CENTRAL ELECTRICITY REGULATORY COMMISSION

NEW DELHI

No.L-1/236/2018/CERC Dated 7th March, 2019

NOTIFICATION

In exercise of powers conferred under section 178 of the Electricity Act, 2003 (36 of 2003) read with Section 61 thereof and all other powers enabling it in this behalf, and after previous publication, the Central Electricity Regulatory Commission hereby makes the following regulations, namely:

CHAPTER – 1

PRELIMINARY

1. Short title and commencement. (1) These regulations may be called the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019.

(2) These regulations shall come into force on 1.4.2019, and unless reviewed earlier or extended by the Commission, shall remain in force for a period of five years from 1.4.2019 to 31.3.2024:

Provided that where a generating station or unit thereof and transmission system or an element 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 generating station or unit thereof and transmission system or an element thereof for the period ending 31.3.2019 shall be determined in accordance with the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 as amended from time to time.

2. Scope and extent of application. (1) These regulations shall apply in all cases where tariff for a generating station or a unit thereof and a transmission system or an element thereof is required to be determined by the Commission under section 62 of the Act read with section 79 thereof:

Provided that any generating station for which agreement(s) have been executed for supply of electricity to the beneficiaries on or before 5.1.2011 and the financial closure for the said generating station has not been achieved by 31.3.2019, such projects shall not be eligible for determination of tariff under these regulations unless fresh consent of the beneficiaries is obtained and furnished.

(2) These regulations shall not apply to the following cases:-

(a) Generating stations or transmission systems whose tariff has been discovered through tariff based competitive bidding in accordance with the guidelines issued by the Central Government and adopted by the Commission under section 63 of the Act;

(b) Generating stations based on renewable sources of energy whose tariff is determined in accordance with the Central Electricity Regulatory Commission (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2017.

3. **Definitions. -** In these regulations, unless the context otherwise requires:-

(1) **'Act'** means the Electricity Act, 2003 (36 of 2003);

(2) **'Additional Capital expenditure'** means the capital expenditure incurred, or projected to be incurred after the date of commercial operation of the project by the generating company or the transmission licensee, as the case may be, in accordance with the provisions of these regulations;

(3) **'Additional Capitalisation'** means the additional capital expenditure admitted by the Commission after prudence check, in accordance with these regulations;

(4) **'Admitted capital cost'** means the capital cost which has been allowed by the Commission for servicing through tariff after due prudence check in accordance with the relevant tariff regulations;

(5) **'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 and integrated coal mine;

Provided further that auxiliary energy consumption for compliance of revised emission standards, sewage treatment plant and external coal handling plant (jetty and associated infrastructure) shall be considered separately.

(6) '**Auditor**' means an auditor appointed by a generating company or a transmission licensee, as the case may be, in accordance with the provisions of sections 224, 233B and 619 of the Companies Act, 1956 (1 of 1956), as amended from time to time or Chapter X of the Companies Act, 2013 (18 of 2013) or any other law for the time being in force;

(7) '**Bank Rate**' means the one year marginal cost of lending rate (MCLR) of the State Bank of India issued from time to time plus 350 basis points;

(8) ‘**Beneficiary**’ in relation to a generating station covered under clauses (a) or (b) of sub-section 1 of section 79 of the Act, means a distribution licensee who is purchasing electricity generated at such generating station by entering into a Power Purchase Agreement either directly or through a trading licensee on payment of capacity charges and energy charges;

Provided that where the distribution licensee is procuring power through a trading licensee, the arrangement shall be secured by the trading licensee through back to back power purchase agreement and power sale agreement.

Provided further that beneficiary shall also include any person who has been allocated capacity in any inter-State generating station by Government of India.

(9) ‘**Capital Cost**’ means the capital cost as determined in accordance with Regulation 19 of these regulations;

(10) ‘**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 or treaty between the Government of India and any other Sovereign Government having implication for the generating station or the transmission system regulated under these regulations.

(11) **'Commission'** means the Central Electricity Regulatory Commission referred to in sub-section (1) of section 76 of the Act;

(12) '**Communication System'** means communication system as defined in sub-clause (h) of clause (i) of Regulation 2 of the Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017;

(13) '**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;

(14) **'Cut-off Date**' means the last day of the calendar month after thirty six months from the date of commercial operation of the project;

(15) '**Date of Commercial Operation**' or '**COD**' shall have the same meaning as defined in the Grid Code as amended from time to time;

(16) **'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 these regulations;

(17) **'De-capitalisation'** for the purpose of the tariff under these regulations, means reduction in Gross Fixed Assets of the project as admitted by the Commission corresponding to inter-unit transfer of assets or the assets taken out from service;

(18) **'De-commissioning'** means removal from service of a generating station or a unit thereof or transmission 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;

(19) '**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;

(20) **'Element'** means an asset which has been distinctively defined under the scope of the transmission project in the Investment Approval such as transmission lines including line bays and line reactors, substations, bays, compensation device, Interconnecting Transformers;

(21) **'Existing Project'** means a project which has been declared under commercial operation on a date prior to 1.4.2019;

(22) **'Expansion project'** shall include any addition of new capacity to the existing generating station or augmentation of the transmission system, as the case may be;

(23) '**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;

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

(25) '**Force Majeure'** for the purpose of these regulations means the events or circumstances or combination of events or circumstances including those stated below which partly or fully prevents the generating company or transmission licensee to complete the project within the time specified in the Investment Approval, and only if

such events or circumstances are not within the control of the generating company or transmission licensee and could not have been avoided, had the generating company or transmission 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; or

(c) Industry wide strikes and labour disturbances having a nationwide impact in India; or

(d) Delay in obtaining statutory approval for the project except where the delay is attributable to project developer;

(26) **'Fuel Supply Agreement'** means the agreement executed between the generating company and the fuel supplier for generation and supply of electricity to the beneficiaries;

(27) **'Generating Station'** shall have the same meaning as defined under sub-Section 30 of Section 2 of the Act and for the purpose of these regulations shall also include stages or blocks or units of a generating station;

(28) **'Generating Unit' or '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 or combustion turbine-generator, associated waste heat recovery boiler, connected steam turbine- generator and auxiliaries, and in relation to a hydro generating station means turbine-generator and its auxiliaries;

(29) **'Grid Code'** means the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010;

(30) **'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 litre of liquid fuel or one standard cubic meter of gaseous fuel, as the case may be;

(31) **'GCV as Received'** means the GCV of coal as measured at the unloading point of the thermal generating station through collection, preparation and testing of samples from the loaded wagons, trucks, ropeways, Merry-Go-Round (MGR), belt conveyors and ships in accordance with the IS 436 (Part-1/ Section 1)- 1964:

Provided that the measurement of coal shall be carried out through sampling by third party to be appointed by the generating companies in accordance with the guidelines, if any, issued by Central Government:

Provided further that samples of coal shall be collected either manually or through hydraulic augur or through any other method considered suitable keeping in view the safety of personnel and equipment:

Provided also that the generating companies may adopt any advance technology for collection, preparation and testing of samples for measurement of GCV in a fair and transparent manner;

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

(33) '**Implementation Agreement**' means any agreement or covenant entered into (i) between the transmission licensee and the generating company or (ii) between transmission licensee and developer of the interconnected transmission system for the execution of generation and transmission projects in a coordinated manner, laying down the project implementation schedule and mechanism for monitoring the progress of the projects;

(34) **'Indian Governmental Instrumentality'** means the Government of India, Governments of State (where the project is located) and any ministry or department or board or agency controlled by Government of India or Government of State where the project is located, or quasi-judicial authority constituted under the relevant statutes in India;

(35) ‘**Infirm Power**’ means electricity injected into the grid prior to the date of commercial operation of a unit of the generating station in accordance with Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009;

(36) ‘**Input Price’** means the price of coal or lignite sourced from the integrated mines at which the coal or lignite is transferred to the generating station for the purpose of computing the energy charges for generation and supply of electricity to the beneficiaries and determined in accordance with Chapter 9 of these regulations;

(37) ‘**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;

(38) ‘**Integrated Mine**’ means the captive mine (allocated for use in one or more identified generating station) or basket mine (allocated to a generating company for use in any of its generating stations) or both being developed by the generating company for supply of coal or lignite to one or more specified end use generating stations for generation and sale of electricity to the beneficiaries;

(39) ‘**Inter-State Generating Station**’ or ‘**ISGS**’ has the meaning as assigned in the Grid Code;

(40) ‘**Investment Approval**’ means approval by the Board of the generating company or the transmission 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 of the Board of the generating company or the transmission licensee where the Board is competent to accord such approval and from the date of sanction letter of competent authority in other cases;

(41) **‘Landed Fuel Cost’** means the total cost of coal (including biomass in case of co-firing), lignite or the gas delivered at the unloading point of the generating station and shall include the base price or input price, washery charges wherever applicable, transportation cost (overseas or inland or both) and handling cost, charges for third party sampling and applicable statutory charges;

(42) '**Long-Term Customer**' shall have the same meaning as ‘Long Term Customer’ as defined in the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009;

(43) ‘**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;

(44) **'New Project'** means the generating station or unit thereof and the transmission system or element thereof achieving its commercial operation on or after 1.4.2019;

(45) '**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, maintenance, repairs and maintenance spares, consumables, insurance and overheads and fuel other than used for generation of electricity;

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

(47) **'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;

(48) **'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:

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

Where,

IC = Installed Capacity of the generating station or unit in MW,

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

N = Number of time blocks during the period, and

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

(49) '**Procedure Regulations**' means the Central Electricity Regulatory Commission (Procedure for making of application for determination of tariff, publication of the application and other related matters) Regulations, 2004;

(50) **'Project'** means:

i) in case of thermal generating station, all components of the thermal generating station and includes integrated coal mine, biomass pellet handling system, pollution control system, effluent treatment plan, as may be required;

ii) in case of hydro generating station, all components of the hydro generating station and includes dam, intake water conductor system, power generating station, as apportioned to power generation; and

iii) in case of transmission, all components of the transmission system including communication system;

(51) **'Prudence Check'** means scrutiny of reasonableness of any cost or expenditure incurred or proposed to be incurred in accordance with these regulations by the generating company or the transmission licensee, as the case may be;

(52) **'Pumped Storage Hydro Generating Station'** means a hydro generating station which generates power through energy stored in the form of water energy, pumped from a lower elevation reservoir to a higher elevation reservoir;

(53) **'Rated Voltage'** means the manufacturer's design voltage at which the transmission system is designed to operate and includes such lower voltage at which any transmission line is charged or for the time being charged, in consultation with long-term customers;

(54) **'Revised Emission Standards'** in respect of thermal generating station means the revised norms notified as per Environment (Protection) Amendment Rules, 2015 or any other Rules as may be notified from time to time;

(55) **'Run-of-River Generating Station'** means a hydro generating station which does not have upstream pondage;

(56) '**Run–of-River Generating Station with Pondage'** means a hydro generating

station with sufficient pondage for meeting the diurnal variation of power demand;

(57) **'Scheduled Commercial Operation Date or 'SCOD'** shall mean the date(s) of commercial operation of a generating station or generating unit thereof or transmission system or element thereof and associated communication system as indicated in the Investment Approval or as agreed in power purchase agreement or transmission service agreement as the case may be, whichever is earlier;

(58) **'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;

(59) **'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 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 drawl schedule of beneficiaries shall be corrected in proportion to their scheduled drawl with adjustment of transmission losses on post facto basis.

(60) **'Sharing Regulations'** means Central Electricity Regulatory Commission (Sharing of Transmission Charges and Losses in inter-State Transmission System) Regulations, 2010;

(61) **'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;

(62) **'Start Date or Zero Date**' means the date indicated in the Investment Approval for commencement of implementation of the project and where no such date has been indicated, the date of Investment Approval shall be deemed to be Start Date or Zero Date;

(63) **'Statutory Charges'** comprises taxes, cess, duties, royalties and other charges levied through Acts of the Parliament or State Legislatures or by Indian Government Instrumentality under relevant statutes;

(64) '**Storage Type Generating Station**' means a hydro generating station associated with storage capacity to enable variation of generation of electricity according to demand;

(65) **'Thermal Generating Station' m**eans 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 or co-firing of biomass with coal;

(66) '**Transmission Line**' shall have the same meaning as defined in sub-section (72) of Section 2 of the Act;

(67) '**Transmission Service Agreement**' means the agreement entered into between the transmission licensee and the Designated ISTS Customers in accordance with the Sharing Regulations and shall include the Bulk Power Transmission Agreement and Long Term Access Agreement;

(68) '**Transmission System**' means a line or a group of lines with or without associated sub-station, equipment associated with transmission lines and sub-stations identified under the scheme as per the Investment Approval(s) and shall include associated communication system;

(69) **'Trial Operation'** in relation to transmission system shall have the same meaning as specified in Clause (5) of Regulation 6.3A of Grid Code;

(70) **'Trial Run'** in relation to generating station shall have the same meaning as specified in Clause (3) of Regulation 6.3A of Grid Code;

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

(72) **'Unloading Point'** means the point within the premises of the coal or lignite based thermal generating station where the coal or lignite is unloaded from the rake or truck or any other mode of transport;

(73) **'Useful Life'** in relation to a unit of a generating station, integrated mines, transmission system and communication system from the date of commercial operation shall mean the following:

(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 including pumped storage hydro generating stations	40 years
(f)	Transmission line (including HVAC & HVDC)	35 years
(g)	Communication system	15 years

Provided that the extension of life of the projects beyond the completion of their useful life shall be decided by the Commission on case to case basis;

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

4. Interpretations:- In these regulations, unless the context otherwise requires:

(1) **'Day'** means a calendar day consisting of 24 hours period starting at 0000 hours;

(2) '**kCal'**means a unit of heat energy contents in mineral, measured in one kilo calories or one thousand calories of heat produced at any instantaneous period;

(3) '**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;

(4) **'Quarter**' means the period of three months commencing on the first day of April, July, October and January of each financial year in case of existing project, and in case of a new project, in respect of the first quarter, from the date of commercial operation to the last day of June, September, December or March, as the case may be;

(5) **'Year'** means a financial year from 1st April to 31st March in case of an existing project, and from date of commercial operation to 31st March in case of a new project;

(6) Reference to any Act, Rules and Regulations shall include amendment or consolidation or re-enactment thereof.

CHAPTER – 2

DATE OF COMMERCIAL OPERATION

5. Date of Commercial Operation: (1) The date of commercial operation of a generating station or unit thereof or a transmission system or element thereof and associated communication system shall be determined in accordance with the provisions of the Grid Code.

(2) In case the transmission system or element thereof executed by a transmission licensee is ready for commercial operation but the interconnected generating station or the transmission system of other transmission licensee as per the agreed project implementation schedule is not ready for commercial operation, the transmission licensee may file petition before the Commission for approval of the date of commercial operation of such transmission system or element thereof:

Provided that the transmission licensee seeking the approval of the date of commercial operation under this clause shall give prior notice of at least one month, to the generating company or the other transmission licensee and the long term customers of its transmission system, as the case may be, regarding the date of commercial operation:

Provided further that the transmission licensee seeking the approval of the date of commercial operation of the transmission system under this clause shall be required to submit the following documents along with the petition:

(a) Energisation certificate issued by the Regional Electrical Inspector under Central Electricity Authority;

(b) Trial operation certificate issued by the concerned RLDC for charging element with or without electrical load;

(c) Implementation Agreement, if any, executed by the parties;

(d) Minutes of the coordination meetings or related correspondences regarding the monitoring of the progress of the generating station and transmission systems;

(e) Notice issued by the transmission licensee as per the first proviso under this clause and the response;

(f) Certificate of the CEO or MD of the company regarding the completion of the transmission system including associated communication system in all respects.

