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No. L-7/25(5)/2003-CERC 26th March 2004

In exercise of powers conferred under Section 178 of the Electricity Act, 2003, and all other powers enabling 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, 2004.

(2) These regulations shall come into force on 1.4.2004, and unless reviewed earlier or extended by the Commission, shall remain in force for a period of 5 years.

Provided that where a project, including a part thereof, has been commissioned 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 a project or part thereof, as the case may be, for the period ending 31.3.2004 shall be determined in accordance with the Central Electricity Regulatory Commission (Terms & Conditions of Tariff) Regulations, 2001.

(3) Words and expressions used in these regulations and not defined herein but defined in the Act shall have the meaning assigned to them under the Act.

2. **Scope and extent of application**: (1) Where tariff has been determined through transparent process of bidding in accordance with the guidelines issued by the Central Government, the Commission shall adopt such tariff in accordance with the provisions of the Act.

(2) These regulations shall apply in all other cases where tariff is to be determined by the Commission based on capital cost.

Provided that the Commission may prescribe the relaxed norms of operation, including the norms of target availability and Plant Load Factor contained in these regulations for a generating station the tariff of which is not determined in accordance with the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2001, and the relaxed norms shall be applicable for determination of tariff for such a generating station.

3. **Norms of operation to be ceiling norms:** For removal of doubts, it is clarified that the norms of operation specified under these regulations are the ceiling norms and this shall not preclude the generating company or the transmission licensee, as the case may be, and the beneficiaries from agreeing to improved norms of operation and in case the improved norms are agreed to, such improved norms shall be applicable for determination of tariff.

4. **Tariff determination:** (1) Tariff in respect of a generating station under these regulations shall be determined stage-wise, unit-wise or for the whole generating station and tariff for the transmission system shall be determined line-wise, sub-station-wise and system-wise, as the case may be, and aggregated to regional tariff.

(2) For the purpose of tariff, the capital cost of the project shall be broken up into stages and by distinct units forming part of the project. Where the stage-wise, unit-wise, line-wise or sub-station-wise break up of the capital cost of the project is not available and in case of on-going projects, the common facilities shall be apportioned on the basis of the installed capacity of the units and lines or sub-stations. In relation to multi-purpose hydro electric projects, with irrigation, flood control and power components, the capital cost chargeable to the power component of the project only shall be considered for determination of tariff.

Explanation

For the purpose of this chapter, 'project' includes a generating station and the transmission system.

5. **Application for determination of tariff:** (1) The generating company or the transmission licensee, as the case may be, may make an application for fixation of tariff in respect of the completed units of the generating station or the lines or sub-stations of the transmission system.

(2) In case of the existing generating station or the existing transmission system, the generating company or the transmission licensee, as the case may be, shall make an application for determination of tariff as per Appendix I to these regulations.

(3) In case of a generating station or the transmission system declared under commercial operation on or after 1.4.2004, an application for fixation of tariff shall be made in two stages, namely:

(i) A generating company or a transmission licensee may make an application as per Appendix I to these regulations, for determination of provisional tariff in advance of the anticipated date of completion of the project based on the capital expenditure actually incurred up to the date of making of the application or a date prior to making of the application, duly audited and certified by the statutory auditors, and the provisional tariff shall be charged from the date of commercial operation of the respective unit of the generating station or the line or sub-station of the transmission system;

(ii) A generating company or the transmission licensee shall make a fresh application as per Appendix I to these regulations, for determination of final tariff based on actual capital expenditure incurred up to the date of commercial operation of the generating station or the transmission system, duly audited and certified by the statutory auditors.

6. **Core Business :** For the purpose of these regulations, core business means the regulated activities of generation or transmission of electricity and does not include any other business or activity, like consultancy, telecommunication, of the generating company or the transmission licensee.

7. **Tax on Income:** (1) Tax on the income streams of the generating company or the transmission licensee, as the case may be, from its core business, shall be computed as an expense and shall be recovered from the beneficiaries.

(2) Any under-recoveries or over-recoveries of tax on income shall be adjusted every year on the basis of income-tax assessment under the Income-Tax Act, 1961, as certified by the statutory auditors.

Provided that tax on any income stream other than the core business shall not constitute a pass through component in tariff and tax on such other income shall be payable by the generating company or transmission licensee, as the case may be.

Provided further that the generating station-wise profit before tax in the case of the generating company and the region-wise profit before tax in case of the transmission licensee as estimated for a year in advance shall constitute the basis for distribution of the corporate tax liability to all the generating stations and regions.

Provided further that the benefits of tax-holiday as applicable in accordance with the provisions of the Income-Tax Act, 1961 shall be passed on to the beneficiaries.

Provided further that in the absence of any other equitable basis the credit for carry forward losses and unabsorbed depreciation shall be given in the proportion as provided in the second proviso to this regulation.

Provided further that income-tax allocated to the thermal generating station shall be charged to the beneficiaries in the same proportion as annual fixed charges, the income-tax allocated to the hydro generating station shall be charged to the beneficiaries in the same proportion as annual capacity charges and in case of inter-state transmission, the sharing of income-tax shall be in the same proportion as annual transmission charges.

8. **Tax Escrow Mechanism:** (1) The beneficiaries shall maintain an interest-bearing tax escrow account in a scheduled bank, to which all amounts of interest shall be credited .

(2) The tax liability shall be estimated two months before the commencement of each year and intimated to the beneficiaries. The generating company or the transmission

licensee shall endeavour to minimize its liability on account of taxes recoverable from the beneficiaries.

(3) The generating company or the transmission licensee shall be authorised to withdraw the amounts for settling the income-tax liability on presentation to the escrow holder, a certificate from their statutory auditors that the amounts are immediately due and payable to the taxing authority.

(4) The generating company or the transmission licensee shall pay into the tax escrow account any refund received from the taxing authority.

(5) The refunds, if any, shall not be paid back to the beneficiaries and shall be adjusted in the escrow account. Any balance due or returnable shall be rolled over to the next year.

(6) The escrow accounts shall be reflected in the books of accounts of the beneficiaries as their bank account.

9. **Extra Rupee Liability:** (1) Extra rupee liability towards interest payment and loan repayment corresponding to the normative foreign debt or actual foreign debt, as the case may be, in the relevant year shall be permissible provided it directly arises out of Foreign Exchange Rate Variation and is not attributable to the generating company or the transmission licensee or its suppliers or contractors. Every generating company and the transmission licensee shall recover Foreign Exchange Rate Variation on a year to year basis as income or expense in the period in which it arises and Foreign Exchange Rate Variation shall be adjusted on a year to year basis.

10. **Recovery of Income-tax and Foreign Exchange Rate Variation:** Recovery of Income-tax and Foreign Exchange Rate Variation shall be done directly by the generating company or the transmission licensee, as the case may be, from the beneficiaries without making any application before the Commission.

Provided that in case of any objections by the beneficiaries to the amounts claimed on account of income-tax 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.

11. **Deviation from norms:** (1) Tariff for sale of electricity by a generating company may also be determined in deviation of the norms specified in these regulations subject to the conditions that:

> (a) The overall per unit tariff of electricity over the entire life of the asset, calculated on the basis of the norms in deviation does not exceed the per unit tariff calculated on the basis of the norms specified in these regulations; and
>
> (b) Any such deviation shall come into effect only after approval by the Commission.

(2) In case of the existing generating stations, TPS-I and TPS-II (Stage I & II) of Neyveli Lignite Corporation Ltd, whose tariff was initially determined by following Net Fixed Assets approach based on mutual agreement between Neyveli Lignite Corporation Ltd and the beneficiaries, tariff shall continue to be determined by adopting Net Fixed Assets approach.

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

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

CHAPTER 2

THERMAL POWER GENERATING STATIONS

14. **Definitions:** Unless the context otherwise requires, for the purpose of this chapter, :-

(i) **'Act'** means the Electricity Act, 2003;

(ii) **`Additional Capitalisation'** means the capital expenditure actually incurred after the date of commercial operation of the generating station and admitted by the Commission after prudence check subject to provisions of regulation 18;

(iii) **'Authority** ' means Central Electricity Authority referred to in Section 70 of the Act;

(iv) **'Auxiliary Energy Consumption' or 'AUX'** in relation to a period means the quantum of energy consumed by auxiliary equipment of the generating station and transformer losses within the generating station, and shall be expressed as a percentage of the sum of gross energy generated at the generator terminals of all the units of the generating station;

(v) **'Availability'** in relation to a thermal generating station for any period means the average of the daily average declared capacities (DCs) for all the days during that period expressed as a percentage of the installed capacity of the generating station minus normative auxiliary consumption in MW, and shall be computed in accordance with the following formula:

$$\textbf{Availability} = 10000 \times \sum_{i=1}^{N} DC_i \Big/ \left\{ N \times IC \times \left(100 - AUX_n\right) \right\} \%$$

where,
IC = Installed Capacity of the generating station in MW,

DC_i = Average declared capacity for the i^{th} day of the period in MW,

N = Number of days during the period, and

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

(vi) **'Beneficiary'** in relation to a generating station means the person buying power generated at such a generating station on payment of Annual Fixed Charges;

(vii) ‘**Block**’ in relation to a combined cycle thermal generating station includes combustion turbine – generator(s), associated waste heat recovery boiler(s), connected steam turbine – generator and auxiliaries;

(viii) **'Commission'** means the Central Electricity Regulatory Commission referred to in Section 76 of the Act;

(ix) **‘Cut off Date’** means the date of first financial year closing after one year of the date of commercial operation of the generating station;

(x) **‘Date of Commercial Operation’ or ‘COD**’ in relation to a unit means the date declared by the generator after demonstrating the Maximum Continuous Rating (MCR) or Installed Capacity (IC) through a successful trial run after notice to the beneficiaries and in relation to the generating station the date of commercial operation means the date of commercial operation of the last unit or block of the generating station;

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

Note

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

(xii) **`Existing Generating Station'** means a generating station declared under commercial operation from a date prior to 1.4.2004;

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

(xiv) ‘**Gross Station Heat Rate’ or ‘GHR’** means the heat energy input in kCal required to generate one kWh of electrical energy at generator terminals;

(xv) **‘Infirm Power’** means electricity generated prior to commercial operation of the unit of a generating station;

(xvi) ‘**Installed Capacity' or 'IC**’ means the summation of the name plate capacities of all the units of the generating station or the capacity of the generating station (reckoned at the generator terminals) as approved by the Commission from time to time;

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

(xviii) **'Operation and Maintenance Expenses' or 'O&M Expenses'** means the expenditure incurred on operation and maintenance of the generating station, including part thereof, and includes the expenditure on manpower, repairs, spares, consumables, insurance and overheads;

(xix) **`Original Project Cost'** means the actual expenditure incurred by the generating company, as per the original scope of the project up to the first financial year closing after one year of the date of commercial operation of the last unit as admitted by the Commission for determination of tariff;

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

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

where,

IC = Installed Capacity of the generating station in MW,

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

N = Number of time blocks during the period, and

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

(xxi) **'Project'** means a generating station;

(xxii) **`Scheduled Generation' or 'SG'** at any time or for any period or time block means schedule of generation in MW ex-bus given by the Regional Load Despatch Centre;

Note

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

(xxiii) **`Small Gas Turbine Power Generating Station'** means and includes gas turbine/combined cycle generating stations with gas turbines in the capacity range of 50 MW or below;

(xxiv) '**Unit'** in relation to a thermal power generating station means steam generator, turbine-generator and auxiliaries, or in relation to a combined cycle thermal power generating station, means turbine-generator and auxiliaries; and

(xxv) **'Year'** means a financial year.

