charged/taken in revenue requirements, but actually not set aside or written off as depreciation in books and not included above are to be indicated.
7. The basis and the approval of the Competent Authority for the rates of Depreciation is to be enclosed.

g. Loans

1. Details of Loans borrowed from institutions, organizations and the public needs to be provided.
2. Loan wise statement of loans taken/proposed to be taken along with rates of interest, tenure, repayment schedule, actual interest repayment if any, penal interest paid if nay and the purpose for which the loans were taken and other relevant details are to be submitted as in Form-C.
3. The impact of all foreign exchange variations to be indicated separately along with manner in which the same has been dealt in the accounts and revenue requirements.
4. Details of finance charges along with calculation methodology needs to be provided

h. Cash Security deposits by consumers

i. Others

1. Consumers Account (amount available for distribution to consumers at the beginning of the year).
2. Tariffs and Dividends Control Reserve (Credit balance at the beginning of the year)
3. Development Reserve(Credit balance at the end of the year)
4. Please also indicate how the funds under these heads has been deployed and income earned there from treated.

j. Sub total of f to i

## **2. EXPENDITURE**

Expenditure properly, prudently and economically incurred on generation, transmission and distribution are to be submitted. Expenditure to be capitalized are not be included herein and details of the same needs to be separately indicated. If any foreign exchange variation is claimable and is being claimed under any head, details thereof are to be indicated separately.

a. Power Purchase Cost

1. Source of energy purchased, purchase rate, quantum of energy purchased, escalation/rebate adjustment clause in the purchase rate, if any, may be given along with all the relevant details. Whether there is any dispute on purchase rate and if yes, the details thereof may be submitted.; Also indicate the maximum and minimum power drawn in MW from each source and date and time of such drawal and similar data for own generation by distribution licensee.
2. Whether any power purchase agreements (PPA), if required, have been entered into which will be in force during the period for which the tariff has been proposed. Copies of PPAs are to be enclosed.
3. Whether the Commission has approved the purchase and procurement process as per the Act and if not, details and reasons thereof.
4. Whether any procurement is made from co-generation/renewable sources of energy. If yes, details thereof may be submitted.; If not, plans for such procurement may be indicated.
5. Merit Order Purchase Planning and detailed justification for purchase from each source.

b. COST OF GENERATION INCLUDING OWN GENERATION BY DISTRIBUTION LICENSEE

1. Station wise cost sheets giving information relating to fuel charges, other fuel related costs, repairs & maintenance (separately for buildings and civil work, plant & machinery and electrical installations and others), salary & wages, depreciation, interest, other financing charges, if any, water charges, travel, other management & administrative expenses, bad debts & others, if any.
2. Unit wise and plant wise availability factors and plant load factors are to be given.

3. Plant wise gross energy available at generators, terminals, auxiliary consumption and net energy set out ex-bus (before transmission loss) are to be given. The energy consumed in the offices and also allowed to employee free or concessional rate are to be shown separately.
4. Consumption statements of primary fuel and secondary fuel both in physical quantity and financial value and heat value of coal and fuel oil are to be given. Details as required in Form-D may be submitted.
5. Main sources of fuel supply and break up of fuel prices to be submitted.
6. The normative value of various parameters like station heat rate and secondary fuel consumption etc. Adopted, if any, may also be submitted.

c. Expenses on Transmission, Distribution and Sale of Energy.

Relevant details, as applicable, as 4.1 are to be submitted.

d. Rent, rates \* taxes.

(other than all taxes on income and profits)

e. Interest and Finance Charges: The broad details and basis of financing charges and its justification needs to be provided

- (1) Interest charges on accounts borrowed/funding facilities from institutions, organizations and the public.
- (2) Lease rental.
- (3) Interest on security deposits
- (4) Interest on working capital
- (5) Interest on other than loan
- (6) Financing charges.

f. Legal charges.

g. Consultancy Fees, Charges & Expenses.

h. Bad debts.

i. Auditor's Fees.

Separately details for Audit Fee for audit of Accounts, Audit expenses, Fees for certification and other audits, Consultancy/Management services etc.

j. Depreciation.

k. Effects of variation of exchange rate in case of debts linked to any foreign currency.

l. Other Expenses.

Expenses as are admissible and/or arising from and/or arising from and ancillary/incidental to the business of electricity generation/supply and not covered under any other specific expenditure head

are to be given. If expenditure under any particular head of expenditure is more than 1/2% of total projected revenue of the year or 5% of the other expenses whichever is less, the same may be shown under a separate head of expense.

Sub Total of Expenditure

**3. Special Appropriation, if any**

As per Tariff Regulations.

Sub-Total 2&3

**4. Income**

As per existing tariff and charges, as detailed in Annex 2.

a. Receipts from Sale of Energy

b. Other Income derived from :

- (i) Rental of meters and other apparatus hired out
- (ii) Rents
- (iii) Income on fixed and call deposits, bank balance and investments
- (iv) Charges recovered from consumers under section 46 of the Act.
- (v) Surcharge for late payments
- (vi) Other general receipts arising from and ancillary or incidental to the business of generation/supply of electricity. Please give separate details if any, individual item is more than 1/2% of the total income or 5% of the other income.
- (vii) Trading Income Loss with relevant details.

Sub-Total of other income

Total of Income

**5. Contingencies Reserve**

Opening balance of Contingencies Reserve, the amount appropriated to the Reserve, the amount drawn from the Reserve to meet charges, amount drawal as advance, purposes for which it was drawn and the authority who has approved the drawal along with terms and conditions as may have been prescribed by such authority. In case any advance has been drawn and if the same has been refunded or it has been utilized for financing any project or capital assets, then details thereof may be submitted.

**6. Summary of revenue requirement**

As in enclosed **Form-E**

**7. Debtors List**

A list of debtors indicating the total amount outstanding against a consumer and/or party who satisfies both the following criteria

- (a) whose debts are outstanding for over six months, and,
  - (b) such debts exceeds 2 lakhs in individual case,
- Utility shall also enclose the details of steps taken for realization of such sums.



### **8. Utilization of assets in other business**

Please indicate whether the licensee has engaged and utilized its assets in any other business. If yeas, the details thereof and the income and benefits derived there from along with the expenditure, if any and how the same has been treated in Revenue Requirement.

### **9. Gist of Tariff Revision Petition**

A gist of tariff revision petition with following minimum details may be submitted.