6. Treatment of mismatch in date of commercial operation: (1) In case of mismatch of the date of commercial operation of the generating station and the transmission system, the liability for the transmission charges shall be determined as under:

(a) Where the generating station has not achieved the commercial operation as on the date of commercial operation of the associated transmission system (which is not before the SCOD of the generating station) and the Commission has approved the date of commercial operation of such transmission system in terms of clause (2) of the Regulation 5 of these regulations, the generating company shall be liable to pay the transmission charges of the associated transmission system in accordance with clause (5) of Regulation 14 of these regulations to the transmission licensee till the generating station or unit thereof achieves commercial operation:

(b) Where the associated transmission system has not achieved the commercial operation as on the date of commercial operation of the concerned generating station or unit thereof (which is not before the SCOD of the transmission system), the transmission licensee shall make alternate arrangement for the evacuation from the generating station at its own cost, failing which, the transmission licensee shall be liable to pay the transmission charges to the generating company as determined by the Commission, in accordance with clause (5) of Regulation 14 of these regulations, till the transmission system achieves the commercial operation.

(2) In case of mismatch of the date of commercial operation of the transmission system and the transmission system of other transmission licensee, the liability for the transmission charges shall be determined as under:

(a) Where an interconnected transmission system of other transmission licensee has not achieved the commercial operation as on the date of commercial operation of the transmission system (which is not before the SCOD of the interconnected transmission system) and the Commission has approved the date of commercial operation of such transmission system in terms of clause (2) of Regulation 5 of these regulations, the other transmission licensee shall be liable to pay the transmission charges of the transmission system in accordance with clause (5) of Regulation 14 of these regulations to the transmission licensee till the interconnected transmission system achieves commercial operation:

(b) Where the transmission system has not achieved the commercial operation as on the date of commercial operation of the interconnected transmission system of other transmission licensee (which is not before the SCOD of the transmission system), the transmission licensee shall be liable to pay the transmission charges of such interconnected transmission system to the other transmission licensee or as may be determined by the Commission, in accordance with clause (5) of Regulation 14 of these regulations, till the transmission system achieves the commercial operation.

7. Sale of Infirm Power: 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:

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.

CHAPTER - 3

PROCEDURE FOR TARIFF DETERMINATION

8. Tariff determination

(1) Tariff in respect of a generating station may be determined for the whole of the generating station or unit thereof, and tariff in respect of a transmission system may be determined for the whole of the transmission system or element thereof or associated communication system:

Provided that:

(i) In case of commercial operation of all the units of a generating station or all elements of a transmission system prior to 1.4.2019, the generating company or the transmission licensee, as the case may be, shall file consolidated petition in respect of the entire generating station or transmission system for the purpose of determination of tariff for the period 1.4.2019 to 31.3.2024:

(ii) In case of commercial operation of units of generating station or elements of the transmission system on or after 1.4.2019, the generating company or the transmission licensee shall file a consolidated petition, in accordance with the provisions of the Procedure Regulations, combining all the units of the generating station or all elements of the transmission system which are anticipated to achieve commercial operation during the next two months from the date of application:

(iii) Tariff of the associated communication system forming part of transmission system which has achieved commercial operation prior to 1.4.2014 shall be as per the methodology approved by the Commission prior to 1.4.2014.

(2) 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, the units for such part capacity shall be clearly identified and in such cases, the tariff shall be determined for such identified capacity. Where the unit(s) corresponding to such part capacity cannot be identified, the tariff of the generating station may be determined with reference to the capital cost of the entire project, but tariff so determined shall be applicable corresponding to the part capacity contracted for supply to the beneficiaries.

(3) In case of expansion of existing generating station, the tariff shall be determined for the expanded capacity in accordance with these regulations:

Provided that the common infrastructure of existing generating station, shall be utilized for the expanded capacity and the benefit of new technology in the expanded capacity, as determined by the Commission, shall be extended to the existing capacity.

(4) Assets installed for implementation of the revised emission standards shall form part of the existing generation project and tariff thereof shall be determined separately on submission of the completion certificate by the Board of the generating company.

(5) Energy charge component of tariff of the generating station sourcing coal or lignite from the integrated mine shall be determined based on the input price of coal or lignite,

as the case may be, from such integrated mines:

Provided that the generating company shall maintain the account of the integrated mine separately and submit the cost of integrated mine, in accordance with these regulations, duly certified by the Auditor.

(6) Tariff of generating station using coal washery rejects developed by Central or State PSUs or Joint Venture between a Government Company and company other than Government Company shall be determined in accordance with these regulations:

Provided that in case of Joint Venture between a Government Company and a Company other than Government Company, the shareholding of the company other than Government Company either directly or through any of its subsidiary company or associate company shall not exceed 26% of the paid up share capital:

Provided further that the energy charge component of the tariff of such generating station or unit thereof shall be determined based on the fixed cost and the variable cost of the coal washery project:

Provided also that the Gross Calorific Value of coal rejects shall be as measured jointly by the generating company and the beneficiaries.

(7) In case of multi-purpose hydro schemes, with irrigation, flood control and power components, the capital cost chargeable to the power component of the scheme only shall be considered for determination of tariff.

(8) If an existing transmission project is granted licence under section 14 of the Act

read with clause (c) of Regulation 6 of the Central Electricity Regulatory Commission (Terms and Conditions of grant of Transmission Licence for inter-State Transmission of electricity and related matters) Regulations, 2009, the tariff of such project shall be applicable from the date of grant of transmission licence or from the date as indicated in the transmission licence, as the case may be. In such cases, the applicant shall file petition as per **Annexure-I (Part III)** to these regulations**,** clearly demarcating the assets which form part of the business of generation and transmission, the value of such assets, source of funding and other relevant details after adjusting the cumulative depreciation and loan repayment, duly certified by the Auditor.

9. Application for determination of tariff

(1) The generating company or the transmission licensee may make an application for determination of tariff for new generating station or unit thereof or transmission system or element thereof in accordance with the Procedure Regulations within 60 days of the anticipated date of commercial operation:

Provided that where the transmission system comprises various elements, the transmission licensee shall file an application for determination of tariff for a group of elements on incurring of expenditure of not less than 70% of the cost envisaged in the Investment Approval or Rs. 200 Crore, whichever is lower, as on the anticipated date of commercial operation:

Provided further that the generating company or the transmission licensee, as the case may be, shall submit Auditor Certificate and in case of non-availability of Auditor Certificate, a Management Certificate duly signed by an authorised person, not below the level of Director of the company, indicating the capital cost incurred as on the date of commercial operation and the projected additional capital expenditure for respective years of the tariff period 2019-24:

Provided also that where interim tariff of the generating station or unit thereof and the transmission system or element thereof including communication system has been determined based on Management Certificate, the generating company or the transmission licensee shall submit the Auditor Certificate not later than 60 days from date of granting interim tariff.

(2) In case of an existing generating station or unit thereof, or transmission system or element thereof, the application shall be made by the generating company or the transmission licensee, as the case may be, by 31.10.2019, based on admitted capital cost including additional capital expenditure already admitted and incurred up to 31.3.2019 (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure for the respective years of the tariff period 2019-24 along with the true up petition for the period 2014-19 in accordance with the CERC (Terms and Conditions of Tariff) Regulations, 2014.

(3) In case of emission control system required to be installed in existing generating station or unit thereof to meet the revised emission standards, an application shall be

made for determination of supplementary tariff (capacity charges or energy charge or both) based on the actual capital expenditure duly certified by the Auditor.

(4) Where the generating company has the arrangement for supply of coal or lignite from an integrated mine(s) to one or more of its generating stations, the generating company shall file a petition for determination of the input price for determining the energy charge along with the tariff petitions for one or more generating stations in accordance with the provision of Chapter 9 of these regulations.

10. Determination of tariff

(1) The generating company or the transmission licensee, as the case may be, shall file petition before the Commission as per **Annexure-I to** these regulations containing the details of underlying assumptions for the capital expenditure and additional capital expenditure incurred and projected to be incurred, wherever applicable.

(2) If the petition is inadequate in any respect as required under **Annexure-I** to these regulations, the application shall be returned to the generating company or transmission licensee, as the case may be, for resubmission of the petition within one month after rectifying the deficiencies as may be pointed out by the staff of the Commission.

(3) If the information furnished in the petition is in accordance with these regulations and is adequate for carrying out prudence check of the claims made, the Commission

may consider granting interim tariff in case of new projects.

(4) In case of the existing projects, the generating company or the transmission licensee, as the case may be, shall continue to bill the beneficiaries or the long term customers at the capacity charges or the transmission charges respectively as approved by the Commission and applicable as on 31.3.2019 for the period starting from 1.4.2019 till approval of final capacity charges or transmission charges by the Commission in accordance with these regulations:

Provided that the billing for energy charges w.e.f. 1.4.2019 shall be as per the operational norms specified in these regulations.

(5) The Commission shall grant final tariff in case of existing and new projects, after considering the replies received from the respondents, and suggestions and objections, if any, received from the general public and any other person permitted by the Commission including the consumers or consumer associations.

(6) The Commission may hear the petitioner, the respondents and any other person permitted including the consumers or consumer associations while granting interim or final tariff.

(7) The difference between the tariff determined in accordance with clauses (3) and (5) above and clauses (4) and (5) above, shall be recovered from or refunded to, the beneficiaries or the long term customers, as the case may be, with simple interest at the

rate equal to the bank rate prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments.

(8) Where the capital cost considered by the Commission on the basis of projected additional capital expenditure exceeds the actual additional capital expenditure incurred on year to year basis by more than 10%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term customers as the case may be, the tariff recovered corresponding to the additional capital expenditure not incurred, as approved by the Commission, along with interest at 1.20 times of the bank rate as prevalent on 1st April of the respective year.

(9) Where the capital cost considered by the Commission on the basis of projected additional capital expenditure falls short of the actual additional capital expenditure incurred by more than 10% on year to year basis, the generating company or the transmission licensee shall recover from the beneficiaries or the long term customers as the case may be, the shortfall in tariff corresponding to difference in additional capital expenditure, as approved by the Commission, along with interest at the bank rate as prevalent on 1st April of the respective year.

11. In-principle approval in specific circumstances: The generating company or the transmission licensee undertaking any additional capitalization on account of change in law events or force majeure conditions may file petition for in-principle approval for incurring such expenditure after prior notice to the beneficiaries or the long term customers, as the case may be, along with underlying assumptions, estimates and justification for such expenditure if the estimated expenditure exceeds 10% of the admitted capital cost of the project or Rs.100 Crore, whichever is lower.

12. Truing up of tariff for the period 2014-19: The tariff of the generating stations and the transmission systems for the period 2014-19 shall be trued up in accordance with the provisions of Regulation 8 of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 along with the tariff petition for the period 2019-24. The capital cost admitted as on 31.3.2019 based on the truing up shall form the basis of the opening capital cost as on 1.4.2019 for the tariff determination for the period 2019-24.

13. Truing up of tariff for the period 2019-24: (1) The Commission shall carry out truing up exercise for the period 2019-24 along with the tariff petition filed for the next tariff period, for the following:

a) the capital expenditure including additional capital expenditure incurred up to 31.3.2024, as admitted by the Commission after prudence check at the time of truing up:

b) the capital expenditure including additional capital expenditure incurred up to 31.3.2024, on account of Force Majeure and Change in Law.

(2) The generating company or the transmission licensee, as the case may be, shall make an application, as per **Annexure-I** to these regulations, for carrying out truing up exercise in respect of the generating station or a unit thereof or the transmission system or an element thereof by 30.11.2024.

(3) The generating company or the transmission licensee, as the case may be, may make an application for interim truing up of tariff in the year 2021-22, if the annual fixed cost increases by more than 20% over the annual fixed cost as determined by the Commission for the respective years of the tariff period:

Provided that if the actual additional capital expenditure falls short of the projected additional capital expenditure allowed under provisions of Chapter 7 of these regulations, the generating company or the transmission licensee, as the case may be, shall not be required to file any interim true up petition for this purpose and shall refund to the beneficiaries or the long term customers, as the case may be, the excess tariff recovered corresponding to the projected additional capital expenditure not incurred at the bank rate as on 1st April of the respective years, under intimation to the Commission:

Provided further that the generating company or the transmission licensee shall submit the complete details along with the calculations of the refunds made to the beneficiaries or the long term customers, as the case may be, at the time of true up.

(4) After truing up, if the tariff already recovered exceeds or falls short of the tariff

approved by the Commission under these regulations, the generating company or the transmission licensee, shall refund to or recover from, the beneficiaries or the long term customers, as the case may be, the excess or the shortfall amount along with simple interest at the rate equal to the bank rate as on 1st April of the respective years of the tariff period in six equal monthly instalments.

CHAPTER – 4

TARIFF STRUCTURE

14. Components of Tariff: (1) 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 Regulation 15 of these regulations) and energy charge (for recovery of primary and secondary fuel cost and cost of limestone and any other reagent, where applicable as specified in Regulation 16 of these regulations).

(2) The supplementary capacity charges for additional capitalization and supplementary energy charges, on account of implementation of revised emission standards in existing generating station or new generating station, as the case may be, shall be determined by the Commission separately.

(3) The capacity charge and energy charge of a generating station shall be determined in accordance with the provisions of Chapter 11 of these regulations. The input price of coal or lignite from the integrated mine as determined in accordance with the provisions of Chapter 9 of these regulations shall form part of energy charge of the generating station.

(4) 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 Regulation 44 or 45 of these regulations, as may be applicable, for recovery of annual fixed cost consisting of the components referred to in Regulation 15 of these regulations.

(5) The tariff for transmission of electricity on inter-State transmission system shall comprise transmission charges for recovery of annual fixed cost consisting of the components specified in Regulation 15 of these regulations.

15. Capacity Charges: 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; and

(e) Operation and maintenance expenses:

Provided that Special Allowance in lieu of R&M, where opted in accordance with Regulation 28 of these regulations, shall be recovered separately and shall not be considered for computation of working capital.

16. Energy Charges: Energy charges shall be derived on the basis of the landed fuel cost (LFC) of a generating station (excluding hydro) and shall consist of the following cost:

(a) Landed Fuel Cost of primary fuel;

(b) Cost of secondary fuel oil consumption; and

(c) Cost of limestone or any other reagent, as applicable:

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

Provided further that the supplementary energy charges, if any, on account of meeting the revised emission standards in case of a thermal generating station shall be determined separately by the Commission.

17. Special Provisions for Tariff for Thermal Generating Station which have Completed 25 Years of Operation from Date of Commercial Operation: (1) In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation, the generating company and the beneficiary may agree on an arrangement, including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation.

(2) The beneficiary shall have the first right of refusal and upon its refusal to enter into an arrangement as above, the generatingcompany shall be free to sell the electricity generated from such station in a manner as it deems fit.

CHAPTER – 5

CAPITAL STRUCTURE

18. Debt-Equity Ratio: (1) For new projects, the debt-equity ratio of 70:30 as on date of commercial operation shall be considered. 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 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 utilised for meeting the capital expenditure of the generating station or the transmission system.

(2) The generating company or the transmission licensee, as the case may be, shall submit the resolution of the Board of the company or approval of the competent authority in other cases regarding infusion of funds 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 system including communication system, as the case may be.

(3) In case of the generating station and the transmission system including communication system declared under commercial operation prior to 1.4.2019, debt: equity ratio allowed by the Commission for determination of tariff for the period ending 31.3.2019 shall be considered:

Provided that in case of a generating station or a transmission system including communication system which has completed its useful life as on or after 1.4.2019, if the equity actually deployed as on 1.4.2019 is more than 30% of the capital cost, equity in excess of 30%shall not be taken into account for tariff computation;

Provided further that in case of projects owned by Damodar Valley Corporation, the debt: equity ratio shall be governed as per sub-clause (ii) of clause (2) of Regulation 72 of these regulations.