15. **<u>Components of Tariff</u>**: (1) Tariff for sale of electricity from a thermal power generating station shall comprise of two parts, namely, the recovery of annual capacity (fixed) charges and energy (variable) charges.

(2) The annual capacity (fixed) charges shall consist of:

(a) Interest on loan capital;

(b) Depreciation, including Advance Against Depreciation;

(c) Return on equity;

(d) Operation and maintenance expenses; and

(e) Interest on working capital.

(3) The energy (variable) charges shall cover fuel cost.

16. **<u>Norms of Operation</u>**: The norms of operation as given hereunder shall apply:

(i) <u>Target Availability for recovery of full Capacity (Fixed) charges</u>

(a) All thermal power generating stations, except those covered under clauses (b) and (c) below - 80%

(b) Thermal power generating stations of Neyveli Lignite Corporation Ltd (TPS-I, TPS-II, Stage I&II and TPS-I Expansion) and Talchar Thermal Power Station of National Thermal Power Corporation Ltd. - 75%

(c) Tanda Thermal Power Station of National Thermal Power Corporation Ltd. - 60%

Note

Recovery of capacity (fixed) charges below the level of target availability shall be on *pro rata* basis. At zero availability, no capacity charges shall be payable.

(ii) <u>Target Plant Load Factor for Incentive</u>

(a) All thermal power generating stations, except those covered under clauses (b) and (c) below - 80%

(b) Thermal power generating stations of Neyveli Lignite Corporation Ltd (TPS-I, TPS-II, Stage I&II and TPS I Expansion) and Talcher Thermal Power Station of National Thermal Power Corporation Ltd. - 75%

(c) Tanda Thermal Power Station of National Thermal Power Corporation Ltd. - 60%

(iii) <u>Gross Station Heat Rate</u>

(a) Coal-based thermal power generating stations, other than those covered under clauses (b) and (c) below

	200/210/250 MW sets	**500 MW and above sets**
During stabilization period	2600 KCal/kWh	2550 KCal/kWh
Subsequent period	2500 KCal/kWh	2450 KCal/kWh

Note 1

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

Note 2

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

(b) Talcher Thermal Power Station 3100 kCal/kWh

(c) Tanda Thermal Power Station 3000 kCal/kWh

(d) Lignite-fired thermal power generating stations

(1) For lignite-fired generating stations except for TPS-I and TPS-II (Stage I & II) of Neyveli Lignite Corporation Ltd, the gross station heat rates specified under clause (a) above for coal-based thermal power generating stations shall be corrected, using multiplying factors as given below:

(i) For lignite having 50% moisture: Multiplying factor of 1.10

(ii) For lignite having 40% moisture: Multiplying factor of 1.07

(iii) For lignite having 30% moisture: Multiplying factor of 1.04

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

(2) TPS-I and TPS-II (Stage I & II) of Neveli Lignite Corporation Ltd

TPS-I 3900 kCal/kWh
TPS-II 2850 kCal/kWh

(e) Gas Turbine/Combined Cycle generating stations

(i) Existing generating stations owned by National Thermal Power Corporation Ltd

Name of Generating station	Combined cycle (kCal/kWh)	Open cycle (kCal/kWh)
Gandhar GPS	2000	2900
Kawas GPS	2075	3010
Anta GPS	2075	3010
Dadri GPS	2075	3010
Auraiya GPS	2100	3045
Faridabad GPS	2000	2900
Kayamkulam GPS	2000	2900

(ii) Generating stations declared under commercial operation on or after 1.4.2004

	Advanced Class	
E/EA/EC/E2 Class Machines		**Machines**

Open cycle -	2685 kCal/kWh	2830 kCal/kWh
Combined cycle -	1850 kCal/kWh	1950 kCal/kWh

(iii) Small Gas Turbine Power Generating Stations:

(a) Assam Gas Based Power Station, Kathalguri:

Open Cycle	--	3225 kCal/kWh
Combined Cycle	--	2250 kCal/kWh

(b) Agartala Gas Based Power Station, Ramachandranagar:

Open Cycle	--	3580 kCal/kWh

(c) Other than (a) and (b) above:

	With Natural Gas	With Liquid Fuel
Open Cycle	3125 kCal/kWh	1.02 x 3125 kCal/kWh
Combined Cycle	2030 kCal/kWh	1.02 x 2030 kCal/kWh

(iv) <u>Secondary fuel oil consumption</u>

(a) Coal-based generating stations:

(i) All coal-based thermal power generating stations except those covered under sub-clauses (ii) and (iii) below

During Stabilization period	Subsequent period
4.5 ml/kWh	2.0 ml/kWh

(ii)Talcher Thermal Power Station	3.5 ml/kWh
(iii) Tanda Thermal Power Station	3.5 ml/kWh

(b) Lignite-fired generating stations:

During Stabilization period	Subsequent period
5.0 ml/kWh	3.0 ml/kWh

(v) <u>Auxiliary Energy Consumption</u>

(a) Coal-based generating stations:

	With cooling tower	Without cooling tower
(i) 200 MW series	9.0%	8.5%
(ii) 500 MW series		
Steam driven boiler feed pumps	7.5%	7.0%
Electrically driven boiler feed pumps	9.0%	8.5%
(iii) Talcher Thermal Power Station	11.0%	
(iv) Tanda Thermal Power Station	11.0%	

(b) Gas Turbine/Combined Cycle generating stations:

(i)	Combined cycle	3.0%
(ii)	Open cycle	1.0%

(c) Lignite-fired thermal power generating stations:

(i) All generating stations, except TPS-I and TPS-II (Stage I & II) of Neyveli Lignite Corporation Ltd:

The auxiliary energy consumption norms shall be 0.5 percentage point more than the above auxiliary energy consumption norms of coal-based generating stations at (v) (a) (i) & (ii) above.

(ii) TPS-I & TPS-II Stage-I&II of Neyveli Lignite Corporation Ltd.:

TPS-I	12.0%
TPS-II	10.0%

Note

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

(vi) <u>Stabilization period</u>

In relation to a unit, stabilization period shall be reckoned commencing from the date of commercial operation of that unit as follows, namely:

(a) Coal-based and lignite-fired generating stations	-	180 days
(b) Gas turbine/combined cycle generating stations	-	90 days

Note

The stabilization period and relaxed norms applicable during the stabilization period shall cease to apply from 1.4.2006.

17. **<u>Capital Cost:</u>** Subject to prudence check by the Commission, the actual expenditure incurred on completion of the project shall form the basis for determination of final tariff. The final tariff shall be determined based on the admitted capital expenditure actually incurred up to the date of commercial operation of the generating station and shall include capitalised initial spares subject to following ceiling norms as a percentage of the original project cost as on the cut off date:

(i)	Coal-based/lignite-fired generating stations	-	2.5%
(ii)	Gas Turbine/Combined Cycle generating stations	-	4.0%

Provided that where the power purchase agreement entered into between the generating company and the beneficiaries provides a ceiling of actual expenditure, the capital expenditure shall not exceed such ceiling for determination of tariff;

Provided further that in case of the existing generating stations, the capital cost admitted by the Commission prior to 1.4.2004 shall form the basis for determination of tariff.

Note

Scrutiny of the project cost estimates by the Commission shall be limited to the reasonableness of the capital cost, financing plan, interest during construction, use of efficient technology, and such other matters for determination of tariff.

18. **<u>Additional capitalisation:</u>** (1) The following capital expenditure within the original scope of work actually incurred after the date of commercial operation and up to the cut off date may be admitted by the Commission, subject to prudence check:

(i) Deferred liabilities;

(ii) Works deferred for execution;

(iii) Procurement of initial capital spares in the original scope of work, subject to ceiling specified in regulation 17;

(iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court; and

(v) On account of change in law.

Provided that original scope of work along with estimates of expenditure shall be submitted along with the application for provisional tariff.

Provided further that a list of the deferred liabilities and works deferred for execution shall be submitted along with the application for final tariff after the date of commercial operation of the generating station.

(2) Subject to the provisions of clause (3) of this regulation, the capital expenditure of the following nature actually incurred after the cut off date may be admitted by the Commission, subject to prudence check:

(i) Deferred liabilities relating to works/services within the original scope of work;

(ii) Liabilities to meet award of arbitration or for compliance of the order or decree of a court;

(iii) On account of change in law;

(iv) Any additional works/services which have become necessary for efficient and successful operation of the generating station, but not included in the original project cost; and

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

(3) Any expenditure on minor items/assets like normal tools and tackles, personal computers, furniture, air-conditioners, voltage stabilizers, refrigerators, fans, coolers, TV, washing machines, heat-convectors, carpets, mattresses etc. brought after the cut off date shall not be considered for additional capitalisation for determination of tariff with effect from 1.4.2004.

Note

The list of items is illustrative and not exhaustive.

(4) Impact of additional capitalisation in tariff revision may be considered by the Commission twice in a tariff period, including revision of tariff after the cut off date.

Note 1

Any expenditure admitted on account of committed liabilities within the original scope of work and the expenditure deferred on techno-economic grounds but falling within the original scope of work shall be serviced in the normative debt-equity ratio specified in regulation 20.

Note 2

Any expenditure on replacement of old assets shall be considered after writing off the gross value of the original assets from the original project cost, except such items as are listed in clause (3) of this regulation.

Note 3

Any expenditure admitted by the Commission for determination of tariff on account of new works not in the original scope of work shall be serviced in the normative debt-equity ratio specified in regulation 20.

Note 4

Any expenditure admitted by the Commission for determination of tariff on renovation and modernization and life extension shall be serviced on normative debt-equity ratio specified in regulation 20 after writing off the original amount of the replaced assets from the original project cost.

19. **Sale of Infirm Power:** Any revenue (other than the recovery of fuel cost) earned by the generating company from sale of infirm power, shall be taken as reduction in capital cost and shall not be treated as revenue.

20. **Debt-Equity Ratio:** (1) In case of all generating stations, debt–equity ratio as on the date of commercial operation shall be 70:30 for determination of tariff. Where equity employed is more than 30%, the amount of equity for determination of tariff shall be limited to 30% and the balance amount shall be considered as the normative loan.

Provided that in case of a generating station where actual equity employed is less than 30%, the actual debt and equity shall be considered for determination of tariff.

(2) The debt and equity amount arrived at in accordance with clause (1) shall be used for calculating interest on loan, return on equity, Advance Against Depreciation and Foreign Exchange Rate Variation.

21. **Computation of Capacity (Fixed) Charges**: (1) The capacity charges shall be computed on the following basis and their recovery shall be related to target availability.

(i) **Interest on loan capital**

(a) Interest on loan capital shall be computed loan wise on the loans arrived at in the manner indicated in regulation 20.

