Explanatory Memorandum
On Draft Tariff Regulations
for Generation (other than
Renewable Energy),
Transmission & Distribution
of Electricity
for the Control Period from
FY 2019-20
To
FY 2023-24

February, 2019

Rajasthan Electricity Regulatory Commission,
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1 Introduction

1.1 Background & Regulatory framework

1.1.1 As per Section 86 (1) (a) of the Electricity Act, 2003 ("EA 2003" or "the Act"), the State Electricity Regulatory Commissions (SERCs or Commissions) have been assigned the function of determining the tariff for generation, supply, transmission and wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State.

1.1.2 Section 61 of the Act requires the Appropriate Commission to be guided by below mentioned principles while specifying the Terms and Conditions for determination of tariff:

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

(a) The principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;

(b) The generation, transmission, distribution and supply of electricity are conducted on commercial principles;

(c) The factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;

(d) Safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;

(e) The principles rewarding efficiency in performance;

(f) Multi year tariff principles;

(g) That the tariff progressively reflects the cost of supply of electricity and also reduces cross-subsidies in the manner specified by the Appropriate Commission;

(h) The promotion of co-generation and generation of electricity from renewable sources of energy;

(i) The National Electricity Policy and tariff policy"

1.1.3 As per Section 62 of the Act, the Appropriate Commission has to determine the tariff for supply *of electricity by a generating company to a distribution licensee*, *transmission, wheeling and retail sale of electricity*, and may require the licensee or generating company to furnish separate details in respect of generation, transmission and distribution of tariff. The relevant extract of Section 62 of the Act is reproduced herewith:

"62. (1) The Appropriate Commission shall determine the tariff in accordance with provisions of this Act for –

(a) supply of electricity by a generating company to a distribution licensee:

...

(b) transmission of electricity;

(c) wheeling of electricity;
(d) retail sale of electricity.
...
(2) The Appropriate Commission may require a licensee or a generating company to furnish separate details, as may be specified in respect of generation, transmission and distribution for determination of tariff.
…
(5) The Commission may require a licensee or a generating company to comply with such procedures as may be specified for calculating the expected revenues from the tariff and charges which he or it is permitted to recover
…"

1.1.4 Also, the National Electricity Policy and Tariff Policy have been notified by the Ministry of Power, Government of India, which provides the guidelines for determination of the revenue requirement and tariff. The National Electricity Policy provides certain guidelines as regards performance norms and the need to provide incentives and disincentives, as reproduced below:

"5.8.5 All efforts will have to be made to improve the efficiency of operations in all the segments of the industry. Suitable performance norms of operations together with incentives and disincentives will need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. This will ensure protection of consumers' interests on the one hand and provide motivation for improving the efficiency of operations on the other".

1.1.5 RERC notified the Rajasthan Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff) Regulations, 2004 on October 15, 2004, under Section 61 of the Act. Subsequently, the Commission on January 23, 2009 notified the Rajasthan Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff) Regulations, 2009 for the Control Period of five (5) financial years from April 1, 2009 to March 31, 2014. Further, the Commission on February 24, 2014 notified the Rajasthan Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff) Regulations, 2014 (hereinafter referred as "RERC Tariff Regulations, 2014") for the Control Period of further five (5) financial years from April 1, 2014 to March 31, 2019, thereby repealing earlier Tariff Regulations.

1.1.6 As the current MYT Control Period is coming to an end on March 31, 2019, the RERC has formulated the draft RERC (Terms and Conditions for Determination of Tariff) Regulations, 2014 (hereinafter referred as "draft RERC Tariff Regulations, 2019) covering the Generation (Conventional), Transmission, and Distribution functions for the next MYT Control Period of 5 years, i.e., FY 2019-20 to FY 2023-24. Further, it is pertinent to mention that these Regulations shall also be not applicable for determination of tariff from captive generating plant and Renewable Energy Sources, but applicable for Mini and Micro Hydel Plants, as per existing Regulations.

1.1.7 For formulation of the draft RERC Tariff Regulations, 2019, the Commission has considered the Central Electricity Regulatory Commission (Terms and Conditions for Tariff) Regulations, 2014 (hereinafter referred as “CERC Tariff Regulations, 2014”), draft Central Electricity Regulatory Commission (Terms and Conditions for Tariff) Regulations, 2019 (hereinafter referred as “draft CERC Tariff Regulations, 2019”) issued by CERC on December 14, 2018, National Electricity Policy, Tariff Policy, relevant Regulations of this Commission and other SERC’s, FOR Recommendations on MYT Framework, APTEL Judgments, etc.

1.1.8 The Explanatory Memorandum is organised in the following Sections:

Section 1: Introduction

Section 2: General Principles of Tariff Determination

Section 3: Financial Principles

Section 4: Norms and Principles for determination of ARR and tariff for Generation Business

Section 5: Norms and Principles for determination of ARR and Tariff for Transmission Business

Section 6: Norms and Principles for determination of ARR and Tariff for Distribution Business

2 General Principles of Tariff Determination

2.1 Objectives

2.1.1 This section of Explanatory Memorandum elaborates the principles for formulation of Regulations for determination of Aggregate Revenue Requirement and Tariff under a Multi-year Tariff (MYT) framework.

2.1.2 The broad objectives of any regulatory framework are to:

(a) Provide regulatory certainty to the Utilities, investors and consumers by promoting transparency, consistency and predictability of regulatory approach, thereby minimizing the perception of regulatory risk.
(b) Address the risk sharing mechanism between Utilities and consumers based on controllable and uncontrollable factors.
(c) Ensure financial viability of the sector to attract investment, ensure growth and safeguard the interest of the consumers.
(d) Establish operational norms for Generation, Transmission, and Distribution businesses.
(e) Promote operational efficiency.

2.1.3 Long-Term Tariff principles are intended to give clarity to the Generating Companies, Transmission Licensees, Distribution Licensees, consumers, and the other stakeholders regarding the principles governing the determination of revenue requirement and tariffs in the State of Rajasthan.

2.1.4 For the Generating Companies and Licensees, the principles provide clarity on the regulatory framework applicable over the long-term, and help finance growth and operations better, and facilitate improvement in supply quality and customer service. Secondly, the design of efficiency incentives helps promote operational efficiency.

2.1.5 For consumers, improvement in operational efficiency translates into more cost-effective tariffs, as efficient licensees can provide better supply and service, and remain viable.

2.2 Prescribing Norms Vs Prescribing Principles in the Regulations

2.2.1 There are two options to specify trajectories for performance parameters under the Regulations, viz.:

(a) Prescribing operational and financial norms, based on the analysis of past performance levels vis-a-vis the approved levels and benchmarking with comparable entities across different States.
(b) Prescribing principles outlining the approach that needs to be followed while determining the ARR.

2.2.2 However, the Commission in RERC Tariff Regulations, 2014 has specified norms for performance parameters and O&M Expenses. In the draft RERC Tariff Regulations, 2019, it is proposed to continue with the same approach and accordingly, norms for performance parameters and O&M Expenses have been stipulated. Further, only in case of O&M expenses for SLDC, the principles for determination of normative O&M Expenses has been stipulated in draft Regulations.

2.3 Control Period

2.3.1 The Control Period means a multi-year period typically ranging from 3 to 5 years, fixed by the Commission from time to time for the duration of which, the principles for determination of Aggregate Revenue Requirement (ARR) and tariff will be fixed.

2.3.2 The prevailing (third) Control Period is for five years, ending on March 31, 2019. The fourth Control Period is due to begin on April 1, 2019. Hence, in accordance with the Tariff Policy and considering the past experience of the State having three successive Control Periods of five years, it is proposed to have the fourth Control Period of five years, from April 1, 2019 to March 31, 2024.

2.4 Multi-Year Tariff Principles and filings under MYT Period

2.4.1 As regards the determination of Tariff, Regulation 5 of RERC Tariff Regulations, 2014 specifies as under:

"5. Tariff Determination and Multi-Year Tariff principles
(1) The Commission shall determine the tariff and charges for matters covered under regulation 3, on application of Generating Company or the Licensee, as the case may be, during the control period starting from 1.4.2014 in accordance with relevant provisions of these Regulations.

(2) The Multi-Year Tariff principles shall apply to applications made for determination of tariff for a Generating Company, Transmission Licensee, and Distribution Licensee.

(3) The Multi-Year Tariff principles shall be based on the following elements, for calculation of Aggregate Revenue Requirement and expected revenue from tariff and charges of a Generating Company, Transmission Licensee, and Distribution Licensee:

(i) The applicant shall submit the forecast of Aggregate Revenue Requirement, expected revenue from existing tariffs and proposed tariff of the ensuing year and the Commission shall determine the ARR & tariff for the ensuing year of the Generating Company, Transmission Licensee and Distribution Licensee;

(ii) Truing up of previous year's expenses and revenue based on Audited Accounts vis-à-vis the approved forecast and categorization of variation in performance as those caused by factors within the control of the applicant (controllable factors) and those caused by factors beyond the control of the applicant (uncontrollable factors), shall be undertaken by the Commission;

(iii)The mechanism for pass-through of approved gains or losses on account of uncontrollable factors as specified by the Commission in these Regulations;

(iv)Annual tariff determination for Generating Company, Transmission Licensee

and Distribution Licensee, for each financial year within the Control period, based on the approved forecast and results of the truing up exercise.

2.4.2 In the present and earlier Control Periods, the tariff determination has been specified on an annual basis. Ideally, multi-year tariff approach can be adopted to provide regulatory certainty for the next Control Period. However, the readiness of the Generating Company or Licensee also needs to be considered while adopting multi-year tariff approach. Hence, it is proposed to have an option in the Draft Regulations for filing and determination of Multi Year Tariff at the time of filing First ARR/Tariff Petition after notification of the Regulations for all the years of Control Period and the Commission shall determine the ARR & tariff for each year of the Control Period in the MYT Order itself, under this option.

2.4.3 Moreover, it is observed that there is a need to clearly define the treatment of controllable and uncontrollable factors. Hence, the mechanism for approval of gains on account of controllable factors should be part of these Regulations. Accordingly, the following has been proposed:

"The mechanism for pass-through of approved gains on account of controllable factors as specified by the Commission in these Regulations."

2.4.4 Accordingly, Multi year tariff determination has been proposed in this Draft RERC Tariff Regulations, 2019 as under:

"

(1) *The Commission shall determine the tariff and charges for matters covered under Regulation 3, on an application of Generating Company or the Licensee, as the case may be, during the control period starting from 1.4.2019 in accordance with relevant provisions of these Regulations.*

(2) *The Multi-Year Tariff principles shall apply to applications made for determination of tariff for a Generating Company, Transmission Licensee, and Distribution Licensee.*

(3) *The Multi-Year Tariff principles shall be based on the following elements, for calculation of Aggregate Revenue Requirement and expected revenue from tariff and charges of a Generating Company, Transmission Licensee, and Distribution Licensee:*

(i) The applicant shall submit the forecast of Aggregate Revenue Requirement, expected revenue from existing tariffs and proposed tariff for the ensuing year and the Commission shall determine the ARR & tariff for the ensuing year of the Generating Company, Transmission Licensee and Distribution Licensee:

(ii) Truing up of previous year's expenses and revenue based on Audited Accounts vis-à-vis the approved forecast and categorisation of variation in performance as those caused by factors within the control of the applicant (controllable factors) and those caused by factors beyond the control of the applicant (uncontrollable factors), shall be undertaken by the Commission;

(iii) The mechanism for pass-through of approved gains or losses on account of uncontrollable factors as specified by the Commission in these Regulations;

(iv) The mechanism for pass-through of approved gains or losses on account of controllable factors as specified by the Commission in these Regulations;

(v) Annual tariff determination for Generating Company, Transmission Licensee and Distribution Licensee, for each financial year within the Control period, based on the approved forecast and results of the truing up exercise:

(4) *The Generating Company or Licensee shall have an option for filing the Petition for Multi Year Tariff determination at the time of filing first ARR/Tariff Petition after notification of these Regulations. If the Generating Company or Licensee has opted for Multi Year Tariff determination, it shall submit the forecast of Aggregate Revenue Requirement, expected revenue from existing tariffs and proposed tariff for each year of the Control Period and the Commission shall determine the ARR & tariff for each year of the Control Period:*

Provided that if the Generating Company or Licensee has opted for Multi Year Tariff Determination, it shall submit the Petition for truing up of ARR for the previous year during each year of the Control Period and may submit the Petition to re-determine the ARR and Tariff for ensuing year based on truing up of previous year."

2.4.5 Further, either Multi Year tariff determination or annual tariff determination for next Control Period shall be undertaken based on the option chosen by the generating company or the licensee. Accordingly, the Petitions are required to be filed by Generating Company and the Licensee. In view of optional Multi Year Tariff and annual tariff, Regulation 6 of RERC Tariff Regulations, 2014 is modified as under:

"6. Filing under MYT Period

(1) Every Generating Company or Licensee, latest by 30th November of each year, shall file the following applications during the Control Period:

a) Petition for approval of ARR and determination of tariff for ensuing year
b) Petition for Truing up of ARR for the previous year:

Provided that Truing up for years of the previous MYT Control Periods shall be carried out under respective Tariff Regulations:

Provided further that application for approval of ARR and determination of tariff for the first year of the Control Period, i.e., 2019-20 by every Generating Company and Licensee shall be filed within eight weeks of notification of these Regulations in the official gazette:

Provided further that in case the Generating Company or Licensee has opted for Multi Year Tariff Determination, it shall file the Multi Year Tariff Petition for approval of ARR and determination of tariff for each year of the Control Period within eight weeks of notification of these Regulations in the official gazette:

Provided further that for the first year of the Control Period, i.e., FY 2019-20, the Commission may extend the applicable tariff of FY 2018-19 for a period not exceeding six months by a separate order on an interim basis, subject to adjustment as per the Tariff Order issued by the Commission under these Regulations."

2.5 Specific trajectory for certain variables

2.5.1 The existing Regulation 7(1) of RERC Tariff Regulations, 2014 provides for stipulation of the trajectory for distribution losses, transmission losses and collection efficiency. However, this Regulation has been modified as under so that the trajectory for other variables, if required, may be stipulated by the Commission:

"The Commission may stipulate a trajectory for the Control Period for certain variables including but not limited to transmission losses, distribution losses and collection efficiency, having regard to the past performance."

2.6 Revision in Operational Norms

2.6.1 A suitable performance trajectory for improvement in operational parameters has to be evolved so that the Utilities can strive to achieve superior performance, the benefits of which can be shared with the consumers. This will ensure protection of consumers' interests as well as provide motivation to the Utilities for improving the efficiency of operations.

2.6.2 While setting the norms, due regard has to be given to the existing performance levels and the desired performance levels, and the performance improvement trajectory has to be designed accordingly.

2.7 Truing Up

2.7.1 The existing Regulation 8 of RERC Tariff Regulations, 2014 provides for annual truing up exercise based on a comparison of the audited performance of the Generating Company or Transmission Licensee or Distribution Licensee for the previous financial year, with the approved forecast of aggregate revenue requirement and expected revenue from tariff and charges. The scope of truing up exercise has been retained as per existing Regulation.