- (1) Gist of tariff revision petition before the Tripura Electricity Regulatory Commission for the year .....and admitted on ..... (date).
- (2) Name of the licensee/generation company
- (3) Address of the licensee/generating company
- (4) Tariff revision proposed to be applicable from ....
- (5) Expected revenue at current tariff – Rs .... crores
- (6) Expected revenue at proposed tariff – Rs .. crores.
- (7) Range of percentage of increase/decrease sought in Petition.
- (8) Major reasons for increase/decrease in Tariff proposed.
- (9) Major factors not considered in the above increase sought, if any.
- (10) Details of major changes proposed in applicable terms and conditions.
- (11) Amount of Outstanding Debtors along with name of party/consumer against whom consolidated amount of 1% of the sale of last year or Rs.25 lakhs whichever is lower is outstanding for more than 6 months.
- (12) Any other important issue.

Petition submitted by the licensee/generating company may be inspected at theoffice of the Commission and .....(other addresses, if any) by .....(date) and copies obtained from the office of the Commission on by ..... (date).

Objections and comments, if any, may be submitted at the office of the Commission by (date).

**Note:** Dates will be filled by the Commission later on.

**Form-A: Planned repairs and Maintenance/forced outage/major repairs for generation plants (station-wise)**

Unit No	Outage From/ To	Nature (Planned/ Forced)	Duration in Hrs	Summary Details	Next period as per schedule of planned maintenance	Period of last major maintenance (scheduled)	Period of last major maintenance (actual)	Remarks

**FORM-B DETAILS OF DEPRECIATION CHARGEABLE TO REVENUE ACCOUNTS FOR THE YEAR**

S.No.	Assets Group	Rate of Depreciation	Gross fixed Assets				Provisions for depreciation				Net fixed Assets	
			At the beginning of the year	Additions during the year	Adjust. & deductions	At the end of the year	Cumulative upto the beginning of the year	Additions during the year	Adjust. during the year	Cumulative at the end of the year	At the beginning of the year	At the end of the year
1	Land & Land Rights	Nil										
2	Building & Civil Works of Power Plants											
3	Hydraulic Works											
4	Other Civil Works											
5	Plant & Machinery											
6	Lines & Cable Network											
7	Vehicles											
8	Furniture & Fixtures											
9	Office Equipment											
10	Capital Spares											
11	Others											
TOTAL												

**FORM-C STATEMENT OF LOANS AND CALCULATION OF INTEREST THEREOF**

S.No	Sources of Loans	Original Amount of Loan	Outstanding balance at the beginning of the year	Normal rate of interest (%)	Period rate of interest, if any (%)	Rebate (If any) for prompt payment	Repayment due amount/date	Fresh drawal if any, amount due	Interest paid Payable				Balance at the close of the year.	Purpose of Loan	Remarks (if any)
									Normal	Penal	Rebate	Total			
1.	2.	3.	4.	5.	6.	7.	8.	9.	10.	11.	12.	13.	14.	15.	16.
Total															
Less IDC															
Net															

**NOTE:**

- 1) The statement should be consolidated for all the loans taken separately for capital accounts & revenue Accounts.
- 2) Loans bearing different interest rate and terms should not be dubbed even if from the same sources
- 3) Loans with variable rate of interest should be clearly identified with the mention of base date rates.
- 4) In case of foreign currency loans, the exchange rates adopted at opening balance, closing balance and repayment should be mentioned. The rate of exchange on the date of drawal of capital loan should be indicated.
- 5) If the loan is taken from a group company or subsidiary etc., the same may be justified.
- 6) Any rate of interest above the Bank PLR should be fully justified along with the necessity of the loan.
- 7) The details of fresh drawal of loan may be endorsed along with detail justification purpose and supporting cash flow which necessitated the drawal of loan along with investments made or proposed and average bank balances.
- 8) Any default in repayment of loan may also be suitably explained along with relevant details.
- 9) Rebate for prompt payment etc. or penalty for delayed/non-payment to be disposed separately.
- 10) **FORM D : DETAILS OF FUEL CONSUMPTION (PLANT-WISE)**

## 1) COAL/GAS

S.No	Month	Unit	For preceding 3rd Month		For preceding 2nd Month		For preceding 1st Month		Quarterly Average		
			Domestic coal	Imported coal	Domestic coal	Imported coal	Domestic coal	Imported coal	Domestic coal	Imported coal	Gross
1	2	3	4	5	6	7	8	9	10	11	12
1	Quantity of coal/gas in stock at the beginning of the month	(MMT)									
2	Quantity of Coal/gas supplied by Coal Company	(MMT)									
3	Adjustment (+/-) in quantity supplied made by Coal/gas Company for diversion of wagons etc.	(MMT)									
4	Coal/gas supplied by Coal/gas Company (2+3)	(MMT)									
5	Normative Transit & Handling Losses (For coal based Projects)	(MMT)									
6	Net coal/gas Supplied (4-5)	(MMT)									
7	Total coal/gas (Receipts & Opening Stock) (1)+(6)	(MMT)									
8	Coal/gas burnt/consumed	(MMT)									
9	Coal/gas in stock at the end of the month	(MMT)									
10	Value of coal/gas in stock (Landed cost of 1)	(Rs.)									
11	Amount charged by the Coal/gas Company	(Rs.)									
12	Adjustment (+/-) in amount charged made by Coal/gas Company	(Rs.)									
13	Total amount Charged (11+12)	(Rs.)									
14	Transportation charges by rail/ship/road transport	(Rs.)									
15	Adjustment (+/-) in amount charged made by Railways/Transport Company	(Rs.)									
16	Demurrage Charges, if any	(Rs.)									
17	Cost of diesel in transporting coal through MGR system, if applicable	(Rs.)									
18	Total Transportation Charges (14+/-15+16+17)	(Rs.)									
19	Total amount Charged for coal/gas supplied including Transportation (13+18)	(Rs.)									
20	Average cost of coal/gas (Opening stock + receipts) (19+10)/7	(Rs/MMT)									
21	Cost of coal/gas in stock at the end of the month (20)x(9)	(Rs.)									
22	Weighted average GCV of coal/gas as fired	(kCal/Kg)									