(4) In case of the generating station and the transmission system including communication system declared under commercial operation prior to 1.4.2019, but where debt: equity ratio has not been determined by the Commission for determination of tariff for the period ending 31.3.2019, the Commission shall approve the debt: equity ratio in accordance with clause (1) of this Regulation.

(5) Any expenditure incurred or projected to be incurred on or after 1.4.2019 as may be admitted by the Commission as additional capital expenditure for determination of tariff, and renovation and modernisation expenditure for life extension shall be serviced in the manner specified in clause (1) of this Regulation.

CHAPTER - 6

COMPUTATION OF CAPITAL COST

19. Capital Cost: (1) The Capital cost of the generating station or the transmission system, as the case may be, as determined by the Commission after prudence check in accordance with these regulations shall form the basis for determination of tariff for existing and new projects.

(2) The Capital Cost of a new project shall include the following:

(a) The expenditure incurred or projected to be incurred up to the date of commercial operation of the project;

(b) 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;

(c) Any gain or loss on account of foreign exchange risk variation pertaining to the loan amount availed during the construction period;

(d) Interest during construction and incidental expenditure during construction as computed in accordance with these regulations;

(e) Capitalised initial spares subject to the ceiling rates in accordance with these regulations;

(f) Expenditure on account of additional capitalization and de-capitalisation determined in accordance with these regulations;

(g) Adjustment of revenue due to sale of infirm power in excess of fuel cost prior to the date of commercial operation as specified under Regulation 7 of these regulations;

(h) Adjustment of revenue earned by the transmission licensee by using the assets before the date of commercial operation;

(i) Capital expenditure on account of ash disposal and utilization including handling and transportation facility;

(j) Capital expenditure incurred towards railway infrastructure and its augmentation for transportation of coal upto the receiving end of the generating station but does not include the transportation cost and any other appurtenant cost paid to the railway;

(k) Capital expenditure on account of biomass handling equipment and facilities, for co-firing;

(l) Capital expenditure on account of emission control system necessary to meet the revised emission standards and sewage treatment plant;

(m) Expenditure on account of fulfilment of any conditions for obtaining environment clearance for the project;

(n) Expenditure on account of change in law and force majeure events; and

(o) Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under Perform, Achieve and Trade (PAT) scheme of Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries.

(3) The Capital cost of an existing project shall include the following:

(a) Capital cost admitted by the Commission prior to 1.4.2019 duly trued up by excluding liability, if any, as on 1.4.2019;

(b) Additional capitalization and de-capitalization for the respective year of tariff as determined in accordance with these regulations;

(c) Capital expenditure on account of renovation and modernisation as admitted by this Commission in accordance with these regulations;

(d) Capital expenditure on account of ash disposal and utilization including handling and transportation facility;

(e) Capital expenditure incurred towards railway infrastructure and its augmentation for transportation of coal upto the receiving end of generating station but does not include the transportation cost and any other appurtenant cost paid to the railway; and

(f) Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under Perform, Achieve and Trade (PAT) scheme of Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries.

(4) The capital cost in case of existing or new hydro generating station shall also include:

(a) 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

(b) cost of the developer's 10% contribution towards Rajiv Gandhi Grameen

Vidyutikaran Yojana (RGGVY) and Deendayal Upadhyaya Gram Jyoti Yojana (DDUGJY) project in the affected area.

(5) The following shall be excluded from the capital cost of the existing and new projects:

(a) The assets forming part of the project, but not in use, as declared in the tariff petition;

(b) De-capitalised Assets after the date of commercial operation on account of replacement or removal on account of obsolescence or shifting from one project to another project:

Provided that in case replacement of transmission asset is recommended by Regional Power Committee, such asset shall be de-capitalised only after its redeployment;

Provided further that unless shifting of an asset from one project to another is of permanent nature, there shall be no de-capitalization of the concerned assets.

(c) In case of hydro generating stations, 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 transparent process;

(d) Proportionate cost of land of the existing project which is being used for generating power from generating station based on renewable energy; and

(e) 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.

20. Prudence Check of Capital Cost : The following principles shall be adopted for prudence check of capital cost of the existing or new projects:

(1) In case of the thermal generating station and the transmission system, prudence check of capital cost shall include scrutiny of the capital expenditure, in the light of capital cost of similar projects based on past historical data, wherever available, reasonableness of financing plan, interest during construction, incidental expenditure during construction, use of efficient technology, cost over-run and time over-run, procurement of equipment and materials through competitive bidding and such other matters as may be considered appropriate by the Commission:

Provided that, while carrying out the prudence check, the Commission shall also examine whether the generating company or transmission licensee, as the case may be, has been careful in its judgments and decisions in execution of the project.

(2) The Commission may, for the purpose of vetting of capital cost of hydro generating stations, appoint an independent agency or an expert body:

Provided that the Designated Independent Agency already appointed under the guidelines issued by the Commission under Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009 shall continue till completion of the assigned project.

(3) 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 prudence check.

(4) The generating company or the transmission licensee, as the case may be, shall

furnish the capital cost for execution of the existing and new projects as per **Annexure-I** to these regulations along with tariff petition for the purpose of creating a database of benchmark capital cost of various components.

21. Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC)

(1) Interest during construction (IDC) 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 SCOD.

(2) Incidental expenditure during construction (IEDC) shall be computed from the zero date, taking into account pre-operative expenses upto SCOD:

Provided that any revenue earned during construction period up to SCOD on account of interest on deposits or advances, or any other receipts shall be taken into account for reduction in incidental expenditure during construction.

(3) In case of additional costs on account of IDC and IEDC due to delay in achieving the COD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds in case of IDC and details of IEDC during the period of delay and liquidated damages recovered or recoverable corresponding to the delay.

(4) If the delay in achieving the COD is not attributable to the generating company or the transmission licensee, IDC and IEDC beyond SCOD may be allowed after prudence

check and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be adjusted in the capital cost of the generating station or the transmission system, as the case may be.

(5) If the delay in achieving the COD is attributable either in entirety on in part to the generating company or the transmission licensee or its contractor or supplier or agency, in such cases, IDC and IEDC beyond SCOD may be disallowed after prudence check either in entirety or on pro-rata basis corresponding to the period of delay not condoned and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be retained by the generating company or the transmission licensee, as the case may be.

22. Controllable and Uncontrollable factors: The following shall be considered as controllable and uncontrollable factors for deciding time over-run, cost escalation, IDC and IEDC of the project:

(1) The "controllable factors" shall include but shall not be limited to the following:

a. Efficiency in the implementation of the project not involving approved change in scope of such project, change in statutory levies or change in law or force majeure events; and

b. Delay in execution of the project on account of contractor or supplier or agency of the generating company or transmission licensee.

(2) The "uncontrollable factors" shall include but shall not be limited to the following:

a. Force Majeure events;

b. Change in law; and

c. Land acquisition except where the delay is attributable to the generating company or the transmission licensee.

23. Initial Spares: Initial spares shall be capitalised as a percentage of the Plant and Machinery cost, 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 including pumped storage hydro generating station	-	4.0%
(d)	Transmission system		
	(i) Transmission line	-	1.00%
	(ii) Transmission Sub-station		
	- Green Field	-	4.00%
	- Brown Field	-	6.00%
	(iii) Series Compensation devices and HVDC Station	-	4.00%
	(iv) Gas Insulated Sub-station (GIS)		
	- Green Field	-	5.00%
	- Brown Field	-	7.00%
	(v) Communication system	-	3.50%
	(vi) Static Synchronous Compensator	-	6.00%

Provided that:

i. Plant and Machinery cost shall be considered as the original project cost excluding IDC, IEDC, Land Cost and Cost of Civil Works. The generating company and the transmission licensee for the purpose of estimating Plant and Machinery Cost, shall submit the break-up of head wise IDC and IEDC in its tariff application;

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.

CHAPTER – 7

COMPUTATION OF ADDITIONAL CAPITAL EXPENDITURE

24. Additional Capitalisation within the original scope and upto the cut-off date

(1) The additional capital expenditure in respect of a 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:

(a) Undischarged liabilities recognized to be payable at a future date;

(b) Works deferred for execution;

(c) Procurement of initial capital spares within the original scope of work, in accordance with the provisions of Regulation 23 of these regulations;

(d) Liabilities to meet award of arbitration or for compliance of the directions or order of any statutory authority or order or decree of any court of law;

(e) Change in law or compliance of any existing law; and

(f) Force Majeure events:

Provided that in case of any replacement of the assets, the additional capitalization shall be worked out after adjusting the gross fixed assets and cumulative depreciation of the assets replaced on account of de-capitalization.

(2) The generating company or the transmission licensee, as the case may be shall submit 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.

25. Additional Capitalisation within the original scope and after the cut-off date:

(1) The additional capital expenditure incurred or projected to be incurred in respect of an existing project or a new project on the following counts within the original scope of work and after the cut-off date may be admitted by the Commission, subject to prudence check:

(a) Liabilities to meet award of arbitration or for compliance of the directions or order of any statutory authority, or order or decree of any court of law;

(b) Change in law or compliance of any existing law;

(c) Deferred works relating to ash pond or ash handling system in the original scope of work;

(d) Liability for works executed prior to the cut-off date;

(e) Force Majeure events;

(f) Liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments; and

(g) Raising of ash dyke as a part of ash disposal system.

(2) In case of replacement of assets deployed under the original scope of the existing project after cut-off date, the additional capitalization may be admitted by the Commission, after making necessary adjustments in the gross fixed assets and the cumulative depreciation, subject to prudence check on the following grounds:

(a) The useful life of the assets is not commensurate with the useful life of the project and such assets have been fully depreciated in accordance with the provisions of these regulations;

(b) The replacement of the asset or equipment is necessary on account of change in law or Force Majeure conditions;

(c) The replacement of such asset or equipment is necessary on account of obsolescence of technology; and

(d) The replacement of such asset or equipment has otherwise been allowed by the Commission.

26. Additional Capitalisation beyond the original scope

(1) The capital expenditure, in respect of existing generating station or the transmission system including communication system, incurred or projected to be incurred on the following counts beyond the original scope, may be admitted by the Commission, subject to prudence check:

(a) Liabilities to meet award of arbitration or for compliance of order or directions of any statutory authority, or order or decree of any court of law;

(b) Change in law or compliance of any existing law;

(c) Force Majeure events;

(d) Need for higher security and safety of the plant as advised or directed by appropriate Indian Government Instrumentality or statutory authorities responsible for national or internal security;

(e) Deferred works relating to ash pond or ash handling system in additional to the original scope of work, on case to case basis:

Provided also that if any expenditure has been claimed under Renovation and Modernisation (R&M) or repairs and maintenance under O&M expenses, the same shall not be claimed under this Regulation;

(f) Usage of water from sewage treatment plant in thermal generating station.

(2) In case of de-capitalisation of assets of a generating company or the transmission licensee, as the case may be, the original cost of such asset as on the date of de-capitalisation 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-capitalisation takes place with corresponding adjustments in cumulative depreciation and cumulative repayment of loan, duly taking into consideration the year in which it was capitalised.

27. Additional Capitalisation on account of Renovation and Modernisation

(1) The generating company or the transmission licensee, as the case may be, intending to undertake renovation and modernization (R&M) of the generating station or unit thereof or transmission system or element thereof for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff, shall file a petition 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:

Provided that the generating company making the applications for renovation and modernization (R&M) shall not be eligible for Special Allowance under Regulation 28 of these regulations;

Provided further that the generating company or the transmission licensee intending to undertake renovation and modernization (R&M) shall be required to obtain the consent of the beneficiaries or the long term customers, as the case may be, for such renovation and modernization (R&M) and submit the same along with the petition.

(2) Where the generating company or the transmission licensee, as the case may be, makes an application for approval of its proposal for renovation and modernisation (R&M), approval may be granted after due consideration of reasonableness of the proposed cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, expected duration of life extension, consent of the beneficiaries or long term customers, if obtained, and such other factors as may be considered relevant by the Commission.

(3) In case of gas/ liquid fuel based open/ combined cycle thermal generating station after 25 years of operation from date of commercial operation, any additional capital expenditure which has become necessary for renovation of gas turbines/steam turbine or additional capital expenditure necessary due to obsolescence or non-availability of spares for efficient operation of the stations shall be allowed:

Provided that any expenditure included in the renovation and modernisation (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 from the expenditure to be allowed after prudence check.

(4) After completion of the renovation and modernisation (R&M), the generating company or the transmission licensee, as the case may be, shall file a petition for determination of tariff. Expenditure incurred or projected to be incurred and admitted by the Commission after prudence check, and after deducting the accumulated depreciation already recovered from the admitted project cost, shall form the basis for determination of tariff.

28. Special Allowance for Coal-based/Lignite fired Thermal Generating station

(1) In case of coal-based/lignite fired thermal generating stations, the generating company, instead of availing renovation and modernization (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 modernisation beyond the useful life of the generating station or a unit thereof and in such an event, upward 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 thereof 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;

Provided further that special allowance shall also be available for a generating station which has availed the Special Allowance during the tariff period 2009-14 or 2014-19 as applicable from the date of completion of the useful life.

(2) The Special Allowance admissible to a generating station shall be @ Rs 9.5 lakh per MW per year for the tariff period 2019-24.

(3) In the event of a generating station availing Special Allowance, the expenditure incurred upon 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.

(4) The Special Allowance allowed under this Regulation shall be transferred to a separate fund for utilization towards Renovation &Modernisation activities, for which detailed methodology shall be issued separately.

29. Additional Capitalization on account of Revised Emission Standards: (1) A generating company requiring to incur additional capital expenditure in the existing generating station for compliance of the revised emissions standards shall share its proposal with the beneficiaries and file a petition for undertaking such additional capitalization.

(2) The proposal under clause (1) above shall contain details of proposed technology as specified by the Central Electricity Authority, scope of the work, phasing of expenditure, schedule of completion, estimated completion cost including foreign exchange component, if any, detailed computation of indicative impact on tariff to the

beneficiaries, and any other information considered to be relevant by the generating company.

(3) Where the generating company makes an application for approval of additional capital expenditure on account of implementation of revised emission standards, the Commission may grant approval after due consideration of the 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.

(4) After completion of the implementation of revised emission standards, the generating company shall file a petition for determination of tariff. Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on reasonableness of the cost and impact on operational parameters shall form the basis of determination of tariff.

CHAPTER – 8

COMPUTATION OF ANNUAL FIXED COST

30. **Return on Equity**: (1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with Regulation 18 of these regulations.

(2) Return on equity shall be computed at the base rate of 15.50% for thermal generating station, transmission system including communication system and run-of-river hydro generating station, and at the base rate of 16.50% for the storage type hydro generating stations including pumped storage hydro generating stations and run-of-river generating station with pondage:

Provided that return on equity in respect of additional capitalization after cut-off date beyond the original scope excluding additional capitalization due to Change in Law, shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system;

Provided further that:

i. In case of a new project, the rate of return on equity shall be reduced by 1.00% 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) or Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the respective RLDC;

ii. in case of existing generating station, as and when any of the requirements under (i) above of this Regulation are found lacking based on the report submitted by the concerned RLDC, rate of return on equity shall be reduced by 1.00% for the period for which the deficiency continues;

iii. in case of a thermal generating station, with effect from 1.4.2020:

a) rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate of 1% per minute;

b) an additional rate of return on equity of 0.25% shall be allowed for every incremental ramp rate of 1% per minute achieved over and above the ramp rate of 1% per minute, subject to ceiling of additional rate of return on equity of 1.00%:

Provided that the detailed guidelines in this regard shall be issued by National Load Dispatch Centre by 30.6.2019.