2.8 Controllable and Uncontrollable Factors

2.8.1 It is essential to clearly specify the controllable factors and uncontrollable factors and their treatment, since, the impact on the Utility due to uncontrollable factors is generally considered as a pass-through element in tariffs, while the impact of efficiency gain or loss on account of identified controllable factors has to be adjusted between the Utility and the consumers in a specified manner. Accordingly, the Commission has specified the Controllable and Uncontrollable factors in Regulation 9(1) and 9(2) as under:

"(1) The "uncontrollable factors" shall comprise the following factors which were beyond the control of, and could not be mitigated by, the applicant, as determined by the Commission:
a) Force Majeure events;
b) Change in law, judicial pronouncements and Orders of the Central Government, State Government or Commission;
c) Economy wide influences such as unforeseen changes in inflation rate, taxes and statutory levies;
d) Variation in fuel cost on account of variation in coal, oil and all primary-secondary fuel prices;
e) Variation in power purchase expenses for the Distribution Licensees;
f) Variation in freight rates; and
g) Variation in number of consumers or mix of consumers or quantities of electricity supplied to the consumers.

(2) Some illustrative variations or expected variations in the performance of the applicant which may be attributed by the Commission to controllable factors include, but are not limited to, the following:
a) Variations in transmission losses, distribution losses and collection efficiency;
b) Variations in performance parameters such as Station Heat Rate, Coal Transit Losses, Auxiliary Consumption, Secondary Fuel Oil consumption, etc;
c) Variation in rate of interest on working capital requirement;
d) Variation in operation & maintenance expenses."

2.8.2 The uncontrollable factors include Force Majeure events and Change in law. Both factors are proposed to be retained, moreover, definitions of force majeure and change in law have been modified in line with definitions specified in draft CERC Tariff Regulations, 2019 as follows:

""Change in Law" *means occurrence of any of the following events:*

i. *the enactment, bringing into effect or promulgation of any new Indian law;*
ii. *adoption, amendment, modification, repeal or re-enactment of any existing Indian law; or*
iii. *change in interpretation of any Indian law by a competent Court, Tribunal or Indian Governmental Instrumentality, which is the final authority under Indian law for such interpretation or application; or*
iv. *change by any competent statutory authority, in any condition or covenant of any consent or clearances or approval or licence available or obtained for the project; or*
v. *coming into force or change in any bilateral or multilateral agreement or treaty between the Government of India and any other Sovereign Government having implication for the Generating Company or Licensee regulated under these Regulations;*

"Force Majeure Event" *means, with respect to any party, any event or circumstance, which is not within the reasonable control of, or due to an act or omission of, that party and which, by the exercise of reasonable care* *and diligence, that party is not able to prevent, including, without limiting the generality of the foregoing:*

(a) acts of God, including but not limited to lightning, storm, earthquakes, flood, drought and natural disaster;

(b) strikes, lockouts, go-slow, bandh or other industrial disturbances;

(c) acts of public enemy, wars (declared or undeclared), blockades, insurrections, riots, revolution, sabotage, vandalism and civil disturbance;

(d) unavoidable accident, including but not limited to fire, explosion, radioactive contamination and toxic chemical contamination;

(e) any shutdown or interruption of the grid, which is required or directed by the State or Central Government or by the Commission or the State Load Despatch Centre; and any shut down or interruption, which is required to avoid serious and immediate risks of a significant plant or equipment failure;"

2.9 Gains and losses on account of uncontrollable and controllable factors

2.9.1 In this Section, the proposed mechanism for passing through/adjusting the gains and losses on account of uncontrollable and controllable factors has been discussed.

2.9.2 Regulation 9 (1) of RERC Regulations, 2014 specifies that gains or losses on account of uncontrollable factors shall be allowed as an adjustment in tariff. The same proviso has been proposed to be retained in draft RERC Tariff Regulations, 2019.

2.9.3 Further, Regulation 9 (2) of RERC Regulations, 2014 specifies that gains or loss on account of controllable factors shall be retained or borne by Generating Company or Licensee, as the case may be, except for rate of Interest on working capital requirement, Station Heat Rate, Auxiliary Consumption, Secondary Fuel Oil Consumption and Distribution Loss. The sharing ratio for Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption has been specified as 60:40. The Commission has proposed to revise this sharing ratio to 50:50 in line with sharing ratio for other controllable factors.

2.10 Periodicity of Tariff Determination

2.10.1 Presently, the Commission has been undertaking annual determination of tariff in the State of Rajasthan. However, as discussed earlier, in the draft Regulations the Commission has proposed the option to the Generating Company and Licensee to choose either Multi Year tariff determination for the entire Control Period or annual tariff determination. This will provide certainty to the Generating Company and Licensee on the income and expense projections. There are SERCs who are following the Multi Year Tariff determination approach coupled with specifying the year on year trajectory of performance parameters of the Control Period.

2.10.2 Accordingly, the following Regulation has been proposed for periodicity of tariff determination:

"10. Periodicity of tariff determination

(1) *The Commission shall determine the tariff of a Generating Company, except Captive Generating Plants and Renewable Energy Power Plants, or Licensee covered under multi-year tariff principles for each financial year during the Control Period, at the commencement of such financial year, having regard to the following:*

a) The MYT principles specified under these Regulations;
b) In case of Generating Company and Licensee, the approved forecast of aggregate revenue requirement and expected revenue from tariff and charges for such financial year(s);
c) Impact of truing up for previous financial year; and
d) Approved gains and losses to be duly adjusted in tariffs, following the truing up of expenses and revenue.

Provided further that in case the Generating Company or Licensee has opted for Multi Year Tariff Determination, the Commission shall determine the ARR and Tariff for each financial year of the Control Period as a part of approval of Multi Year Tariff Petition

(2) *The tariff for a Generating Company or Licensee shall ordinarily be determined not more than once in a year, except in case of adjustment of fuel cost and/or rate of power purchase, wherever applicable."*

2.11 Suo-Motu determination of tariff

2.11.1 The enabling clause for suo-motu determination of tariff is proposed to be retained as per RERC Tariff Regulations, 2014. Such enabling clause shall confer specific powers to the Commission to initiate suo-motu proceedings for tariff determination in the absence of tariff applications.

2.11.2 It is proposed that in case the Petition is not filed within three months of stipulated date, the Commission may, on its own initiate proceedings for tariff determination.

2.12 Petition for approval of ARR and determination of tariff

2.12.1 As regards the procedure for determination of tariff, the Commission has proposed to retain the existing Regulations 11 and 12 of RERC Tariff Regulations, 2014.

2.13 Subsidy by the State Government

2.13.1 Regarding the subsidy by the State Government, the existing Regulation 13 of RERC Tariff Regulations, 2014 is proposed to be retained.

2.14 Timeline for implementation

2.14.1 The proposed RERC Tariff Regulations, 2019 shall extend to the whole of the State of Rajasthan. These Regulations shall be applicable for determination of tariff in cases covered under these Regulations from FY 2019-20, i.e., April 1, 2019 and onwards up to FY 2023-24, i.e., March 31, 2024. However, for all purposes including the review matters pertaining to the period till FY 2018-19, the issues related to determination of tariff shall be governed by the RERC Tariff Regulations, 2014 or RERC (Terms and Conditions for Determination of Tariff) Regulations, 2009, including amendments thereto, as the case may be.

3 Financial Principles for computing costs & return

3.1 Capital Cost and capital structure

3.1.1 Capital Expenditure (Capex) forms an important and integral part of the expenses incurred by the Utilities and contributes significantly to the final prices that consumers pay. There is also a close link between capital expenditure and quality of supply. Hence, there is a need to ensure that capital expenditure incurred by the Utility is prudent and efficient. Once this is determined, the Regulator has to allow the appropriate level of Capex to form part of the revenue requirement of the Utility.

3.1.2 Capital expenditure has a significant bearing on the tariff payable by the consumers, on account of the pass through of the related expenses like depreciation, interest on long-term loans, return on equity/capital employed, etc.

3.1.3 The RERC Tariff Regulations, 2014 specifies the procedure for approval of capital expenditure by the Generating Companies and Licensees. Further, draft CERC Tariff Regulations, 2019 also specifies the procedure of check for approval of capital expenditure.

3.1.4 The approval of Capital Cost is one of the most critical aspects for the determination of Tariff. Capital Cost is considered as the base for determination of return on investment. The existing Regulations allow capital cost for the new projects (to be commissioned in the Control Period) based on the expenditure incurred as on date of commercial operation (COD), duly certified by the Auditors subject to prudence check by the Commission. For the existing projects, the capital cost admitted by the Commission during the preceding tariff periods is considered along with additional capitalization during the Control Period after due diligence.

3.1.5 The Capital Cost includes interest during construction, financing charges and foreign exchange rate variation, capitalized initial spares, additional capitalization, etc., up to the date of commercial operation of the project. Further, any revenue generated on account of injection of infirm power through unscheduled interchange in excess of fuel cost is used to reduce the capital cost.

3.1.6 The existing provisions related to Capital Cost in RERC MYT Regulations, 2014 is reproduced below:

"***16. Capital Cost and Capital Structure:***

(1) In case of existing projects, the capital cost admitted by the Commission prior to 01.04.2014 and the additional capital expenditure projected to be incurred for the respective year of the control period 2014-19, as may be admitted by the Commission, shall form the basis for determination of tariff.

(2)Capital Cost for a project shall include:
(a) the expenditure incurred including interest during construction and financing charges, any gain or loss on account of foreign exchange risk variation on the loan during construction up to the date of commercial operation of the project as admitted by the Commission after prudence check;
(b) capitalized initial spares subject to the ceiling rates specified in this regulation; and
(c)additional capitalization determined under regulation 17;
Provided that the assets forming part of the project but not put to use or not in use, shall be taken out of the capital cost.

(3) The capital cost shall be admitted by the Commission after prudence check and shall form the basis for determination of tariff.
Provided that the actual capital expenditure as on COD for the original scope of work based on audited accounts of the company may be considered subject to prudence check by the Commission. If sufficient justification is provided for any escalation in the capital cost beyond the original scope of works, the same may be considered by the Commission during prudence check.

(4) The prudence check may include scrutiny of the reasonableness of the capital expenditure, financing plan, interest during construction, use of efficient technology, cost over-run, and such other matters as may be considered appropriate by the Commission for determination of tariff. While carrying out the prudence check of the capital cost, the Commission shall look into whether the Generating Company or Licensee has been careful in its judgements and decisions while executing the project or has been careful and vigilant in executing the project.

(5)Where power purchase agreement or transmission agreement or wheeling agreement provides for a ceiling of capital cost, the capital cost to be considered shall not exceed such ceiling.

(6) The capital cost may include capitalized initial spares as a percentage of original capital cost upto cut off date subject to the following ceiling norms:

- *a) 2.5%, in case of coal based/ lignite fired generating stations,*
- *b) 4.0%, in case of gas turbine/ combined cycle generating stations,*
- *c) 1.5%, in case of hydro-generating stations,*
- *d) 1.5% in case of transmission licensees*
- *e) 1.5% in case of distribution licensees.*

(7) Swapping of foreign currency loans will be permitted. Cost of swapping and interest rate charges thereafter, will be considered by the Commission after prudence check. The Generating Company or Licensee shall provide full particulars of the swapped loans. Cost of swapping will be considered towards interest and finance charges.

(8)Restructuring of capital in terms of relative share of equity and loan shall be permitted during life of the project provided it does not affect tariff adversely. Any benefit from such restructuring shall be passed on to persons sharing the capacity charge in case of a Generating Company and to long-term intra-State open access customers of Transmission Licensee or Distribution Licensee or consumers in case of such Licensees.
… …

3.1.7 There are several issues and challenges with respect to the Capital Cost of generating companies and licensees which needs to be addressed in the Regulations. The critical issues with respect to the Capital Cost are provisions to handle capital expenditure to comply with new environmental norms, expenditure due to change in law and force majeure events, availability of wagons, etc. The several new capital expenditures on account of new developments in the power sector namely, ash utilisation, emission control system, fulfilment of any conditions for obtaining environmental clearance of the project, etc., are required to be mentioned in the capital cost.

3.1.8 Regarding prudence check of the capital cost, the Commission has proposed to analyse capital cost of similar projects based on historical data, wherever available, while scrutinizing capital expenditure of a thermal generating station or the licensee.

3.1.9 As regards initial spares, the existing Regulations specifies the basis for initial spares as project cost. It was observed that typically the initial spares are procured from the OEM suppliers and it may not be appropriate to consider the cost of initial spares as percentage of the total capital cost. Accordingly, the Commission proposes to consider initial spares as a percentage of the Plant and Machinery cost upto cut-off date, subject to the ceiling norms. This is in line with the CERC Tariff Regulations, 2014 as well as Draft CERC Tariff Regulations, 2019.

3.1.10 Further, with respect to initial spares, the Commission has proposed different initial spares for Transmission lines and sub-stations whereas the initial spares of all compensation devices including series and shunt compensation and HVDC are kept the same.

3.1.11 It is proposed to make provision for approval of capital cost in line with provisions specified in draft CERC Tariff Regulations, 2019, to have better clarity for approval and prudence of capital cost. The Commission after taking into consideration the above mentioned issues and the various aspects with respect to Capital Cost has proposed the Regulation 16 as reproduced hereunder:

"

(1) In case of existing projects, the capital cost admitted by the Commission prior to 01.04.2019 and the additional capital expenditure projected to be incurred for the respective year of the control period 2019-24, as may be admitted by the Commission, shall form the basis for determination of tariff.

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

(a) the expenditure incurred including interest during construction and financing charges, any gain or loss on account of foreign exchange risk variation on the loan during construction up to the date of commercial operation of the project as admitted by the Commission after prudence check;

(b) capitalised initial spares subject to the ceiling rates specified in this

regulation; and

(c) expenditure on account of additional capitalisation determined under regulation 17 and de-capitalisation:

(d) Provided that the assets forming part of the project but not put to use or not in use, shall be taken out of the capital cost.

(e) Adjustment due to revenue from sale of infirm power in excess of fuel cost prior to date of commercial operation;

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

(g) Expenditure on account of emission control system necessary to meet applicable emission standards notified by Government;

(h) Expenditure on account of fulfilment of any conditions for obtaining environmental clearance for the project;

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

(3) The capital cost in case of existing or new hydro generating station shall also include cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved.

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

(a) The assets forming part of the project, but not in use (to be declared at the time of filing tariff petition);

(b) De-capitalisation of assets after the date of commercial operation on account of replacement or removal on account of obsolescence or shifting from one project to another project;

(c) In case of hydro generating station, any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State Government by following a transparent process;

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

(e) Any grant received from the Central or State Government or any statutory body or authority for the execution of the project, which does not carry any liability of repayment.

(5) The capital cost shall be admitted by the Commission after prudence check and shall form the basis for determination of tariff.

Provided that the actual capital expenditure as on COD for the original scope of work based on audited accounts of the company may be considered subject to prudence check by the Commission. If sufficient justification is provided for any escalation in the capital cost beyond the original scope of works, the same may be considered by the Commission during prudence check.

(6) The prudence check may include scrutiny of the reasonableness of the capital expenditure, financing plan, interest during construction, use of efficient technology, cost over-run, and such other matters as may be considered appropriate by the Commission for determination of tariff.

While carrying out the prudence check of the capital cost, the Commission shall look into whether the Generating Company or Licensee has been careful in its judgements and decisions while executing the project or has been careful and vigilant in executing the project.