S.N O	PARTICULARS	-	For preceding 3rd Month			For preceding 2nd Month			For preceding 1st Month			Quarterly Average			
			Unit	FO	HSD	LDO	FO	HSD	LDO	FO	HSD	LDO	FO	HSD	LDO
1	Quantity of Sec. Fuel oil(FO, HSD,LDO) in stock at the beginning of the month	KL	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Quantity of Sec. Fuel oil(FO, HSD,LDO) supplied by company	KL	-	-	-	-	-	-	-	-	-	-	-	-	
3	Adjustment (+/-) in quantity of Sec. Fuel oil(FO, HSD,LDO) supplied by company	KL	-	-	-	-	-	-	-	-	-	-	-	-	
4	Gross Oil(FO, HSD,LDO) supplied by company(2+3)	KL	-	-	-	-	-	-	-	-	-	-	-	-	
5	Normative/Transit Loss	KL	-	-	-	-	-	-	-	-	-	-	-	-	
6	Net Oil(FO, HSD,LDO) supplied by company(4-5)	KL	-	-	-	-	-	-	-	-	-	-	-	-	
7	Total oil receipt & in stock (1+6)	KL	-	-	-	-	-	-	-	-	-	-	-	-	
8	Total Oil Consumed	KL	-	-	-	-	-	-	-	-	-	-	-	-	
9	Oil in stock at the end of month	KL	-	-	-	-	-	-	-	-	-	-	-	-	
10	Value of oil in stock (Landed cost of 1)	RS	-	-	-	-	-	-	-	-	-	-	-	-	
11	Amount charged by company	RS	-	-	-	-	-	-	-	-	-	-	-	-	
12	Adjustment (+/-) in Amount charged by company	RS	-	-	-	-	-	-	-	-	-	-	-	-	
13	Total amount charged(11+12)	RS	-	-	-	-	-	-	-	-	-	-	-	-	
14	Transportation charges	RS	-	-	-	-	-	-	-	-	-	-	-	-	
15	Adjustment (+/-) in Transportation charges	RS	-	-	-	-	-	-	-	-	-	-	-	-	
16	Demurrage charges if any	RS	-	-	-	-	-	-	-	-	-	-	-	-	
17	Cost of diesel in transporting oil through MGR System if applicable	RS	-	-	-	-	-	-	-	-	-	-	-	-	
18	Total Transportation charges(14+15+16+17)	RS	-	-	-	-	-	-	-	-	-	-	-	-	
19	Total amount charged for oil including Transportation(13+18)	RS	-	-	-	-	-	-	-	-	-	-	-	-	
20	Average cost of oil(in stock+receipt)	RS	-	-	-	-	-	-	-	-	-	-	-	-	
21	Cost of Oil in stock at the end of month	RS	-	-	-	-	-	-	-	-	-	-	-	-	
22	WTG AVG GCV of oil fired	(Kcal/ ltr)	-	-	-	-	-	-	-	-	-	-	-	-	

**Notes:**

Price List and calculation of the price in support of the price claimed may be endorsed.

Source of supply may be shown separately with reference to grade of coal/gas.

Declared heat value shall be based on Minimum Guaranteed Heat value or actual whichever is higher.

Coal/gas Price from authorized dealers, if any shall be provided

FORM-E: Revenue RequirementGeneration

S.No.	Particulars	Units		Previous year as per tariff order/True-up	Current year			Ensuing Year
					(Actual) Till Sept	( Anticipated) Oct to Mar	( Anticipated) Current year	Petitioned
1	2	3	4	5	6	7	8	9
<b>A</b>	<b>Fixed Charge</b>							
1	O & M Expenses							
2	Depreciation							
3	Interest on Term Loans & Fin. Charges							
4	Interest on Working Capital Loans							
5	Recovery of ARR & Tariff Petition Fees							
6	Return on Equity							
<b>7</b>	<b>Total Fixed Charge</b>							
8	Less: Non-Tariff Income							
<b>9</b>	<b>Net Fixed Charge</b>							
<b>B</b>	<b>Variable Cost</b>							
<b>C</b>	<b>Total Cost</b>							
<b>D</b>	Unit Sold to Discoms							
<b>E</b>	Rate of Fixed Charge(Paisa/kwh)							
<b>F</b>	Rate of Variable Charge(Paisa/kwh)							
<b>G</b>	Rate of Sale of Energy (Paisa./kwh)							

Transmission and Wheeling

S.No.	Particulars	Units		Previous year as per tariff order/True-up	Current year			Ensuing Year
					(Actual) Till Sept	( Anticipated) Oct to Mar	( Anticipated) Current year	Petitioned
1	2	3	4	5	6	7	8	9
<b>A</b>	<b>Fixed Charge</b>							
1	O & M Expenses							
2	Depreciation							
3	Interest on Term Loans & Fin. Charges							
4	Interest on Working Capital Loans							
5	Recovery of ARR & Tariff Petition Fees							
6	Return on Equity							
7	Provision for bad and Doubtful debt							
<b>8</b>	<b>Total Fixed Charge</b>							
9	Less: Non-Tariff Income							
<b>10</b>	<b>Total Cost</b>							
<b>B</b>	Total unit transmitted or wheeled							
<b>C</b>	Transmission and Wheeling Charge (Paisa/kwh)							



Distribution

S.No.	Particulars	Units		Previous year as per tariff order/True- up	Current year			Ensuing Year
					(Actual) Till Sept	( Anticipated) Oct to Mar	( Anticipated) Current year	Petitioned
1	2	3	4	5	6	7	8	9
<b>A</b>	<b>Fixed Charge</b>							
1	Power Purchase Cost							
2	Transmission Charges							
3	O & M Expenses							
4	Depreciation							
5	Interest on Term Loans & Fin. Charges							
6	Interest on Working Capital Loans							
7	Recovery of ARR & Tariff Petition Fees							
8	Return on Equity							
9	Provision for bad and Doubtful debt							
<b>10</b>	<b>Total Fixed Charge</b>							
11	Less: Non-Tariff Income							
12	Less: Receipt on account of Cross Subsidy Surcharge							
<b>13</b>	<b>Total Cost</b>							

Form-F: Plant Characteristics (Generation)

<b>Plant Characteristics (Generation)</b>								
<b>Name of the Utility / Company :</b>								
<b>Name of the Thermal Power Station:</b>								
								<b>Year Ending March</b>
<u>Basic characteristics of the plant<sup>1</sup></u>	<u>Coal Based Thermal Power Plant (conventional steam generator)</u>							
<b>Special Features of the Plant</b>								
<u>Site Specific Features<sup>2</sup></u>								
<u>Special Technological Features<sup>3</sup></u>								
<u>Environmental Regulation related features<sup>4</sup></u>								
<u>Any other special features</u>								
<b>Fuel Details<sup>5</sup></b>	<u>Primary Fuel</u>			<u>Secondary Fuel</u>			<u>Alternate Fuels</u>	
<b>Details</b>	<b>Module number or Unit number</b>							
	<u>Unit # 1</u>	<u>Unit # 2</u>	<u>Unit # 3</u>	<u>Unit # 4</u>	<u>Unit # 5</u>	<u>Unit # 6</u>	<u>Unit # 7</u>	<u>So on</u>
<u>Installed Capacity (IC) MW</u>	-	-	-	-	-	-	-	-
<u>Date of Commercial Operation (COD)</u>	-	-	-	-	-	-	-	-
<u>Type of cooling system<sup>6</sup></u>								
<u>Type of Boiler Feed Pump<sup>7</sup></u>								-
<u>Pressure (kg/cm2)</u>								
<u>Temperature 0C</u>								
<u>-At Superheater Outlet</u>								