31. Tax on Return on Equity. (1) The base rate of return on equity as allowed by the Commission under Regulation 30 of these regulations 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 respect of the financial year in line with the provisions of the relevant Finance Acts by the concerned generating company or the transmission licensee, as the case may be. The actual tax paid on income from other businesses including deferred tax liability (i.e. income from business other than business of generation or transmission, as the case may be) shall be excluded for the calculation of effective tax rate.

(2) Rate of return on equity shall be rounded off to three decimal places and shall be 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 (1) 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 business, as the case may be, and the corresponding tax thereon. In case of generating company or transmission licensee paying Minimum Alternate Tax (MAT), "t" shall be considered as MAT rate including surcharge and cess.

Illustration-

(i) In case of a generating company or a transmission licensee paying Minimum Alternate Tax (MAT) @ 21.55% including surcharge and cess:

Rate of return on equity = 15.50/(1-0.2155) = 19.758%

(ii) In case of a generating company or a transmission licensee paying normal corporate tax including surcharge and cess:

(a) Estimated Gross Income from generation or transmission business for FY 2019-20 is Rs 1,000 crore;

(b) Estimated Advance Tax for the year on above is Rs 240 crore;

(c) Effective Tax Rate for the year 2019-20 = Rs 240 Crore/Rs 1000 Crore = 24%;

(d) Rate of return on equity = 15.50/ (1-0.24) = 20.395%.

(3) The generating company or the transmission 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 2019-24 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 licensee, as the case may be. Any under-recovery or over-recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries or the long term customers, as the case may be, on year to year basis.

32. Interest on loan capital: (1) The loans arrived at in the manner indicated in Regulation 18 of these regulations shall be considered as gross normative loan for calculation of interest on loan.

(2) The normative loan outstanding as on 1.4.2019 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2019 from the gross normative loan.

(3) The repayment for each of the year of the tariff period 2019-24 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-capitalisation of such asset.

(4) Notwithstanding any moratorium period availed by the generating company or the transmission 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.

(5) 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 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 licensee as a whole shall be considered.

(6) The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest.

(7) The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

33. Depreciation: (1) Depreciation shall be computed from the date of commercial operation of a generating station or unit thereof or a transmission system or element thereof including communication system. 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:

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.

(2) 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 a 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.

(3) 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 the salvage value for IT equipment and software shall be considered as NIL and 100% value of the assets shall be considered depreciable;

Provided further that in case of hydro generating stations, the salvage value shall be as provided in the agreement, if any, signed by the developers with the State Government for development of the generating station:

Provided also 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 unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life or the extended life.

(4) 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.

(5) Depreciation shall be calculated annually based on Straight Line Method and at rates specified in **Appendix-I** to these regulations for the assets of the generating station and transmission system:

Provided that the remaining depreciable value as on 31st March of the year closing after a period of 12 years from the effective date of commercial operation of the station shall be spread over the balance useful life of the assets.

(6) In case of the existing projects, the balance depreciable value as on 1.4.2019 shall be worked out by deducting the cumulative depreciation as admitted by the Commission upto 31.3.2019 from the gross depreciable value of the assets.

(7) The generating company or the transmission licensee, as the case may be, shall submit the details of proposed capital expenditure five years before the completion of useful life of the project along with justification and proposed life extension. The Commission based on prudence check of such submissions shall approve the depreciation on capital expenditure.

(8) In case of de-capitalization of assets in respect of generating station or unit thereof or transmission 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.

34. Interest on Working Capital: (1) The working capital shall cover:

(a) For Coal-based/lignite-fired thermal generating stations:

(i) Cost of coal or lignite and limestone towards stock, if applicable, for 10 days for pit-head generating stations and 20 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) Advance payment for 30 days towards cost of coal or lignite and limestone 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 including water charges and security expenses;

(v) Receivables equivalent to 45 days of capacity charge and energy charge for sale of electricity calculated on the normative annual plant availability factor; and

(vi) Operation and maintenance expenses, including water charges and security expenses, for one month.

(b) For 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 including water charges and security expenses;

(iv) Receivables equivalent to 45 days 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, including water charges and security expenses, for one month.

(c) For Hydro Generating Station (including Pumped Storage Hydro Generating Station) and Transmission System:

(i) Receivables equivalent to 45 days of annual fixed cost;

(ii) Maintenance spares @ 15% of operation and maintenance expenses including security expenses; and

(iii) Operation and maintenance expenses, including security expenses for one month.

(2) The cost of fuel in cases covered under sub-clauses (a) and (b) of clause (1) of this Regulation shall be based on the landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 39 of these regulations) by the generating station and gross calorific value of the fuel as per actual weighted average for the third quarter of preceding financial year in case of each financial year for which tariff is to be determined:

Provided that in case of new generating station, the cost of fuel for the first financial year shall be considered based on landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 39 of these regulations) and gross calorific value of the fuel as per actual weighted average for three months, as used for infirm power, preceding date of commercial operation for which tariff is to be determined.

(3) Rate of interest on working capital shall be on normative basis and shall be considered as the bank rate as on 1.4.2019 or as on 1st April of the year during the tariff period 2019-24 in which the generating station or a unit thereof or the transmission system including communication system or element thereof, as the case may be, is declared under commercial operation, whichever is later:

Provided that in case of truing-up, the rate of interest on working capital shall be considered at bank rate as on 1st April of each of the financial year during the tariff period 2019-24.

(4) Interest on working capital shall be payable on normative basis notwithstanding

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

35. Operation and Maintenance Expenses:

(1) Thermal Generating Station: Normative Operation and Maintenance expenses of thermal generating stations shall be as follows:

(1) Coal based and lignite fired (including those based on Circulating Fluidised Bed Combustion (CFBC) technology) generating stations, other than the generating stations or units referred to in clauses (2), (4) and (5) of this Regulation:

(in Rs Lakh/MW)

Year	200/210/ 250 MW Series	300/330/ 350 MW Series	500 MW Series	600 MW Series	800 MW Series and above
FY 2019-20	32.96	27.74	22.51	20.26	18.23
FY 2020-21	34.12	28.71	23.30	20.97	18.87
FY 2021-22	35.31	29.72	24.12	21.71	19.54
FY 2022-23	36.56	30.76	24.97	22.47	20.22
FY 2023-24	37.84	31.84	25.84	23.26	20.93

Provided that where the date of commercial operation of any additional unit(s)of a generating station after first four units occurs on or after 1.4.2019, the O&M expenses of such additional unit(s) shall be admissible at 90% of the operation and maintenance expenses as specified above;

Provided further that operation and maintenance expenses of generating station and the transmission system of Bhakra Beas Management Board (BBMB) and Sardar Sarovar Project (SSP) shall be determined after taking into account provisions of the Punjab Reorganization Act, 1996 and Narmada Water Scheme, 1980 under Section 6-A of the Inter-State Water Disputes Act, 1956 respectively;

Provided also that operation and maintenance expenses of generating station having unit size of less than 200 MW not covered above shall be determined on case to case basis.

(2) Talcher Thermal Power Station (TPS), Tanda TPS and Chandrapura TPS Unit 3 and Durgapur TPS Unit 1 of DVC:

(in Rs Lakh/MW)

Year	Talcher TPS	Chandrapura TPS (Unit 3), Tanda TPS, Durgapur TPS(Unit 1)
FY 2019-20 to FY 2023-24	56.34	46.16

(3) Open Cycle Gas Turbine/Combined Cycle generating stations:

(in Rs Lakh/MW)

Year	Gas Turbine/ Combined Cycle generating stations other than small gas turbine power generating stations	Small gas turbine power generating stations	Agartala GPS	Advance F Class Machines
FY 2019-20	17.58	36.21	42.85	26.34
FY 2020-21	18.20	37.48	44.35	27.27
FY 2021-22	18.84	38.80	45.91	28.23
FY 2022-23	19.50	40.16	47.52	29.22
FY 2023-24	20.19	41.57	49.19	30.24

(4) **Lignite-fired generating stations**:

(in Rs Lakh/MW)

Year	125 MW Sets	TPS-I of NLC
FY 2019-20	31.15	42.91
FY 2020-21	32.24	44.42
FY 2021-22	33.37	45.98
FY 2022-23	34.54	47.59
FY 2023-24	35.76	49.26

(5) **Generating Stations based on coal rejects**:

(in Rs Lakh/MW)

Year	O&M Expenses
FY 2019-20	31.15
FY 2020-21	32.24
FY 2021-22	33.37
FY 2022-23	34.54
FY 2023-24	35.76

(6) The Water Charges, Security Expenses and Capital Spares for thermal generating stations shall be allowed separately after prudence check:

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

Provided further that the generating station shall submit the assessment of the security requirement and estimated expenses;

Provided also 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 as per Regulation 17 of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 or Special Allowance or claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.

(7) The additional operation and maintenance expenses on account of implementation of revised emission standards shall be notified separately:

Provided that till the norms are notified, the Commission shall decide the additional O&M expenses on case to case basis.

(2) Hydro Generating Station: (a) Following operations and maintenance expense norms shall be applicable for hydro generating stations which have been operational for three or more years as on 1.4.2019:

(in Rs Lakh)

Particulars	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
THDC Stage I	27,788.87	29,113.44	30,501.14	31,955.00	33,478.15
KHEP	13,452.46	14,093.68	14,765.46	15,469.26	16,206.61
Bairasul	8,292.11	8,687.36	9,101.45	9,535.28	9,989.78
Loktak	9,538.27	9,992.91	10,469.23	10,968.25	11,491.06
Salal	19,207.75	20,123.29	21,082.48	22,087.39	23,140.19
Tanakpur	10,520.33	11,021.79	11,547.15	12,097.55	12,674.18
Chamera-I	11,773.57	12,334.77	12,922.71	13,538.68	14,184.00
Uri I	9,865.77	10,336.03	10,828.70	11,344.85	11,885.61
Rangit	5,336.17	5,590.53	5,857.00	6,136.18	6,428.66
Chamera-II	10,670.68	11,179.30	11,712.17	12,270.44	12,855.31
Dhauliganga	8,813.40	9,233.50	9,673.61	10,134.71	10,617.79
Dulhasti	18,563.04	19,447.85	20,374.84	21,346.02	22,363.49
Teesta-V	12,186.58	12,767.46	13,376.02	14,013.60	14,681.56
Sewa-II	7,079.34	7,416.78	7,770.31	8,140.68	8,528.71
TLDP III	7,539.76	7,899.14	8,275.66	8,670.12	9,083.39
Chamera III	9,078.72	9,511.46	9,964.83	10,439.81	10,937.43
Chutak	3,536.67	3,705.25	3,881.86	4,066.89	4,260.74
Nimmo Bazgo	3,527.43	3,695.57	3,871.72	4,056.27	4,249.61
Uri II	7,058.82	7,395.28	7,747.78	8,117.08	8,503.99
Parbati III	6,618.29	6,933.76	7,264.26	7,610.51	7,973.27
Indira Sagar	11,728.40	12,287.44	12,873.12	13,486.73	14,129.58
Omkareshwar	7,198.97	7,542.12	7,901.62	8,278.25	8,672.84
Naptha Jhakari	33,326.11	34,914.62	36,578.84	38,322.39	40,149.04
Rampur	12,267.22	12,851.94	13,464.54	14,106.33	14,778.72
Koldam	12,659.94	13,263.39	13,895.59	14,557.93	15,251.84
Karcham Wangtoo	11,710.14	12,268.31	12,853.09	13,465.74	14,107.59
Kopili-I	9,044.47	9,475.58	9,927.24	10,400.43	10,896.17
Kopili-II	1,130.56	1,184.45	1,240.90	1,300.05	1,362.02
Khandong	2,261.12	2,368.90	2,481.81	2,600.11	2,724.04
Doyang	5,654.57	5,924.10	6,206.47	6,502.31	6,812.24

Particulars	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
Ranganadi	12,095.88	12,672.44	13,276.47	13,909.30	14,572.30
Maithon	2,892.40	3,030.26	3,174.70	3,326.03	3,484.56
Panchet	2,191.37	2,295.83	2,405.26	2,519.90	2,640.02
Tilaiya	900.17	943.08	988.03	1,035.13	1,084.47

Note: The impact in respect of revision of minimum wage and GST, if any, will be considered at the time of determination of tariff.

(b) In case of the hydro generating stations declared under commercial operation on or after 1.4.2019, operation and maintenance expenses of first year shall be fixed at 3.5% and 5.0% of the original project cost (excluding cost of rehabilitation & resettlement works, IDC and IEDC) for stations with installed capacity exceeding 200 MW and for stations with installed capacity less than 200 MW, respectively.

(c) In case of hydro generating stations which have not completed a period of three years as on 1.4.2019, operation and maintenance expenses for 2019-20 shall be worked out by applying escalation rate of 4.77% on the applicable operation and maintenance expenses as on 31.3.2019. The operation and maintenance expenses for subsequent years of the tariff period shall be worked out by applying escalation rate of 4.77% per annum.

(c) The Security Expenses and Capital Spares for hydro generating stations shall be allowed separately after prudence check:

Provided further that the generating station shall submit the assessment of the security requirement and estimated expenses, the details of year-wise actual capital spares consumed at the time of truing up with appropriate justification.

(3) Transmission system: (a) The following normative operation and maintenance expenses shall be admissible for the transmission system:

Particulars	2019-20	2020-21	2021-22	2022-23	2023-24
Norms for sub-station Bays (Rs Lakh per bay)					
765 kV	45.01	46.60	48.23	49.93	51.68
400 kV	32.15	33.28	34.45	35.66	36.91
220 kV	22.51	23.30	24.12	24.96	25.84
132 kV and below	16.08	16.64	17.23	17.83	18.46
Norms for Transformers (Rs Lakh per MVA)					
765 kV	0.491	0.508	0.526	0.545	0.564
400 kV	0.358	0.371	0.384	0.398	0.411
220 kV	0.245	0.254	0.263	0.272	0.282
132 kV and below	0.245	0.254	0.263	0.272	0.282
Norms for AC and HVDC lines (Rs Lakh per km)					
Single Circuit (Bundled Conductor with six or more sub-conductors)	0.881	0.912	0.944	0.977	1.011
Single Circuit (Bundled conductor with four sub-conductors)	0.755	0.781	0.809	0.837	0.867
Single Circuit (Twin & Triple Conductor)	0.503	0.521	0.539	0.558	0.578
Single Circuit (Single Conductor)	0.252	0.260	0.270	0.279	0.289
Double Circuit (Bundled conductor with four or more sub-conductors)	1.322	1.368	1.416	1.466	1.517
Double Circuit (Twin & Triple Conductor)	0.881	0.912	0.944	0.977	1.011
Double Circuit (Single Conductor)	0.377	0.391	0.404	0.419	0.433
Multi Circuit (Bundled Conductor with four or more sub-conductor)	2.319	2.401	2.485	2.572	2.662
Multi Circuit (Twin & Triple Conductor)	1.544	1.598	1.654	1.713	1.773
Norms for HVDC stations					
HVDC Back-to-Back stations (Rs Lakh per 500 MW) (Except Gazuwaka BTB)	834	864	894	925	958
Gazuwaka HVDC Back-to-Back station (Rs. Lakh per 500 MW)	1,666	1,725	1,785	1,848	1,913
500 kV Rihand-Dadri HVDC bipole scheme (Rs Lakh) (1500 MW)	2,252	2,331	2,413	2,498	2,586
±500 kV Talcher- Kolar HVDC bipole scheme (Rs Lakh) (2000 MW)	2,468	2,555	2,645	2,738	2,834
±500 kV Bhiwadi-Balia HVDC bipole scheme (Rs Lakh) (2500 MW)	1,696	1,756	1,817	1,881	1,947
±800 kV, Bishwanath-Agra HVDC bipole scheme (Rs Lakh) (3000 MW)	2,563	2,653	2,746	2,842	2,942

Provided that the O&M expenses for the GIS bays shall be allowed as worked out by multiplying 0.70 of the O&M expenses of the normative O&M expenses for bays;

Provided further that:

(i) the operation and maintenance expenses for new HVDC bi-pole schemes commissioned after 1.4.2019 for a particular year shall be allowed pro-rata on the basis of normative rate of operation and maintenance expenses of similar HVDC bi-pole scheme for the corresponding year of the tariff period;

(ii) the O&M expenses norms for HVDC bi-pole line shall be considered as Double Circuit quad AC line;

(iii) the O&M expenses of ±500 kV Mundra-Mohindergarh HVDC bipole scheme (2000 MW)shall be allowed as worked out by multiplying 0.80 of the normative O&M expenses for ±500 kV Talchar-Kolar HVDC bi-pole scheme (2000 MW);

(iv) the O&M expenses of ±800 kV Champa-Kurukshetra HVDC bi-pole scheme (3000 MW) shall be on the basis of the normative O&M expenses for ±800 kV, Bishwanath-Agra HVDC bi-pole scheme;

(v) the O&M expenses of ±800 kV, Alipurduar-Agra HVDC bi-pole scheme (3000 MW)shall be allowed as worked out by multiplying 0.80 of the normative O&M expenses for ±800 kV, Bishwanath-Agra HVDC bi-pole scheme; and

(v) the O&M expenses of Static Synchronous Compensator and Static Var Compensator shall be worked at 1.5% of original project cost as on commercial operation which shall be escalated at the rate of 3.51% to work out the O&M expenses during the tariff period. The O&M expenses of Static Synchronous Compensator and Static Var Compensator, if required, may be reviewed after three years.