(7) Where power purchase agreement or transmission agreement or wheeling agreement provides for a ceiling of capital cost, the capital cost to be considered shall not exceed such ceiling.

(8) Initial spares shall be capitalised as a percentage of the Plant and Machinery cost upto cut-off date, subject to following ceiling norms:

(a) Coal-based/lignite-fired thermal generating stations- 4.0%

(b) Gas Turbine/Combined Cycle thermal generating stations -4.0%

(c) Hydro generating stations including pumped storage hydro generating station- 4.0%

(d) Transmission System

Transmission Line-	*1.00%*
Transmission Sub-station	*4.00%*
Series Compensation devices and HVDC Station	*4.00%*
Gas Insulated Sub-station	*5.00%*
Static Synchronous Compensator	*3.50%*

(e) Distribution System

Distribution Line-	*1.00%*
Distribution Sub-station	*4.00%*

Provided that where the generating station has any transmission equipment forming part of the generation project, the ceiling norms for initial spares for such equipment shall be as per the ceiling norms specified for transmission system under these Regulations:

Provided further that once the transmission project is commissioned, the cost of initial spares shall be restricted on the basis of plant and machinery cost corresponding to the transmission project at the time of truing up:

Provided also that, for the purpose of computing the cost of initial spares, plant and machinery cost shall be considered as project cost as on cut-off date excluding IDC, Financing Charges, overheads, Land Cost and cost of civil works.

(9) Swapping of foreign currency loans will be permitted. Cost of swapping and interest rate charges thereafter, will be considered by the Commission after prudence check. The Generating Company or Licensee shall provide full particulars of the swapped loans. Cost of swapping will be considered towards interest and finance charges.

(10) Restructuring of capital in terms of relative share of equity and loan shall be permitted during life of the project provided it does not affect tariff adversely. Any benefit from such restructuring shall be passed on to persons sharing the capacity charge in case of a Generating Company and to long-term intra-State open access customers of Transmission Licensee or Distribution Licensee or consumers in case of such Licensees."

3.2 Additional capitalization

3.2.1 As regards Additional Capitalisation, the existing provisions of the RERC Tariff Regulations, 2014 specify that the capital expenditure on account of certain components 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 as Additional Capital Expenditure, subject to prudence check. Further, the existing Tariff Regulations also allows additional capital expenditure on new assets, incurred after cut-off date for meeting liabilities of arbitration award, decree or order of the court; on account of change in law; and deferred works relating to ash pond or ash handling system in the original scope of work. The Commission has also proposed to clearly segregate the additional capitalisation within the original scope and upto cut-off date, additional capitalisation within original scope and after cut-off date, and additional capitalisation beyond the original scope,

3.2.2 Further, the existing Regulations have specified the cut-off date as 31st March of the year closing after 365 days from COD of the project, and in case the project is declared under COD in the last quarter of a year, the cut-off date shall be 31st March of the year closing after 730 days from the date of commercial operation.

3.2.3 In order to give sufficient time to complete the balance works after the date of commercial operation of a project and to close the contracts, the above period has been provided. However, it has been observed that Generating Companies and Licensees have been facing difficulty in completing the additional capitalisation within original scope of the project in a year as some of the works and closing of contracts gets extended beyond one year. Also, there is provision for different cut-off date for the project under COD in last quarter of the year, effective 2 years. Hence, in order to bring uniformity for all projects and to provide sufficient time for completion of balance work, the Commission has proposed to extend cut-off date up to three years from the COD and the same is in line with CERC Draft Tariff Regulations, 2019.

3.2.4 Further, existing Regulation 17 of RERC Tariff Regulations, 2014 provides no segregation for additional capitalisation for existing and new projects up to cut-off date. Hence for more clarity, separate provisions have been proposed for additional capitalisation for existing and new projects.

3.2.5 Further, enabling provision for additional capitalisation beyond original scope and additional capitalisation on account of revision of emission standards have been proposed in line with the draft CERC Tariff Regulations, 2019.

3.2.6 In view of the above, the Regulation 17 of draft RERC Tariff Regulations, 2019 has been proposed as under:

"

(1) The following capital expenditure in respect of a new project or existing project, actually incurred or projected to be incurred within original scope of work, after the date of commercial operation and upto the cut-off date and duly audited, may be considered by the Commission against the original scope of work, subject to prudence check:

(a) Due to undischarged liabilities recognised to be payable at a future date;

(b) On works deferred for execution;

(c) Liabilities to meet award of arbitration or for compliance of direction or order of any statutory authority or satisfaction of order or decree of any court of law;

(d) On account of change in law or compliance of any existing law within cut-off date;

(e) On procurement of initial spares included in the original project costs subject to the ceiling norm laid down in regulation 16(8);

(f) Force Majeure events:

Provided that the details of the work included in the 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 undischarged 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:

Provided also that the generating company or the transmission licensee, as the case may be, shall submit the details of works asset wise/work wise included in the original scope of work along with estimates of expenditure, liabilities recognized to be payable at a future date and the works deferred for execution.

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

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

(b) Change in law;

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

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

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

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

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

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

(c) The replacement of such asset has otherwise been allowed by the Commission based on sufficient grounds.

(4) 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 19.

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

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

(b) Change in law;

(c) Force Majeure Events;

(d) Any capital expenditure to be incurred on account of need for higher security and safety of the plant as advised or directed by appropriate Indian Government Instrumentality or statutory authorities responsible for national or internal security;

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

(f) Any additions works/services, necessary for efficient and successful operation of a generation station or transmission system but not included in the original capital cost

Provided that 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 19:

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

(6) Any expenditure admitted by the Commission for determination of tariff on renovation, modernization, life extension and restoration of assets damaged due to natural calamities shall be serviced on normative debt-equity ratio specified in regulation 19 after writing off the original amount of the replaced assets from the original cost.

(7) The additional capitalisation on account of revised emission standards shall be as under:

(a) A generating company requiring to incur additional capital expenditure

in the existing generating station for compliance of the applicable revised emission standards shall share its proposal with the beneficiaries and file a petition for approval for undertaking such additional capitalization;

(b) The proposal under clause (a) above shall contain details of proposed technology as specified by the Central Electricity Authority, scope of the work, phasing of expenditure, schedule of completion, estimated completion cost including foreign exchange component, if any, detailed computation of indicative impact on tariff to the beneficiaries, and any other information considered to be relevant by the generating company;

(c) Where the generating company makes an application for approval of additional capital expenditure on account of implementation of revised emission standards, the Commission may grant approval after due consideration of the reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.

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

(8) In case of de-Capitalisation or retirement of assets of a generating company or licensee, as the case may be,

(a) the original approved cost of such assets shall be deducted from the value of gross fixed assets;

(b) the original approved equity of such assets shall be deducted from the value of equity.

(c) The value of loan shall be reduced by the normative outstanding debt component i.e., original approved cost of such assets less accumulated depreciation allowed for such assets less approved equity of such assets

3.3 Assets Created out of Consumer Contribution, Deposit Work and Grants

3.3.1 The depreciation in regulated industries is used for repayment of loans and it is not used for replacement of assets. The Utilities may receive Consumer Contribution from their consumers for creation of fixed assets used for serving the consumers. However, such assets remain in the books of the Utility. Similarly, one-time grants or capital subsidies are generally given to the Utilities by the Government for creation of fixed assets. At the end of the life span of such fixed assets created out of grants or Consumer Contribution, replacement of these old fixed assets are generally included in the normal capital expenditure plan and the funding of the same is claimed by the Utilities from the pool of consumers through the ARR and tariff, irrespective of the source of funding of the original fixed assets. When the Utility funds such replacement of old fixed assets, either by its own equity or by loan or by a mix of both, then only it will become eligible to claim returns on the new assets, subject to the prescribed Debt-Equity norm.

3.3.2 Therefore, allowing depreciation on fixed assets created out of Consumer Contribution or Grants will result in making available undue surplus to the Generating Company or Licensee at the expense of the consumers.

3.3.3 The RERC Tariff Regulations, 2014 also does not provide for depreciation on the assets to the extent of financial support provided through consumer contribution, deposit work and grants.

3.3.4 The RERC Tariff Regulations, 2014 specifies as under:

"18. Consumer Contribution, Deposit Works and Grant

(1) The following nature of work carried out by the Generating Company or Licensee shall be classified under this category:

(a) Works after obtaining a part or all of the funds from the users/consumers in the context of consumer contribution, deposit works, or grant.

(b) Capital works undertaken by utilising grants received from the State and Central Governments, including funds under RGGVY, R-APDRP, IPDS, DDUGJY etc.

(2) Principles for treatment of the expenses on such capital expenditure shall be as follows:

(a) Normative O&M expenses as specified in these Regulations shall be allowed.

(b) Provisions related to Depreciation, as specified in regulation 22, shall not be applicable to the extent of financial support provided through consumer contribution, deposit work and grant. The licensee or generating company, as the case may be, shall be allowed to claim deprecation to the extent of financial support, including the loan and equity contribution, provided by them.

(c) Provisions related to return on equity, as specified in regulation 20 shall be applicable to the extent of normative debt: equity mix of 70:30 or actual equity, whichever is less, on the contribution made by the licensee or generating company, as the case may be."

3.3.5 It is proposed to continue with the existing approach. In addition to this, it is proposed that debt:equity ratio shall be computed after deducting the amount of consumer contribution, deposit works and grants as the generating company of licensee is not making any investments for these works. The similar approach is adopted by some of the other SERCs in the country. Hence, the following has been proposed under Regulation 18 (2):

"The debt: equity ratio shall be considered in accordance with Regulation 19, after deducting the amount of such financial support;"

3.3.6 Also, in case funds of similar nature are received but not qualified under consumer contribution, deposit works and grants, the following has been proposed under Regulation 18 (1):

"(c) Other works undertaken with funding received without any obligation of repayment and with no interest costs."

3.4 Debt - Equity Ratio

3.4.1 The capital expenditure made by Licensees and Generation Companies should be done at an optimum debt:equity ratio, in order to balance the need for providing sufficient returns that can be earned by Licensees and Generation Companies and protecting the interest of consumers. Since, it is proposed to adopt Equity as the Rate Base for Utilities in Rajasthan, it is necessary to specify the normative Debt-Equity ratio. The existing RERC Regulations, 2014 specified the normative debt: equity ratio of 70:30. In case the actual equity employed is less than 30% of the capital cost, then actual equity is considered for determination of tariff. In case the actual equity employed is more than 30% of the capital cost, then the equity in excess of 30% is considered as normative loan for determination of tariff. Other SERCs have followed the same normative debt:equity ratio for tariff determination in their respective States.

3.4.2 In this context, Clause 5.3 (b) of Tariff Policy stipulates:

"For financing of future capital cost of projects, a Debt: Equity ratio of 70:30 should be adopted. Promoters would be free to have higher quantum of equity investments. The equity in excess of this norm should be treated as loans advanced at the weighted average rate of interest and for a weighted average tenor of the long term debt component of the project after ascertaining the reasonableness of the interest rates and taking into account the effect of debt restructuring done, if any. In case of equity below the normative level, the actual equity would be used for determination of Return on Equity in tariff computations. "

3.4.3 Regulation 19 of existing RERC Tariff Regulations, 2014 specifies as under:

"19. Debt-equity ratio

For the purpose of determination of tariff, debt-equity ratio as on date of commercial operation in case of a new generating station, transmission line and distribution line or substation commissioned or capacity expanded on and/or after 1.4.2014, shall be 70:30. 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 loan. Where actual equity employed is less than 30%, the actual equity shall be considered:

Provided that in case of the Generating Company, Transmission Licensee and Distribution Licensee, if any fixed asset is capitalised on account of capital expenditure project prior to April 1, 2014, debt-equity ratio allowed by the Commission for determination of tariff for the period ending March 31, 2014 shall be considered:

Provided further that the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment:

Provided further that in case of retirement or replacement of assets, the equity capital approved as mentioned above, shall be reduced to the extent of 30% (or actual equity component based on documentary evidence, if it is lower than 30%) of the original cost of the retired or replaced asset.

Explanation

The premium, if any, raised by the generating company or the licensee, while issuing share capital and investment of internal resources created out of its free reserves, for the funding of the project, shall 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 or the transmission system or distribution system. "

3.4.4 It is proposed to continue with the said provision of Debt - Equity ratio of 70:30 for tariff determination of Generation Companies, Transmission Licensee and Distribution Licensees during the next Control Period, which is also in line with CERC Draft Regulations, 2019.

3.4.5 Further, the existing Tariff Regulations provide return on entire equity, even after the plant has been fully depreciated. The internal resources generated by way of depreciation are reutilized for further capacity addition. However, the Commission deems it appropriate to base the returns after completion of useful life of the asset by reducing the balance depreciation after repayment of loan in respect of the original project cost. Hence, the following proviso has been proposed:

"In case of generating station or a transmission system or distribution system, which has completed its useful life as on or after 1.4.2019, the accumulated depreciation as on the completion of the useful life less cumulative repayment of loan shall be utilized for reduction of the equity and depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan and thereafter shall be utilized for reduction of equity. "

3.5 Approach for Providing Returns

3.5.1 In any business, in addition to recovery of the costs incurred, the investors are entitled to earn an appropriate return on their investment, since there are alternative investment opportunities and the investor has to choose between these alternative investment opportunities, keeping in view his risk-return profile.

3.5.2 Returns are allowed on the Rate Base of Utilities for the investments made by Utilities in the regulated business. The Commission in existing RERC Tariff Regulations, 2014 has adopted Return on Equity approach, where the rate base is equal to the equity invested in the business.

3.5.3 Most of the State Electricity Regulatory Commissions (SERCs) in India have adopted the RoE approach for providing returns, which is a tried and tested approach and is also easy to implement. CERC has also been following the ROE approach. In draft CERC Tariff Regulations, 2019, Return on Equity approach has been adopted for providing return on investment.

3.5.4 Hence, it is proposed that the present approach used by the Commission, i.e., RoE approach, be continued for the next Control Period.

3.6 Rate of Return

3.6.1 Clause (d) of Section 61 of the Act provides that the Commission while specifying the terms and conditions for determination of tariff, shall be guided by the principle of "*safeguarding of consumers interest and at the same time, recovery of cost of electricity in a reasonable manner*".

3.6.2 The Commission adopted the RoE approach while formulating the RERC Tariff Regulations, 2014. The RERC Tariff Regulations, 2014 specified that the return on equity shall be computed on pre-tax basis at the base rate of 15.5% for conventional generating stations and transmission licensee, and 16% for distribution licensee.

3.6.3 In the draft CERC Regulations, 2019, CERC has adopted the Capital Asset Pricing Model (CAPM) to determine the cost of equity as it was more suitable and widely accepted for determining cost of equity investment in Indian Power Sector. It is recognised that this model will not give the exact rate of return on equity, as it is based on the assumption of data which is taken as input. However, the CAPM gives an approximate rate of return on equity, which can be used to take an informed decision on rate of return on equity.

3.6.4 The CAPM describes the relationship between the expected return and risk of investing in a security. It shows that the expected return on a security is equal to the risk-free return plus a risk premium, which is based on the beta of that security. CAPM can be summarized according to the following formula:

Required (or expected) Return = Risk Free Rate + (Market Return – Risk Free Rate) x Beta.