(b) The loan outstanding as on 1.4.2004 shall be worked out as the gross loan as per regulation 20 minus cumulative repayment as admitted by the Commission up to 31.3.2004. The repayment for the period 2004-09 shall be worked out on a normative basis.

(c) The generating company shall make every effort to swap the loan as long as it results in net benefit to the beneficiaries. The costs associated with such swapping shall be borne by the beneficiaries.

(d) The changes to the loan terms and conditions shall be reflected from the date of such swapping and benefit passed on to the beneficiaries.

(e) In case of any dispute, any of the parties may approach the Commission with proper application. However, the beneficiaries shall not withhold any payment as ordered by the Commission to the generating company during pendency of any dispute relating to swapping of loan.

(f) In case any moratorium period is availed of by the generating company, depreciation provided for in the tariff during the years of moratorium shall be treated as repayment during those years and interest on loan capital shall be calculated accordingly.

(g) The generating company shall not make any profit on account of swapping of loan and interest on loan.

(ii) **Depreciation, including Advance Against Depreciation**

(a) **Depreciation**

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

(i) The value base for the purpose of depreciation shall be the historical cost of the asset;

(ii) Depreciation shall be calculated annually, based on straight line method over the useful life of the asset and at the rates prescribed in Appendix II to these regulations.

The residual life of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the historical capital cost of the asset. Land is not a depreciable asset and its cost shall be excluded from the capital cost while computing 90% of the historical cost of the asset. The historical capital cost of the asset shall include additional capitalisation on account of Foreign Exchange Rate Variation up to 31.3.2004 already allowed by the Central Government /Commission.

(iii) On repayment of entire loan, the remaining depreciable value shall be spread over the balance useful life of the asset.

(iv) Depreciation shall be chargeable from the first year of operation. In case of operation of the asset for part of the year, depreciation shall be charged on *pro rata* basis.

(b) **Advance Against Depreciation**

In addition to allowable depreciation, the generating company shall be entitled to Advance Against Depreciation, computed in the manner given hereunder:

AAD = Loan repayment amount as per regulation 21 (i) subject to a ceiling of $1/10^{th}$ of loan amount as per regulation 20 minus depreciation as per schedule

Provided that Advance Against Depreciation shall be permitted only if the cumulative repayment up to a particular year exceeds the cumulative depreciation up to that year;

Provided further that Advance Against Depreciation in a year shall be restricted to the extent of difference between cumulative repayment and cumulative depreciation up to that year.

(iii) **Return on Equity**:

Return on equity shall be computed on the equity base determined in accordance with regulation 20 @ 14% per annum.

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

Explanation

The premium raised by the generating company while issuing share capital and investment of internal resources created out of free reserve of the generating company, if any, for the funding of the project, shall also be reckoned as paid up capital for the purpose of computing return on equity, provided such premium amount and internal resources are actually utilised for meeting the capital expenditure of the generating station and forms part of the approved financial package.

(iv) **Operation and Maintenance expenses**

Normative operation and maintenance expenses shall be as follows, namely:

(a) Coal-based generating stations except Talcher Thermal Power Station and Tanda Thermal Power Station of National Thermal Power Corporation Ltd

(Rs. in lakh/MW)

Year	200/210/250 MW sets	500 MW and above sets
2004-05	10.40	9.36
2005-06	10.82	9.73
2006-07	11.25	10.12
2007-08	11.70	10.52
2008-09	12.17	10.95

Note

For the generating stations having combination of 200/210/250 MW sets and 500 MW and above set, the weighted average value for operation and maintenance expenses shall be adopted.

(b) (i) Talcher Thermal Power Station

The base operation and maintenance expenses including insurance, for the year 2000-01 shall be derived by averaging the actual operation and maintenance expenses for the years 1998-99 to 2002-03 based on the audited balance sheets and by excluding abnormal operation and maintenance expenses, if any, after a prudence check by the Commission.

The average of such normalised operation and maintenance expenses, after prudence check, for the years 1998-99 to 2002-03 considered as operation and maintenance expenses for the year 2000-01 shall be escalated at the rate of 4% per annum to arrive at operation and maintenance expenses for the base year 2003-04.

The operation and maintenance expenses for the base year 2003-04 shall be escalated further at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant year of tariff period.

(ii) Tanda Thermal Power Station

The base operation and maintenance expenses including insurance, for the year 2001-02 shall be derived by averaging the actual operation and maintenance expenses for the years 2000-01 to 2002-03 based on the audited balance sheets and by excluding abnormal operation and maintenance expenses, if any, after a prudence check by the Commission.

The average of such normalised operation and maintenance expenses, after prudence check, for the years 2000-01 to 2002-03 considered as operation and maintenance expenses for the year 2001-02 shall be escalated at the rate of 4% per annum to arrive at operation and maintenance expenses for the base year 2003-04.

The operation and maintenance expenses for the base year 2003-04 shall be escalated further at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant year of tariff period.

(c) Gas Turbine/Combined Cycle generating stations

(Rs. in lakh/MW)

Year	Gas Turbine/Combined Cycle generating stations other than small gas turbine power generating stations		Small gas turbine power generating stations
	With warranty spares of 10 years	Without warranty spares	Without warranty spares
2004-05	5.20	7.80	9.46
2005-06	5.41	8.11	9.84
2006-07	5.62	8.44	10.24
2007-08	5.85	8.77	10.65
2008-09	6.08	9.12	11.07

(d) Lignite-fired generating stations

(Rs. in lakh/MW)

Year	200/210/250 MW series	TPS-I of NLC
2004-05	10.40	15.20
2005-06	10.82	15.81
2006-07	11.25	16.44
2007-08	11.70	17.10
2008-09	12.17	17.78

(v) **<u>Interest on Working Capital</u>**

(a) Working capital shall cover:

<u>Coal based/Lignite-fired generating stations</u>

(i) Cost of coal or lignite for 1½ months for pit-head generating stations and two months for non-pit-head generating stations, corresponding to the target availability;

(ii) Cost of secondary fuel oil for two months corresponding to the target availability;

(iii) Operation and Maintenance expenses for one month;

(iv) Maintenance spares @ 1% of the historical cost escalated @ 6% per annum from the date of commercial operation; and

(v) Receivables equivalent to two months of fixed and variable charges for sale of electricity calculated on the target availability.

<u>Gas Turbine/Combined Cycle generating stations</u>

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

(ii) Liquid fuel stock for ½ month;

(iii) Operation and maintenance expenses for one month;

(iv) Maintenance spares at 1% of the historical cost escalated @ 6% per annum from the date of commercial operation ; and

(v) Receivables equivalent to two months of fixed and variable charges for sale of electricity calculated on target availability.

(b) Rate of interest on working capital shall be on normative basis and shall be equal to the short-term Prime Lending Rate of State Bank of India as on 1.4.2004 or on 1st April of the year in which the generating station or a unit thereof is declared under commercial operation, whichever is later. Interest on working capital shall be payable on normative basis notwithstanding that the generating company has not taken working capital loan from any outside agency.

(2) Full capacity charges shall be recoverable at target availability specified in regulation 16. Recovery of capacity (fixed) charges below the level of target availability shall be on *pro rata* basis. At zero availability, no capacity charges shall be payable.

(3) The payment of capacity charges shall be on monthly basis in proportion to the allocated capacity.

22. **Energy Charges:**

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

Energy (variable) Charges shall cover fuel costs and shall be worked out on the basis of ex-bus energy scheduled to be sent out from the generating station as per the following formula:

Energy Charges (Rs) = Rate of Energy Charges in Rs/kWh X Scheduled Energy (ex-bus) for the month in kWh corresponding to scheduled generation.

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

Energy (variable) charges shall cover fuel costs and shall be worked out on the basis of ex-bus energy delivered / sent out from the generating station as per the following formula:

Energy Charges (Rs) = Rate of Energy Charges in Rs/kWh X Energy delivered (ex-bus) for the month in kWh

Where,

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

$$\text{REC} = \frac{100\left\{P_p \text{ x } (Q_p)_n + P_s \text{ x } (Q_s)_n\right\}}{(100-(AUX_n))} \quad \text{(Rs/kWh)}$$

Where,

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

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

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

$(Q_s)_n$ = Normative Quantity of Secondary fuel oil in ml/kWh as per clause 16 (iv), as the case may be, and

AUX_n= Normative Auxiliary Energy Consumption as % of gross generation as per clause 16 (v), as the case may be.

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

Initially, Gross Calorific Value of coal/lignite or gas or liquid fuel shall be taken as per actuals of the preceding three months. Any variation shall be adjusted on month to month basis on the basis of Gross Calorific Value of coal/lignite or gas or liquid fuel received and burnt and landed cost incurred by the generating company for procurement of coal/lignite, oil, or gas or liquid fuel, as the case may be. No separate petition need to be filed with the Commission for fuel price adjustment. In case of any dispute, an appropriate application in accordance with Central Electricity Regulatory Commission (Conduct of Business Regulations), 1999, as amended from time to time or any statutory re-enactment thereof, shall be made before the Commission.

(iv) **<u>Landed Cost of Coal</u>**

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

Pit head generating stations	:	0.3%
Non-Pit head generating stations	:	0.8%

23. **<u>Incentive</u>**: Incentive shall be payable at a flat rate of 25.0 paise/kWh for ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to target Plant Load Factor.

24. **<u>Unscheduled Interchange(UI) Charges</u>**: (1) Variation between actual generation or actual drawal and scheduled generation or scheduled drawal shall be accounted for through Unscheduled Interchange (UI) Charges. UI for a generating station shall be equal to its actual generation minus its scheduled generation. UI for a beneficiary shall be equal to its total actual drawal minus its total scheduled drawal. UI shall be worked out for each 15 minute time block. Charges for all UI transactions shall be based on average frequency of the time block and the following rates shall apply with effect from 1.4.2004 :

Average Frequency of time block	UI Rate (Paise per kWh)
50.5 Hz and above	0.0
Below 50.5 Hz and up to 50.48 Hz	8.0
Below 49.04 Hz and up to 49.02 Hz	592.0
Below 49.02 Hz	600.0
Between 50.5 Hz and 49.02 Hz	linear in 0.02 Hz step

(Each 0.02 Hz step is equivalent to 8.0 paise /kWh within the above range.)

Note
The above average frequency range and UI rates are subject to change through a separate notification by the Commission.

(2) (i) Any generation up to 105% of the declared capacity in any time block of 15 minutes and averaging up to 101% of the average declared capacity over a day shall not be construed as gaming, and the generator shall be entitled to UI charges for such excess generation above the scheduled generation (SG).

(ii) For any generation beyond the prescribed limits, the Regional Load Despatch Centre shall investigate so as to ensure that there is no gaming, and if gaming is found by the Regional Load Despatch Centre, the corresponding UI charges due to the generating station on account of such extra generation shall be reduced to zero and the amount shall be adjusted in UI account of beneficiaries in the ratio of their capacity share in the generating station.

25. **Rebate**: For payment of bills of capacity charges and energy charges through a letter of credit on presentation, a rebate of 2% shall be allowed. If the payments are made by a mode other than through a letter of credit but within a period of one month of presentation of bills by the generating company, a rebate of 1% shall be allowed.

26. **Late Payment Surcharge**: In case the payment of bills of capacity charges and energy charges by the beneficiary (ies) is delayed beyond a period of 1 month from the date of billing, a late payment surcharge at the rate of 1.25% per month shall be levied by the generating company.