(b) The total allowable operation and maintenance expenses for the transmission system shall be calculated by multiplying the number of sub-station bays, transformer capacity of the transformer (in MVA) and km of line length with the applicable norms for the operation and maintenance expenses per bay, per MVA and per km respectively.

(c) The Security Expenses and Capital Spares for transmission system shall be allowed separately after prudence check:

Provided that the transmission licensee shall submit the assessment of the security requirement and estimated security expenses, the details of year-wise actual capital spares consumed at the time of truing up with appropriate justification.

(4) **Communication system:** The operation and maintenance expenses for the communication system shall be worked out at 2.0% of the original project cost related to such communication system. The transmission licensee shall submit the actual operation and maintenance expenses for truing up.

CHAPTER – 9

COMPUTATION OF INPUT PRICE OF COAL AND LIGNITE FROM INTEGRATED MINE

36. Input Price of coal and lignite for energy charges: (1) Where the generating company has the arrangement for supply of coal or lignite from the integrated mine(s) allocated to it, for use in one or more of its generating stations as end use, the energy charge component of tariff of the generating station shall be determined based on the input price of coal or lignite, as the case may be, from such integrated mines computed in accordance with the regulations to be notified separately by the Commission.

(2) Till the regulation for computation of input price of coal is notified, the generating company shall continue to adopt the notified price of Coal India Limited commensurate with the grade of the coal from the integrated mine:

Provided that after notification of the regulation for input price of coal, the same shall be applicable from 1.4.2019 or the date of commercial operation of the integrated mine, whichever is later, and the difference between the input price of coal so decided and the input price of coal for quantity billed shall be adjusted in accordance with the regulations to be notified.

(3) Till the regulations for computation of input price of lignite is notified, the input price of lignite shall continue to be determined as per the guidelines specified by Ministry of Coal, Government of India.

CHAPTER – 10

COMPONENTS OF ENERGY CHARGE

37. Energy Charge: The energy charge in respect of the thermal generating Stations shall comprise of landed fuel cost of primary fuel, cost of secondary fuel oil consumption and landed cost of reagents on account of implementation of the revised emission standards.

38. Landed Fuel Cost of Primary Fuel: The landed fuel cost of primary fuel for any month shall consist of base price or input price of fuel corresponding to the grade and quality of fuel and shall be inclusive of statutory charges as applicable, washery charges, transportation cost by rail or road or any other means and loading, unloading and handling charges:

Provided that procurement of fuel at a price other than Government notified prices may be considered, if it is based on competitive bidding through transparent process;

Provided further that landed fuel cost of primary fuel shall be worked out based on the actual bill paid by the generating company including any adjustment on account of quantity and quality;

Provided also that in case of coal-fired or lignite based thermal generating station, the Gross Calorific Value shall be measured by third party sampling and the expenses towards the third party sampling facility shall be reimbursed by the beneficiaries.

39. Transit and Handling Losses: For coal and lignite, the transit and handling losses shall be as per the following norms:-

Thermal Generating Station	**Transit and Handling Loss (%)**
Pit head	0.20%
Non-pit head	0.80%

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 and handling losses applicable for non-pit head station shall apply;

Provided further that in case of imported coal, the transit and handling losses applicable for pit-head station shall apply.

40. Gross Calorific Value of Primary Fuel: (1) The gross calorific value for computation of energy charges as per Regulation 43 of these regulations shall be done in accordance with 'GCV as received' basis.

(2) The generating company shall provide to the beneficiaries of the generating station the details in respect 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 Form 15 prescribed at **Annexure-I (Part I)** to these regulations:

Provided that the additional details of the weighted average GCV of the fuel on as received basis used for generation during the period, blending ratio of the imported coal with domestic coal, proportion of e-auction coal shall be provided, along with the bills of the respective month;

Provided further that copies of the bills and details of parameters of GCV and price of fuel such as domestic coal, imported coal, e-auction coal, lignite, natural gas, RLNG, liquid fuel, details of blending ratio of the imported coal with domestic coal, proportion of e-auction coal shall also be displayed on the website of the generating company.

41. Landed Cost of Reagent: (1) Where specific reagents such as Limestone, Sodium Bi-Carbonate, Urea or Anhydrous Ammonia are used during operation of emission control system for meeting revised emission standards, the landed cost of such reagents shall be determined based on normative consumption and purchase price of the reagent through competitive bidding, applicable statutory charges and transportation cost.

(2) The normative consumption of specific reagent for the various technologies installed for meeting revised emission standards shall be notified separately.

CHAPTER – 11

COMPUTATION OF CAPACITY CHARGES AND ENERGY CHARGES

42. Computation and Payment of Capacity Charge for Thermal Generating Stations:

(1) The fixed cost of a thermal generating station shall be computed on annual basis based on the 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 or allocation in the capacity of the generating station. The capacity charge shall be recovered under two segments of the year, i.e. High Demand Season (period of three months) and Low Demand Season (period of remaining nine months), and within each season in two parts viz., Capacity Charge for Peak Hours of the month and Capacity Charge for Off-Peak Hours of the month as follows:

Capacity Charge for the Year (CC_y) =

Sum of Capacity Charge for three months of High Demand Season +

Sum of Capacity Charge for nine months of Low Demand Season

(2) The Capacity Charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:

Capacity Charge for the Month (CC_m) =

Capacity Charge for Peak Hours of the Month (CC_p) +

Capacity Charge for Off-Peak Hours of the Month (CC_{op})

Where,

High Demand Season:

CC_{p1}= $(0.20\ x\ \text{AFC})\ x\ \left(\frac{1}{12}\right)\ x\ \left(\frac{PAFMp}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\ \text{AFC})\ x\ \left(\frac{1}{12}\right)$

CC_{p2} = $\{(0.20\ x\text{AFC})x\left(\frac{1}{6}\right)x\left(\frac{PAFMp2}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{6}\right)\} - CCp1$

CC_{p3}= $\{(0.20\ x\text{AFC})x\left(\frac{1}{4}\right)x\left(\frac{PAFMp}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{4}\right)\} - (CCp1 + CCp2)]\}$

CC_{op1}= $\{(0.80\ x\text{AFC})x\left(\frac{1}{12}\right)x\left(\frac{PAFMop1}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{12}\right)\}$

CC_{op2} = $\{(0.80\ x\text{AFC})x\left(\frac{1}{6}\right)x\left(\frac{PAFMop2}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{6}\right)\} - CCop1$

CC_{op3} = $\{(0.80\ x\text{AFC})x\left(\frac{1}{4}\right)x\left(\frac{PAFMop3}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{4}\right)\} - (CCop1 + CCop2)$

Low Demand Season:

CC_{p1} = $\{(0.20\ x\text{AFC})x\left(\frac{1}{12}\right)x\left(\frac{PAFMp1}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{12}\right)\}$

CC_{p2}= $\{(0.20\ x\text{AFC})x\left(\frac{1}{6}\right)x\left(\frac{PAFMp2}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{6}\right)\} - CCp1$

CC_{p3}= $\{(0.20\ x\text{AFC})x\left(\frac{1}{4}\right)x\left(\frac{PAFMp3}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{4}\right)\} - (CCp1 + CCp2)$

CC_{p4}= $\{(0.20\ x\text{AFC})x\left(\frac{1}{3}\right)x\left(\frac{PAFMp4}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{3}\right)\} - (CCp1 + CCp2 + CCp3)$

$CC_{p5}=$ $\{(0.20\ x\text{AFC})x\left(\frac{5}{12}\right)x\left(\frac{PAFMp5}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{5}{12}\right)\} - (CCp1 + CCp2 + CCp3 + CCp4)$

$CC_{p6} =$ $\{(0.20\ x\text{AFC})x\left(\frac{1}{2}\right)x\left(\frac{PAFMp}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{2}\right)\} - (CCp1 + CCp2 + CCp3 + CCp4 + CCp5)$

$CC_{p7} =$ $\{(0.20\ x\text{AFC})x\left(\frac{7}{12}\right)x\left(\frac{PAFMp7}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{7}{12}\right)\} - (CCp1 + CCp2 + CCp3 + CCp4 + CCp5 + CCp6)$

$CC_{p8}=$ $\{(0.20\ x\text{AFC})x\left(\frac{2}{3}\right)x\left(\frac{PAFMp8}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{2}{3}\right)\} - (CCp1 + CCp2 + CCp3 + CCp4 + CCp5 + CCp6 + CCp7)$

$CC_{p9} =$ $\{(0.20\ x\text{AFC})x\left(\frac{3}{4}\right)x\left(\frac{PAFMp}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{3}{4}\right)\} - (CCp1 + CCp2 + CCp3 + CCp4 + CCp5 + CCp6 + CCp7 + CCp8)$

$CC_{op1} =$ $\{(0.80\ x\text{AFC})x\left(\frac{1}{12}\right)x\left(\frac{PAFMop1}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{12}\right)\}$

$CC_{op2} =$ $\{(0.80\ x\text{AFC})x\left(\frac{1}{6}\right)x\left(\frac{PAFMop2}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{6}\right)\} - CCop1$

$CC_{op3} =$ $\{(0.80\ x\text{AFC})x\left(\frac{1}{4}\right)x\left(\frac{PAFMop3}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{4}\right)\} - (CCop1 + CCop2)$

$CC_{op4} =$ $\{(0.80\ x\text{AFC})x\left(\frac{1}{3}\right)x\left(\frac{PAFMop4}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{3}\right)\} - (CCop1 + CCop2 + CCop3)$

$CC_{op5}=$ $\{(0.80\ x\text{AFC})x\left(\frac{5}{12}\right)x\left(\frac{PAFMop5}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{5}{12}\right)\} - (CCop1 + CCop2 + CCop3 + CCop4)$

CC_{op6} = $\{(0.80\ x\text{AFC})x\left(\frac{1}{2}\right)x\left(\frac{PAFMop6}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{2}\right)\} - (CCop1 + CCop2 + CCop3 + CCop4 + CCop5)$

CC_{op7}= $\{(0.80\ x\text{AFC})x\left(\frac{7}{12}\right)x\left(\frac{PAFMop7}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{7}{12}\right)\} - (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6)$

CC_{op8} = $\{(0.80\ x\text{AFC})x\left(\frac{2}{3}\right)x\left(\frac{PAFMo}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{2}{3}\right)\} - (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7)$

CC_{op9} = $\{(0.80\ x\text{AFC})x\left(\frac{3}{4}\right)x\left(\frac{PAFMop9}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{3}{4}\right)\} - (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7 + CCop8)$

Provided that in case of generating station or unit thereof under shutdown due to Renovation and Modernisation, the generating company shall be allowed to recover O&M expenses and interest on loan only.

Where,

CC_m= Capacity Charge for the Month;

CC_p= Capacity Charge for the Peak Hours of the Month;

CC_{op}= Capacity Charge for the Off-Peak Hours of the Month;

CC_{pn}= Capacity Charge for the Peak Hours of n^{th} Month in a specific Season;

CC_{opn}= Capacity Charge for the Off-Peak of n^{th} Month in a specific Season;

AFC = Annual Fixed Cost;

$PAFM_{pn}$ = Plant Availability Factor achieved during Peak Hours upto the end of n^{th} Month in a Season;

$PAFM_{opn}$ = Plant Availability Factor achieved during Off-Peak Hours upto the end of n^{th} Month in a Season;

NAPAF= Normative Annual Plant Availability Factor.

(3) Normative Plant Availability Factor for "Peak" and "Off-Peak" Hours in a month shall be equivalent to the NAPAF specified in Clause (A) of Regulation 49 of these regulations. The number of hours of "Peak" and "Off-Peak" periods during a day shall be four and twenty respectively. The hours of Peak and Off-Peak periods during a day shall be declared by the concerned RLDC at least a week in advance. The High Demand Season (period of three months, consecutive or otherwise) and Low Demand Season (period of remaining nine months, consecutive or otherwise) in a region shall be declared by the concerned RLDC, at least six months in advance:

Provided that RLDC, after duly considering the comments of the concerned stakeholders, shall declare Peak Hours and High Demand Season in such a way as to coincide with the majority of the Peak Hours and High Demand Season of the region to the maximum extent possible:

Provided further that in respect of a generating station having beneficiaries across different regions, the High Demand Season and the Peak Hours shall correspond to the High Demand Season and Peak Hours of the region in which majority of its beneficiaries, in terms of percentage of allocation of share, are located.

(4) Any under-recovery or over-recovery of Capacity Charge as a result of under-achievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of

a Season (High Demand Season or Low Demand Season, as the case may be) shall not be adjusted with under-achievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of the other Season:

Provided that within a Season, the shortfall in recovery of Capacity Charge for cumulative Off-Peak Hours derived based on NAPAF, shall be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Peak Hours in that Season:

Provided further that within a Season, the shortfall in recovery of Capacity Charge for cumulative Peak Hours derived based on NAPAF, shall not be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Off-Peak Hours in that Season.

(5) The Plant Availability Factor achieved for a Month (PAFM) shall be computed in accordance with the following formula:

$$\text{PAFM} = 1000\ x \sum_{i=1}^{N} \frac{DCi}{[N\ x\ IC\ x\ (100 - Aux)]} \%$$

Where,

AUX = Normative auxiliary energy consumption in percentage.

DCi = Average declared capacity (in ex-bus MW), for the i^{th} 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: DCi 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.

(6) In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 50 paise/ kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis within each Season (High Demand Season or Low Demand Season, as the case may be), as specified in Clause (B) of Regulation 49 of these regulations.

(7) The provisions under Clauses (1) to (6) of this Regulation shall come into force with effect from 1.4.2020. Till that date, the capacity charge for a thermal generating station determined under these regulations shall be recovered in accordance with the provisions contained in Clauses (1) to (4) of Regulation 30 of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014, subject to the condition that the NAPAF and NAPLF shall be taken as specified under these regulations.