3.6.5 CERC in Draft Regulations, 2019 has considered the yield on zero coupon Government securities as Risk Free rate. The Risk Free rate has been considered as average of the yield on 10-year government securities yield for the period April, 2017 to March, 2018, i.e., 6.97% and for first quarter of FY 2018-19 is 7.76%. In the last 12 months or so, the 10-year government securities yield has been showing an increasing trajectory and has increased to 7.76%, after touching a 10-year low of 6.97% in FY 2017-18.

3.6.6 In order to compute the Market Risk Premium (Rm), the return expected by the market has been estimated by assuming the past returns provided by the equity market, as it mirrors the expectations of the investors. The average annual growth rate of the BSE Sensex over the period of 2001–2019 (Q-1) works out to around 17.00%. Further, Beta is a measure of the volatility, or systematic risk, of a security or a portfolio in comparison to the market as a whole.

3.6.7 For computing the Beta for CAPM formula, firstly the levered Beta is estimated for all major power sector companies in the business of power generation and transmission listed in the BSE. The overall market has a beta of 1.0, and individual stocks are ranked according to how much they deviate from the market. Then the levered Beta is converted to unlevered Beta considering the actual debt: equity ratio and effective tax rate to gauge the business risk.

3.6.8 After adopting CAPM model, the cost of equity for regulated entities in the power sector works out to be in the range of 12%-15%.

3.6.9 It is noted that the existing RERC Regulations, 2014 specifies the rate of return on equity for Generation and Transmission as 15.5%. Considering the reduction in interest rates over a period of time and cost of equity computed as discussed above, it is considered necessary to re-visit the rate of return on equity specified in RERC Regulations, 2014.

3.6.10 It is observed that the gestation period for transmission assets is around 2-3 years, while for Generation projects, the gestation period is around 4-7 years. Therefore, at the same rate of return, the effective IRR for a conventional generation project would be marginally lower than that of a transmission project due to higher gestation period, as the equity investments made during the development and construction stage do not earn any returns till COD of the project is achieved.

3.6.11 In view of the cost of equity derived and gestation period, the Commission has proposed rate of return on equity of 14% for Transmission and 15% for Generation. However, being the business with highest risk, rate of return on equity for distribution is proposed to be continued at same level of 16%.

3.7 Tax on Return on Equity

3.7.1 Regulation 29 of RERC Tariff Regulations, 2014 specifies Tax on Return on Equity as under:

"(1) Tax on the income corresponding to Return on Equity approved by the Commission for the generating company or the licensee, as the case may be, shall be directly recovered from the beneficiaries. Tax on the income shall be computed with reference to the total actual income tax paid by the generating company or the licensee as the case may be, on pro-rata basis with respect to return on equity. The tax on any other income stream (including efficiency gains, incentive, etc) other than Return on Equity shall not be recovered from beneficiaries, and tax on such other income shall be payable by the generating company or licensee, as the case may be.

(2) In case the profit before tax for a particular year is higher than the Return on Equity as approved by the Commission for any year, the Income Tax on Return

on Equity to be recovered from the beneficiaries on pro-rata basis in the following manner:
Income Tax to be recovered = Total Income Tax Paid x RoE approved by the Commission/Profit before Tax.

(3) In case the Profit before Tax for a particular year is lower than the Return on Equity as approved by the Commission for any year, the actual Income Tax paid by the Generating Company or Transmission Licensee shall be recovered from beneficiaries.

(4) Any under-recovery or over-recovery 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 auditor:

Provided that income-tax allocated to the thermal generating station shall be charged to the beneficiaries in the same proportion as annual fixed charges, and 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 transmission licensee, the sharing of income-tax shall be in the same proportion as annual transmission charges, and in case of distribution licensee, the sharing of income-tax shall be in the proportion of monthly bill:

Provided further that the generating company and licensee shall bill the Income Tax under a separate head called 'Income Tax Reimbursement' in their respective bills.

(5) The tax computation on ROE as approved by the Commission may be made based on advance tax assessed or deposited subject to adjustment on actual at the end of the year. The recovery or refund of tax, if any, in comparison with actual tax shall be made along with interest as determined by the assessing officer of Income Tax department. The penalty, if any, arising on account of delay in deposit of tax or short deposit of tax amount shall not be claimed by the generating company or the licensee as the case may be:

Provided that the deferred tax liability before 1.4.2009 shall be recovered from the beneficiaries as and when the same gets finalized. No claim on account of deferred tax liability arising after 1.4.2009 shall be made from the beneficiaries."

3.7.2 The above said Regulation specifies that Income Tax shall be directly recovered from the beneficiaries. Income Tax shall be computed on return on equity and limited to that extent.

3.7.3 The tariff is approved based on ARR, which includes the profit equal to RoE allowed by the Commission. If Generating company or the Licensee separately recovers the Income Tax and the same becomes part of their income, on this again Income Tax is applicable. To avoid such problem, CERC has been allowing Tax on Return on Equity by grossing up the base rate of return on equity with the effective tax rate. Similar approach of grossing up the Return on Equity for providing the tax on return on equity has been proposed in the Draft Regulations.

3.7.4 Further, if the Generating Company or Licensee reduces its expenses during the year on efficiency improvement on account of controllable factors, the profit would be more than the RoE allowed. However, as per the existing Regulations, Generating Company or the Licensee has to bear the Income Tax on account of such efficiency improvement, as Income Tax has been limited to tax on RoE, and income tax on profits due to such efficiency improvement is not considered, while the savings on account of efficient improvement on account of controllable factors is shared with the beneficiaries. The Commission is of the view that with this approach, the net savings allowed to be retained by Generating Company or Licensee on account of efficiency gains gets reduced with respect to sharing ratio prescribed in the Regulations. Hence, it is proposed to consider the sharing of efficiency gains on account of controllable factors net of income tax based on effective tax rate.

3.7.5 Accordingly, the following Regulation has been proposed:

" ***29 Tax on Return on Equity***

(1) The base rate of return on equity as allowed by the Commission shall be grossed up with the effective tax rate of the respective financial year. For this purpose, the effective tax rate shall be considered on the basis of actual tax paid in the respect of the financial year in line with the provisions of the relevant Finance Acts by the concerned generating company or the licensee, as the case may be. The actual tax paid on income from other businesses including deferred tax liability (i.e. income from business other than business of generation or transmission, as the case may be) shall be excluded for the calculation of effective tax rate.

(2) Rate of return on equity shall be rounded off to three decimal places and shall be computed as per the formula given below:

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

Where "t" is the effective tax rate and shall be calculated at the beginning of every financial year based on the estimated profit and tax to be paid estimated in line with the provisions of the relevant Finance Act applicable for that financial year to the company on pro-rata basis by excluding the income of non-generation, non-transmission and non-distribution business, as the case may be, and the corresponding tax thereon. In case of generating company or licensee paying Minimum Alternate Tax (MAT), "t" shall be considered as MAT rate including surcharge and cess.

Illustration-

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

Rate of return on equity = 15.00/(1-0.2155) = 19.120%

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

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

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

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

(d) Rate of return on equity = 15/ (1-0.24) = 19.737%

(3) The Generating Company or licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year considering the effective tax rate computed based on actual tax paid together with any additional tax demand including interest thereon, duly adjusted for any refund of tax including interest received from the income tax authorities pertaining to the tariff period 2019-24 on actual gross income of any financial year. However, penalty, if any, arising on account of delay in deposit or short deposit of tax amount shall not be claimed by the generating company or the licensee as the case may be. Any under-recovery or over-recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries as the case may be on year to year basis as part of truing-up."

3.8 Interest and finance charges on loan capital

3.8.1 The Regulation 21 of RERC Tariff Regulations, 2014 specifies as under:

"***21. Interest and finance charges on long-term loans***

(1) The loans arrived at in the manner indicated in regulation 19 shall be considered as gross normative loan for calculation of interest on loan.

(2) The normative loan outstanding as on 1.4.2014 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2014 from the gross normative loan.

(3) The repayment for each year of the Control Period shall be deemed to be equal to the depreciation allowed for that year.

(4) Notwithstanding any moratorium period availed by the Generating company or the Licensee, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the annual depreciation allowed.

(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the regulated business of the Generating Company or Licensee as the case may be:

Provided that the weighted average interest rate allowed by the Commission for normative loans shall continue to be applicable to the outstanding normative loans:

Provided further that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest shall be considered:

Provided further that if the regulated business of the Generating Company or Licensee, as the case may be, does not have actual loan, then the weighted average rate of interest of the Generating Company or Licensee as a whole shall be considered.

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

(7) The Generating Company or the Licensee shall make every effort to re-finance the actual loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings on interest shall be shared between the beneficiaries and the Generating Company or the Licensee in the ratio of 2:1.

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

3.8.2 As per RERC Tariff Regulations, 2014, the rate of interest shall be the weighted average rate of interest computed on the basis of the actual loan portfolio at the beginning of each year applicable to the Generation Company or the Transmission Licensee or the Distribution Licensee. However, the actual interest incurred during the year varies depending on the variation in the interest rates. Hence, it is proposed to consider the weighted average rate of interest computed on the basis of the actual loan portfolio during the year, at the time of Truing-up.

3.8.3 Further, as regards the finance charges, it is proposed that actual finance charges incurred for obtaining the actual loans shall be allowed at time of Truing-up, subject to prudence check by the Commission.

3.8.4 As discussed earlier, while computing the debt and equity amount, it is proposed that the debt-equity ratio of 70:30 is to be applied on the asset value after reducing the funds received through consumer contribution, grants, deposit works, and capital subsidy.

3.8.5 The variation in market interest rate is not within the control of the Utility. However, the option of re-financing of loan is always available with the Utility for reducing the interest expenses. The existing RERC Tariff Regulations, 2014 also provides for the same. It is proposed that Utilities shall make their every effort to re-finance/re-structure the loan as long as its results in net savings on interest and such benefit shall be shared between beneficiaries and Utilities in the ratio of 50:50, and the costs associated with such refinancing/re-structuring shall be borne by the beneficiaries.

3.8.6 Security deposits are paid by the consumers availing service from Distribution Licensees on post-paid basis, thus, the security deposits act as a guarantee for Distribution Licensees. Interest on security deposits is payable by the Distribution Licensees to the consumers. The Electricity Act, 2003 specifies that the

Distribution Licensee shall pay interest at the rate equivalent to the Bank Rate or more.

3.8.7 As regards the interest on consumer security deposit, it is proposed that, at time of truing up, actual interest paid on consumer security deposit during the year shall be allowed by the Commission, subject to prudence check.

3.8.8 In view of the above, Interest and finance charges on long-term loans has been proposed as under:

“

(1) The loans arrived at in the manner indicated in regulation 19 shall be considered as gross normative loan for calculation of interest on loan:

Provided further that in case of retirement or de-capitalisation of assets, the loan arrived as mentioned above, shall be reduced in accordance with Regulation 17(8).

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

(3) The repayment for each year of the Control Period shall be deemed to be equal to the depreciation allowed for that year.

(4) Notwithstanding any moratorium period availed by the Generating Company or the Licensee, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the annual depreciation allowed.

(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the regulated business of the Generating Company or Licensee as the case may be:

Provided that at the time of truing up, the weighted average rate of interest computed on the basis of actual loan portfolio during the concerned year shall be considered as the rate of interest:

Provided further that the weighted average interest rate allowed by the Commission for normative loans shall continue to be applicable to the outstanding normative loans:

Provided further that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest shall be considered:

Provided also that if the regulated business of the Generating Company or Licensee, as the case may be, does not have actual loan, then the weighted average rate of interest of the Generating Company or Licensee as a whole shall be considered.

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

(7) *The above interest computation shall exclude the interest on loan amount, normative or otherwise, to the extent of capital asset funded by Consumer Contribution, Deposit Works, Grants and Capital Subsidy.*

(8) *The finance charges incurred for obtaining loans from financial institutions for any year shall be allowed by the Commission at the time of Truing up, subject to prudence check.*

(9) *The Generating Company or the Licensee shall make every effort to re-finance/re-structure the actual loan as long as it results in net savings on interest and in that event the costs associated with such re-financing/re-structuring shall be borne by the beneficiaries and the net savings on interest shall be shared between the beneficiaries and the Generating Company or the Licensee in the ratio of 1:1.*

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

(10) *Interest shall be allowed only on the amount held in cash as security deposit as per the provisions of Rajasthan Electricity Regulatory Commission (Electricity supply Code and Connected Matters), Regulations, 2004 as amended from time to time;*

Provided that at the time of Truing-up, the interest on the amount of security deposit for the year shall be considered on the basis of the actual interest paid by the Licensee during the year, subject to prudence check by the Commission."

3.9 Depreciation

3.9.1 The principles behind the charging of depreciation and the depreciation rates have been a subject of debate over the years, including the linkage of depreciation to creation of a reserve fund for replacement of assets versus the linkage of depreciation to providing cash flow for repayment of loans taken by the Utility.

3.9.2 CERC has specified the depreciation rates for assets, the weighted average rate of which comes to approximately 5.28%. This has been done by considering the loan repayment period of 12 years. The remaining depreciable value of an asset as on 31st March of the year closing after a period of 12 years from the COD shall be spread over the balance useful life of the asset. The Tariff Policy stipulates that the depreciation rates specified by the CERC should be adopted for generation and transmission business, and may be adopted for the distribution business also, after suitable modification to be undertaken by the Forum of Regulators.

3.9.3 The draft CERC Regulations, 2019 has proposed to reduce the salvage value of the assets from 10% to 5%, thereby increasing the depreciable value of assets from 90% to 95%, in line with the provisions of the Companies Act, 2013. However, the Commission is of the view that the purpose of depreciation in regulatory regime is repayment of loan, which has been repaid during first 12 years. For the remaining part, the depreciation is allowed on asset cost, which was funded through equity. The Commission has not proposed to reduce the salvage value and continues with the present salvage value of 10%.

3.9.4 It is proposed to continue with the existing provisions regarding depreciation and specified asset life and the philosophy of linking depreciation with repayment of loan, as well as the existing depreciation rates.

3.10 Operation & Maintenance (O&M) expenses

3.10.1 The Commission has specified the normative O&M expenses for the first year of the Control Period for each business separately, as discussed in the subsequent Sections. In the existing Regulations, the Commission has proposed the fixed escalation rate of 5.85%.

3.10.2 For the next Control Period, it is proposed that the escalation rate shall be based on the movement of Consumer Price Index (CPI) and Wholesale Price Index (WPI), in the ratio of 50:50. The detailed discussion on O&M Expenses for Generating Company, Transmission Licensee and Distribution Licensee has been elaborated in subsequent chapter.

3.10.3 Currently, the Licence fees and Petition filing fees are allowed separately to Generating Company and Licensee. As discussed in detail in subsequent sections, though the actual O&M expenses of Generating Company and Licensees are lower than the normative O&M expenses during the current Control Period from FY 2014-15 to FY 2018-19, the Commission has proposed to allow the norms for O&M expenses for FY 2019-20 equivalent to FY 2018-19 mainly to take care of impact of VII Pay Commission. The Commission has also proposed to include the Petition filing fees and Licence fees as part of O&M expenses as these fees are part of actual O&M expenses which have been considered for arriving at the O&M norms for FY 2019-20.