-At Reheater Outlet	-	-	-	-	-	-	-	-
<b>Guaranteed Design Heat rate (kCal/kWh)<sup>8</sup></b>	-	-	-	-	-	-	-	-
<b>Conditions on which guaranteed</b>								-
% MCR								-
% Makeup								-
Design Fuel	-	-	-	-	-	-	-	-
Design cooling water Temperature								-
Back Pressure								-
	-	-	-	-	-	-	-	-
<sup>1</sup> Describe the basic characteristics of the plant e.g. in the case of a coal based plant whether it is a conventional steam generator or circulating fluidized bed combustion generator or sub-critical once through steam generator etc.								-
<sup>2</sup> Any site specific feature such as Merry-Go-Round, Vicinity to sea, Intake /makeup water systems etc. scrubbers etc. Specify all such features.								-
<sup>3</sup> Any Special Technological feature like Advanced class FA technology in Gas Turbines, etc.								-
<sup>4</sup> Environmental regulation related features like FGD, ESP etc.								-
<sup>5</sup> Coal , oil etc.								-
<sup>6</sup> Closed circuit cooling, once through cooling, sea cooling etc.								-
<sup>7</sup> Motor driven, Steam turbine driven etc.								-
<sup>8</sup> In case guaranteed unit heat rate is not available then furnish the guaranteed turbine cycle heat rate and guaranteed boiler efficiency separately along with condition of guarantee.								-

## FORM-G: Energy Charges for thermal Generation

Particulars	Units		Previous year as per tariff order/True- up	Current year			Ensuing Year
				(Actual) Till Sept	( Anticipated) Oct to Mar	( Anticipated) (2012-13)	Petitioned
<b>Operational Parameter</b>							
<b>Number of Units</b>							
<i>Upto 250 MW</i>							
<i>More than 250 MW</i>							
Total Capacity	MW						
Availability	%						
PLF	%						
Gross Generation	MU						
Auxiliary Energy Consumption	%						
Auxiliary Energy Consumption	MU						
Net Generation	MU						
Heat Rate	kcal/kwh						
Fly Ash Utilization	%						
Other By product utilization (with List)	%						
<b>Fuel Parameters</b>							
<b>Calorific Value for Different Fuels</b>							
Fuel 5 (Indigenous Coal)	kcal/Kg						

Fuel 4 (Imported Coal)	kcal/Kg						
Fuel 1 (HFO)	kcal/Ltr.						
Fuel 2(HSD)	kcal/Ltr.						
Fuel 3 (LDO)	kcal/Ltr.						
<b>Landed Fuel Price for different fuels</b>							
Fuel 5 (Indigenous Coal)	Rs/MT						
Fuel 4 (Imported Coal)	Rs/MT						
Fuel 1 (HFO)	Rs/KL						
Fuel 2(HSD)	Rs/KL						
Fuel 3 (LDO)	Rs/KL						
<b>Specific Fuel Consumption</b>							
Fuel 5 (Indigenous Coal)	Kg/kWh						
Fuel 4 (Imported Coal)	Kg/kWh						
Fuel 1 (HFO)	ml/kWh						
Fuel 2(HSD)	ml/kWh						
Fuel 3 (LDO)	ml/kWh						
<b>Total Fuel Consumption</b>							
Fuel 5 (Indigenous Coal)	MT						
Fuel 4 (Imported Coal)	MT						
Fuel 1 (HFO)	KL						
Fuel 2(HSD)	KL						
Fuel 3 (LDO)	KL						
<b>Heat Content (each fuel separately)</b>							
Fuel 5 (Indigenous Coal)	Million kcal						
Fuel 4 (Imported Coal)	Million kcal						
Fuel 1 (HFO)	Million kcal						

Fuel 2(HSD)	Million kcal						
Fuel 3 (LDO)	Million kcal						
<b>Total Fuel Cost</b>							
<b>Fuel 5 (Indigenous Coal)</b>	<b>Rs Crore</b>						
Fuel 4 (Imported Coal)	Rs Crore						
Fuel 1 (HFO)	Rs Crore						
Fuel 2(HSD)	Rs Crore						
Fuel 3 (LDO)	Rs Crore						
Total fuel Cost							
<b>Other Charges and Adjustments</b>							
Other Charges FOR WATER CESS & WATER CONSUMPTION	Rs Crore						
Other Adjustments	Rs Crore						
<b>Total Cost</b>	<b>Rs Crore</b>						
Cost of Generation per unit							
Energy Charges per unit							

## ANNEXURE-2

### CURRENT TARIFF RATES AND EXPECTED REVENUE AT CURRENT TARIFF

**(1) Statement of expected revenue of current tariff:**

Following details may be submitted –

- a) Category/Sub-Category of Consumers.
- b) Annual sales volume (million units)
- c) Gross tariff rate (paise per unit)
- d) Rebates ( paise per unit)
- e) Net tariff rate (paise per unit)
- f) Fuel and power purchase adjustment charge, if any (paise per unit) as per , Fuel and Power Purchase Price Adjustment Formula Regulation ,2011
- g) Subsidy from external sources, if any (paise per unit)
- h) Full year revenue on gross basis separately indicating rebate and surcharges to arrive at net revenue (rupees lakhs)
- i) Full year revenue on net basis (rupees lakhs)

**Notes :**

- a) Final total of Items (h) and (i) shall be the same.
- b) In case of unmetered supply, the rate charged is to be multiplied with estimated usage and suitably included in the above. A note for the reasons for unmetered supply and basis for various estimations is to be submitted as also plans and estimated timeframe for installing meters for such supplies.
- c) Meter rental and late payment surcharge are to be included in Item-2.
- d) Duties and taxes, if any, are not to be included herein.

**(2) Revenue from other charges.**

Items not included under Item 1 are to be submitted (meter rental, late payment surcharge etc.)

**(3) Broad financial terms of supply:** Present terms of supply may be indicated.

## ANNEXURE-3

### (1) PROPOSED TARIFF RATES AND EXPECTED REVENUE AT PROPOSED TARIFF

A statement of expected revenue at proposed tariff with following details may be submitted –

- a) Category/Sub-Category of consumers.
- b) Annual sales volume (million units)
- c) Gross tariff rate (paise per unit)
- d) Rebates (paise per unit)
- e) Net tariff rate (paise per unit)
- f) Subsidy from external sources, if any (paise per unit)
- g) Full year revenue on gross basis, separately indicating rebates and surcharges to arrive at net revenue (rupees lakhs)
- h) Full year revenue on net basis (rupees lakhs)

### Notes

- a) Final total of Items (g) and (h) to be the same.
- b) In case of un-metered supply, the rate charged is to be multiplied with estimated usage and suitably included in the above.
- c) Meter rental and late payment surcharge are to be included in Item-2.
- d) Duties and taxes, if any, are not to be included herein.
- e) There will be no fuel and power purchase adjustment charge under the proposed tariff; the same will be merged into gross/net tariff rate.