43. Computation and Payment of Energy Charge for Thermal Generating Stations

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

(2) 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 = {(SHR – SFC x CVSF) x LPPF / (CVPF + SFC x LPSFi + LC x LPL} x 100 /(100 – AUX)

(b) For gas and liquid fuel based stations:

ECR = SHR x LPPF x 100 / {(CVPF) x (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 less 85 Kcal/Kg on account of variation during storage at generating station;

(b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per litre 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;

SHR = Gross station heat rate, in kCal per kWh;

LC = Normative limestone consumption in kg per kWh;

LPL = Weighted average landed cost of limestone in Rupees per kg;

LPPF = Weighted average landed fuel cost 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 fuel cost 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 Fuel Cost of Secondary Fuel in Rs./ml during the month:

Provided that energy charge rate for a gas or liquid fuel based station shall be adjusted for open cycle operation based on certification of Member Secretary of respective Regional Power Committee during the month.

(3) 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 alternative source of fuel shall not exceed 30% of base price of fuel computed as per clause (5) of this Regulation:

Provided also that where the energy charge rate based on weighted average price of fuel upon use of alternative source of fuel supply exceeds 30% of base energy charge rate as approved by the Commission for that year or exceeds 20% of energy charge rate for the previous month, whichever is lower shall be considered and in that event, prior consultation with beneficiary shall be made at least three days in advance.

(4) Where biomass fuel is used for blending with coal, the landed cost of biomass fuel shall be worked out based on the delivered cost of biomass at the unloading point of the generating station, inclusive of taxes and duties as applicable. The energy charge rate of the blended fuel shall be worked out considering consumption of biomass based on blending ratio as specified by Authority or actual consumption of biomass, whichever is lower.

(5) The Commission through 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 rate so approved shall be the base energy charge rate for the first year 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 by escalation rates for payment purposes as notified by the Commission from time to time under competitive bidding guidelines.

(6) The tariff structure as provided in this Regulation 42 and Regulation 43 of these regulations may be adopted by the Department of Atomic Energy, Government of India for the nuclear generating stations by specifying annual fixed cost (AFC), normative

annual plant availability factor (NAPAF), installed capacity (IC), normative auxiliary energy consumption (AUX) and energy charge rate (ECR) for such stations.

44. Computation and Payment of Capacity Charge and Energy Charge for Hydro Generating Stations:

(1) 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.

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

AFC x 0.5 x NDM / NDY x (PAFM / NAPAF) (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

(3) The PAFM shall be computed in accordance with the following formula:

$$PAFM = 10000 \times \sum_{i=1}^{N} DC_i / \{ N \times IC \times (100 - AUX) \} \%$$

Where

AUX = Normative auxiliary energy consumption in percentage

DCi = Declared capacity (in ex-bus MW) for the i^{th} 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

(4) 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-bus basis, at the computed energy charge rate. Total energy charge payable to the generating company for a month shall be:

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

(5) 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 (7) of this Regulation:

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

Where,

DE = Annual design energy specified for the hydro generating station, in MWh, subject to the provision in clause (6) below.

FEHS = Free energy for home State, in per cent, as mentioned in Note 3 under Regulation 55 of these regulations.

(6) In case the saleable scheduled energy (ex-bus) of a hydro generating station during a year is less than the saleable design energy (ex-bus) for reasons beyond the control of the generating station, the treatment shall be as per clause (7) of this Regulation, on an application filed by the generating company.

(7) Shortfall in energy charges in comparison to fifty percent of the annual fixed cost shall be allowed to be recovered in six equal monthly installments:

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

(8) Any shortfall in the energy charges on account of saleable scheduled energy (ex-bus) being less than the saleable design energy (ex-bus) during the tariff period 2014-19 which was beyond the control of the generating station and which could not be

recovered during the said tariff period shall be recovered in accordance with clause (7) of this Regulation.

(9) In case the energy charge rate (ECR) for a hydro generating station, computed as per clause (5) of this Regulation exceeds one hundred and twenty 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 one hundred and twenty paise per kWh only.

(10) In case of the hydro generating stations located in the State of Jammu and Kashmir, any expenditure incurred for payment of water usage charges to the State Water Resources Development Authority, Jammu under Jammu & Kashmir Water Resources (Regulations and Management) Act, 2010 shall be payable by the beneficiaries as additional energy charge in proportion of the supply of power from the generating stations on month to month basis:

Provided that the provisions of this clause shall be subject to the decision of the Hon'ble High Court of Jammu & Kashmir in OWP No. 604/2011 and shall stand modified in accordance with the decision of the High Court.

45. Computation and Payment of Capacity Charge and Energy Charge for Pumped Storage Hydro Generating Stations:

(1) The fixed cost of a pumped storage hydro generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis as capacity charge. The capacity charge shall be payable by the

beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station, i.e., 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 be worked out based on the latest estimate of the completion cost for the generating station, for the purpose of determining the capacity charge payment during such period.

(2) The capacity charge payable to a pumped storage hydro generating station for a calendar month shall be:

(AFC x NDM / NDY) (In Rupees), if actual Generation during the month is >= 75 % of the Pumping Energy consumed by the station during the month and

{(AFC x NDM / NDY) x (Actual Generation during the month during peak hours/ 75% of the Pumping Energy consumed by the station during the month) (in Rupees)}, if actual Generation during the month is < 75 % of the Pumping Energy consumed by the station during the month.

Where,

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

NDM = Number of days in the month

NDY = Number of days in the year

Provided that there would be adjustment at the end of the year based on actual generation and actual pumping energy consumed by the station during the year.

(3) The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary in excess of the design energy plus 75% of

the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir, at a flat rate equal to the average energy charge rate of 20 paise per kWh, excluding free energy, if any, during the calendar month, on ex power plant basis.

(4) Energy charge payable to the generating company for a month shall be:

= 0.20 x {Scheduled energy (ex-bus) for the month in kWh – (Design Energy for the month (DEm) + 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir of the month)} x (100 – FEHS)/ 100.

Where,

DEm = Design energy for the month specified for the hydro generating station, in MWh

FEHS = Free energy for home State, in per cent, as mentioned in Note 3 under Regulation 55 of these regulations, if any.

Provided that in case the Scheduled energy in a month is less than the Design Energy for the month plus 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir of the month, then the energy charges payable by the beneficiaries shall be zero.

(5) The generating company shall maintain the record of daily inflows of natural water into the upper elevation reservoir and the reservoir levels of upper elevation reservoir and lower elevation reservoir on hourly basis. The generator shall be required to maximize the peak hour supplies with the available water including the natural flow of water. In case it is established that generator is deliberately or otherwise without any

valid reason, is not pumping water from lower elevation reservoir to the higher elevation during off-peak period or not generating power to its potential or wasting natural flow of water, the capacity charges of the day shall not be payable by the beneficiary. For this purpose, outages of the unit(s)/station including planned outages and the forced outages up to 15% in a year shall be construed as the valid reason for not pumping water from lower elevation reservoir to the higher elevation during off-peak period or not generating power using energy of pumped water or natural flow of water:

Provided that the total capacity charges recovered during the year shall be adjusted on pro-rata basis in the following manner in the event of total machine outages in a year exceeds 15%:

$$(ACC)adj = (ACC)\,R \times (100 - ATO)/85$$

Where,

(ACC)adj – Adjusted Annual Capacity Charges

(ACC) R – Annual Capacity Charges recovered

ATO - Total Outages in percentage for the year including forced and planned outages

Provided further that the generating station shall be required to declare its machine availability daily on day ahead basis for all the time blocks of the day in line with the scheduling procedure of Grid Code.

(6) The concerned Load Despatch Centre shall finalise the schedules for the hydro generating stations, in consultation with the beneficiaries, for optimal utilization of all

the energy declared to be available, which shall be scheduled for all beneficiaries in proportion to their respective allocations in the generating station.

46. Computation and Payment of Transmission Charge for Inter-State Transmission System and Communication System:

(1) 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 (2) of this Regulation.

(2) The Transmission charge (inclusive of incentive) payable for a calendar month for transmission system or part shall be computed for each region separately for AC and DC system as under:

For AC system:

a) For TAFM $n \leq 98.00\%$

$$AFC \times (NDMn/NDY) \times (TAFMn/98.00\%)$$

b) For TAFMn: $98.00\% < TAFMn < 98.50\%$

$$AFC \times (NDMn/NDY) \times (1)$$

c) For TAFMn: $98.50\% < TAFMn \leq 99.75\%$

$$AFC \times (NDMn/NDY) \times (TAFM/98.50\%)$$

d) For TAFM$n \geq 99.75\%$

$$AFC \times (NDMn/NDY) \times (99.75\%/98.50\%)$$

Where,

AFC = Annual Fixed Cost specified for the year in Rupees

NDMn = Number of days in nth month

NDY = Number of days in the year

TAFMn = Transmission System availability factor for the nth month, in percent computed in accordance with Appendix II.

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

TC_1 = AFC x (NDM_1 / NDY) x ($TAFM_1$/NATAF)

TC_2 = AFC x (NDM_2 / NDY) x ($TAFM_2$/NATAF) – TC_1

TC_3 = AFC x (NDM_3 / NDY) x ($TAFM_3$/NATAF) – (TC_1+TC_2)

TC_4 = AFC x (NDM_4 / NDY) x ($TAFM_4$/NATAF) – (TC_1+TC_2+TC_3)

….

TC_{11} = AFC x (NDM_{11}/NDY) x ($TAFM_{11}$/NATAF) - (TC_1+TC_2+….+TC_{10})

TC_{12} = AFC x (TAFY/NATAF) – (TC_1+TC_2+….+TC_{11});

If,

(i) TAFM: 95.00%< TAFM < 97.50%, then TAFM=NATAF;

(ii) TAFM: 97.50%$\leq$ TAFM $\leq$ 99.75%, then NATAF=97.50%; and

(iii) For TAFM $\geq$ 99.75%, then TAFM=99.75% and NATAF= 97.50%.

Where,

TCn = Transmission charges inclusive of incentive up to the nth month

AFC = Annual fixed cost specified for the year in rupees

NATAF = Normative Annual Transmission Availability Factor in percentage

NDMn= No of days upto the end of nth month of the financial year

NDY = No. of days in the year

TAFMn= Transmission availability factor upto the end of the nth month of the year in percentage computed in accordance with Appendix –II

TAFY = Transmission availability factor in percent for the year.

(3) 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 customers. The charges of the communication system shall be a part of the transmission charges and shall be shared by the long term customers.

47. Deviation Charges: (1) Variations between actual net injection and scheduled net injection for the generating stations, and variations between actual net drawl and scheduled net drawl 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.

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

CHAPTER - 12

NORMS OF OPERATION

48. Recovery of Tariff and Incentive: (1) 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 Regulation 49 to Regulation 52 of these regulations.

(2) The Commission may on its own revise the norms of Station Heat Rate specified in Regulation 49 (C) of these regulations in respect of any of the generating stations for which relaxed norms have been specified.

Norms of operation for thermal generating station

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

(A) Normative Annual Plant Availability Factor (NAPAF)

(a) For all thermal generating stations, except those covered under clauses (b), (c), (d), & (e) - 85% ;

(b) For following Lignite-fired Thermal generating stations of NLC India Ltd:

TPS-I	72%

(c) For following Thermal Generating Stations of DVC:

Bokaro TPS	75%
Chandrapura TPS	75%
Durgapur TPS	74%

(d) For following Gas based Thermal Generating Stations of NEEPCO:

Assam GPS	72%

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

1. First Three years from the date of commercial operation – 75%

2. For next year after completion of three years of the date of commercial operation – 80%

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

(a) For all thermal generating stations, except those covered under clauses (b), (c) - 85% ;

(b) For following Lignite-fired Thermal generating stations of NLC India Ltd:

TPS –I	75%

(c) For following Thermal Generating Stations of Damodar Valley Corporation (DVC):

Bokaro TPS	80%
Chandrapur TPS	80%
Durgapur TPS	80%

(C) Gross Station Heat Rate:

(a) Existing Thermal Generating Stations

(i) For existing Coal-based Thermal Generating Stations, other than those covered under clauses (ii) and (iii) below:

200/210/250 MW Sets	500 MW Sets (Sub-critical)
2,430kCal/kWh	2,390kCal/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.

Note 3

The normative gross station heat rate above is exclusive of the compensation specified in Regulation 6.3 B of the Grid Code. The generating company shall, based on unit loading factor, consider the compensation in addition to the normative gross heat rate above.

Note 4

The gross station heat rate for the unit capacity of less than 200 MW sets, shall be dealt on case to case basis.

(ii) For following Thermal generating stations of NTPC Ltd:

Talcher TPS	2,830 kCal/kWh
Tanda TPS	2,750 kCal/kWh

(iii) For Thermal Generating Stations of Damodar Valley Corporation (DVC):

Bokaro TPS	2,700 kCal/kWh
Chandrapura TPS (Unit 3)	3,000 kCal/kWh
Durgapur TPS	2,750 kCal/kWh

(iv) For Lignite-fired Thermal Generating Stations: For lignite-fired thermal generating stations, except for TPS-I and TPS-II (Stage I & II) of NLC India Ltd, the gross station heat rates specified under sub-clause (i) 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

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

(v) TPS-I and TPS-II (Stage I & II) of NLC India Ltd:

TPS-I:	4,000 kCal/kWh
TPS-II:	2,890 kCal/kWh
TPS- I (Expansion):	2,720 kCal/kWh

(vi) Open Cycle Gas Turbine/Combined Cycle Generating Stations: For the following gas based thermal generating stations:

Name of generating station	Combined cycle (kCal/kWh)	Open Cycle (kCal/kWh)
Gandhar GPS	2,040	2,960
Kawas GPS	2,050	3,010
Anta GPS	2,075	3,010
Dadri GPS	2,000	3,010
Auraiya GPS	2,100	3,045
Faridabad GPS	1,975	2,900
Kayamkulam GPS	2,000	2,900
Assam GPS	2,600	3,578
Agartala GPS	2,600	3,578
Ratnagiri	1,820	2,641

(b) Thermal Generating Stations achieving COD on or after 1.4.2009:

(i) For Coal-based and lignite-fired Thermal Generating Stations:

1.05 X 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/cm2)	150	170	170
SHT/RHT (^{0}C)	535/535	537/537	537/565
Type of BFP	Electrical Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1955	1950	1935
Min. Boiler Efficiency			
Sub-Bituminous Indian Coal	0.86	0.86	0.86
Bituminous Imported Coal	0.89	0.89	0.89
Max. Design Heat Rate (kCal/kWh)			
Sub-Bituminous Indian Coal	2273	2267	2250
Bituminous Imported Coal	2197	2191	2174

Pressure Rating (Kg/cm2)	247	247	270	270
SHT/RHT (^{0}C)	537/565	565/593	593/593	600/ 600
Type of BFP	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1900	1850	1810	1800
Min. Boiler Efficiency				
Sub-Bituminous Indian Coal	0.86	0.86	0.865	0.865
Bituminous Imported Coal	0.89	0.89	0.895	0.895
Max. Design Heat Rate (kCal/kWh)				
Sub-Bituminous Indian Coal	2222	2151	2105	2081
Bituminous Imported Coal	2135	2078	2034	2022

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

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

Provided also that where the boiler efficiency is lower than 86% for Sub-bituminous Indian coal and 89% for bituminous imported coal, the same shall be considered as 86% and 89% for Sub-bituminous Indian coal and bituminous imported coal respectively, 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 in case of coal based generating station if one or more generating units were declared under commercial operation prior to 1.4.2019, the heat rate norms for those generating units as well as generating units declared under commercial operation on or after 1.4.2019 shall be lowest of the heat rate norms considered by the Commission during tariff period 2014-19 or those arrived at by above methodology or the norms as per the sub-clause (C)(a)(i) 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 (C)(a)(iv) of this Regulation:

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

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

(c) For Gas-based/ Liquid-based Thermal Generating Unit(s)/ Block(s) having COD on or after 1.4.2009:

For Natural Gas = 1.050 X Design Heat Rate of the unit/block (kCal/kWh)

For RLNG =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) For Coal-based generating stations other than at (c) below: 0.50 ml/kWh

(b) (i) For Lignite-fired generating stations except TPS-I: 1.0 ml/kWh

(ii) For TPS-I: 1.5 ml/kWh

(c) For Coal-based generating stations of DVC:

Bokaro TPS	1.5 ml/kWh
Chandrapur TPS	1.5 ml/kWh
Durgapur TPS	2.4 ml/kWh

(d) For Generating Stations based on Coal Rejects: 2.0 ml/kWh

(E) Auxiliary Energy Consumption:

(a) For Coal-based generating stations except at (b) below:

S. No.	Generating Station	With Natural Draft cooling tower or without cooling tower
(i)	200 MW series	8.50%
(ii)	300 MW and above	
	Steam driven boiler feed pumps	5.75%
	Electrically driven boiler feed pumps	8.00%

Provided that for thermal generating stations with induced draft cooling towers and where tube type coal mill is used, the norms shall be further increased by 0.5% and 0.8% respectively:

Provided further that Additional Auxiliary Energy Consumption as follows shall 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	1.0%
Indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower	0.5%

Note: The auxiliary energy consumption for the unit capacity of less than 200 MW sets shall be dealt on case to case basis.