3.11 Interest on Working Capital

3.11.1 Regulation 27 of RERC Tariff Regulations, 2014 specifies the computation of Working Capital Requirement for Generating Company and Licensee as under:

"(1) The amount of normative working capital shall cover:
1. Generation
(a) For coal based/Lignite-fired generating stations
(i) Landed Cost of coal or lignite for ½ (half) month for pit-head generating stations and 1½ (one and a half) months for non-pit-head generating stations, corresponding to the target availability;
(ii) Landed cost of limestone for 1½ (one and a half) month, corresponding to the target availability, wherever applicable;

(iii) Cost of secondary fuel oil for two months corresponding to the target availability and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil;
(iv) Operation and Maintenance expenses for one month;
(v) Maintenance spares @ 20% of operation and maintenance expenses specified in regulation 47; and
(vi) Receivables equivalent to 1½ (one and a half) months of fixed and variable charges for sale of electricity calculated on the target availability:
Provided that in case of own generating stations, no amount shall be allowed towards receivables, to the extent of supply of power by the Generation Business to the Retail Supply Business, in the computation of working capital in accordance with these Regulations.

(b) For Gas Turbine/Combined Cycle generating stations
(i) Landed fuel cost for ½ (half) 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 (half) month corresponding to the target availability, and in case of use of more than one liquid fuel, cost of main liquid fuel;
(iii) Operation and maintenance expenses for one month;
(iv) Maintenance spares @ 30% of operation and maintenance expenses specified in regulation 47; and
(v) Receivables equivalent to 1½ (one and a half) months of fixed and variable charges for sale of electricity calculated on target availability:
Provided that in case of own generating stations, no amount shall be allowed towards receivables, to the extent of supply of power by the Generation Business to the Retail Supply Business, in the computation of working capital in accordance with these Regulations.

(c) For Hydro Power generating stations
(i) Operation and Maintenance expenses for one month;
(ii) Maintenance spares @ 15% of operation and maintenance expenses specified in regulation 47; and
(iii) Receivables equivalent to one and a half(1½) months of fixed charges for sale of electricity, calculated on normative capacity index:

Provided that in case of own generating stations, no amount shall be allowed towards receivables, to the extent of supply of power by the Generation Business to the Retail Supply Business, in the computation of working capital in accordance with these Regulations.

2. Transmission
(i) Operation and maintenance expenses for one month; plus
(ii) Maintenance spares @ 15% of operation and maintenance expenses specified in regulation 65; plus
(iii) Receivables equivalent to one and a half (1½) months of transmission charges calculated on target availability level;
Less
Amount held as security deposits from Users except security deposits held in the form of Bank Guarantees;

3. Distribution
(i) Operation and maintenance expenses for one month; plus
(ii) Maintenance spares @ 15% of operation and maintenance expenses specified in regulation 83; plus

(iii) Receivables equivalent to one and a half (1½) months of billing of consumers;

Less

Amount held as security deposits from Distribution System Users (Open Access consumers) and retail supply consumers except the security deposits held in the form of Bank Guarantees;

(2) Rate of interest on working capital to be computed shall be on normative basis and shall be 250 basis points higher than the average Base Rate of State Bank of India prevalent during first six months of the year previous to the relevant year. The interest on working capital shall be computed on normative basis notwithstanding that the generating company or licensee has not taken working capital loan from any outside agency. The variation in the interest amount on account of actual vis-a-vis normative interest rate on normative working capital shall be shared in the ratio of 50:50 between the generating company/licensee and the beneficiary."

The above said Regulation specifies Interest on working capital on normative basis and the savings in interest amount on account of actual vis-à-vis normative interest shall be shared in the ratio 50:50. For the next Control Period, it is proposed to continue with the same approach of determining the interest on working capital on normative basis. Further, the computation of working capital requirement for Generation, transmission and Distribution has been proposed same as specified in RERC Tariff Regulations, 2014.

3.11.2 As per the Reserve Bank of India (RBI) Guidelines dated 3 March, 2016 (updated on 29 March, 2016), new loans will be sanctioned only on the basis of Marginal Cost of Funds-based Lending Rates (MCLR):

> *"All rupee loans sanctioned and credit limits renewed w.e.f. April 1, 2016 shall be priced with reference to the Marginal Cost of Funds based Lending Rate (MCLR) which will be the internal benchmark for such purposes."*

3.11.3 RERC Tariff Regulations, 2014 link the normative interest rate of short term and long-term loans to the Base Rate of State Bank of India (SBI). While SBI continues to notify its Base Rate, it will be relevant only for existing loans and all new loans will be based on the MCLR. The determination of the benchmark reference rate (Base Rate) affects the treatment of interest on working capital (IoWC) and the reference interest rate for normative long term loans since these are linked to the benchmark reference rate. Hence, the revision in the basis of the reference rate by the RBI Guidelines needs to be considered.

3.11.4 Rate of interest on working capital to be computed shall be on normative basis. It is proposed to consider Marginal Cost of funds-based lending rate (MCLR) as on April 1 of financial year plus 300 basis points. The interest on working capital shall be computed on normative basis notwithstanding that the Licensee or

Generating Company has not taken working capital loan from any outside agency.

3.11.5 Further, it is proposed to consider savings in actual interest on working capital amount with respect to normative interest on working capital amount as efficiency gain to be shared with the beneficiaries. Accordingly, following provision is added in Draft Regulations.

"For the purpose of truing-up for each year, the variation between the normative interest on working capital computed at the time of truing-up and the actual interest on working capital incurred by the Generating Company or Licensee, substantiated by documentary evidence, shall be considered as an efficiency gain or efficiency loss, as the case may be, on account of controllable factors. The efficiency gain on this account, shall be shared in the ratio of 50:50 between the generating company/licensee and the beneficiary an efficiency loss on this account shall be borne by the Generating Company/Licensee:

Provided that the efficiency gain on account of savings in interest on working capital to be shared with the beneficiary shall be considered net of income tax as follows:

Gain to be shared with Beneficiary = 50% of total Gain X (1-t)

Where "t" is the effective tax rate applicable for the year at the time of truing up."

3.12 Foreign Exchange Rate Variation (FERV)

3.12.1 As regards the treatment of equity invested in foreign currency, RERC Regulations, 2014 specifies that the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment. The purpose is to ensure that the debt:equity ratio remains unaffected by the foreign exchange rate variation and provide regulatory certainty. The same approach has also been adopted by CERC in its CERC Tariff Regulations, 2014 as well as draft CERC Tariff Regulations, 2019. Hence, the existing approach for considering the equity invested in foreign currency is proposed to be continued.

3.12.2 Further, Regulation 28 of RERC Tariff Regulations, 2014 provides the option of hedging. The Generation Company or the Licensee draws foreign currency loan for most economical interest rate and mitigating its funding and financial risk. However, foreign currency loans are exposed to variation in exchange rate and treatment of the same has to be addressed in Tariff Regulations. The hedging of foreign currency loans is generally market adopted practice to mitigate the risk of foreign currency loan. The options are either to consider the cost of hedging to be recovered through ARR; or to allow the variation in foreign exchange to be passed through ARR in case no hedging is done.

3.12.3 As regards the treatment of FERV, draft CERC Tariff Regulations, 2019 has provided the option of hedging to the Generation Company or the Licensee on foreign exchange exposure in respect of the interest on foreign currency loan. Also, hedging cost or FERV shall be allowed on year to year basis as income or expenses. It is proposed to adopt the CERC approach at State Level also.

3.12.4 Further, draft CERC Tariff Regulations, 2019 allows recovery of cost of hedging or FERV by the Generation Company or Licensee from the beneficiaries. It may be noted that, in case of no hedging of foreign exposure, extra rupee liability shall be permissible and to ascertain the fact that extra rupee liability is not attributable to Generation Company or the Licensee or its suppliers or contractors, the approval of the Commission is required for recovery of such cost of hedging or FERV.

3.12.5 Accordingly, the following Regulations are proposed regarding the treatment of Foreign Exchange Rate Variation:

"(1) The generating company or the licensee, as the case may be, may hedge foreign exchange exposure in respect of the interest on foreign currency loan and repayment of foreign loan acquired for the generating station or the transmission system, in part or in full, at the discretion of the generating company or the licensee.

(2) As and when the generating company or the licensee enters into any hedging based on its approved hedging policy, the generating company or the licensee should communicate to the beneficiaries concerned about its hedging decision within thirty days of entering into such hedging transaction(s).

(3) Every generating company or licensee shall recover the cost of hedging of foreign exchange rate variation corresponding to the normative foreign debt, in the relevant year on year-to-year basis as expense in the period in which it arises, and extra rupee liability corresponding to such foreign exchange rate variation shall not be allowed against the hedged foreign debt.

(4) To the extent the generating company or the licensee is not able to hedge the foreign exchange exposure, the extra rupee liability towards interest payment and loan repayment corresponding to the normative foreign currency loan in the relevant year shall be permissible provided it is not attributable to the generating company or the licensee or its suppliers or contractors.

(5) Every generating company or licensee shall recover the cost of hedging and foreign exchange rate variation on year-to-year basis as income or expense in the period in which it arises."

3.13 Late Payment Surcharge

3.13.1 The Commission has observed that majority of the utilities either claim the rebate through early payment, or at least make payment in time to avoid the late payment surcharge. The existing Regulations specifies the late payment surcharge at rate of 1.25% per month on daily basis. This rate is fixed irrespective of variation in rate of interest of working capital loans borrowed by Utility. Hence, in order to align with the actual rate of interest of working capital loans, it is proposed to link the late payment surcharge rate with the base rate, to which interest rate for working capital is linked in these Regulations. The late payment surcharge rate is proposed to kept higher than interest rate for working capital as it has to act as deterrent for making late payments.

3.13.2 With an objective to further improve the cash cycle in the state of Rajasthan, the Commission has proposed to apply the late payment surcharge equivalent to Base Rate plus 400 basis points per annum on daily basis to be levied by the Generating company or Licensee.

3.14 Rebate for Prompt Payment

3.14.1 The existing Regulations specifies the fixed rebate for prompt payment. Similar to late payment surcharge, rate of rebate for prompt payment is linked to base rate. The rate of rebate for prompt payment is proposed to kept at par with interest rate for working capital.

3.14.2 In order to encourage prompt payment of bills, the Commission has proposed to modify the clause and if payments are made beyond 3 working days through Letter of Credit or by cash/cheque or through electronic transfer but within a period of 30 days of presentation of bills, a rebate equivalent to (one-twelfth of Base Rate plus 300 basis points) shall be allowed.

3.15 Non-Tariff Income

3.15.1 Non-Tariff Income for generating company or the licensee means income relating to the regulated business other than from Tariff.

3.15.2 This income includes the interest income on account of investment made out of ROE. It is not intended to regulate the ROE allowed by the Commission. Hence, the Commission is of the opinion that any interest or dividend earned on account of investments made out of ROE shall not constitute a part of Non-Tariff Income. Also, the Licensee shall submit a documentary evidence justifying the same. The similar practice is adopted by some of the other SERCs in their Tariff Regulations.

3.15.3 Further, late payment surcharge has been considered as part of non-tariff income presently. Since, interest on working capital is allowed on normative basis, it is proposed not to consider the income from late payment surcharge as part of non-tariff income.

3.15.4 Accordingly, the following proviso has been proposed:

"Provided that interest or dividend earned from investments made out of Return on Equity corresponding to the regulated business of Generating Company or Licensee shall not be included in Non-Tariff Income:

Provided further that Licensee or Generating Company shall submit the documentary evidence of such income justifying that the same has been received from investment made out of Return on Equity:

Provided also that Late Payment Surcharge and Interest on Late Payment earned by the Generating Company or the Licensee shall not be considered under Non-tariff Income. "

4 Norms and Principles for Determination of ARR & Tariff for Generation Business

4.1 Background

4.1.1 This section deals with the issues related to the tariff applicable for a Generating Company supplying power to the Distribution Licensees in the State.

4.1.2 The Rajasthan Vidyut Utpadan Nigam Limited (RVUNL) is the State owned Generating Company, which owns and operates Thermal, Gas and Hydel based generating assets in the State. The brief summary of RVUNL's generating stations is given in the following Table:

Table 4-1*: Generating Station of RVUNL*

Sl.	Station Name	Capacity	Unit Details	Fuel	Status
1.	Kota STPS	1240 MW	2 x 110 MW 3 x 210 MW 2 x 195 MW	Coal	Operational
2.	Suratgarh STPS	1500 MW	6 x 250 MW	Coal	Operational
3.	Dholpur CCGBP	330 MW	3 x 110 MW	Gas	Operational
4.	Ramgarh Gas based Station	110.50 MW	2 x 37.5 MW 1 x 35.5 MW	Gas	Operational
5.	Mahi HEP	140 MW	2 x 25 MW 2 x 45 MW	Hydel	Operational
6.	Mini-micro Hydro Projects	23.85 MW		Hydel	Operational
7.	Chhabra TPS	500 MW	2 x 250 MW	Coal	Operational

4.1.3 In addition to the above generating Stations, there are certain other shared generating Stations (shared between Rajasthan and Madhya Pradesh), and Rajasthan's share of these shared Stations have been allocated to the State-owned Transmission Licensee, viz., Rajasthan Rajya Vidyut Prasaran Nigam Limited (RVPNL). There are other generation projects located on the river Sutlej and river Beas, the benefits of which are shared between Rajasthan and more than one other State, and which are collectively operated and maintained by Bhakra Beas Management Board (BBMB). The cost is shared amongst the Partners. For such generating Stations, RVUNL is only the Operation & Maintenance (O&M) contractor. The list of such shared Stations, primarily, shared with Madhya Pradesh and under the BBMB is given in the Table below:

Table 4-2*: Partnership Projects*

S. No	Station	Installed Cap.	Rajasthan Share	
		MW	%	MW
1	BBMB-Bhakra	1480	15.22%	225
2	BBMB-Dehar	990	20.00%	198
3	BBMB-Pong	396	58.50%	232

S. No	Station	Installed Cap.	Rajasthan Share	
		MW	%	MW
4	Chambal	386	50.00%	193
5	Satpura	313	40.00%	125
	Total			**973**

4.1.4 Apart from this, a subsidiary of RVUN, i.e., Giral Lignite Power Ltd. (GLPL) also owns a 125 MW Lignite based thermal Unit. Further, RajWest Power Ltd., a wholly owned subsidiary of JSW Group, also owns a 1080 MW lignite based thermal power plant near Barmer.

4.1.5 The Commission proposes to determine generation tariffs using a performance based approach linked to efficiency parameters, which would be used to provide incentives based on actual performance. This Section of the Explanatory Memorandum deals with the issues related to tariff determination of conventional generation projects and the mini/micro hydro generating stations.

4.2 Petition for determination of Tariff

4.2.1 The existing RERC Tariff Regulations, 2014 provides for determination of provisional tariff for the Unit or Stage or Generating Station as a whole based on the capital expenditure actually incurred up to the date of making the Petition or a date prior to making of the Petition, duly certified by the Statutory Auditors. Such provisional tariff shall be applicable from the date of commercial operation till the final tariff issued by the Commission. It is proposed that the Generating Company may file a Petition for provisional tariff within six months of the anticipated date of commercial operation.