27. **Scheduling**: Read with the provisions of the Indian Electricity Grid Code, the methodology of scheduling and calculating availability shall be as under:

(i) The generator shall make an advance declaration of capability of its generating station. The declaration shall be for that capability which can be actually made available.

The declaration shall be for the capability of the generating station to deliver ex-bus MW for the next day either as one figure for the whole day or as different figures for different periods of the day. The capability as declared by the generator, also referred to as the declared capacity, shall form the basis of generation scheduling.

(ii) While making or revising its declaration of capability, the generator shall ensure that the declared capability during peak hours is not less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronisation of units as a result of forced outage of units.

(iii) Generation scheduling shall be done in accordance with the operating procedure stipulated in the Indian Electricity Grid Code.

(iv) Based on the declaration of the generator, the Regional Load Despatch Centre shall communicate their shares to the beneficiaries out of which they shall give their requisitions.

(v) Based on the requisitions given by the beneficiaries and taking into account technical limitations on varying the generation and also taking into account transmission system constraints, if any, the Regional Load Despatch Centre shall prepare the economically optimal generation schedules and drawal schedules and communicate the same to the generator and the beneficiaries.

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

(vi) The scheduled generation and actual generation shall be ex-bus at the generating station. For beneficiaries, the scheduled and actual net drawals shall be at their respective receiving points.

(vii) For calculating the net drawal schedules of beneficiaries, the transmission losses shall be apportioned to their drawal schedules for the time being.

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

(viii) In case of forced outage of a unit, the Regional Load Despatch Centre shall revise the schedules on the basis of revised declared capability. The revised declared capability and the revised schedules shall become effective from the 4th time block, counting the time block in which the revision is advised by the generator to be the first one.

(ix) In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, associated switchyard and sub- stations owned by the Central Transmission Utility or any other transmission licensee involved in inter-state transmission (as certified by the Regional Load Despatch Centre) necessitating reduction in generation, the Regional Load Despatch Centre shall revise the schedules which shall become effective from the 4th time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. Also, during the first, second and third time blocks of such an event, the scheduled generation of the generating station shall be deemed to have been revised to be equal to actual generation, and the scheduled drawals of the beneficiaries shall be deemed to have been revised to be equal to their actual drawals.

(x) In case of any grid disturbance, scheduled generation of all the generating stations and scheduled drawal of all the beneficiaries shall be deemed to have been revised to be equal to their actual generation/drawal for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the Regional Load Despatch Centre.

(xi) Revision of declared capability by the generator(s) and requisition by beneficiary(ies) for the remaining period of the day shall also be permitted with advance notice. Revised schedules/declared capability in such cases shall become effective from the 6th time block, counting the time block in which the request for revision has been received in the Regional Load Despatch Centre to be the first one.

(xii) If, at any point of time, the Regional Load Despatch Centre observes that there is need for revision of the schedules in the interest of better system operation, it may do so on its own, and in such cases, the revised schedules shall become effective from the 4th time block, counting the time block in which the revised schedule is issued by the Regional Load Despatch Centre to be the first one.

(xiii) Generation schedules and drawal schedules issued/revised by the Regional Load Despatch Centre shall become effective from designated time block irrespective of communication success.

(xiv) For any revision of scheduled generation, including post facto deemed revision, there shall be a corresponding revision of scheduled drawals of the beneficiaries.

(xv) A procedure for recording the communication regarding changes to schedules duly taking into account the time factor shall be evolved by the Central Transmission Utility.

Note

In case of a generating station, contracting to supply power only to the State in which it is located, the scheduling, metering and energy accounting shall be carried out by the respective State Load Despatch Centre.

28. **Demonstration of Declared Capability**: (1) The generating company may be required to demonstrate the declared capability of its generating station as and when asked by the Regional Load Despatch Centre of the region in which the generating station is situated. In the event of the generating company failing to demonstrate the declared capability, the capacity charges due to the generator shall be reduced as a measure of penalty.

(2) The quantum of penalty for the first mis-declaration for any duration/block in a day shall be the charges corresponding to two days fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in the geometrical progression.

(3) The operating log books of the generating station shall be available for review by the Regional Electricity Board or Regional Power Committee, as the case may be. These books shall keep record of machine operation and maintenance.

29. **Metering and Accounting**: Metering arrangements, including installation, testing and operation and maintenance of meters and collection, transportation and processing of data required for accounting of energy exchanges and average frequency on 15 minute time block basis shall be organised by the Central Transmission Utility/Regional Load Despatch Centres. All concerned entities (in whose premises the special energy meters are installed), shall fully cooperate with the Central Transmission Utility/Regional Load Despatch Centre and extend the necessary assistance by taking weekly meter readings and transmitting them to the Regional Load Despatch Centre. Processed data of meters along with data relating to declared capability and schedules etc., shall be supplied by the Regional Load Despatch Centres to the Regional Power Committee or the Regional Electricity Board and the Regional Power Committee or the Regional Electricity Board shall issue the Regional Accounts for energy on monthly basis as well as UI charges on weekly basis. UI accounting procedures shall be governed by the orders of the Commission.

Note

In case of a generating station, contracting to supply power only to the State in which it is located, the scheduling, metering and energy accounting shall be carried out by the respective State Load Despatch Centre.

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

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

Note 1

Allocation of total capacity of central sector generating stations is made by Central Government from time to time which also has an unallocated portion. Allocation of the unallocated portion as made by the Central Government from time to time, for the total unallocated capacity shall be notified by the Member Secretary, Regional Electricity Board/Regional Power Committee in advance, at least 3 days prior to such change in allocation taking effect. The total capacity share of any beneficiaries would be sum of its capacity share plus allocation out of the unallocated portion. In the absence of no specific distribution 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 share to other States within/outside the region. In such cases, depending upon the technical feasibility of power transfer and specific agreements reached by the generating company with other States within/outside the region for such transfers, the shares of the beneficiaries may be re-allocated by the Central Government for a specific period. 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 fixed charges as per allocated capacity shares. Any such reallocation shall be notified by the Member Secretary, Regional Electricity Board/Regional Power Committee in advance, at least 3 days prior to such reallocation taking effect.

(ii) The beneficiaries shall have full freedom for negotiating any transaction for utilisation of their capacity shares. In such cases, the beneficiary having allocation in the capacity of the generating station shall be liable for full payment of capacity charges and energy charges (including that for sale of power under the transaction negotiated by him) corresponding to his total allocation and schedule respectively.

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

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

(iv) The capacity charges shall be paid by the beneficiary(ies) including those outside the region to the generating company every month in accordance with the following formulas:

(a) <u>Total Capacity charges payable to the thermal power generating company for the</u>:

1^{st} month = (1xACC1)/12
2^{nd} month = (2XACC2 - 1XACC1)/12
3^{rd} month = (3xACC3 - 2XACC2)/12
4^{th} month = (4xACC4 - 3xACC3)/12

5^{th} month = (5XACC5 - 4xACC4)/12
6^{th} month = (6XACC5 - 5xACC5)/12
7^{th} month = (7XACC7 - 6xACC6)/12
8^{th} month = (8xACC8 - 7xACC7)/12
9^{th} month = (9xACC9 - 8xACC8)/12
10^{th} month = (10xACC10 – 9xACC9)/12
11^{th} month = (11xACC11 - 10xACC10)/12
12^{th} month = (12xACC12 - 11xACC11)/12

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

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

Where,

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

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

CHAPTER 3

HYDRO POWER GENERATING STATIONS

31. **Definitions:** Unless the context otherwise requires for the purpose of this chapter, :-

(i) **'Act'** means the Electricity Act, 2003;

(ii) **`Additional Capitalisation'** means the capital expenditure actually incurred after the date of commercial operation of the station and admitted by the Commission after prudence check subject to provisions of regulation 34;

(iii) **'Authority** ' means Central Electricity Authority referred to in Section 70 of the Act;

(iv) '**Auxiliary Energy Consumption'** in relation to a period means the quantum of energy consumed by auxiliary equipment of the generating station, and shall be expressed as a percentage of the sum of gross energy generated at generator terminals of all the units of the generating station;

(v) **'Beneficiary'** in relation to a generating station means the person buying power generated at such a generating station on payment of annual capacity charges;

(vi) **'Capacity Index**' means the average of the daily capacity indices over one year;

(vii) **'Commission'** means the Central Electricity Regulatory Commission referred to in Section 76 of the Act;

(viii) **'Cut off Date'** means after one year of the date of commercial operation of the generating station;

(ix) **'Date of Commercial Operation' or 'COD**' in relation to a unit means the date declared by the generator after demonstrating the Maximum Continuous Rating (MCR) or Installed Capacity (IC) through a successful trial run, after notice to the beneficiaries, and in relation to the generating station the date of commercial operation means the date of commercial operation of the last unit of the generating station;

(x) **'Daily Capacity Index'** means the declared capacity expressed as a percentage of the maximum available capacity for the day and shall be mathematically expressed as hereunder:

$$\text{Daily Capacity Index} = \frac{\text{Declared Capacity (MW)}}{\text{Maximum Available Capacity (MW)}} \times 100$$

Daily capacity index shall be limited to 100%.

(xi) ‘**Declared Capacity'** or **'DC'**

(a) For run-of-river power station with pondage and storage-type power stations, declared capacity means the ex-bus capacity in MW expected to be available from the generating station over the peaking hours of next day, as declared by the generator, taking into account the availability of water, optimum use of water and availability of machines and for this purpose, the peaking hours shall not be less than 3 hours within 24 hour period, and

(b) In case of purely run-of–river power stations, declared capacity means the ex-bus capacity in MW expected to be available from the generating station during the next day, as declared by the generating station, taking into account the availability of water, optimum use of water and availability of machines;

(xii) **‘Deemed Generation '** means the energy which a generating station was capable of generating but could not generate due to the conditions of grid or power system, beyond the control of generating station resulting in spillage of water;

(xiii) **'Design Energy'** means the quantum of energy which could be generated in a 90% dependable year with 95% installed capacity of the generating station;

(xiv) **`Existing Generating Station'** means a generating station declared under commercial operation from a date prior to 1.4.2004;

(xv) **‘Infirm Power’** means electricity generated prior to commercial operation of the unit of a generating station;

(xvi) ‘**Installed Capacity' or 'IC**’ means the summation of the name plate capacities of the units in the generating station or the capacity of the generating station (reckoned at the generator terminals) as approved by the Commission from time to time;

(xvii) **'Maximum Available Capacity'** means the following:

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

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

Explanation

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

(b) Purely run-of-river power stations

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

(xviii) **'Operation and Maintenance Expenses' or `O&M Expenses**' means the expenditure incurred in operation and maintenance of the generating station, including part thereof, including the expenditure on manpower, repairs, spares, consumables, insurance and overheads;

(xix) **`Original Project Cost'** means the actual expenditure incurred by the generating company, as per the original scope of project up to first financial year closing after one year of the date of commercial operation of the last unit as admitted by the Commission for determination of tariff;

(xx) **'Primary Energy '** means the quantum of energy generated up to the design energy on per year basis at the generating station;

(xxi) **'Project '** means a generating station and includes the complete hydro power generating facility covering all components such as dam, intake, water conductor system, power generating station and generating units of the scheme as apportioned to power generation;

(xxii) **'Run-of-river power station'** means a hydro electric power generating station which has no upstream pondage;

(xxiii) ' **Run –of-river power station with pondage'** means a hydro electric power generating station with sufficient pondage for meeting the diurnal variation of power demand;

(xiv) **' Storage Type power station'** means a hydro electric power generating station associated with large storage capacity to enable variation of generation of power according to demand;

(xxv) **'Saleable Primary Energy'** means the quantum of primary energy available for sale (ex-bus) after allowing for 12% free energy to the home state;

(xxvi) **'Secondary Energy'** means the quantum of energy generated in excess of the design energy on per year basis at the generating station;

(xxvii) **'Saleable Secondary Energy'** means the quantum of secondary energy available for sale (ex-bus) after allowing for 12% free energy to the home state;

(xxviii) **'Scheduled Energy'** means the quantum of energy to be generated at the generating station over the 24-hour period, as scheduled by the Regional Load Despatch Centre;

(xxix) **'Year'** means a financial year.