(b) For other Coal-based generating stations:

(i)	Talcher Thermal Power Station	10.50%
(ii)	Tanda Thermal Power Station	11.50%
(iii)	Bokaro Thermal Power Station	10.25%
(iv)	Chandrapur Thermal Power Station	9.50%
(v)	Durgapur Thermal Power Station	10.50%

(c) For Gas Turbine /Combined Cycle generating stations:

(i) Combined Cycle : 2.75%

(ii) Open Cycle : 1.00%

Provided that where the gas based generating station is using electric motor driven Gas Booster Compressor, the Auxiliary Energy Consumption in case of Combine Cycle mode shall be 3.30% (including impact of air-cooled condensers for Steam Turbine Generators):

Provided further that an additional Auxiliary Energy Consumption of 0.35% shall be allowed for Combine Cycle Generating Stations having direct cooling air cooled condensers with mechanical draft fans.

(d) For Lignite-fired thermal generating stations:

(i) For 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) For Barsingsar Generating station of NLC using CFBC technology: 12.50%

(iii) For TPS-I, TPS-I (Expansion) and TPS-II Stage-I&II of NLC India Ltd.:

TPS-I	12.00%
TPS-II	10.00%
TPS-I (Expansion)	8.50%

(iv) Limestone consumption for lignite-based generating station using CFBC technology:

Barsingsar : 0.056 kg/kWh

TPS-II (Expansion) : 0.046 kg/kWh

(e) For Generating Stations based on coal rejects: 10%

50. Norms of Operation for Hydro Generating Stations: The norms of operation as given hereunder shall apply to hydro generating station:

(A) Normative Annual Plant Availability Factor (NAPAF): (1) 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%.

Run-of-river generating stations: NAPAF to be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant.

(2) 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.

(3) A further allowance of 5% may be allowed for difficulties in North East Region.

(4) Based on the above, the Normative annual plant availability factor (NAPAF) of the hydro generating stations already in operation shall be as follows:-

Station	Type of Plant	Plant Capacity No. of Units x MW	NAPAF (%)
THDC			
THDC Stage I	Storage	4x250	80
KHEP	Storage	4x100	68
NHPC			
Bairasul	Pondage	3x60	90
Loktak	Pondage	3x35	88
Salal	ROR	6x115	64
Tanakpur	ROR	3x31.4	59
Chamera-I	Pondage	3x180	90
Uri I	ROR	4x120	74
Rangit	Pondage	3x20	90
Chamera-II	Pondage	3x100	90
Dhauliganga	Pondage	4x70	78
Dulhasti	Pondage	3x130	90
Teesta-V	Pondage	3x170	87

Station	Type of Plant	Plant Capacity No. of Units x MW	NAPAF (%)
Sewa-II	Pondage	3x40	89
TLDP III	Pondage	4x33	77
Chamera III	Pondage	3x77	87
Chutak	ROR	4x11	48
Nimmo Bazgo	Pondage	3x15	70
Uri II	ROR	4x60	70
Parbati III	Pondage	4x130	43
NHDC			
Indira Sagar	Storage	8x125	87
Omkareshwar	Pondage	8x65	90
NEEPCO			
Kopili I	Storage	4x50	69
Khandong	Storage	2x25	67
Kopili II	Storage	1x25	69
Doyang	Storage	3x25	70
Ranganadi	Pondage	3x135	88
NTPC			
Koldam	Storage	4x200	90
SJVNL			
Nathpa Jhakri	ROR	6x250	90
Rampur	ROR	6x68.67	85
DVC			
Panchet	Storage	2x40	80
Tilaya	Storage	2x2	80
Maithon	Storage	3x20	80
Teesta III	Pondage	6x200	85

(B) In case of pumped storage hydro generating stations, the quantum of electricity required for pumping water from down-stream reservoir to up-stream reservoir shall be arranged by the beneficiaries duly taking into account the transmission and distribution losses up to the bus bar of the generating station. In return, beneficiaries shall be entitled to equivalent energy of 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir from the generating station during peak hours and the generating station shall be under obligation to supply such quantum of electricity during peak hours:

Provided that in the event of the beneficiaries failing to supply the desired level of energy during off-peak hours, there will be pro-rata reduction in their energy entitlement from the station during peak hours:

Provided further that the beneficiaries may assign or surrender their share of capacity in the generating station, in part or in full, or the capacity may be reallocated by the Central Government, and in that event, the owner or assignee of the capacity share shall be responsible for arranging the equivalent energy to the generating station in off-peak hours, and be entitled to corresponding energy during peak hours in the same way as the original beneficiary was entitled.

(C) Auxiliary Energy Consumption (AEC):

Type of Station	**AEC**	
	Installed Capacity above 200 MW	**Installed Capacity upto 200 MW**
Surface		
Rotating Excitation	0.7%	0.7%
Static	1.0%	1.2%
Underground		
Rotating Excitation	0.9%	0.9%
Static	1.2%	1.3%

Norms of operation for transmission system

51. Normative Annual Transmission System Availability Factor (NATAF):

(a) For recovery of Annual Fixed Cost, NATAF shall be as under:

(1) AC system: 98.00%;

(2) HVDC bi-pole links 95.00% and HVDC back-to-back stations: 95.00%:

Provided that the normative annual transmission availability factor of the HVDC bi-pole links shall be 85%for first twelve months from the date of commercial operation.

(b) For Incentive, NATAF shall be as under:

(1) AC system: 98.50%;

(2) HVDC bi-pole links and HVDC back-to-back Stations: 97.50%:

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

Provided further that for AC and HVDC system, actual outage hours shall be considered for computation of availability upto two trippings per year. After two trippings in a year, for every tripping, additional 12 hours outage shall be considered in addition to the actual outage hours:

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

52. Auxiliary Energy Consumption in the Sub-station

(1) 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.

(2) HVDC sub-station: For auxiliary energy consumption in HVDC sub-stations, the Central Government may allocate an appropriate share from one or more ISGS. The charges for such power shall be borne by the transmission licensee from the normative operation and maintenance expenses.

CHAPTER - 13

SCHEDULING, ACCOUNTING AND BILLING

53. Scheduling: The methodology for scheduling and dispatch for the generating station shall be as specified in the Grid Code.

54. Metering and Accounting: For metering and accounting, the provisions of the Grid Code shall be applicable.

55. Billing and Payment of charges: (1) Bills shall be raised for capacity charge and energy charge by the generating company and for transmission charge by the transmission licensee on monthly basis in accordance with these regulations, and payments shall be made by the beneficiaries or the long term customers directly to the generating company or the transmission licensee, as the case may be:

Provided that the physical copy of the Bill in Original at the office of the Authorised Person of the beneficiary or long term customer, as the case may be, or the scanned copy of Original Bill through official email ID of the Authorised Signatory of the Generating Company or the Transmission Licensee, as the case may be, shall be recognized as valid mode of presentation of Bill:

Provided further that Authorized Signatory or Signatories (official designation only) shall be notified in advance by the Managing Director or Chief Executive Officer of the Company and any change in the list of Authorised Signatory for the purpose, shall be communicated in the same manner.

(2) 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 or allocations of each beneficiary in the total capacity of 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 States within or 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 or outside the region for such transfers, the shares of the beneficiaries may be re-allocated by the 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) 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.

56. Recovery of Statutory Charges: The generating company shall recover the statutory charges imposed by the State and Central Government such as electricity duty, water cess by considering normative parameters specified in these regulations. In case of the electricity duty is applied on the auxiliary energy consumption, such amount of electricity duty shall apply on normative auxiliary energy consumption of the generating station (excluding colony consumption) and apportioned to each of the beneficiaries in proportion to their schedule dispatch during the month.

57. Sharing of Transmission Charges: (1) The sharing of transmission charges shall be governed by the Sharing Regulations.

(2) The charges determined under these regulations in relation to communication system forming part of transmission system shall be shared by the beneficiaries or long term customers in accordance with the Sharing Regulations:

Provided that charges determined under these regulations in relation to communication system other than that of central portion shall be shared by the beneficiaries in proportion to the capital cost belonging to respective beneficiaries.

58. Rebate. (1) For payment of bills of the generating company and the transmission licensee through letter of credit on presentation or through National Electronic Fund Transfer (NEFT) or Real Time Gross Settlement (RTGS) payment mode within a period of 5 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1.50% shall be allowed.

Explanation: In case of computation of '5 days', the number of days shall be counted consecutively without considering any holiday. However, in case the last day or 5th day is official holiday, the 5th day for the purpose of Rebate shall be construed as the immediate succeeding working day (as per the official State Government's calendar, where the Office of the Authorised Signatory or Representative of the Beneficiary, for the purpose of receipt or acknowledgement of Bill is situated).

(2) Where payments are made on any day after 5 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.

59. Late payment surcharge: In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary or long term customers as the case may be, beyond a period of 45 days from the date of presentation of bills, 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 – 14

SHARING OF BENEFITS

60. Sharing of gains due to variation in norms: (1) The generating company or the transmission licensee shall workout gains based on the actual performance of applicable Controllable parameters as under:

i) Station Heat Rate;

ii) Secondary Fuel Oil Consumption; and

iii) Auxiliary Energy Consumption.

(2) The financial gains by the generating company or the transmission licensee, as the case may be, on account of controllable parameters shall be shared between generating company or transmission licensee and the beneficiaries or long term customers, as the case may be on annual basis. The financial gains computed as per the following formulae in case of generating station other than hydro generating stations on account of operational parameters as shown in Clause (1) of this Regulation shall be shared in the ratio of 50:50 between the generating stations and beneficiaries.

Net Gain = (ECR_N– ECR_A) x Scheduled Generation

Where,

ECR_N = Normative Energy Charge Rate computed on the basis of norms specified for Station Heat Rate, Auxiliary Energy Consumption and Secondary Fuel Oil consumption.

ECR_A = Actual Energy Charge Rate computed on the basis of actual Station Heat Rate, Auxiliary Energy Consumption and Secondary Fuel Oil

Consumption for the month.

Provided that in case of hydro generating stations, the net gain on account of Actual Auxiliary Energy Consumption being less than the Normative Auxiliary Energy Consumption, shall be computed as per following formulae provided the saleable scheduled generation is more than the saleable design energy and shall be shared in the ratio of 50:50 between generating station and beneficiaries.:

(i) When saleable scheduled generation is more than saleable design energy on the basis of normative auxiliary energy consumption and less than or equal to saleable design energy on the basis of actual auxiliary energy consumption:

Net gain (Million Rupees) = [(Saleable Scheduled generation in MUs) – (Saleable Design energy on the basis of normative auxiliary energy consumption in MUs)] x [1.20 or ECR, whichever is lower]

(ii) When saleable scheduled generation is more than saleable design energy on the basis of actual auxiliary energy consumption:

Net gain (Million Rupees)= {Saleable Scheduled generation in MUs- [(Saleable Scheduled Generation in MUs x (100-normative AEC in %)/(100- actual AEC in %)]}x [1.20 or ECR, whichever is lower]

61. Sharing of saving in interest due to re-financing or restructuring of loan :(1) If re-financing or restructuring of loan by the generating company or the transmission licensee, as the case may be, results in net savings on interest after accounting for cost associated with such refinancing or restructuring, the same shall be shared between the beneficiaries and the generating company or the transmission licensee, as the case may be, in the ratio of 50:50.

(2) In case of dispute, any of the parties may make an application in accordance with the Central Electricity Regulatory Commission (Conduct of Business) Regulations, 1999 for settlement of the dispute:

Provided that the beneficiaries or the long term customers shall not withhold any payment on account of the interest claimed by the generating company or the transmission licensee during the pendency of any dispute arising out of re-financing of loan.

62. Sharing of Non-Tariff Income: The non-tariff net income in case of generating station and transmission system from rent of land or buildings, sale of scrap and advertisements shall be shared between the beneficiaries or the long term customers and the generating company or the transmission licensee, as the case may be, in the ratio 50:50.

63. Sharing of Clean Development Mechanism Benefits: The proceeds of carbon credit from approved emission reduction projects under Clean Development Mechanism shall be shared in the following manner:-

(a) 100% of the gross proceeds on account of 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 system, as the case may be;

(b) 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%, where after the proceeds shall be shared in equal proportion, by the generating company or the transmission licensee, as the case may be, and the beneficiaries.

64. Sharing of income from other business of transmission licensee: The income from other business of transmission licensee shall be shared with the long term customer in the manner as specified in the Central Electricity Regulatory Commission (Sharing of revenue derived from utilization of transmission assets for other business) Regulations, 2007.

CHAPTER 15

MISCELLANEOUS PROVISIONS

65. Operational Norms to be ceiling norms: Operational norms specified in these regulations are the ceiling norms and shall not preclude the generating company or the transmission licensee, as the case may be, and the beneficiaries and the long-term customers 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.

66. Deviation from ceiling tariff: (1) The tariff determined in these regulations shall be a ceiling tariff. The generating company or the transmission licensee and the beneficiaries or the long-term customer, as the case may be, may mutually agree to charge a lower tariff.

(2) The generating company or the transmission licensee, may opt to charge a lower tariff for a period not exceeding the validity of these regulations on agreeing to deviation from operational parameters, reduction in operation and maintenance expenses, reduced return on equity and incentive specified in these regulations.

(3) If the generating company or the transmission licensee opts to charge a lower tariff for a period not exceeding the validity of these regulations on account of lower depreciation based on the requirement of repayment in such case the unrecovered depreciation on account of reduction of depreciation by the generating company or the transmission licensee during useful life shall be allowed to be recovered after the useful life in these regulations.

(4) The deviation from the ceiling tariff specified by the Commission, shall come into effect from the date agreed to by the generating company or the transmission licensee and the beneficiaries or the long-term customer, as the case may be.

(5) The generating company and the beneficiaries of a generating station or the transmission licensee and the long term customer of transmission system shall be required to approach the Commission for charging lower tariff in accordance with clauses (1) to (3) above. The details of the accounts and the tariff actually charged under clauses (1) to (3) shall be submitted at the time of true up.

67. Deferred Tax liability with respect to previous tariff period: Deferred tax liabilities for the period upto 31^{st} March, 2009 whenever they materialise shall be recoverable directly by the generating companies or transmission licensees from the then beneficiaries or long term customers, as the case may be. Deferred tax liabilities for the period arising from 1.4.2009 to 31.3.2014 if any, shall not be recoverable from the beneficiaries or the long term customers, as the case may be.