4.2.2 Further it is also proposed that any difference in provisional tariff (other than interim tariff) and the final tariff determined by the Commission and not attributable to the generating company shall be recovered from or refunded to the beneficiaries with simple interest at the rate equal to Base Rate as on 1st April of the respective year plus 300 basis points, for the following year as directed by the Commission in the Order on determination on final Tariff.

4.3 Components of Tariff

4.3.1 The tariff determined by the Commission is the prime source of revenue for a Generating Company and hence, the mechanism of cost recovery needs to be designed to ensure full cost recovery at normative levels prescribed by the Commission.

4.3.2 Typically, the tariff for generating stations has two components, i.e., fixed (capacity) charge and variable charge. The variable charge component is intended to recover the fuel costs for the primary and secondary fuel consumption at normative parameters, in case of thermal generating stations.

4.3.3 The fixed charge (capacity charge) component comprises the following elements:

(a) Operation & Maintenance Expenses;
(b) Interest on term loans and finance charges;
(c) Depreciation;
(d) Interest on Working Capital;
(e) Return on Equity Capital;

Minus the following:

(f) Non-Tariff Income;
(g) Other income

4.4 Fixed Cost Recovery

4.4.1 Fixed cost recovery for thermal generating stations based on plant availability is a tested and widely adopted method by CERC as well as other SERCs. In this regard, RERC Tariff Regulations, 2014 stipulates target availability for full fixed cost recovery for all thermal stations. The relevant extract of RERC Tariff Regulations, 2014 specifying fixed charge recovery linked to plant availability factor is reproduced below:

"***45. Norms of operation for Thermal Generating Stations***
The norms of operation as given hereunder shall apply:
(1) Target Availability for recovery of full Annual Fixed Charges for thermal Generating Stations
a) Target Availability for full recovery of annual fixed charges shall be 83 per cent for all thermal Generating Stations, except those covered under sub-regulation (1) b), c) and d).

b) Lignite fired thermal power stations using CFBC technology:

For the first year of operation	70.0%
For second year of operation	72.5%
For third year of operation	75.0%
For Fourth year of operation	77.5%
Fifth year and onwards	80.0%

Note: First year of operation for the above sub-regulation means 365 days from the Date of Commercial Operation and so on.

c) Target Availability for full recovery of annual fixed charges for the following stations shall be:

Station Name	Target Availability
Kota TPS (Unit 1 to 7)	82%
Suratgarh TPS (Unit 1 to 6)	82%
Ramgarh Gas TPS(Unit 1 to 4)	70%
Dholpur CCPP (Unit 1 to 3)	80%

Station Name	Target Availability
Chhabra TPS (Unit 1 to 3)	80%

d) Other coal/lignite and gas based thermal power stations declared under commercial operation prior to 01.04.14: 80% "

4.4.2 While computing the Availability, the actual ability of the Station/Unit to generate needs to be considered after taking into consideration the loadability of machines and fuel related aspects, rather than considering plant availability on the basis of machine availability, which considers only the readiness of machine/equipment for generating electricity but in reality, the plant may not be available due to inter-alia, lack of fuel or loadability issues. Normally, in case of supply shortage scenario, the PLF should be almost equivalent to plant availability, since the plants would not be backed down and would be utilised fully when available. In the RERC Tariff Regulations, 2014, Availability has been defined as actual availability after taking into account the availability of fuel. In view of the above, the Definition of Availability is proposed as follows:

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

$$Availability = 10000 \times \sum_{i=1}^{N} DCi \;/\; \{ N \times IC \times (100 - AUXn) \} \%$$

where - N = number of time blocks in the given period
DC = Average Declared Capacity for the i^{th} time block in such period
IC = Installed Capacity of the generating station in MW
AUX = Normative Auxiliary Consumption in MW, expressed as a percentage of gross generation"

4.4.3 The Plant Availability is linked to the vintage and the technology of the Plant. As the Plant becomes older, the time taken for overhaul of the Plant increases and the Availability of the Generating Station/Unit reduces. CERC, in its draft CERC (Terms and Conditions of Tariff) Regulations, 2014, has also specified lower availability norm for some Units/ Generating Stations. Further, CERC has specified the Availability norm of 83% for thermal generating stations, as compared to the earlier norm of 85%.

4.4.4 Further, it is noted that the generating stations are allowed to completely recover their fixed cost. The present Regulations do not address the issue of declaration of lower availability during month or during quarter when the requirement from Distribution Licensee is at peak. This often forces the Discoms to procure power from short-term market because of uncertainty from generation stations' side. However, during low demand period, the generating stations may declare higher availability so as to achieve the target cumulative availability on annual basis to recover the full annual fixed charges. As a result, the beneficiaries do not get the electricity when required the most. In order to avoid such situation and regulate the demand-supply of the power during the year, CERC has proposed to allow the recovery of fixed cost on quarterly basis instead of annual basis. Also, separate recovery has been allowed for peak and off-peak period.

4.4.5 After perusal of the draft CERC Tariff Regulations, 2019, it is observed that the implementation of quarterly as well as peak-off-peak fixed cost recovery has not yet been tested. It may create practical issues such as shifting of maintenance schedule, availability of spares, etc. Further, the quarterly fixed cost recovery mechanism as well as separate fixed cost recovery is more suitable in case of power deficit situation, which is not the situation currently in the State of Rajasthan. Hence, the Commission is of the view that fixed cost recovery mechanism proposed by CERC may not be suitable for State of Rajasthan where Generation entities and licensee are limited and considering the current power surplus scenario. Hence, it is proposed to continue with the existing approach of annual fixed cost recovery for the next Control Period. However, the Commission has taken the cognizance of the issue of availability of power to distribution licensee from tied up sources during peak demand period. The Commission will monitor and analyse the availability of power and allied issues during the next Control Period and will take an appropriate view thereafter.

4.4.6 At this stage, it is proposed to continue the existing practice of fixed cost recovery based on the normative plant availability. However, the Normative plant availability shall be on annual basis. Accordingly, full fixed charge recovery shall be allowed at Normative Annual Plant Availability Factor (NAPAF) specified by the Commission.

4.4.7 Further, the actual availability for existing Stations has been shown in the following Table:

Table 3 Actual Availability

Years	KTPS (Units 1 to 7)	STPS (Units 1 to 6)	CTPP (Units 1 & 2)	DCCPP	RGTPS
Normative	82.00%	82.00%	80.00%	80.00%	70.00%
FY 2012-13	92.44%	85.86%	74.60%	49.34%	69.79%
FY 2013-14	94.41%	79.68%	79.94%	46.75%	82.80%
FY 2014-15	88.00%	87.98%	77.86%	45.75%	78.13%
FY 2015-16	89.89%	81.70%	44.29%	66.58%	83.07%
FY 2016-17	88.74%	85.77%	81.37%	26.47%	45.72%

4.4.8 From the above Table, it is observed that KTPS, STPS and CTPP have achieved the normative Availability in past years, which were relaxed norms. Hence, it is proposed that no further relaxation is to be provided for these three Stations.

4.4.9 In view of the above, Availability norms been proposed in Draft Regulations are as follows:"

(1) Normative Annual Plant Availability Factor (NAPAF) for full recovery of Fixed Charges for thermal Generating Stations:

a) Normative Annual Plant Availability Factor (NAPAF) for full recovery of Fixed Charges shall be 83 per cent for all thermal Generating Stations, except those covered under sub-regulation (1) b), (c) and (d).

b) Lignite fired thermal power stations using CFBC technology:

For first three years of operation	*75.0%*
Fourth year and onwards	*80.0%*

Note: First year of operation for the above sub-regulation means 365 days from the Date of Commercial Operation and so on.

c) Normative Annual Plant Availability Factor (NQPAF) for full recovery of Annual Fixed Charges for the following stations shall be:

Station Name	***Target Availability***
Ramgarh Gas TPS (Stage 1 to 3)	*70%*
Dholpur CCPP (Unit 1 to 3)	*70%*

4.4.10 For hydro stations, the RERC Tariff Regulations, 2014 has specified the normative Capacity Index for full recovery of capacity charges, as follows:

"64(1)Normative capacity index for recovery of full capacity charges

(a) During first year of commercial operation of the generating station

(i) Run-of-river power stations without pondage 85%

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

(b) After first year of commercial operation of the generating station

(i) Run-of –river power stations without pondage 90%

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

(c) The Commission may relax the normative capacity index in case of non availability of adequate quantity of water on case to case basis.

(d) 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."

4.4.11 The normative capacity index for existing hydro generating stations is proposed to be retained as specified in the existing Regulations. Further, the Commission may relax the normative capacity index in case of non-availability of adequate quantity of water on case to case basis.

4.5 Norms of Operation

4.5.1 Apart from Target Availability for recovery of Fixed Costs, the other Performance norms to be specified for a thermal generating station include:

- Station Heat Rate
- Auxiliary Power Consumption
- Secondary Fuel Consumption
- Transit Losses

4.5.2 **<u>Gross Station Heat Rate</u>**

4.5.2.1 Heat rate is an indicator of power plant efficiency and it depends on the age, generation capacity, and technology of the generating unit. In the prevailing RERC Tariff Regulations, the Commission has specified the following heat rate norms:

"(3) Gross Station Heat Rate –

(a) Existing coal & Gas based Thermal Generating Stations/ units achieving COD prior to 01.04.2009:

Stations/ Unit		***Gross Station Heat Rate (kcal/kWh)***
Kota TPS (Unit 1 to Unit 6)		*2605.26*
Suratgarh TPS (Unit 1 to Unit 5)		*2500.00*
Ramgarh GTPS (Unit 1 to 3)	*Combined Cycle*	*1950.00*
	Open Cycle	*2850.00**
Dholpur CCPP (Unit 1 to 3)	*Combined Cycle*	*1950.00*
	Open Cycle	*2830.00*

**With annual reduction of 10 kcal/kWh till target Gross Heat Rate of 2830 kCal/kWh*

(b) Gross Station Heat Rate for new Thermal Generating stations/units achieving COD on or after 01.04.2009 till 31.03.2014:
Coal and lignite based thermal power generating stations

= 1.045 X Design Heat Rate (kcal/kWh)

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

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

Provided further that where Unit heat rate has not been guaranteed and turbine cycle heat rate and boiler efficiency guaranteed by the supplier is *also not available the design heat rate shall not exceed the limit as specified under Annexure- 2:*

Provided further that in case of lignite-fired generating stations (including stations based on CFBC technology), maximum design heat rates shall be increased using factor for moisture content 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-sub- regulations (i) to (iii) above.*
- *v) Moisture content shall be determined at the stage of firing.*

Provided that the heat rate norms computed as per above shall be limited to the heat rate norms approved during FY 2009-10 to FY 2013-14.

(c) Gross Station Heat Rate for new Thermal Generating stations/units achieving COD on or after 01.04.2014:

Coal and lignite based thermal power generating stations

= 1.045 X Design Heat Rate (kcal/kWh)

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

Provided that the design heat rate shall not exceed the limit as specified under Annexure- 2:

Provided further that in case of lignite-fired generating stations (including stations based on CFBC technology), maximum design heat rates shall be increased using factor for moisture content 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-sub- regulations (i) to (iii) above.*
- *v) Moisture content shall be determined at the stage of firing.*

(d) Gas-based / Liquid-based thermal generating Unit(s) achieving COD on or after 01.04.2009

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

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

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

4.5.2.2 CERC, in its Tariff Regulations, has considered the technology, configuration, and operating level of different power plants and accordingly different heat rates have been fixed for thermal and gas turbine/combined cycle power plants. The practice followed by CERC covers all the dimensions of a generating Unit, which may have a bearing on the station heat rate. The experience of many other Generating Companies/SERCs and the data available in this regard suggests that the various factors affecting the Heat Rate are vintage, size, past generating history, past maintenance practices, condition of plant, etc.

4.5.2.3 The Commission has analysed the actual performance of existing Generating Stations during the present Control period. The actual Station Heat Rate vis-à-vis Normative Station Heat Rate are tabulated as under:

Table 4-4: Actual Station Heat Rate for Existing Generating Stations

Particulars	Normative	FY 2014-15	FY 2015-16	FY 2016-17
KTPS (Units 1 to 7)	2561.70	3101.39	2805.19	2551.16
STPS (Units 1 to 6)	2476.28	2953.78	2653.93	2452.08
CTPP (Units 1 & 2)	2312.31	3050.44	2746.31	2615.92
DCCPP	1994.00	2245.00	2420.79	2334.08
RGTPS	2214.00	2461.14	2533.23	2596.60
GLPL	2449.50	3751.43	3936.74	-
Raj West LTPS		2609.62	2600.63	2610.02

4.5.2.4 From the above table, it is observed that many of stations have not achieved the normative SHR. However, in case of KTPS, STPS and CTPP, though actual SHR is more than normative, actual SHR has been improved from FY 2014-15 to FY 2016-17. In fact, KTPS and STPS has achieved the norms in FY 2016-17. For other Stations, actual SHR is much more than norms.

4.5.2.5 Further, the Commission in Tariff Order for respective Generating Stations has specified the Gross Station Heat Rate based on the provisions of the RERC Tariff Regulations, 2014. It is proposed to continue with the same Gross Station

Heat rate Norms for the next Control Period. Further, in case of CTPP, the combined Station heat Rate norms has been considered for Unit 1 to 4.

4.5.2.6 Based on the above, the Heat Rate norms specified for existing thermal generating stations in the Draft Regulations are as under:

Stations/ Unit		Gross Station Heat Rate (kcal/kWh)
Kota TPS (Unit 1 to Unit 7)		2561.70
Suratgarh TPS (Unit 1 to Unit 6)		2476.28
Ramgarh GTPS (Stage1 to 3)	Combined Cycle	1950.00
	Open Cycle	2830.00
Dholpur CCPP (Unit 1 to 3)	Combined Cycle	1950.00
	Open Cycle	2830.00
Chhabra TPS (Unit1 to 4		2400.00
Raj West Lignite Thermal Power Station		2403.50
Giral Lignite Thermal Power Station		2403.50

4.5.2.7 In addition to the above, different multiplying factors have been specified based on moisture content for Lignite based Generating Stations.

4.5.2.8 Also, the draft CERC Regulations 2019 have specified the norms for Gross Station Heat Rate for new Generating Stations at 5% higher than Design Heat Rate based on the inputs from Central Electricity Authority (CEA). The same provision has been considered in draft RERC Tariff Regulations, 2019.

4.5.3 <u>Auxiliary Consumption for Thermal Generating Stations</u>

4.5.3.1 The existing norms of auxiliary consumption specified in RERC Tariff Regulations, 2014 are as follows:

"(7) Auxiliary Energy Consumption
(a) Coal-based generating stations other than those covered under sub-regulation (6)d) below:
(A) For 110 MW and above up to 250 MW units
(i) With induced draft cooling towers 9.0 %
(ii) With natural draft cooling tower or without cooling towers 8.5 %
(B) Above 250 MW units
(a) Steam driven boiler feed pumps
(i) With induced draft cooling towers 5.75%
(ii) With natural draft cooling tower or without cooling towers 5.25%
(b) Electrically driven boiler feed pumps
(i) With induced draft cooling towers 8.25%
(ii) With natural draft cooling tower or without cooling towers 7.75%
(b) Gas Turbine/Combined cycle generating stations other than those covered under sub-regulation (6)d) below:
(i) Combined cycle 2.5%
(ii) Open cycle 1.0%
I Lignite-fired thermal power generating stations:
(i) 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 sub-regulation (6)a) above.