32. **<u>Norms of Operation</u>:** The norms of operation shall be as under, namely:

(i) **<u>Normative capacity index for recovery of full capacity charges</u>**

(a) **<u>During first year of commercial operation of the generating station</u>**

(i) Purely Run-of-river power stations - 85%
(ii) Storage type and Run-of-river power stations with pondage - 80%

(b) **<u>After first year of commercial operation of the generating station</u>**

(i) Purely Run-of –river power stations - 90%

(ii) Storage type and Run-of-river power stations with pondage - 85%

Note

There shall be *pro rata* recovery of capacity charges in case the generating station achieves capacity index below the prescribed normative levels. At Zero capacity index, no capacity charges shall be payable to the generating station.

(ii) **<u>Auxiliary Energy Consumption</u> :**

(a) Surface hydro electric power generating stations with rotating exciters mounted on the generator shaft - 0.2% of energy generated

(b) Surface hydro electric power generating stations with static excitation system - 0.5% of energy generated

(c) Underground hydro electric power generating stations with rotating exciters mounted on the generator shaft - 0.4% of energy generated

(d) Underground hydro electric power generating stations with static excitation system - 0.7% of energy generated

(iii) **<u>Transformation losses</u>**

From generation voltage to transmission voltage - 0.5% of energy generated.

33. **<u>Capital Cost:</u>** Subject to prudence check by the Commission, the actual expenditure incurred on completion of the project shall form the basis for determination of final tariff. The final tariff shall be determined based on the admitted capital expenditure actually incurred up to the date of commercial operation of the generating station and shall include initial capital spares subject to a ceiling norm of 1.5% of the original project cost as on the cut off date.

Provided further that where the power purchase agreement entered into between the generating company and the beneficiaries provides a ceiling of actual expenditure, the capital expenditure shall not exceed such ceiling for determination of tariff.

In case of existing generating stations, the project cost admitted by the Commission prior to 1.4.2004 shall form the basis for determination of tariff.

Note

The scrutiny of the project cost estimates by the Commission shall be limited to the reasonableness of the capital cost, financing plan, interest during construction, use of efficient technology and such other matters for the purposes of determination of tariff.

34. **<u>Additional capitalisation:</u>** (1) The following capital expenditure within the original scope of work actually incurred after the date of commercial operation and up to the cut off date may be admitted by the Commission subject to prudence check.

(i) Deferred liabilities,

(ii) Works deferred for execution,

(iii) Procurement of initial capital spares in the original scope of works subject to ceiling specified in regulation 33,

(iv) Liabilities to meet award of arbitration or in compliance of the order or decree of a court, and

(iv) On account of change in law.

Provided that original scope of works along with estimates of expenditure shall be submitted along with the application for provisional tariff.

Provided further that a list of the deferred liabilities and works deferred for execution shall be submitted along with the application for final tariff after the date of commercial operation of generating station.

(2) Subject to the provision of clause (3) of this regulation, the capital expenditure of the following nature actually incurred after the cut off date may be admitted by the Commission subject to prudence check:

(i) Deferred liabilities relating to works/services within the original scope of work;

(ii) Liabilities to meet award of arbitration or in compliance of the order or decree of a court;

(iii) On account of change in law; and

(iv) Any additional works/service which has become necessary for efficient and successful operation of plant but not included in the original capital cost.

(3) Any expenditure incurred on acquiring minor items/assets like tools and tackles, personal computers, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, fans, T.V, washing machine, heat-convectors, mattresses, carpets, etc brought after the cut off date shall not be considered for additional capitalization for determination of tariff with effect from 1.4.2004.

Note

The list of items is illustrative and not exhaustive.

(4) Impact of additional capitalisation in tariff revision may be considered by the Commission twice in a tariff period, including revision of tariff after the cut off date.

Note 1

Any expenditure admitted on account of committed liabilities within the original scope of work and the expenditure deferred on techno-economic grounds but falling within the original scope of work shall be serviced in the normative debt-equity ratio specified in regulation 36.

Note 2

Any expenditure on replacement of old assets shall be considered after writing off the gross value of the original assets from the original capital cost, except such items as are listed in Clause (3) of this regulation.

Note 3

Any expenditure admitted by the Commission for determination of tariff on account of new works not in the original scope of work shall be serviced in the normative debt-equity ratio specified in regulation 36.

Note 4

Any expenditure admitted on renovation and modernization and life extension shall be serviced on normative debt-equity ratio specified in regulation 36 after writing off the original amount of the replaced assets from the original capital cost.

35. **Sale of Infirm Power:** Any revenue earned by the generating company from sale of infirm power, shall be taken as reduction in capital cost and shall not be treated as revenue. The rate for infirm power shall be same as the primary energy rate of the generating station.

36. **Debt-Equity Ratio**: (1) In case of all generating stations, debt–equity ratio as on the date of commercial operation shall be 70:30 for determination of tariff. Where equity employed is more than 30%, the amount of equity for determination of tariff shall be limited to 30% and the balance amount shall be considered as the normative loan.

Provided that in case actual equity employed is less than 30%, the actual debt and equity shall be considered for determination of tariff.

(2) The debt and equity amounts arrived at in accordance with clause (1) shall be used for calculating interest on loan, return on equity, Advance Against Depreciation and Foreign Exchange Rate Variation.

37. **Computation of Annual Charges**: The two-part tariff for sale of electricity from a hydro power generating station shall comprise of recovery of annual capacity charge and primary energy charges:

(i) **Capacity Charges**: The capacity charges shall be computed in accordance with the following formula:

Capacity Charges = (Annual Fixed Charge- Primary Energy Charge)

Note

Recovery through Primary energy charge shall not be more than Annual Fixed Charge.

(ii) **Annual Fixed Charges**: Annual Fixed Charges shall consist of:

(a) Interest on loan capital;

(b) Depreciation, including Advance Against Depreciation;

(c) Return on equity;

(d) Operation and maintenance expenses; and

(e) Interest on working capital.

38. **Computation of Annual Fixed Charges**: The annual fixed charges shall be computed on the following basis:

(i) **Interest on loan capital**

(a) Interest on loan capital shall be computed loan wise on the loans arrived at in the manner indicated in regulation 36.

(b) The loan outstanding as on 1.4.2004 shall be worked out as the gross loan as per regulation 36 minus cumulative repayment as admitted by the Commission up to 31.3.2004. The repayment for the period 2004-09 shall be worked out on a normative basis.

(c) The generating company shall make every effort to swap the loan as long as it results in net benefit to the beneficiaries. The costs associated with such swapping shall be borne by the beneficiaries.

(d) The changes to the loan terms and conditions shall be reflected from the date of such swapping and benefit passed on to the beneficiaries.

(e) In case of any dispute, any of the parties may approach the Commission with proper application. However, the beneficiaries shall not withhold any payment as ordered by the Commission to the generating company during pendency of any dispute relating to swapping of loan.

(f) In case any moratorium period is availed of by the generating company, depreciation provided for in the tariff during the years of moratorium shall be treated as repayment during those years and the interest on loan capital shall be calculated accordingly.

(g) The generating company shall not make any profit on account of swapping of loan and interest on loan.

(ii) **Depreciation, including Advance Against Depreciation**

(a) **Depreciation**

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

(i) The value base for the purpose of depreciation shall be the historical cost of the asset.

(ii) Depreciation shall be calculated annually based on straight line method over the useful life of the asset and at the rates prescribed in Appendix II to these regulations.

The residual life of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the historical capital cost of the asset. Land is not a depreciable asset and its cost shall be excluded from the capital cost while computing 90% of the historical cost of the asset. The historical capital cost of the asset shall include additional capitalisation on account of Foreign Exchange Rate Variation up to 31.3.2004 already allowed by the Central Government/Commission.

(iii) On repayment of entire loan, the remaining depreciable value shall be spread over the balance useful life of the asset.

(iv) Depreciation shall be chargeable from the first year of operation. In case of operation of the asset for part of the year, depreciation shall be charged on *pro rata* basis.

(b) **Advance Against Depreciation**

In addition to allowable depreciation, the generating company shall be entitled to Advance Against Depreciation, computed in the manner given hereunder:

AAD = Loan repayment amount as per regulation 38 (i) subject to a ceiling of 1/10th of loan amount as per regulation 36 minus depreciation as per schedule

Provided that Advance Against Depreciation shall be permitted only if the cumulative repayment up to a particular year exceeds the cumulative depreciation up to that year;

Provided further that Advance Against Depreciation in a year shall be restricted to the extent of difference between cumulative repayment and cumulative depreciation up to that year.

(iii) **Return on Equity**

Return on equity shall be computed on the equity base determined in accordance with regulation 36 and shall be @ 14% per annum.

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

Explanation

The premium raised by the generating company while issuing share capital and investment of internal resources created out of free reserve of the existing generating station, if any, for the funding of the project, shall also be reckoned as paid up capital for the purpose of computing return on equity, provided such premium amount and internal resources are actually utilised for meeting the capital expenditure of the generating station and forms part of the approved financial package.

(iv) **<u>Operation and Maintenance expenses</u>**

(a) The operation and maintenance expenses including insurance, for the existing generating stations which have been in operation for 5 years or more in the base year of 2003-04, shall be derived on the basis of actual operation and maintenance expenses for the years 1998-99 to 2002-03, based on the audited balance sheets, excluding abnormal operation and maintenance expenses, if any, after prudence check by the Commission.

The average of such normalised operation and maintenance expenses after prudence check, for the years 1998-99 to 2002-03 considered as operation and maintenance expenses for the year 2000-01 shall be escalated at the rate of 4% per annum to arrive at operation and maintenance expenses for the base year 2003-04.

The base operation and maintenance expenses for the year 2003-04 shall be escalated further at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant year of tariff period.

(b) In case of the hydro electric generating stations, which have not been in existence for a period of five years, the operation and maintenance expenses shall be fixed at 1.5% of the capital cost as admitted by the Commission and shall be escalated at the rate of 4% per annum from the subsequent year to arrive at operation and maintenance expenses for the base year 2003-04. The base operation and maintenance expenses shall be further escalated at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant year.