### (2) Revenue from other charges.

Items not included under Item 1 are to be submitted (meter rental, late payment surcharge etc.)

### (3) Broad financial terms of supply: Monthly Tariff change for average consumers may be indicated.

- a) Category/sub-category of consumers.
- b) Average monthly consumption(units)
- c) Gross tariff rate under proposed tariff(paise per unit)
- d) Rebates under proposed tariff (paise per unit)
- e) Net tariff rate under proposed tariff(paise per unit)
- f) Total amount payable on energy charges under proposed tariff(rupees)(b) x (e)
- g) Other charges under proposed tariff, including meter rental(rupees)
- h) Duties and taxes (as presently applicable)(rupees)
- i) Total payable under proposed tariff(rupees)(f+g+h)
- j) Gross tariff rate under current tariff (paise per unit)
- k) Rebates under current tariff (paise per unit)
- l) Net tariff rate under current tariff(paise per unit)
- m) Fuel and power purchase adjustment charge, if any, under current tariff(paise per unit).
- n) Total payable on energy charges and fuel and power purchase adjustment charges under current tariff(rupees)((b)x(l+m)
- o) Other charges under current tariff including meter rental(rupees)
- p) Duties and taxes (as presently applicable)(rupees)
- q) Total payable under current tariff(rupees)(n+o+p)
- r) Total incremental (+)/ decremental (-)payment
- s) Percentage change(s/q-1).



### Annexure-4(i)

#### Input to EHT system(400kV, 220kV, 132 kV and 66 kV)

a) Own Generating Stations

S.No	Source of Supply	Energy delivered into the Grid System	MU	MW	
				Max	Min
1.	Thermal				
2.	Hydel				
3.	Mini-Hydro				
4.	Wind				
5.	Renewable				
6.	Co-Generation				

b) Energy Purchase-Sources within the state:

1.	Agency-1		
2.	Agency-2		
3.	Agency-3		
4.	Agency-4		

c) Energy Purchase –Sources Outside the State

1.	Agency-1		
2.	Agency-2		
3.	Agency-3		
4.	Agency-4		

d) Others

1.	Agency-1		
2.	Agency-2		
3.	Agency-3		
4.	Agency-4		

### Annexure-4(ii)

#### Delivery to 33 & 11kV Distribution system from EHT system (400 kV, 220 kV, 132 kV and 66 kV)

S.No	Unit Area	Energy Received at all EHTs/Ss(132/33 kV) existing in the region		Total Energy delivered into 33 and 11 kV Distribution System
1.		(a)	(b)	(a) + (b)
2.				
3.				
4.				
	Total			

### Annexure-4(iii)

S.No	Supply Voltage	No. of Consumers	Total Units recorded by HT meters
1.	220 kV		
2.	132 kV		
3.	66 kV		
	Total		

### Annexure-4(iv)

#### Losses (400 kV, 220 kV,132 kV & 66 kV)

S.No	ITEM	MU
(a)	Total Energy Delivered to System-4(i) Own Generating Stations-4(i) Energy Purchase-Sources within the state-4(i) Energy Purchase-Sources Outside the state-4(i) Total Energy Delivered to the System-4(i)	
	Delivered to Distribution System-4(ii) & 4(iii) Energy Received at all EHTs/Ss at 33 kV-4(ii) Energy Received at all EHTs/Ss at 11 kV-4(ii) HT Consumption at 220,132,66 kV-4(ii) Delivered to Distribution System-4(ii) & 4(iii)	
	220 kV,132 kV,66 kV Losses % (a-b)/a *100	

### Annexure-4(v)

**Energy Delivered into 33kV Distribution system at the inter-connection points of the EHT system& other sources of Generation**

S.No	Name of the Unit Area	Energy Delivered into 33kV Distribution system								Total Energy Delivered into the Unit Area (a) + (b)
		From all EHT S/s existing in the unit area (a)			Other Sources of Input in the Unit Area (b)					
		Gross	Export	Net	Own Generation	Purchase	Renewable Co-Generation	Other	Sub Total	
1. 2. 3.	<b><u>Total</u></b>									

### Annexure-4(vi)

**HT Sales at 33 kV**

S, No	Name of the Unit Area	Number of Consumers	Total Units Recorded by 33 kV HT meters
1.			
2.			
	Total Sales at 33 kV		

### Annexure-4(vii)

**Energy Delivered from 33/20/11/6 kV & 6 kV System(including L.T. System)**

S.No	Name of the Unit Area	Energy Delivered at HT from 33/20/11/6 kV Sub Stations in the Unit Area in MU
1.		
2.		
	Total	

### Annexure-4(viii)

**Energy Delivered into 11kV Distribution system at the inter-connection points of the EHT system & other sources of Generation**

S.No	Name of the Unit Area	Energy Delivered into 11kV Distribution system								Total Energy Delivered into the Unit Area (a) + (b)
		From all EHT S/s existing in the unit area (a)			Other Sources of Input in the Unit Area (b)					
		Gross	Export	Net	Own Generation	Purchase	Renewable Co-Generation	Other	Sub Total	
<u>1.</u>										
<u>2.</u>										
<u>3.</u>	<b><u>Total</u></b>									

**Annexure-4(ix)****HT Sales at 20 kV,11 kV, 6 kV and 3.3kV**

S,No	Name of the Unit Area	Number of Consumers	Total Units Recorded by 33 kV HT meters
1.			
2.			
	Total Sales at 33 kV		

**Annexure-4(X)****Energy Sold in L.T. System)**

S,No	Name of the Unit Area	Energy Delivered at HT from 33/20/11/6 kV Sub Stations in the Unit Area in MU						
		Domestic	Commercial	Industrial	Public Lighting	Irrigation	Others to be specified	Total
1.								
	Total							

## Annexure 4(xi)

**Losses at 33 kV and below**

<u>S.No</u>	<u>Loss Calculation</u>		<u>Loss in MU</u>
1.	Losses in 33 kV system and connected equipment a. Total Energy delivered into 33 kV system from EHT S/s and other Generating Stations-4(v) b. Energy sold by HT direct sales at 33 kV-4(vi) c. Energy Delivered from 33/20/11/6 kV & 6 kV System(including L.T. System)-4(vii)	A B C A-(B+C)	
2.	<b>% Losses</b> a. Losses in 11 kV and LT system and connected Equipment-4(vii) b. Energy delivered into 11 kV system from EHT S/s and other Generating Stations-4(viii) Total Energy delivered into 11 kV and LT Distribution system c. Energy sold by HT direct sales at 33 kV-4(ix) d. Energy Sold in the LT System-4(x) Total Sales Losses % Losses	C D C+D E F E+F (C+D)-(E+F) (C+D)- (E+F)*100/(C+D)	