68. Hedging of Foreign Exchange Rate Variation: (1) The generating company or the transmission licensee, as the case may be, may hedge foreign exchange exposure in respect of the interest and repayment of foreign currency loan taken for the generating station or the transmission system, in part or in full at their discretion.

(2) If the petitioner enters into hedging arrangement(s) based on its approved hedging policy, the petitioner shall communicate to the beneficiaries concerned, of

entering into such arrangement(s) within thirty days.

(3) Every generating company and transmission 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.

(4) To the extent the generating company or the transmission 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 licensee or its suppliers or contractors.

69. Recovery of cost of hedging or Foreign Exchange Rate Variation (FERV): (1) Every generating company and the transmission 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.

(2) Recovery of cost of hedging or foreign exchange rate variation shall be made directly by the generating company or the transmission licensee, as the case may be, from the beneficiaries or the long term customers, as the case may be, without making any application before the Commission:

Provided that in case of any objections by the beneficiaries or the long term customers, as the case may be, to the amounts claimed on account of cost of hedging or foreign exchange rate variation, the generating company or the transmission licensee, as the case may be, may make an appropriate application before the Commission for its decision.

70. Application fee and the publication expenses: The following fees, charges and expenses shall be reimbursed directly by the beneficiary in the manner specified herein:

(1) 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 licensee, as the case may be, directly from the beneficiaries or the long term customers, as the case may be.

(2) 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 customers in proportion to their share in the inter-State transmission systems determined in accordance with the Central Electricity Regulatory Commission (Sharing of inter-State Transmission Charges and Losses) Regulations, 2010, as amended from time to time.

(3) Fees and charges paid by the generating companies and inter-State transmission licensees (including deemed inter-State transmission licensee) under the Central Electricity Regulatory Commission (Fees and Charges of Regional Load Despatch Centre and other related matters) Regulations, 2009, as amended from time to time or any subsequent amendment thereof.

(4) Licence fees paid by the inter-State transmission licensees (including the deemed inter-State transmission licensee) in terms of Central Electricity Regulatory Commission (Payment of Fees) Regulations, 2012.

(5) Licence fees paid by NHPC Ltd to the State Water Resources Development Authority, Jammu in accordance with the provisions of Jammu & Kashmir Water Resources (Regulations and Management) Act, 2010.

(6) 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.

71. Special Provisions relating to NLC India Limited: The tariff of the existing generating stations of NLC India Ltd, namely, TPS-I and TPS-II (Stage I & II) and TPS-I (Expansion), whose tariff for the tariff periods 2004-09, 2009-14 and 2014-19 has been determined by following the Net Fixed Assets approach, shall continue to be determined by adopting Net Fixed Assets approach.

72. Special Provisions relating to Damodar Valley Corporation: (1) Subject to clause (2), this Regulation shall apply to determination of tariff of the projects owned by Damodar Valley Corporation (DVC).

(2) The following special provisions shall apply for determination of tariff of the projects owned by DVC:

(i) Capital Cost: The expenditure allocated to the object 'power', in terms of sections 32 and 33 of the Damodar Valley Corporation Act, 1948, to the extent of its apportionment to generation and inter-state transmission, shall form the basis of capital cost for the purpose of determination of tariff:

Provided that the capital expenditure incurred on head office, regional offices, administrative and technical centers of DVC, after due prudence check, shall also form part of the capital cost.

(ii) **Debt Equity Ratio:** The debt equity ratio of all projects of DVC commissioned prior to 01.01.1992 shall be 50:50 and that of the projects commissioned thereafter shall be 70:30.

(iii) **Depreciation:** The depreciation rate stipulated by the Comptroller and Auditor General of India in terms of section 40 of the Damodar Valley Corporation Act, 1948 shall be applied for computation of depreciation of projects of DVC.

(iv) **Funds under section 40 of the Damodar Valley Corporation Act, 1948**: The Fund(s) established in terms of section 40 of the Damodar Valley Corporation Act, 1948 shall be considered as items of expenditure to be recovered through tariff.

73. **Special Provisions relating to BBMB and SSP**: The tariff of generating station and the transmission system of Bhakra Beas Management Board (BBMB) and Sardar Sarovar Project (SSP) shall be determined after taking into consideration, the provisions of the Punjab Reorganization Act, 1996 and Narmada Water Scheme, 1980 under

Section 6-A of the Inter-State Water Disputes Act, 1956, respectively.

74. Special Provisions Relating to Certain Inter-State Generation Projects: The tariff of generating station and the transmission system of Indira Sagar generation project and such other inter-state generation projects shall be determined on case to case basis.

75. Transmission Majoration Factor: Transmission Majoration Factor admissible for the transmission projects executed through JV route in terms of Regulation 4.10A of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2001 shall be available for a period of 25 years from the date of issue of the transmission licence.

76. 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.

77. Power to Remove Difficulty: If any difficulty arises in giving effect to the provisions of these regulations, the Commission may, by order, make such provision not inconsistent with the provisions of the Act or provisions of other regulations specified by the Commission, as may appear to be necessary for removing the difficulty in giving effect to the objectives of these regulations.

Sd/-
(Sanoj Kumar Jha)
Secretary

Appendix I
Depreciation Schedule

Sr. No.	Asset Particulars	Depreciation Rate (Salvage Value=10%) SLM
A	**Land under full ownership**	0.00%
B	**Land under lease**	
(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%
C	**Assets purchased new**	
a.	Plant & 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	
(i)	Station type	5.28%
(ii)	Pole type	5.28%
(iii)	Synchronous condenser	5.28%

Sr. No.	Asset Particulars	Depreciation Rate (Salvage Value=10%) SLM
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 66 KV	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%
(iii)	Fibre Optic	6.33%
p.	I. T Equipment including software	15.00%
q.	Any other assets not covered above	5.28%

Note: Where life of the particular asset is less than useful life of the project, the useful life of such particular asset shall be considered as per the provisions of the Companies Act, 2013 and subsequent amendment thereto.

Appendix-II

Procedure for Calculation of Transmission System Availability Factor for a Month

1. Transmission system availability factor for n^{th} calendar month ("TAFPn") shall be calculated by the respective transmission licensee, got verified by the concerned Regional Load Dispatch Centre (RLDC) and certified by the Member-Secretary, Regional Power Committee of the region concerned, separately for each AC and HVDC transmission system and grouped according to sharing of transmission charges. In case of AC system, transmission System Availability shall be calculated separately for each Regional Transmission System and inter-regional transmission system. In case of HVDC system, transmission System Availability shall be calculated on consolidate basis for all inter-state HVDC system.

2. Transmission system availability factor for n^{th} calendar month ("TAFPn") shall be calculated by consider following:

   i) **AC transmission lines:** Each circuit of AC transmission line shall be considered as one element;

   ii) **Inter-Connecting Transformers (ICTs):** Each ICT bank (three single phase transformer together) shall form one element;

   iii) **Static VAR Compensator (SVC):** SVC along with SVC transformer shall form one element;

   iv) **Bus Reactors or Switchable line reactors**: Each Bus Reactors or Switchable line reactors shall be considered as one element;

   v) **HVDC Bi-pole links:** Each pole of HVDC link along with associated equipment at both ends shall be considered as one element;

   vi) **HVDC back-to-back station:** Each block of HVDC back-to-back station shall be considered as one element. If associated AC line (necessary for transfer of inter- regional power through HVDC back-to-back station) is not available, the HVDC back-to-back station block shall also be considered as unavailable;

vii) **Static Synchronous Compensation ("STATCOM"):** Each STATCOM shall be considered as separate element.

3. The Availability of AC and HVDC portion of Transmission system shall be calculated by considering each category of transmission elements as under:

TAFMn (in %) for AC system:

$$= \frac{o \times AVo)+(p \times AVp) + (q \times AVq) + (r \times AVr)+(u \times AVu)}{(o + p + q + r+u)} \times 100$$

Where,

o	=	Total number of AC lines.
AVo	=	Availability of o number of AC lines.
p	=	Total number of bus reactors/switchable line reactors
AVp	=	Availability of p number of bus reactors/switchable line reactors
q	=	Total number of ICTs.
AVq	=	Availability of q number of ICTs.
r	=	Total number of SVCs.
AVr	=	Availability of r number of SVCs
u	=	Total number of STATCOM.
AVu	=	Availability of u number of STATCOMs

<u>TAFMn (in %) for HVDC System:</u>

$$= \frac{\sum_{x=1}^{s} \mathrm{Cxbp(act)} \times \mathrm{AVxbp} + \sum_{y=1}^{t} \mathrm{Cy(act)btb} \times \mathrm{AVybtb}}{\sum_{x=1}^{s} \mathrm{Cxbp} + \sum_{y=1}^{t} \mathrm{Cybtb}} \times 100$$

Where

Cxbp(act)	=	Total actual operated capacity of x^{th} HVDC pole
Cxbp	=	Total rated capacity of x^{th} HVDC pole

AVxbp	=	Availability of x^{th} HVDC pole
Cybtb(act)	=	Total actual operated capacity of y^{th} HVDC back-to-back station block
Cybtb	=	Total rated capacity of y^{th} HVDC back-to-back station block
AVybtb	=	Availability of y^{th} HVDC back-to-back station block
s	=	Total no of HVDC poles
t	=	Total no of HVDC Back to Back blocks

3. The availability for each category of transmission elements shall be calculated based on the weightage factor, total hours under consideration and non-available hours for each element of that category. The formulae for calculation of Availability of each category of the transmission elements are as per **Appendix-III**. The weightage factor for each category of transmission elements shall be considered asunder:

(a) For each circuit of AC line – Number of sub-conductors in the line multiplied by ckt-km;
(b) For each HVDC pole- The rated MW capacity x ckt-km;
(c) For each ICT bank – The rated MVA capacity;
(d) For SVC- The rated MVAR capacity (inductive and capacitive);
(e) For Bus Reactor/switchable line reactors – The rated MVAR capacity;
(f) For HVDC back-to-back station connecting two Regional grids- Rated MW capacity of each block; and
(g) For STATCOM – Total rated MVAR Capacity.

4. The transmission elements under outage due to following reasons shall be deemed to be available:

i. Shut down availed for maintenance of another transmission scheme or construction of new element or renovation/upgradation/additional capitalization in existing system approved by the Commission. If the other transmission scheme belongs to the transmission licensee, the Member-

Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved. In case of dispute regarding deemed availability, the matter may be referred to Chairperson, CEA within 30 days.

ii. Switching off of a transmission line to restrict over voltage and manual tripping of switched reactors as per the directions of concerned RLDC.

5. For the following contingencies, outage period of transmission elements, as certified by the Member Secretary, RPC, shall be excluded from the total time of the element under period of consideration for the following contingencies:

i) Outage of elements due to acts of God and force majeure events beyond the control of the transmission licensee. However, whether the same outage is due to force majeure (not design failure) will be verified by the Member Secretary, RPC.A reasonable restoration time for the element shall be considered by Member Secretary, RPC and any additional time taken by the transmission licensee for restoration of the element beyond the reasonable time shall be treated as outage time attributable to the transmission licensee. Member Secretary, RPC may consult the transmission licensee or any expert for estimation of reasonable restoration time. Circuits restored through ERS (Emergency Restoration System) shall be considered as available;

ii) Outage caused by grid incident/disturbance not attributable to the transmission licensee, e.g. faults in substation or bays owned by other agency causing outage of the transmission licensee's elements, and tripping of lines, ICTs, HVDC, etc. due to grid disturbance. However, if the element is not restored on receipt of direction from RLDC while normalizing the system following grid incident/disturbance within reasonable time, the element will be considered not available for the period of outage after issuance of RLDC's direction for restoration;

Provided that in case of any disagreement with the transmission licensee regarding reason for outage, same may be referred to Chairperson, CEA within

30 days. The above need to be resolved within two months:

Provided further that where there is a difficulty or delay beyond sixty days, from the incidence in finalizing the recommendation, the Member Secretary of concerned RPC shall allow the outage hours on provisional basis till the final view.

6. Time frame for certification of transmission system availability: (1) Following schedule shall be followed for certification of availability by Member Secretary of concerned RPC:

- Submission of outage data by Transmission Licensees to RLDC/ constituents – By 5^{th} of the following month;
- Review of the outage data by RLDC / constituents and forward the same to respective RPC – by 20^{th} of the month;
- Issue of availability certificate by respective RPC – by 3^{rd} of the next month.

Appendix-III

FORMULAE FOR CALCULATION OF AVAILABILITY OF EACH CATEGORY OF TRANSMISSION ELEMENTS

For AC transmission system

AVo(Availability of o no. of AC lines) = $\frac{\sum_{i=1}^{o} Wi(Ti - TNAi)/Ti}{\sum_{i=1}^{o} Wi}$

AVq(Availability of q no. of ICTs) = $\frac{\sum_{k=1}^{q} Wk(Tk - TNAk)/Tk}{\sum_{k=1}^{q} Wk}$

AVr(Availability of r no. of SVCs) = $\frac{\sum_{l=1}^{r} Wl(Tl - TNAl)/Tl}{\sum_{l=1}^{r} Wl}$

AVp(Availability of p no. of Switched Bus reactors) = $\frac{\sum_{m=1}^{p} Wm(Tm - TNAm)/Tm}{\sum_{m=1}^{p} Wm}$

AVu(Availability of u no. of STATCOMs) = $\frac{\sum_{n=1}^{u} Wn(Tn - TNAn)/Tn}{\sum_{n=1}^{u} Wn}$

AV_{xbp}(Availability of an individual HVDC pole) = $\frac{(Tx - TN\quad)}{Tx}$

AV_{ybtb} (Availability of an individualHVDC Back-to-back Blocks) = $\frac{(Ty - TNAy)}{Ty}$

For HVDC transmission system

For the new HVDC commissioned but not completed twelve months;

For first 12 months: [(AV_{xbp} or AV_{ybtb})x95%/85%], subject to ceiling of 95%.

Where,

o	=	Total number of AC lines;
AVo	=	Availability of o number of AC lines;
p	=	Total number of bus reactors/switchable line reactors;
AVp	=	Availability of p number of bus reactors/switchable line reactors;
q	=	Total number of ICTs;
AVq	=	Availability of q number of ICTs;
r	=	Total number of SVCs;
AVr	=	Availability of r number of SVCs;.
U	=	Total number of STATCOM;

AVu	=	Availability of u number of STATCOMs;
Wi	=	Weightage factor for ith transmission line;
Wk	=	Weightage factor for kth ICT;
Wl	=	Weightage factors for inductive & capacitive operation of lth SVC;
Wm	=	Weightage factor for mth bus reactor;
Wn	=	Weightage factor for nth STATCOM.

Ti, , Tk, Tl, , - Tm, Tn, Tx, Ty	The total hours of i^{th} AC line, k^{th} ICT, l^{th} SVC, m^{th} Switched Bus Reactor & n^{th} STATCOM, x^{th} HVDC pole, y^{th} HVDC back-to-back blocks during the period under consideration (excluding time period for outages not attributable to transmission licensee for reasons given in Para 5of the procedure)
$T_{NA}i$, $T_{NA}k$ - $T_{NA}l$, $T_{NA}m$, $T_{NA}n$, T_{NAx}, $T_{NA}y$	The non-availability hours (excluding the time period for outages not attributable to transmission licensee taken as deemed availability as per Para 5 of the procedure) for i^{th} AC line, k^{th} ICT, l^{th} SVC , m^{th} Switched Bus Reactor, n^{th} STATCOM, x^{th} HVDC pole and y^{th}HVDC back-to-back block .