(c) In case of the hydro electric generating stations declared under commercial operation on or after 1.4.2004, the base operation and maintenance expenses shall be fixed at 1.5% of the actual capital cost as admitted by the Commission, in the year of commissioning and shall be subject to an annual escalation of 4% per annum for the subsequent years.

(v) **Interest on Working Capital**

(a) Working Capital shall cover:

(i) Operation and Maintenance expenses for one month;

(ii) Maintenance spares @ 1% of the historical cost escalated @ 6% per annum from the date of commercial operation; and

(iii) Receivables equivalent to two months of fixed charges for sale of electricity, calculated on normative capacity index.

(b) Rate of interest on working capital shall be the short-term Prime Lending Rate of State Bank of India as on 1.4.2004 or on 1st April of the year in which the generating unit/station is declared under commercial operation, whichever is later. The interest on working capital shall be payable on normative basis notwithstanding that the generating company has not taken working capital loan from any outside agency.

39. **Primary and Secondary Energy Charges**: (1) Primary energy charge shall be worked out on the basis of paise per kWh rate on ex-bus energy scheduled to be sent out from the hydro electric power generating station after adjusting for free power delivered to the home state.

(2) Rate of primary energy for all hydro electric power generating stations, except for pumped storage generating stations, shall be equal to the lowest variable charges of the central sector thermal power generating station of the concerned region. The primary energy charge shall be computed based on the primary energy rate and saleable energy of the station.

Provided that in case the primary energy charge recoverable by applying the above primary energy rate exceeds the Annual Fixed Charge of a generating station, the primary energy rate for such generating station shall be calculated by the following formula:

$$\text{Primary energy rate} = \frac{\text{Annual Fixed Charge}}{\text{Saleable Primary Energy}}$$

(3) Primary Energy Charge = Saleable Primary Energy x Primary Energy Rate

Secondary Energy Rate shall be equal to Primary Energy Rate.
Secondary Energy Charge = Saleable Secondary Energy x Secondary Energy Rate.

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

(2) Incentive shall be payable to the generating company in accordance with the following formula**:**
Incentive = 0.65 x Annual Fixed Charge x $(CI_A – CI_N)/100$

(If incentive is negative, it shall be set to zero.)

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

(3) The incentives on account of capacity index and payment for secondary energy shall be payable on monthly basis, subject to cumulative adjustment in each month of the financial year, separately in respect of each item, and final adjustment shall be made at the end of the financial year.

(4) The total incentive payment calculated on annual basis shall be shared by the beneficiaries based on the allocated capacity.

(5) Incentive for completion of hydro electric power generating stations ahead of schedule

In case of commissioning of a hydro electric power generating station or part thereof ahead of schedule, as set out in the first approval of the Central Government or the techno-economic clearance of the Authority, as applicable, the generating station shall become eligible for incentive for an amount equal to *pro rata* reduction in interest during construction, achieved on commissioning ahead of the schedule. The incentive shall be recovered through tariff in twelve equal monthly installments during the first year of operation of the generating station. In case of delay in commissioning as set out in the first approval of the Central Government or the techno-economic clearance of the Authority, as applicable, interest during construction for the period of delay shall not be allowed to be capitalised for determination of tariff, unless the delay is on account of natural calamities or geological surprises.

41. **Deemed Generation**: (1) In case of reduced generation due to the reasons beyond the control of generating company or on account of non-availability of Board's/transmission licensee's transmission lines or on receipt of backing down instructions from the concerned Regional Load Despatch Centre resulting in spillage of water, the energy charges on account of such spillage shall be payable to the generating company. Apportionment of energy charges for such spillage among the beneficiaries shall be in proportion of their shares in saleable capacity of the generating station.

(2) Energy charges on the above account shall not be admissible if the energy generated during the year is equal to or more than the design energy.

42. **Unscheduled Interchange (UI)**: (1) Variation between actual generation or actual drawal and scheduled generation or scheduled drawal shall be accounted for

through Unscheduled Interchange (UI) charges. UI for a generating station shall be equal to its actual generation minus its scheduled generation. UI for a beneficiary shall be equal to its total actual drawal minus its total scheduled drawal. UI shall be worked out for each 15 minute time block. Charges for all UI transactions shall be based on average frequency of the time block and the following rates shall apply with effect from 1.4.2004:

Average Frequency of time block	UI Rate (Paise per kWh)
50.5 Hz and above	0.0
Below 50.5 Hz and up to 50.48 Hz	8.0
Below 49.04 Hz and up to 49.02 Hz	592.0
Below 49.02 Hz	600.0
Between 50.5 Hz and 49.02 Hz	linear in 0.02 Hz step

(Each 0.02 Hz step is equivalent to 8.0 paise /kWh within the above range)

Note

The above average frequency range and UI rates are subject to change through a separate notification by the Commission.

(2) (i) Any generation up to 105% of declared capacity in any time block of 15 minutes and averaging up to 101% of the average declared capacity over a day shall not be construed as gaming, and generator shall be entitled to UI charges for such excess generation above the scheduled generation (SG).

(ii) For any generation beyond the prescribed limits, the Regional Load Despatch Centre shall investigate so as to ensure that there is no gaming, and if gaming is found by the Regional Load Despatch Centre, the corresponding UI charges due to the generating station on account of such extra generation shall be reduced to zero and the amount shall be adjusted in UI account of beneficiaries, in the ratio of their capacity share in the generating station.

43. **Rebate**: For payment of bills of capacity charge and energy charge through the letter of credit on presentation, a rebate of 2% shall be allowed. If the payments are made by a mode other than through the letter of credit but within a period of one month of presentation of bills by the generating company , a rebate of 1% shall be allowed.

44. **Late Payment Surcharge**: In case the payment of bills of capacity charge and energy charge by the beneficiary (ies) is delayed beyond a period of 1 month from the date of billing, a late payment surcharge at the rate of 1.25% per month shall be levied by the generating company .

45. **Scheduling**: Read with the provisions of the Indian Electricity Grid Code, the methodology of scheduling and calculating capacity index shall be as under:

(i) The generator shall make an advance declaration of capacity of its generating station. The declaration shall be for that capacity which can be

actually made available for a period of time not less than 3 hours within a 24 hours period for pondage and storage type of stations and for the entire day for purely run-of-river type stations.
(ii) The generator shall intimate the declared capacity (MW), for the next day, either as one figure for the whole day or different figures for different periods of the day along with maximum available capacity (MW) and total energy (MWh) ex-bus to the Regional Load Despatch Centre.

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

(iii) While making or revising his declaration of capability, the generator shall ensure that the declared capacity during peak hours is not less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronisation of units as a result of forced outage of units.

(iv) Generation scheduling shall be done in accordance with the operating procedure, as stipulated in the Indian Electricity Grid Code.

(v) Based on the declaration of the generator, the Regional Load Despatch Centre shall communicate their shares to the beneficiaries out of which they shall give their requisitions.

(vi) Based on the requisitions given by the beneficiaries and taking into account technical limitations on varying the generation and also taking into account transmission system constraints, if any, the Regional Load Despatch Centre shall prepare the economically optimal generation schedules and drawal schedules and communicate the same to the generator and the beneficiaries.

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

(vii) The scheduled generation and actual generation shall be ex-bus at the generating station. For beneficiaries, the scheduled and actual net drawals shall be at their respective receiving points.

(viii) For calculating the net drawal schedules of beneficiaries, the transmission losses shall be apportioned to their drawal schedule for the time being. However, a refinement may be specified by the Commission in future, depending upon the preparedness of the respective Regional Load Despatch Centre.

(ix) In case of forced outage of a unit, the Regional Load Despatch Centre shall revise the schedules on the basis of revised declared capability. The revised declared capability and the revised schedules shall become effective from the 4th time block, counting the time block in which the revision is advised by the generator to be the first one.

(x) In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, associated switchyard and sub- stations owned by the Central Transmission Utility or any other transmission licensee involved in inter-state transmission (as certified by the Regional Load Despatch Centre) necessitating reduction in generation, the Regional Load Despatch Centre shall revise the schedules which shall become effective from the 4th time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. Also, during the first, second and third time blocks of such an event, the scheduled generation of the generating station shall be deemed to have been revised to be equal to actual generation, and the scheduled drawals of the beneficiaries shall be deemed to have been revised to be equal to their actual drawals.

(xi) In case of any grid disturbance, scheduled generation of all the generating stations and scheduled drawal of all the beneficiaries shall be deemed to have been revised to be equal to their actual generation/drawal for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the Regional Load Despatch Centre.

(xii) Revision of declared capability by the generator(s) and requisition by beneficiary(ies) for the remaining period of the day shall also be permitted with advance notice. Revised schedules/declared capability in such cases shall become effective from the 6th time block, counting the time block in which the request for revision has been received in the Regional Load Despatch Centre to be the first one.

(xiii) If, at any point of time, the Regional Load Despatch Centre observes that there is need for revision of the schedules in the interest of better system operation, it may do so on its own and in such cases, the revised schedules shall become effective from the 4th time block, counting the time block in which the revised schedule is issued by the Regional Load Despatch Centre to be the first one.

(xiv) Generation schedules and drawal schedules issued/revised by the Regional Load Despatch Centre shall become effective from designated time block irrespective of communication success.

(xv) For any revision of scheduled generation, including post facto deemed revision, there shall be a corresponding revision of scheduled drawals of the beneficiaries.

(xvi) A procedure for recording the communication regarding changes to schedules duly taking into account the time factor shall be evolved by the Central Transmission Utility.

(xvii) Purely run-of-river power stations

Since variation of generation in such stations may lead to spillage, these shall be treated as must run stations. The maximum available capacity, duly taking into account the over load capability, must be equal to or greater than that required to make full use of the available water.

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

These hydro stations are designed to operate during peak hours to meet system peak demand. Maximum available capacity of the station declared for the day shall be equal to the installed capacity including overload capability, minus auxiliary consumption and transformation losses, corrected for the reservoir level. The Regional Load Despatch Centres shall ensure that generation schedules of such type of stations are prepared and the stations dispatched for optimum utilization of available hydro energy except in the event of specific system requirements/constraints.

46. **Demonstration of Declared Capability**: (1) The generating company may be required to demonstrate the declared capacity of its generating station as and when asked by the Regional Load Despatch Centre of the region in which the generating station is situated. In the event of the generating company failing to demonstrate the declared capacity, within the tolerance as specified by the Central Transmission Utility, the capacity charges due to the generating station shall be reduced as a measure of penalty.

(2) The quantum of penalty for the first mis-declaration for any duration or block in a day shall be the charges corresponding to two days fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in the geometrical progression.

(3) The operating log books of the generating station shall be available for review by the Regional Power Committee or the Regional Electricity Board, as the case may be. These books keep record of machine operation and maintenance, reservoir level and spillway gate operation.