## Annexure-5(i)

## VOLTAGE FLUCTUATION

Voltage Level	First Six months of previous year in % of time when voltage was		Last Six months of previous year in % of time when voltage was		First Six months of current year in % of time when voltage was		Corrective Measures proposed
	Below (9%)	Above (6%)	Below (9%)	Above (6%)	Below (9%)	Above (6%)	
At 33 kV Side of Transformer							
At EHT Bus	Below 12.5%	Above 10%	Below 12.5%	Above 10%	Below 12.5%	Above 10%	

### Anenxure-5(ii)

#### **ABSTRACT OF OUTAGES DUE TO TIPPING OF HT FEEDERS**

<u>System</u>	First Six months of previous year			Last Six months of previous year			First Six months of Current year			<u>Remedial Measures Proposed</u>
	No of tripping	Duration of tripping	Average interruption per feeder	No of tripping	Duration of tripping	Average interruption per feeder	No of tripping	Duration of tripping	Average interruption per feeder	
		Hrs	Hrs		Hrs	Hrs		Hrs	Hrs	
All 33 kV Outgoing feeders										
All 6/11 kv outgoing feeders										
Power Transformer										
High Voltage Side/Low Voltage Side										



### Annexure-5(iii)

#### FAILURE OF TRANSFORMERS(NOS)

<u>Period</u>	First Six months of previous year			Last Six months of previous year			First Six months of Current year			<u>Remedial Measures Proposed</u>
	items	No of failures	Total No Installed	% Failure	No of failures	Total No Installed	% Failure	No of failures	Total No Installed	
EHT Transformers										
i) AUTO										
ii) POWER										
Power Transformers										
Distribution Transformers										

### Annexure-5(iv)

#### FREQUENCY EXCURSION

<u>Period</u>	First Six months of previous year in % of time when frequency was		Last Six months of previous year in % of time when frequency was		First Six months of Current year in % of time when frequency was		<u>Remedial Measures Proposed</u>
	Below 48.5 C/S	Above 51.5 C/S	Below 48.5 C/S	Above 51.5 C/S	Below 48.5 C/S	Above 51.5 C/S	

**Annexure-5(v)****MAJOR SYSTEM DISTURBANCE (GRID DISTURBANCE)**

<b><u>S.No</u></b>	<b><u>Period</u></b>	<b>First Six months of previous year</b>	<b>Last Six months of previous year</b>	<b>First Six months of Current year</b>
1.	No of Occurrences			
2.	Total Duration of Interruption exception unserved energy due to such interruptions Example: Loan prior to disturbance* No of hours of Interruption			
3.	No of occasions when system was isolated from the Region Grid due to system disturbance			
4.	No of occasions when system remained stable after being isolated from the Region Grid due to system disturbance			
5.	Remedial Measures			

**Annexure-5(Vi)**

**ELECTRICAL ACCIDENTS**

<b><u>S.No</u></b>	<b>No of Accidents in First Six months of previous year</b>				<b>No of Accidents in Last Six months of previous year</b>				<b>No of Accidents in First Six months of Current year</b>				<b><u>Remedial Measures Proposed</u></b>
<b><u>Nature</u></b>	<b>No of Accidents</b>				<b>No of Accidents</b>				<b>No of Accidents</b>				
<b><u>Victim</u></b>	Fatal		Non fatal		Fatal		Non fatal		Fatal		Non Fatal		
	Human	Animal	Human	Animal	Human	Animal	Human	Animal	Human	Animal	Human	Animal	

**ANNEXURE-5 (vii)****SERVING OF CUSTOMER BILLS**

<b><u>Period</u></b>	<b>First Six months of previous year in which the no of consumer bills served</b>		<b>Last Six months of previous year in which the no of consumer bills served</b>		<b>First Six months of Current year in which the no of consumer bills served</b>		<b><u>Remedial Measures Proposed</u></b>
	Within 30 days of billing period	After 30 days of billing period	Within 30 days of billing Period	After 30 days of billing Period	Within 30 days of billing period	After 30 days of billing period	

**ANNEXURE-5 (viii)****RELEASE OF SERVICE CONNECTION**

<b><u>Period</u></b>					<b>ent</b>		<b><u>Remedial Measures Proposed</u></b>
			<b>provided</b>		<b>provided</b>		
	Within 30 days of valid	After 30 days of valid	Within 30 days of valid	After 30 days of valid	Within 30 days of valid	After 30 days of valid	

	requisition of power supply	requisition of power supply	requisition of power supply	requisition of power supply	requisition of power supply	requisition of power supply	

<u>S.No</u>	<u>Category</u>	<u>Domestic</u>	<u>Commercial</u>	<u>Industry</u>	<u>Public Lighting</u>	<u>PWW</u>	<u>Utility Service</u>	<u>Commercial</u>	<u>Domestic</u>	<u>Traction</u>	<u>Industry</u>	<u>Total</u>
		<u>LT</u>	<u>LT</u>	<u>LT</u>	<u>LT</u>	<u>LT</u>	<u>LT</u>	<u>HT</u>	<u>HT</u>	<u>HT</u>	<u>HT</u>	
<u>1</u>	No of Consumers at the end of Pre-previous year											
	No of consumers with defective meters/un-metered consumers											
	Percentage of defective meters /un-metered consumers											
	No of Consumers at the end of Pre-previous year											
	No of consumers with defective meters/un-metered consumers											
	Percentage of defective meters /un-metered consumers											
	Percentage change from pre-previous year											
	No of Consumers at the end of current year											
	No of consumers with defective meters/un-metered consumers											
	Percentage of defective meters /un-metered consumers											
	Percentage change from previous year											
	Target for Ensuing Year (percentage of defective meters/un-metered meters)											
	Target for Ensuing Year (percentage change from current Year)											

## ANNEXURE-5(x)

**STATEMENT FOR STATUS OF DEMAND**

<u>s.No</u>	<u>Category</u>	<u>Contracted Load</u>	<u>In MW</u>	
			<u>Max. Demand with Date and Time</u>	<u>Max. Demand Met</u>
1.	EHV Consumers			
2.	HV Consumers			
	a) 33 kV			
	b) 11 kV			
3.	LT Consumers			
	a) Domestic			
	b) Commercial			
	c) Industrial			
	d) Public Water Works			
	e) Street Lights			
4.	Agriculture			
5.	Total			