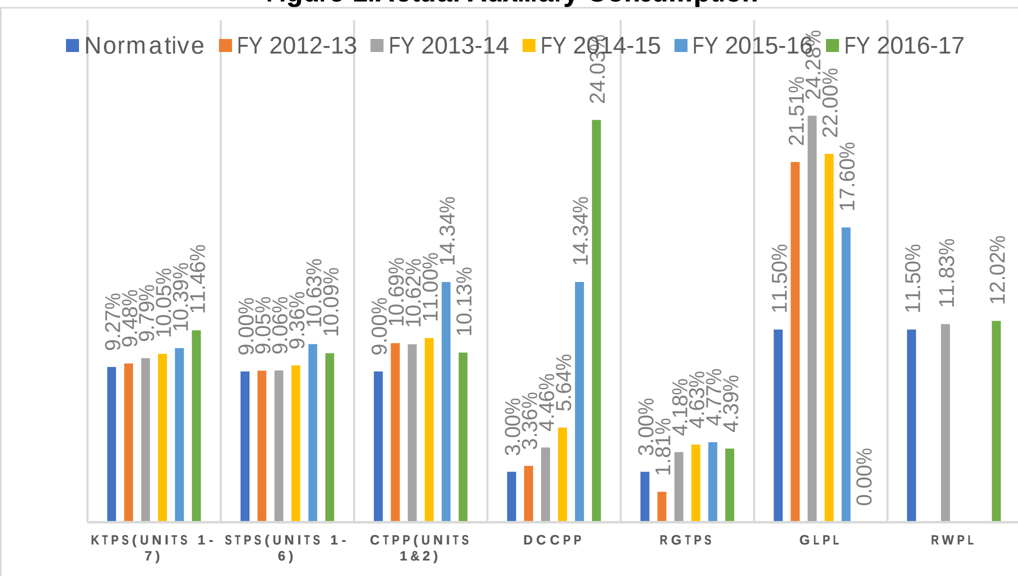
(a) *(ii) For Lignite based generating stations with CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage point more than the above auxiliary energy consumption norms of coal based generating stations at sub-regulation (6)a) aboved) Existing Thermal Generating Stations/Units:*

Stations/ Unit		***Auxiliary Energy Consumption (%)***
Kota TPS (Unit 1 to Unit 7)		*9.27%*
Suratgarh TPS (Unit 1 to Unit 6)		*9.00%*
Chhabra TPS (Unit 1 to 3)		*9.00%*
Ramgarh GTPS (Unit 1 to 4)	*Combined Cycle*	*3.00%*
	Open Cycle	*1.00%*
Dholpur CCPP (Unit 1 to 3)	*Combined Cycle*	*3.00%*
	Open Cycle	*1.00%*
Rajwest Lignite Thermal Power Station		*11.5%*
Giral Lignite Thermal Power Station		*11.5%*

Note: For Ramgarh GTPS, additional auxiliary consumption of 3% for open cycle and 2% for combined cycle shall be applicable for number of days gas compressors are used."

4.5.3.2 The Commission has analysed the actual auxiliary consumption for the generating stations in the State of Rajasthan for the last five years. The actual auxiliary consumption is shown in the graph below:

Figure 1:Actual Auxiliary Consumption



4.5.3.3 It can be seen from the above graph, that the actual auxiliary consumption is higher than the normative consumption for all the generating stations due to certain reasons. The Commission is of the view that the inefficiencies of Generating Companies cannot be passed on to consumers and Generating

Companies should take proper measures to achieve the normative performance parameters. Hence, the Commission has proposed to continue with the norms for existing Stations as per RERC Tariff Regulations, 2014.

4.5.3.4 Further, for new generating stations and Hydro generating stations, the norms for Auxiliary Consumptions have been specified as per draft CERC Tariff Regulations, 2019.

4.5.3.5 In view of the above, the following norms for Auxiliary Consumption has been proposed for new Projects for next Control period:

"

(a) Coal-based generating stations other than those covered under sub-regulation (6)(d) below:

(A) For 110 MW and above up to 250 MW units

(i) With induced draft cooling towers 9.0 %

(ii) With natural draft cooling tower or without cooling towers 8.5 %

(B) Above 250 MW units

(b) Steam driven boiler feed pumps

(i) With induced draft cooling towers 6.25%

(ii) With natural draft cooling tower or without cooling towers 5.75%

(c) Electrically driven boiler feed pumps

(i) With induced draft cooling towers 8.5%

(ii) With natural draft cooling tower or without cooling towers 8.0%

Provided that for Thermal Generating Stations where tube type coal mill is used, the norm shall be further increased by 0.8%.

(b) Gas Turbine/Combined cycle generating stations other than those covered under sub-regulation (6)(d) below:

(i) Combined cycle 2.75%

(ii) Open cycle 1.0%

(c) Lignite-fired thermal power generating stations:

(i) 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 sub-regulation (6)a) above.

(ii) For Lignite based generating stations with CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage point more than the above auxiliary energy consumption norms of coal-based generating stations at sub-regulation (6)a) above.

(d) Existing Thermal Generating Stations/Units:

Stations/ Unit	***Auxiliary Energy Consumption (%)***
Kota TPS (Unit 1 to Unit 7)	*9.27%*
Suratgarh TPS (Unit 1 to Unit 6)	*9.00%*

Stations/ Unit		*Auxiliary Energy Consumption (%)*
Chhabra TPS (Unit 1 to 4)		*9.00%*
Ramgarh GTPS (Stage 1 to34)	*Combined Cycle*	*3.00%*
	Open Cycle	*1.00%*
Dholpur CCPP (Unit 1 to 3)	*Combined Cycle*	*3.00%*
	Open Cycle	*1.00%*
Raj West Lignite Thermal Power Station		*11.5%*
Giral Lignite Thermal Power Station		*11.5%*

Provided that for Thermal Generating Stations where tube type coal mill is used, the norm shall be further increased by 0.8%.

Note: For Ramgarh GTPS, additional auxiliary consumption of 3% for open cycle and 2% for combined cycle shall be applicable for number of days gas compressors are used."

4.5.4 **Secondary Fuel Oil Consumption**

4.5.4.1 The norms of secondary fuel oil consumption specified in RERC Tariff Regulations, 2014 are as follows:

(d) *"(a) Coal-based generating stations: 0.50 ml/kb) Lignite-fired generating stations (based on CFBC Technology): 1.00 ml/kWh"*

4.5.4.2 The actual performance of existing Generating Station for Secondary Fuel Oil Consumption is shown in the following Table:

Table 4-5: Actual SFOC (ml/kWh) for Existing Generating Stations

Particulars	Normative	FY 2014-15	FY 2015-16	FY 2016-17
KTPS (Units 1 to 7)	0.50	0.7	0.8	0.8
STPS (Units 1 to 6)	0.50	0.6	1.3	1.6
CTPP (Units 1& 2)	0.50	1.4	3.0	1.2
GLPL	1.00	1.2	1.2	-
RWPL	1.00	0.11	0.13	0.10

4.5.4.3 It can be seen from the above table, that the actual secondary fuel oil consumption is higher than the normative consumption for all the generating stations. The Commission is of the view that the inefficiencies of Generating Companies cannot be passed on to consumers and Generating Companies should take proper measures to achieve the normative performance parameters. Hence, the Commission has proposed to continue with the norms as per RERC Tariff Regulations, 2014.

4.5.4.4 In view of the above, the following norms for secondary fuel oil Consumption has been proposed for next Control period:

"(a) Coal-based generating stations: 0.50 ml/kWh

(b) Lignite-fired generating stations (based on CFBC Technology): 1.00 ml/kWh"

4.5.5 <u>Transit losses</u>

4.5.5.1 Transit and handling losses are very common in fuel transportation, especially for coal transportation. These losses happen mainly due to theft, leakage, weight reduction due to moisture evaporation, improper stacking, etc., and the losses are higher in load centre based generating stations in comparison to the pit head stations. It is proposed to specify that normative transit and handling losses shall not be applicable if the Fuel Supply Agreement provides for billing based on the quantity of fuel delivered.

4.5.5.2 Transit losses have been proposed for next Control Period in line with draft CERC Tariff Regulations, 2019 as under:

"Normative transit and handling losses for fuel based generating stations, as a percentage of quantity of fuel dispatched by the fuel supply Company during the month:

a) Coal/lignite supply

i.	*Pit head generating stations*	*0.20%*
ii.	*Non-pit head generating stations (upto 1000 km)*	*0.80%*
iii.	*Non-pit head generating stations (more than 1000 km)*	*1.20%*

Provided further that in case of imported coal, the transit and handling losses shall be 0.20%:

:

Provided also that normative transit and handling losses shall not be applicable if the Fuel Supply Agreement provides for billing based on the quantity of fuel delivered."

Liquid or any other fuel 0%

In case of retirement of any Unit of existing thermal generating station, the norms of operation for such generating station shall be as approved by the Commission in Tariff Order. Further, in case the norm of any Unit is not specified above, the same shall be as approved by the Commission in the Tariff Order."

4.6 Operation & Maintenance (O&M) Expenses

4.6.1 The O&M expenses comprise Employee Expenses, R&M Expenses and A&G expenses, and all three together constitute a significant part of the Aggregate Revenue Requirement of any power sector utility. O&M Expenses includes the following:

Employee Expense

Employee expenses include salary, wage arrears, and terminal benefits, etc. Employee expense increases every year due to salary increase and promotion of employees. The increase in salary expenses would be expected to be such that it offsets the effect of inflation. One such indicator denoting the inflation is Consumer Price Index (CPI), reflecting the increase in price of consumer goods.

A&G Expenses

Administrative & General (A&G) expenses comprise expenses on office administration, site office management, rentals, travel, communication, telecommunication and other overheads, etc. Cost on all these parameters increases every year. The general indicators reflecting the variation in cost of general commodities are the Wholesale Price Index (WPI) and CPI.

Repair & Maintenance (R&M) Expense

R&M, in terms of scheduled and forced maintenance, is a part of any running business. Suitable provision for R&M expenses needs to be made for smooth operation of generating station. R&M cost increases with the vintage of the plant. In initial years of operation, R&M cost is low due to new components and it increases with the increase in plant life. For escalation of R&M expense, WPI can be an indicator reflecting the increase in the cost of machinery and machine tools.

4.6.2 In terms of developing the framework for the components of O&M expenses, the various Regulatory Commissions have specified different approaches after duly considering the State specific requirements. The Regulatory Commissions have mainly adopted the following two approaches:

(a) Actual O&M expenses for previous year with certain escalation factor for ensuing years
(b) O&M expenses based on certain performance benchmarks

4.6.3 The exiting RERC Tariff Regulations, 2014 specifies the O&M norms for the Generating Stations having different capacities. There are no separate norms for Employee Expenses, A&G Expenses and R&M Expenses. The norm is combined for total O&M Expenses. The norms specified in RERC Tariff Regulations, 2014 are as under:

"

(1) For coal based generating stations:

a) 110 MW and above up to 250 MW Unit size - Rs. 16.09 lakh per MW for FY 2014-15

b) Above 250 MW unit size – Rs 14.48 lakh/MW for FY 2014-15

(2) For lignite based generating stations: Rs 21.16 Lakh per MW for FY 2014-15

(3) *Gas Turbine/Combined Cycle generating stations*

Particulars	Gas Turbine/Combined Cycle Generating Stations for FY 2014-15		Small Gas Turbine Generating Stations (less than 50 MW unit size) for FY 2014-15
	With warranty spares for 10 years	Without warranty Spares	Without warranty Spares
O&M Expenses for FY 2014-15	Rs 8.04 Lakh/MW	Rs 12.06 Lakh/MW	Rs 14.64 Lakh/MW

(4) In case the process water is required to be transported over a distance of more than 50 km, then appropriate special O&M expenses, subject to the prudence check by the Commission, shall be allowed in addition to the above O&M expenses. It shall include O&M expenses related to pipe line beyond 50 km and water pumping station operation cost, and additional power consumption for such pumping stations.

(5) For Hydro Power generating stations:
a) Operation & Maintenance expenses for Mahi I & Mahi II hydro power stations shall be Rs. 9.92 lakh per MW for FY 2014-15.
b) In case of the hydro electric generating stations, which have not been in operation for a period of five years, the operation and maintenance expenses shall be fixed at 1.0% of the capital cost as admitted by the Commission.

(6) For the generating stations having combination of various Unit sizes, the weighted average value for operation and maintenance expenses shall be adopted.

4.6.4 The actual performance of existing Generating Stations has been analysed for computation of O&M Norms. The following Table indicates the actual Expenses vis-à-vis normative expenses for existing Stations:

Table 6 Actual O&M Expenses for Generating Stations

Particulars	FY 2014-15		FY 2015-16		FY 2016-17	
	Normative	Actual	Normative	Actual	Normative	Actual
KTPS (Units 1 to 7)	199.52	238.61	211.19	245.06	223.55	237.52
STPS (Units 1 to 6)	241.35	199.61	255.47	225.60	270.41	224.43
CTPP (Units 1 & 2)	80.45	58.42	85.16	79.54	90.14	73.92
DCCPP	39.80	24.93	42.13	44.40	44.59	20.23
RGTPS	16.18	10.65	17.13	25.25	18.13	11.33
Mahi Hydel	13.89	17.19	14.70	21.39	15.56	23.54

4.6.5 Actual O&M Expenses per MW is shown in the following Table:

Table 7 Computation of norms for O&M Expenses for Distribution

Particulars	Actual Norms			3-Year Average
	FY 15	FY 16	FY 17	
KTPS	19.24	19.76	19.15	19.39

Particulars	Actual Norms			3-Year Average
	FY 15	FY 16	FY 17	
STPS	13.31	15.04	14.96	14.44
CTPP Unit 1 & 2	11.68	15.91	14.78	14.13
RWPL	18.89	20.10	20.16	19.72
DCCPP	7.55	13.45	6.13	9.05
RGTPS	9.64	22.85	10.25	14.25
Mahi Hydel	12.28	15.28	16.81	14.79

4.6.6 From the above table, it is observed that actual O&M Expenses are lower than normative expenses for all stations except KTPS and Mahi Hydel.

4.6.7 For the next Control Period, it is proposed to continue with the same approach for specifying norms for first year of the Control Period. Further, escalation factor has been determined based on five years average of annual increase in CPI for Industrial Workers (All India) as per Labour Bureau, Government of India and WPI as per Office of Economic Advisor of Government of India in the ratio of 50:50.

4.6.8 Though the actual O&M Expenses during the previous three years, i.e., from FY 2014-15 to FY 2016-17 are lower than normative O&M expenses, this does not include the impact of 7th Pay Commission, which is likely to come in next Control Period. Hence, it may not be appropriate to substantially reduce the norms of O&M expenses with respect to applicable O&M norms for FY 2018-19. Hence, O&M Expenses norm for FY 2019-20 have been kept equivalent to norm of FY 2018-19 as there will be impact of 7th Pay Commission in the next Control Period.

4.6.9 For coal-based stations, norms for 500 MW and above 500 MW unit size has also been specified in view of anticipated COD of higher capacity units in the State.