47. **Metering and Accounting**: Metering arrangements, including installation, testing and operation and maintenance of meters and collection, transportation and processing of data required for accounting of energy exchanges and average frequency on 15 minute time block basis shall be organised by the Central Transmission Utility/Regional Load Despatch Centres. All concerned entities (in whose premises the special energy meters are installed), shall fully cooperate with the Central Transmission Utility/Regional Load Despatch Centre and extend the necessary assistance by taking weekly meter readings and transmitting them to the Regional Load Despatch Centre. Processed data of meters along with data relating to declared capability and schedules etc., shall be supplied by the Regional Load Despatch Centres to the Regional Power Committee or the Regional Electricity Board and the Regional Power Committee or the Regional Electricity Board shall issue the Regional Accounts for energy on monthly

basis as well as UI charges on weekly basis. UI accounting procedures shall be governed by the orders of the Commission.

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

(i) Each beneficiary shall pay the capacity charges in proportion to its percentage share in total saleable capacity of the generating station. Saleable capacity shall mean total capacity minus free capacity to home state(s), if any.

Note 1

Allocation of total capacity of central sector generating stations is made by Central Government from time to time which also has an unallocated portion. Allocation of the unallocated portion shall be made by the Central Government from time to time, for the total unallocated capacity and notified by the Member Secretary, Regional Electricity Board/Regional Power Committee in advance, at least three (3) days prior to such allocation/ change in allocation taking effect. The total capacity share of any beneficiaries would be sum of its capacity share plus allocation out of the unallocated portion. In the absence of specific distribution 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 share to other States within/outside the region. In such cases, depending upon the technical feasibility of power transfer and specific agreements reached by the generating company with other States within/outside the region for such transfers, the shares of the beneficiaries may be re-allocated by the Central Government for a specific period. 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 fixed charges as per allocated capacity shares. Any such re-allocation shall be notified by the Member Secretary, Regional Electricity Board/Regional Power Committee in advance, at least three (3) days prior to such re-allocation taking effect.

(ii) The beneficiaries shall have full freedom for negotiating any transaction for utilisation of their capacity shares. In such cases, the beneficiary having allocation in the capacity of the generating station shall be liable for full payment of capacity charges and energy charges (including that for sale of power under the transaction negotiated by him) corresponding to his total allocation and schedule respectively.

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

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

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

$ACC_1 = AFC – (SPE_1 + DE_{\text{2nd to 12th months}}) * \text{Primary Energy Rate}$
$ACC_2 = AFC – (SPE_2 + DE_{\text{3rd to 12th months}}) * \text{Primary Energy Rate}$
$ACC_3 = AFC – (SPE_3 + DE_{\text{4th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_4 = AFC – (SPE_4 + DE_{\text{5th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_5 = AFC – (SPE_5 + DE_{\text{6th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_6 = AFC – (SPE_6 + DE_{\text{7th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_7 = AFC – (SPE_7 + DE_{\text{8th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_8 = AFC – (SPE_8 + DE_{\text{9th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_9 = AFC – (SPE_9 + DE_{\text{10th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_{10} = AFC – (SPE_{10} + DE_{\text{11th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_{11} = AFC – (SPE_{11} + DE_{\text{12th month}}) * \text{Primary Energy Rate}$
$ACC_{12} = (AFC – SPE_{12}) * \text{Primary Energy Rate}$

Where,

AFC = Annual Fixed Charges
ACC_1, ACC_2, ACC_3, ACC_4, ACC_5 ACC_6, ACC_7, ACC_8, ACC_9, ACC_{10}, ACC_{11} and ACC_{12} are the amount of Annual Capacity Charge for the cumulative period up to the end of 1st, 2nd 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th months respectively.

SPE_1, SPE_2, SPE_3,………………… $SPE_{!2}$ are the ex-bus scheduled primary energy values up to 1st, 2nd, 3rd ……12th months of the year respectively.

$$CC1 = ACC_1 \times \frac{DE1}{DE}$$

$$CC2 = ACC_2 \times \frac{DE2}{DE}$$

$$CC3 = ACC_3 \times \frac{DE3}{DE}$$

$CC4 = ACC_4 \times \underline{DE4}$

DE

$$CC5 = ACC_5 \times \frac{DE5}{DE}$$

$$CC6 = ACC_6 \times \frac{DE6}{DE}$$

$$CC7 = ACC_7 \times \frac{DE7}{DE}$$

$$CC8 = ACC_8 \times \frac{DE8}{DE}$$

$$CC9 = ACC_9 \times \frac{DE9}{DE}$$

$$CC10 = ACC_{10} \times \frac{DE10}{DE}$$

$$CC11 = ACC_{11} \times \frac{DE11}{DE}$$

$$CC12 = ACC_{12} \times \frac{DE12}{DE}$$

Where,
CC1, CC2, CC3,……….CC12 is the monthly capacity charge up to 1^{st}, 2^{nd}, 3^{rd} ……12^{th} months of the year respectively.

DE = Annual Design Energy
DE1, DE2, DE3, ……….DE12 are the ex-bus design energy values up to 1^{st}, 2^{nd}, 3^{rd} ……12^{th} months of the year respectively.

Total capacity charges payable to the generator for the:
1^{st} month = (CC1)
2^{nd} month = (CC2 -CC1)
3^{rd} month = (CC3 - CC2)
4^{th} month = (CC4 -CC3)
5^{th} month = (CC5 - CC4)
6^{th} month = (CC6 -CC5)
7^{th} month = (CC7 -CC6)
8^{th} month = (CC8 -CC7)
9^{th} month = (CC9 -CC8)
10^{th} month =(CC10 – CC9)
11^{th} month =(CC11 -CC10)
12^{th} month =(CC12 -CC11)

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

1^{st} month = [CC1 x WB1]/100
2^{nd} month = [CC2 x WB2 -CC1x WB1]/100
3^{rd} month = (CC3 x WB3 - CC2 x WB2]/100
4^{th} month = (CC4 x WB4 - CC3 x WB3]/100
5^{th} month = (CC5 x WB5 - CC4 x WB4]/100

6^{th} month = (CC6 x WB6 - CC5 x WB5]/100
7^{th} month = (CC7 x WB7 - CC6 x WB6]/100
8^{th} month = (CC8 x WB8 - CC7 x WB7]/100
9^{th} month = (CC9 x WB9 - CC8 x WB8]/100
10^{th} month = (CC10 x WB10- CC9 x WB9]/100
11^{th} month = (CC11 x WB11- CC10x WB10]/100
12^{th} month = (CC12 x WB12- CC11x WB 11]/100

Where,

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

CHAPTER 4

INTER-STATE TRANSMISSION

49. **Definitions:** Unless the context otherwise requires, for the purpose of this chapter, :-

(i) **'Act'** means the Electricity Act, 2003;

(ii) **`Additional Capitalisation'** means the capital expenditure actually incurred after the date of commercial operation of the transmission system and admitted by the Commission after prudence check subject to regulation 53;

(iii) **'Allotted Transmission Capacity'** means the power transfer in MW between the specified point(s) of injection and point(s) of drawal allowed to a long-term customer on the inter-state transmission system under the normal circumstances and the expression "allotment of transmission capacity" shall be construed accordingly;

Allotted Transmission Capacity to a long-term transmission customer shall be sum of the generating capacities allocated to the long-term transmission customer from the ISGS and the contracted power, if any;

(iv) **'Authority'** means Central Electricity Authority referred to in section 70 of the Act;

(v) **'Availability'** in relation to a transmission system for a given period means the time in hours during that period the transmission system is capable to transmit electricity at its rated voltage and shall be expressed in percentage of total hours in the given period and shall be calculated as per the procedure contained in Appendix-III to these regulations;

(vi) **'Commission'** means the Central Electricity Regulatory Commission referred to in Section 76 of the Act;

(vii) '**Contracted Power'** means the power in MW which the transmission licensee has agreed to carry or which the transmission licensee is required to carry as per firm allocation from ISGS outside the region or the long-term agreement between the importing and exporting utility;

(viii) `**Cut off Date'** means the date of first financial year closing after one year of the date of commercial operation of the transmission system.

(ix) **'Date of Commercial Operation' or 'COD**' means the date of charging the project or part thereof to its rated voltage level or seven days after the date on which it is declared ready for charging by the transmission licensee, but is not able to be charged for reasons not attributable to the transmission licensee, its suppliers or contractors.

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

(x) **‘Existing Project’** means the project declared under commercial operation from a date prior to 1.4.2004;

(xi) **‘Implementation Agreement’** means the agreement, contract or memorandum of understanding, or any such covenant, entered into between the transmission licensee and the long-term transmission customers for construction of the project;

(xii) **‘Inter-State Generating Station’ or ‘ISGS’** has the meaning as assigned in the Indian Electricity Grid Code approved/notified by the Commission;

(xiii) **'Long-Term Transmission Customer'** means a person availing or intending to avail access to the inter-state transmission system for a period of twenty five years or more;

(xiv) **`Original Project Cost'** means the actual expenditure incurred by the transmission licensee, as per the original scope of project up to first financial year closing after one year of the date of commercial operation of the last element as admitted by the Commission for the purpose of tariff;

(xv) **'Operation and Maintenance Expenses' or 'O&M Expenses**' means the expenditure incurred in operation and maintenance of the transmission system, including part thereof, and includes the expenditure on manpower, repairs, spares, consumables, insurance and overheads;

(xvi) **‘Project’** includes the transmission system comprising specified transmission lines, sub-stations and associated equipment;

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

(xviii) **'Short-Term Transmission Customer'** means a transmission customer other than the long-term transmission customer;

(xix) **'Transmission Service Agreement** ' means the agreement, contract, memorandum of understanding, or any such covenant, entered into between the transmission licensee and the long-term transmission customers for the operational phase of the project;

(xx) **'Transmission licensee'**, means a person granted licence for inter-state transmission of electricity and includes any person deemed to be a transmission licensee for inter-state transmission of electricity;

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

(xxii) **'Year'** means a financial year.

50. **Auxiliary Energy Consumption in the sub-station**

(a) AC System

The charges for auxiliary energy consumption in the AC sub-station for the purpose of air-conditioning, lighting, technical consumption, etc. shall be borne by the transmission licensee as part of its normative operation and maintenance expenses.

(b) HVDC sub-station

For auxiliary energy consumption in HVDC sub-stations, the Central Government may allocate an appropriate share from one or more ISGS . Capacity and energy charges for such power shall be borne by the transmission licensee as part of its normative operation and maintenance expenses.

51. **Target Availability for recovery of full transmission charges**

(1) AC system : 98%

(2) HVDC bi-pole links and HVDC back-to-back stations: 95%

Note 1

Recovery of fixed charges below the level of target availability shall be on *pro rata* basis. At zero availability, no transmission charges shall be payable.

Note 2

The target availability shall be calculated in accordance with procedure specified in Appendix-III.

52. **Capital Cost:** (1) Subject to prudence check by the Commission, the actual expenditure incurred on completion of the project shall form the basis for determination of final tariff. The final tariff shall be determined based on the admitted capital expenditure actually incurred up to the date of commercial operation of the transmission system and shall include capitalised initial spares subject to a ceiling norm as 1.5% of original project cost.

Provided that where the implementation agreement or the transmission service agreement entered into between the transmission licensee and the long-term transmission customers provides a ceiling of actual expenditure, the capital expenditure shall not exceed such ceiling for determination of tariff.

(2) In case of the existing projects, the project cost admitted by the Commission prior to 1.4.2004 shall form the basis for determination of tariff.