## Notes:

1. If it is not to be supplied category-wise then system peak demand supplied preferably for each month may be given
2. If the full demand has not been met, the reasons thereof along with action taken to meet the shortfall

## ANNEXURE-6

		<u>Previous Year</u>	<u>Current Year (Estimated)</u>	<u>Ensuing Year(Projected)</u>
1.	REVENUE ACCOUNT Operating Incomes a) Sale of Power b) Transmission charges c) Others(to be specified)			
	Total (A)			
2.	OPERATING EXPENSES All revenue nature of expenses other than non-cash charges like Depreciation, DRE etc)			
	Total (B)			
3	INCREASE/ DECREASE IN CURRENT ASSETS/LIABILITIES & PROVISIONS IN REVENUE ACCOUNT a) Sundry Debtors b) Loans & Advances c) Current Liabilities d) Provisions e) Others			
	Total			
4.	OPERATING CASH SURPLUS/SHORT FALL			
5	UTILIZATION OF OPERATING CASH SURPLUS			



		<u>Previous Year</u>	<u>Current Year (Estimated)</u>	<u>Ensuing Year(Projected)</u>
	CAPITAL ACCOUNTS			
	A.ADDITIONAL CAPITAL FUND Additional own fund brought in Additional Borrowings Additional consumer's contribution and security deposits Use of Operating Surplus Increase in liabilities for capital works UTILISATION OF CAPITAL FUND Increase in fixed capital expense Loan repayment Decrease in Liabilities Additional Investment Any other Item			

## **Annexure-7**

### **Timeline for completion of Projects (Refer to Clause 27)**

- I. The completion time schedule shall be reckoned from the date of investment approval by the Board (of the generating company or the transmission licensee), or the CCEA clearance as the case may be, up to the date of commercial operation of the units or block or element of transmission project as applicable.
- II. The time schedule has been indicated in months in the following paragraphs and tables:

#### **(a). Thermal Power Projects**

##### **Coal/Lignite Power Plant**

###### Unit size 200/210/250/300/330 MW and 125 MW CFBC technology

- (a) 33 months for green field projects. Subsequent units at an interval of 4 months each.
- (b) 31 months for extension projects. Subsequent units at an interval of 4 months each.

###### Unit size 250 MW CFBC technology

- (a) 36 months for green field projects. Subsequent units at an interval of 4 months each.
- (b) 34 months for extension projects. Subsequent units at an interval of 4 months each.

###### Unit size 500/600 MW

- (a) 44 months for green field projects. Subsequent units at an interval of 6 months each.
- (b) 42 months for extension projects. Subsequent units at an interval of 6 months each.

###### Unit size 660/800 MW

- (a) 52 months for green field projects. Subsequent units at an interval of 6 months each.
- (b) 50 months for extension projects. Subsequent units at an interval of 6 months each.

## Combined Cycle Power Plant

### Gas Turbine size upto 100 MW (ISO rating)

- (a) 26 months for first block of green field projects. Subsequent blocks at an interval of 2 months each.
- (b) 24 months for first block of extension projects. Subsequent units at an interval of 2 months each.

### Gas Turbine size above 100 MW (ISO rating)

- (a) 30 months for first block of green field projects. Subsequent blocks at an interval of 4 months each.
- (b) 28 months for first block of extension projects. Subsequent units at an interval of 4 months each.

### **(b). Hydro Electric Projects**

The qualifying time schedule for hydro electric projects shall be as stated in the original concurrence issued by the Central Electricity Authority under section 8 of the Act.

### **(c). Transmission Schemes**

Qualifying time schedules in months

Sr. No.	Transmission Work	Plain Area (months)	Hilly Terrain (months)	Snowbound area/ <sup>@</sup> very difficult Terrain (months)
a	765 kV S/C Transmission line	36	42	46
b	765 kV D/C Transmission line	40	46	50
c	+/-500 KV HVDC Transmission line	30	36	40
d	400 KV M/C Quad or more sub-conductor Transmission line	40	46	50

<b>Sr. No.</b>	<b>Transmission Work</b>	<b>Plain Area (months)</b>	<b>Hilly Terrain (months)</b>	<b>Snowbound area/@very difficult Terrain (months)</b>
e	400 KV M/C Twin/Triple Transmission line	38	44	48
f	400 KV D/C Quad Transmission line	38	44	48
g	400 KV D/C Triple Transmission line	36	42	46
h	400 KV D/C Twin Transmission line	34	40	44
i	400 KV S/C Six or more sub-conductor Transmission line	36	42	46
j	400 KV S/C Twin Transmission line	30	36	40
k	220 KV D/C Twin Transmission line	34	40	44
l	220 KV D/C Transmission line	30	36	40
m	220 KV S/C Transmission line	26	32	36
n	New 220 KV AC Sub-Station	24	27	30
o	New 400 KV AC Sub-Station	30	33	36
p	New 765 kV AC Sub-Station	36	40	\$
q	*HVDC bi-pole terminal	42	44	-
r	HVDC back-to-back	32	34	-
@ e.g. Leh, Laddakh				
* Includes +800 kV HVDC bi-pole terminal				

Notes:

- I. In case a scheme having combination of the above mentioned types of projects, the qualifying time schedule of the activity having maximum time period shall be considered for the scheme as a whole.
- II. In case a transmission line falls in plain as well as in hilly terrain/snow bound area/very difficult terrain, the composite qualifying time schedule shall be calculated giving proportional weightage to the line length falling in each area.

## Annexure-8

### Depreciation Schedule

Sr. No.	Asset Particulars	Depreciation Rate (Salvage Value=10%)
		<b>SLM</b>
<b>A</b>	<b>Land under full ownership</b>	<b>0.00%</b>
<b>B</b>	<b>Land under lease</b>	
(a)	for investment in the land	3.34%
(b)	For cost of clearing the site	3.34%
(c)	Land for reservoir in case of hydro generating station	3.34%
<b>C</b>	<b>Assets purchased new</b>	
a.	PI & Machinery in generating stations	
(i)	Hydro electric	5.28%
(ii)	Steam electric NHRB & waste heat recovery boilers	5.28%
(iii)	Diesel electric and gas plant	5.28%
b.	Cooling towers & circulating water systems	5.28%
c.	Hydraulic works forming part of the Hydro-generating stations	
(i)	Dams, Spillways, Weirs, Canals, Reinforced concrete flumes and siphons	5.28%
(ii)	Reinforced concrete pipelines and surge tanks, steel pipelines, sluice gates, steel surge tanks, hydraulic control valves and hydraulic works	5.28%
d.	Building & Civil Engineering works	
(i)	Offices and showrooms	3.34%
(ii)	Containing thermo-electric generating plant	3.34%
(iii)	Containing hydro-electric generating plant	3.34%
(iv)	Temporary erections such as wooden structures	100.00%
(v)	Roads other than Kutcha roads	3.34%
(vi)	Others	3.34%
e.	Transformers, Kiosk, sub-station equipment & other fixed apparatus (including plant	
(i)	Transformers including foundations having rating of 100 KVA and over	5.28%
(ii)	Others	5.28%
f.	Switchgear including cable connections	5.28%
g.	Lightning arrestor	