Note

Scrutiny of the project cost estimates by the Commission shall be limited to the reasonableness of the capital cost, financing plan, interest during construction, use of efficient technology and such other matters for determination of tariff.

53. **Additional capitalisation:** (1) The following capital expenditure within the original scope of work actually incurred after the date of commercial operation and up to the cut off date may be admitted by the Commission, subject to prudence check:

(i) Deferred liabilities;

(ii) Works deferred for execution;

(iii) Procurement of initial capital spares in the original scope of works subject to the ceiling norm specified in regulation 52;

(iv) Liabilities to meet award of arbitration or compliance of the order or decree of a court; and

(v) On account of change in law.

Provided that original scope of work along with estimates of expenditure shall be submitted along with the application for provisional tariff.

Provided further that a list of the deferred liabilities and works deferred for execution shall be submitted along with the application for final tariff after the date of commercial operation of the transmission system.

(2) Subject to the provisions of clause (3) of this regulation, the capital expenditure of the following nature actually incurred after the cut off date may be admitted by the Commission, subject to prudence check:

(i) Deferred liabilities relating to works/services within the original scope of work;

(ii) Liabilities to meet award of arbitration or compliance of the order or decree of a court;

(iii) On account of change in law; and

(iv) Any additional works/services which have become necessary for efficient and successful operation of the project, but not included in the original project cost.

(3) Any expenditure on minor items/assets brought after the cut off date like tools and tackles, personal computers, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, fans, T.V., washing machine, heat-convectors, mattresses, carpets, etc shall not be considered for additional capitalisation for determination of tariff with effect from 1.4.2004.

Note

The list of items is illustrative and not exhaustive.

(4) Impact of additional capitalisation in tariff revision may be considered by the Commission twice in a tariff period, including revision of tariff after the cut off date.

Note 1

Any expenditure admitted on account of committed liabilities within the original scope of work and the expenditure deferred on techno-economic grounds but falling within the original scope of work shall be serviced in the normative debt-equity ratio specified in regulation 54.

Note 2

Any expenditure on replacement of old assets shall be considered after writing off the entire value of the original assets from the original capital cost.

Note 3

Any expenditure admitted by the Commission for determination of tariff on account of new works not in the original scope of work shall be serviced in the normative debt-equity ratio specified in regulation 54.

Note 4

Any expenditure admitted by the Commission for determination of tariff on renovation and modernization and life extension shall be serviced on normative debt-equity ratio specified in regulation 54 after writing off the original amount of the replaced assets from the original capital cost.

54. **Debt-Equity Ratio:** (1) In case of all projects, debt–equity ratio as on the date of commercial operation shall be 70:30 for determination of tariff. Where equity employed is more than 30%, the amount of equity for the purpose of tariff shall be limited to 30% and the balance amount shall be considered as the normative loan.

Provided that in case of the projects where actual equity employed is less than 30%, the actual debt and equity shall be considered for determination of tariff.

(2) The debt and equity amounts arrived at in accordance with clause (i) shall be used in all calculations for calculating interest on loan, return on equity, Advance Against Depreciation and Foreign Exchange Rate Variation.

55. **Transmission Charges** : The tariff for transmission of electricity on inter-state transmission system shall comprise of the recovery of annual transmission charges consisting of the following, namely:

(a) Interest on loan capital;

(b) Depreciation, including Advance Against Depreciation;

(c) Return on equity;

(d) Operation and maintenance expenses; and

(e) Interest on working capital.

56. **Computation of Transmission Charges:** The annual transmission charges shall be computed on the following basis, namely:

(i) **Interest on loan Capital**

(a) Interest on loan capital shall be computed loan wise on the loans arrived at in the manner indicated in regulation 54.

(b) The loan outstanding as on 1.4.2004 shall be worked out as the gross loan as per regulation 54 minus cumulative repayment as admitted by the Commission up to 31.3.2004. The repayment for the period 2004-09 shall be worked out on normative basis.

(c) The transmission licensee shall make every effort to swap the loan as long as it results in net benefit to the long-term transmission customers. The costs associated with such swapping shall be borne by the long-term transmission customers.

(d) The changes to the loan terms and conditions shall be reflected from the date of such swapping and benefits passed on to the beneficiaries.

(e) In case of any dispute, any of the parties may approach the Commission with proper application. However, the long-term transmission customers shall not withhold any payment as ordered by the Commission to the transmission licensee during pendency of any dispute relating to swapping of loan.

(f) In case any moratorium period is availed of by the transmission licensee, depreciation provided for in the tariff during the years of moratorium shall be treated as repayment during those years and interest on loan capital shall be calculated accordingly.

(g) The transmission licensee shall not make any profit on account of swapping of loan and interest on loan.

(ii) **<u>Depreciation, including Advance Against Depreciation</u>**

(a) **Depreciation**

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

(i) The value base for the purpose of depreciation shall be the historical cost of the asset.

(ii) Depreciation shall be calculated annually based on straight line method over the useful life of the asset and at the rates prescribed in Appendix II to these regulations.

The residual life of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the historical capital cost of the asset. Land is not a depreciable asset and its cost shall be excluded from the capital cost while computing 90% of the historical cost of the asset. The historical capital cost of the asset shall include additional capitalisation on account of Foreign Exchange Rate Variation up to 31.3.2004 already allowed by the Central Government/Commission.

(iii) On repayment of entire loan, the remaining depreciable value shall be spread over the balance useful life of the asset.

(iv) Depreciation shall be chargeable from the first year of operation. In case of operation of the asset for part of the year, depreciation shall be charged on *pro rata* basis.

(b) **Advance Against Depreciation**

In addition to allowable depreciation, the transmission licensee shall be entitled to Advance Against Depreciation, computed in the manner given hereunder:

AAD = Loan repayment amount as per regulation 56 (i) subject to a ceiling of $1/10^{th}$ of loan amount as per regulation 54 minus depreciation as per schedule

Provided that Advance Against Depreciation shall be permitted only if the cumulative repayment up to a particular year exceeds the cumulative depreciation up to that year;

Provided further that Advance Against Depreciation in a year shall be restricted to the extent of difference between cumulative repayment and cumulative depreciation up to that year.

(iii) **Return on Equity**:

Return on equity shall be computed on the equity base determined in accordance with regulation 54 and shall be @ 14% per annum.

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

Explanation

The premium raised by the transmission licensee while issuing share capital and investment of internal resources created out of free reserve of the existing transmission licensee, if any, for the funding of the project, shall also be reckoned as paid up capital for the purpose of computing return on equity, provided that such premium amount and internal resources are actually utilised for meeting the capital expenditure of the project and forms part of the approved financial package.

(iv) **Operation and Maintenance expenses**

(a) Norms for operation and maintenance expenses per ckt-km and per bay shall be as under, namely:

Norms for O&M expenses per ckt-km and per bay

	Year				
	2004-05	2005-06	2006-07	2007-08	2008-09
O&M expenses (Rs. in lakh per ckt-km)	0.227	0.236	0.246	0.255	0.266
O&M expenses (Rs. in lakh per bay)	28.12	29.25	30.42	31.63	32.90

(b) The total allowable O&M expenses for a transmission licensee shall be calculated by multiplying the number of bays and ckt-km of line length with the applicable norms for the O&M expenses per bay and per ckt-Km respectively.

(v) **<u>Interest on Working Capital</u>**

(1) Working capital shall cover:

(a) Operation and maintenance expenses for one month;

(b) Maintenance spares @ 1% of the historical cost escalated @ 6% per annum from the date of commercial operation; and

(c) Receivables equivalent to two months of transmission charges calculated on target availability level.

(2) Rate of interest on working capital shall be on normative basis and shall be equal to the short-term Prime Lending Rate of State Bank of India as on 1.4.2004 or on 1st April of the year in which the project or part thereof (as the case may be) is declared under commercial operation, whichever is later. The interest on working capital shall be payable on normative basis notwithstanding that the transmission licensee has not taken working capital loan from any outside agency.

57. **<u>Payment of Transmission Charges</u> :** Full annual transmission charges shall be recoverable at the target availability stipulated in regulation 51. Payment of transmission charges below the target availability shall be on *pro rata* basis. The transmission charges shall be calculated on monthly basis.

58. **<u>Sharing of charges for intra-regional assets</u>:** In case of more than one long-term transmission customer of the regional transmission system, the monthly transmission charges leviable on each long-term transmission customer shall be computed as per the following formula:

Transmission Charges for intra-regional system payable for a month by a long-term transmission customer of that transmission system

$$= \left(\sum_{i=1}^{n} \left(\frac{TCi}{12} \right) - TRSC \right) X \frac{CL}{SCL}$$

Where TCi = Annual Transmission Charges for the i^{th} project in the region computed in accordance with regulation 56

n = Number of projects in the region

TRSC = Total recovery of transmission charges for the month from Short-term transmission customers for the regional transmission system in accordance with the Central Electricity Regulatory Commission (Open Access in Inter-State Transmission) Regulations, 2004.

CL = Allotted Transmission Capacity to the long-term transmission customer

SCL = Sum of the Allotted Transmission Capacities to all the long-term transmission customers of the regional transmission system.

59. **Sharing of charges for inter-regional assets:** The transmission charges of the inter-regional assets, including HVDC system , after deducting the recovery from the short-term customers, shall be shared in the ratio of 50:50 by the long-term transmission customers of the regional transmission system of two contiguous regions in accordance with the following formula:

Transmission Charges payable for a month by a long term-customer within the region for the inter-regional assets connected to that region

$$= 0\ .5x \left\{ \frac{TCj}{12} - RSCj \right\} x \frac{CL}{SCL}$$

Where

TCj = Annual Transmission Charges for the particular inter-regional asset connected to the region computed in accordance with regulation 56,

RSCj = Recovery of Transmission Charges for the month from the short-term customers for the particular inter-regional asset connected to the region in accordance with the Central Electricity Regulatory Commission (Open Access in Inter-State Transmission) Regulations, 2004,

CL = Allotted Transmission Capacity to the long-term transmission customer in the regional transmission system in which it is located,

SCL = Sum of the Allotted Transmission Capacities to all the long-term transmission customers of the regional transmission system in the regional transmission system in which it is located.

60. **<u>Incentive</u> :** (1) The transmission licensee shall be entitled to incentive on achieving annual availability beyond the target availability as per regulation 51, in accordance with the following formula:

Incentive = Annual Transmission Charges x [Annual availability achieved – Target Availability] / Target Availability ;

Where,

Annual transmission Charges shall correspond to intra-regional assets or for a particular inter-regional asset, as the case may be.

Provided that no incentive shall be payable above the availability of 99.75% for AC system and 98.5% for HVDC system.

(2) Incentive shall be shared by the long-term customers in the ratio of their average allotted transmission capacity for the year.

61. **<u>Rebate</u> :** For payment of bills of transmission charges through letter of credit on presentation, a rebate of 2% shall be allowed. Where payments are made subsequently through opening of letter of credit or otherwise, but within a period of one month of presentation of bills by the Transmission licensee, a rebate of 1% shall be allowed.

62. **Late payment surcharge :** In case the payment of bills of transmission charges by the beneficiary (s) is delayed beyond a period of 1 month from the date of billing a late payment surcharge at the rate of 1.25% per month shall be levied by the transmission licensee.

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SECRETARY