<b>Sr. No.</b>	<b>Asset Particulars</b>	<b>Depreciation Rate (Salvage Value=10%)</b>
(i)	Station type	5.28%
(ii)	Pole type	5.28%
(iii)	Synchronous condenser	5.28%
h.	Batteries	5.28%
(i)	Underground cable including joint boxes and disconnected boxes	5.28%
(ii)	Cable duct system	5.28%
i.	Overhead lines including cable support	
(i)	Lines on fabricated steel operating at terminal voltages higher than 66 KV	5.28%
(ii)	Lines on steel supports operating at terminal voltages higher than 13.2 KV but not exceeding	5.28%
(iii)	Lines on steel on reinforced concrete support	5.28%
(iv)	Lines on treated wood support	5.28%
j.	Meters	5.28%
k.	Self propelled vehicles	9.50%
l.	Air Conditioning Plants	
(i)	Static	5.28%
(ii)	Portable	9.50%
m.(i)	Office furniture and furnishing	6.33%
(ii)	Office equipment	6.33%
(iii)	Internal wiring including fittings and apparatus	6.33%
(iv)	Street Light fittings	5.28%
n.	Apparatus let on hire	
(i)	Other than motors	9.50%
(ii)	Motors	6.33%
o.	Communication equipment	
(i)	Radio and high frequency carrier system	6.33%
(ii)	Telephone lines and telephones	6.33%
p.	I. T Equipment including software	15.00%
q.	Any other assets not covered above	5.28%

## **Annexure-9**

### **(For Coal based Generating Stations)**

It is to certify that the **(Name of the Station)** has fulfilled all the key provisions as prescribed below in accordance with Regulation 4 of **Tripura Electricity Regulatory Commission (Multi Year Tariff) Regulations, 2015**.

- I. All documents as prescribed in Regulation 3(8) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations - 2010 have been retained at site and are available at site.
- II. All requirements as per Regulation 5 of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010 have been complied.
- III. The unit operating capability shall be in conformity to Regulation 7(1), 7(2), 7(3) and 7(4) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010.
- IV. All requirements as per Regulation 8 of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations 2010 have been complied for the Steam Generator.
- V. All requirements as per Regulation 9(2), 9(4), 9(9), 9(15), 9(16), 9(18) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations 2010 have been complied for the Steam Turbine Generator.

Name:  
(CMD/CEO/MD)



**(For Gas based Generating Stations)**

It is to certify that the **(Name of the Station)** has fulfilled all the key provisions as prescribed below in accordance with Regulation 4 of **Tripura Electricity Regulatory Commission (Multi Year Tariff) Regulations, 2015**.

- I. All documents as prescribed in Regulation 3(8) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations - 2010 have been retained at site and are available at site.
  
- II. All requirements as per Regulation 5 of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010 have been complied.
  
- III. The unit operating capability shall be in conformity to Regulation 14 (2), 14(3), 14(4), 14(5) and 14(7) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010.
  
- IV. All requirements as per Regulation 17 and Regulations 9(2), 9(4), 9(9), 9(15), 9(16), 9(18) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations 2010 have been complied for the Steam Turbine.

Name:

(CMD/CEO/MD)

**(For Hydro based Generating Stations)**

It is to certify that the (Name of the Station) has fulfilled all the key provisions as prescribed below in accordance with Regulation 4 of **Tripura Electricity Regulatory Commission (Multi Year Tariff) Regulations, 2015**.

- I. All documents as prescribed in Regulation 3(8) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations - 2010 have been retained at site and are available at site.
  
- II. All requirements as per Regulation 30(1), 30(2) and 30(5) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010 have been complied.
  
- III. The unit operating capability shall be in conformity to Regulation 32 (1), 32(3), 32(4), 32(6) and 32(8) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010.
  
- IV. All requirements as per Regulation 33(6), 33(7), 33(8) of the CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations 2010 have been complied for the hydraulic Turbine.

Name:

(CMD/CEO/MD)

## Annexure-10

### Methodology for computation of AT&C loss

Name of the State				
Name of State of <b>DISCOM</b>				
Sl.No	Particulars	Calculation	Unit	Year
1).	Generation (own as well as any other connected generation net after deducting auxiliary consumption) within area of supply of DISCOM.	A	MU	
2).	Input energy (metered Import) received at interface points of DISCOM network	B	MU	
3).	Input energy (metered Export) by the DISCOM at interface points of DISCOM network	C	MU	
4).	Total Energy available for sale within the licensed area to the consumers of the DISCOM	$D=A+B-C$	MU	
5).	Energy billed to metered consumers within the licensed area of the DISCOM	E	MU	
6).	Energy billed to un-metered consumers within the licensed area of the DISCOM @	F	MU	
7).	Total Energy Billed	$G=E+F$	MU	
8).	Amount billed to consumer within the licensed area of the DISCOM	H	RS	
9).	Late payment Surcharge	I	RS	
10).	Amount realized by the DISCOM out of the amount Billed at H	J	RS.	
11).	Subsidy Amount Received	K	RS	
12).	Amount Realized on account of theft cases	L	RS	
13).	Energy Realized on account of theft cases	$M=(L \times G)/H$	MU	
14).	Collection Efficiency (%)	$N=(J-I+K+L/H+K+L) \times 100$	MU	
15).	Energy Realized by the DISCOM	$P=N \times G$		

16).	Distribution Loss (%)	$Q = \{(D-G)/D\} \times 100$		
17).	AT&C Loss (%)	$R = \{(D - (P+M))/D\} \times 100$	%	
<p># Amount received in the current year for the amount billed in the previous years should not be excluded in this head. However, subsidy received against the current year's sale of electricity should be considered in this head.</p>				
<p>@ Norms for determining the energy billed to un-metered consumer may be specified. This should be only for two categories i.e. agricultural consumers and the households below poverty line. The norms could be on the basis of sample metering in case of the agricultural consumers which could be further refined on the basis of the results of the consultancy study on cost of supply to agricultural consumers</p>				
<p>Note: Audited figures must be taken from the Commercial Department of the utility (Billing and Revenue Section) for computing the AT&amp;C losses.</p>				