4.6.10 In view of the above, the following has been proposed for O&M Expenses for generating Stations for next Control period:

"

(1) For coal, lignite and Gas turbine based generating stations:

(a) 110 MW and above upto 250 MW unit size: Rs. 20.20 lakh per MW for FY 2019-20
(b) Above 250 MW Unit size: Rs. 18.18 lakh/MW for FY 2019-20
(c) For 500 MW Unit size: Rs. 15.30 lakh/MW for FY 2019-20
(d) For above 500 MW Unit size: Rs. 13.05 lakh/MW for FY 2019-20

(2) For lignite based generating stations: Rs. 26.56 Lakh per MW for FY 2019-20

(3) Gas Turbine/Combined Cycle generating stations

Particulars	*Gas Turbine/Combined Cycle Generating Stations for FY 2019-20*		*Small Gas Turbine Generating Stations (less than 50 MW unit size) for FY 2019-20*
	With warranty spares for 10 years	*Without warranty Spares*	*Without warranty Spares*
O&M Expenses for FY 2019-20	*Rs.10.09 Lakh/MW*	*Rs. 15.14Lakh/MW*	*Rs. 18.38 Lakh/MW*

(4) In case the process water is required to be transported over a distance of more than 50 km, then appropriate special O&M expenses, subject to the prudence check by the Commission, shall be allowed in addition to the above O&M expenses. It shall include O&M expenses related to pipe line beyond 50 km and water pumping station operation cost, and additional power consumption for such pumping stations.

(5) For Hydro Power generating stations:

a) Operation & Maintenance expenses for Mahi I & Mahi II hydro power stations shall be Rs. 12.45 lakh per MW for FY 2019-20.
b) In case of the hydro electric generating stations, which have not been in operation for a period of five years, the operation and maintenance expenses shall be fixed at 1.0% of the capital cost as admitted by the Commission.

(6) For the generating stations having combination of various Unit sizes, the weighted average value for operation and maintenance expenses shall be adopted.

(7) O&M Expenses norms for each subsequent year shall be escalated by escalation factor determined based on five years average of Annual increase in Consumer Price Index for Industrial Workers (All India) as per Labour Bureau, Government of India and Wholesale Price Index as per Office of Economic Advisor of Government of India in the ratio of 50:50.

Provided that terminal liabilities based on actuarial valuation, over and above the normative O&M Expenses, subject to prudence check shall be allowed separately."

4.7 Cost of Fuel and Calorific Value

4.7.1 For determining the variable charge component of tariff for thermal stations, the cost of fuel to be considered should be the landed cost of fuel. The landed cost of fuel should include price of fuel corresponding to the grade/quality/calorific value of fuel including royalty, taxes and duties as applicable, transportation, coal washing charges as applicable, and the normative transit losses.

4.7.2 While determining the tariff for ensuing year, it will be preferable to consider the landed cost of fuel and calorific value based on actual values for the most recent three months. The variation in landed price of fuel and calorific value of fuel shall be passed on directly to the Distribution Companies based on the bills submitted by Generating Companies clearly indicating the energy charges linked to the base price of primary fuel and secondary fuel.

4.7.3 The existing Regulations provides for consideration of calorific value of fuel on "as received" basis. Further, draft CERC Tariff Regulations, 2019, in this regard has proposed consideration of calorific value of fuel "as received less 85 kcal/kg". Central Electricity Authority has recommended for allowing a margin for loss of GCV between "GCV as received" basis at generation station (wagon top) to "GCV As Fired" basis. The recommended GCV loss figures in case of pit head generating stations is 85-100 kcal/kg and in case of non-pit head generating stations, it is 105-120 kcal/kg. However, the CERC has proposed a weighted average GCV loss of 85 Kcal/Kg on account of variation during storage at generating station for calculation of energy charge, without differentiating between pit head and non-pit head generating stations.

4.7.4 After taking into account the actual calorific value of the fuel, the following has been proposed for consideration of calorific value of fuel for next Control period:

"*Gross calorific value of coal/lignite or gas or liquid fuel as received less 85 kcal/kg or gross calorific value as fired, whichever is higher*".

4.8 Incentive Mechanism

4.8.1 An incentive mechanism should be such that it encourages the performance in terms of higher electricity generation from the same generating stations.

4.8.2 Incentive in terms of paise/kWh for thermal generating stations beyond the normative PLF has been a mechanism widely adopted by the various Regulatory Commissions due to simplicity in implementation, and the fact that it ensures uniform incentive to all generating stations. Further, the PLF linked incentive will encourage the generator to lower its variable cost to rank higher in the Merit Order. Hence, it is proposed to link the incentive mechanism to the actual generation in excess of target PLF.

4.8.3 The existing Regulation provides Incentive of 30 paise/kWh for actual ex-bus energy in excess of ex-bus energy corresponding to target Plant Load Factor.

4.8.4 As discussed in earlier Section, the recovery of fixed charges has been considered on annual basis. In view of this, the incentive mechanism has also been linked to annual Plant Load Factor. Further, the incentive has been specified as 30 paise per unit.

4.8.5 For hydro generating stations, the incentive mechanism as specified in existing Regulations is retained.

4.8.6 In view of the above, the following incentive mechanism for Thermal Generating Stations has been proposed for next Control Period:

"

(1) *For Thermal Power Generating Stations*

(a) *Incentive shall be payable by the beneficiary at a rate of 30 paisa/kWh for actual* ex-bus energy in excess of ex-bus energy corresponding to target Plant Load Factor.

(b) *The incentive amount shall be computed and billed on monthly basis, subject to cumulative adjustment in each month of financial year."*

4.9 Tariff for Mini/Micro Hydel (MMH) Generation Plants

4.9.1 Regulation 58 of RERC Tariff Regulations, 2014 specifies as under:

*"**58. Tariff for existing Mini/ Micro (MMH) Power Station***
Tariff for existing Mini/ Micro (MMH) Power Station for the Control Period shall be Rs 3.78 per kWh.

4.9.2 The Commission has proposed 10% increase in Tariff for Mini/Micro Hydel (MMH) Generating Plant to take into account the increase in O&M expenses over the period of time. Accordingly, the Commission for the next Control Period has proposed tariff of Rs. 4.16 per kWh for Mini/Micro Hydel Generating Plants.

5 Norms and Principles for Determination of ARR and Tariff for Transmission Business

5.1 Background

5.1.1 The Electricity Act 2003 (EA 2003) has laid down the regulatory framework for operation of Transmission Licensees. Section 39(1) of the EA 2003 provides that the State Government may notify the State Electricity Board (SEB) or Government Company as the State Transmission Utility (STU). Accordingly, the Government of Rajasthan (GoR) has notified that the Rajasthan Rajya Vidyut Prasaran Nigam Limited (RVPN) shall operate as the State Transmission Utility in the State of Rajasthan.

5.1.2 RVPN, a Company incorporated on 19th June, 2000 under the Companies Act 1956, has been operating as the Transmission Company in the State of Rajasthan consequent to the unbundling of the Rajasthan State Electricity Board (RSEB) in July 2000. RVPN received the licence for transmission and bulk supply on 30th April, 2001 from the Commission.

5.1.3 Under the provisions of the EA 2003, it is envisaged that the STU (RVPN) shall operate as a Wires Company (i.e., transmission licensee), apart from discharging its statutory function as State Transmission Utility (STU). Section 39 (2) of the EA 2003 provides for Transmission Licensee (RVPN) to undertake following functions:

- To undertake transmission of electricity through the intra-State transmission system
- To discharge all functions of planning and co-ordination related to intra-State transmission.
- To ensure development of efficient, co-ordinated and economical system of intra-State transmission lines for smooth flow of electricity.
- To provide non-discriminatory open access to its transmission system for use by any Licensee or generating company on payment of transmission charge or to any consumer as and when open access is provided by State Commission under sub-section (2) of Section 42, on payment of transmission charges and a surcharge thereon, as may be specified by the State Commission.

5.2 Regulatory Framework and Recent Regulatory Developments

5.2.1 As per Section 40 of the EA 2003, the transmission licensee is obliged (a) to build, maintain and operate an efficient, co-ordinated and economical inter-State transmission system or intra-State transmission, as the case may be (b) to comply with directions of RLDC and SLDC as the case may be, and (c) to provide non-discriminatory open access to its transmission system for use by any licensee or generating company or any consumer as and when such open access is provided by the State Commission on payment of the transmission charges and surcharge thereon. It is envisaged that Transmission Charges should be determined such that it facilitates open access transactions and encourages efficient use of the intra-State transmission system, while ensuring adequacy of revenue requirement for the transmission licensee.

5.3 Objectives of Transmission Pricing

5.3.1 The Transmission pricing framework under MYT regime, in addition to meeting the transmission revenue requirement, needs to be guided by key considerations such as economic and efficient use of transmission network, non-discriminatory approach, encouraging investment, supporting the development of market/trading opportunities, etc.

5.4 Petition for determination of Transmission Tariff

5.4.1 The existing RERC Tariff Regulations, 2014 specifies as under:

*"**60. Petition for determination of Transmission tariff***
A transmission licensee shall file a petition for determination of tariff in respect of existing
lines or substations or transmission system as a whole complying with provisions of Part II of these Regulations:

Provided that the transmission licensee shall propose a transmission loss reduction target for the ensuing year as well as for the subsequent years of the Control Period, giving details of the measures proposed to be taken for achieving the targets proposed, along with the Tariff Petition for the first year of the Control Period."

5.4.2 The Commission has proposed to continue with the existing approach as specified above for the next Control Period.

5.5 Transmission System Availability

5.5.1 RERC Tariff Regulations, 2014 specify the Normative Availability for the Transmission System in the State of Rajasthan, as under:

"63. Norms of operation
(2) Normative Availability of the Transmission System
The Normative Availability of the Transmission System shall be as follows:
(a) High Voltage AC system : 98%
(b) High Voltage DC bipole links & HVDC back-to-back stations: 95%

Availability shall be calculated sub-station wise and integrated for all sub-stations effecting supply to a user in the manner as may be laid down by the Commission in the RERC (Transmission licensee's standards of performance) Regulation 2004.

Note:
Recovery of annual transmission charges below the level of normative availability shall be pro-rata basis. At zero availability, no transmission charges shall be payable."

5.5.2 It noted that draft CERC Tariff Regulations, 2019 specifies two different targets, viz., one for recovery of Annual Transmission Charges and another for computing the incentive, unlike the approach adopted in the existing Tariff Regulations, wherein, the target availability was the same for recovery of Annual Transmission Charges and for computing the incentive.

5.5.3 For setting the Target Availability for the next Control Period, the actual Availability of RVPN has been compared with the Target Availability for the period from FY 2013-14 to FY 2017-18, as tabulated below:

Table 8 Actual Transmission Availability for RVPN

Voltage Level	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18
132 kV	99.88%	99.78%	99.82%	99.87%	99.89%
33 kV	99.74%	99.66%	99.78%	99.63%	99.88%
11 kV	95.11%	99.79%	99.66%	99.73%	99.81%

5.5.4 Considering the actual performance, it is proposed to retain the existing norm in the Regulations for the next Control Period for full recovery of Annual Transmission Charges. Moreover, the norms for incentive have been kept higher in line with the norms specified in draft CERC Tariff Regulations, 2019. Accordingly, the following norms of Transmission Availability have been proposed for next Control Period:

"63. Norms of operation
(2) Normative Availability of the Transmission System
The Normative Availability of the Transmission System shall be as follows:
(a) High Voltage AC system : 98%
(b) High Voltage DC bipole links & HVDC back-to-back stations: 95%

For Incentive consideration:
(a) High Voltage AC system : 98.50%
(b) High Voltage DC bipole links & HVDC back-to-back stations: 97.50%

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

Availability shall be calculated sub-station wise and integrated for all sub-stations effecting supply to a user in the manner as may be laid down by the Commission in the RERC (Transmission licensee's standards of performance) Regulation 2004 and shall be certified by SLDC.

Note:
Recovery of annual transmission charges below the level of normative availability shall be pro-rata basis. At zero availability, no transmission charges shall be payable."

5.6 Components of ARR

5.6.1 It is proposed that the Aggregate Revenue Requirement of the Transmission Licensee shall comprise the following:

a) Operation and maintenance expenses;
b) Interest and finance charges on loan capital;
c) Depreciation and amortisation of intangible assets;
d) Interest on working capital and interest payable on deposits from Transmission System Users; and
e) Return on equity and;

Minus the following:

f) Non-tariff income and other income; and
g) Income from Other Business, to the extent specified in these Regulations:

Provided that in case of RVPN, the ARR shall include the additional contribution towards pension and gratuity trust as determined by the Commission in terms of Regulation 29 of these Regulations.

5.7 O&M Expenses

5.7.1 Regulation 65 of RERC Tariff Regulations, 2014 specifies O&M expenses for Transmission Licensees as under:

"***65. Operation & maintenance (O&M) expenses***

The norms for O&M expenses have been fixed for the first year of the Control Period (i.e. FY 2014-15) on the basis of circuit kilometre of transmission lines, transformation capacity in MVA, and number of feeder bays in the substation, as given below:

(a) O&M expense per ckt-km

- 765 kV : Rs. 1.57 lakh per ckt-km
- 400 kV : Rs. 0.99 lakh per ckt-km
- 220 kV : Rs. 0.39 lakh per ckt-km
- 132 kV : Rs. 0.23 lakh per ckt-km

(b) O&M expense per MVA capacity : Rs. 0.61 lakh per MVA

(c) O&M expense per feeder bay

- 765 kV : Rs. 91.94 lakh per feeder bay
- 400 kV : Rs. 61.29 lakh per feeder bay
- 220 kV : Rs. 8.54 lakh per feeder bay
- 132 kV : Rs. 5.80 lakh per feeder bay

Note: *MVA capacity includes MVAr."*

5.7.2 In the Tariff Order for respective year, the Commission has approved the O&M expenses for RVPN based on the norms specified above and projected transmission parameters. Further, the Commission has also undertaken the Truing up till FY 2016-17, wherein normative O&M Expenses are approved based on the norms and actual transmission parameters. The comparison of actual and normative O&M Expenses for RVPN is shown in the following Table:

Table 9 Actual O&M Expenses vis-à-vis normative O&M Expenses

Sr. No.	Particulars	FY 2014-15	FY 2015-16	FY 2016-17
1	Employee Expenses	384.55	417.03	442.28
2	Provision due to actuarial valuation liability for leave encashment	486.44	453.56	29.83
3	A&G Expenses	69.17	98.49	100.24
4	R&M Expenses	45.25	47.49	57.46
5	Less: Capitalisation of O&M Expenses	173.98	202.05	220.4
6	**Actual Net O&M Expenses (A)**	**811.43**	**814.52**	**409.41**
7	**Normative O&M Expenses (B)**	**706.89**	**836.98**	**950.57**
8	**Gain/(Loss) (B-A)**	**-104.54**	**22.46**	**541.16**

5.7.3 From the above, it is observed that there is loss in FY 2014-15 and gain in subsequent years. Further, Terminal Liabilities have also been made part of O&M Expenses, because of which, the gap accrued in FY 2016-17 is much higher. The Commission is of view that Terminal Liabilities arising out of actuarial valuation shall be allowed separately at actuals over and above the normative O&M expenses subject to prudence check.

5.7.4 For the next Control Period, it is proposed to continue with the same approach of specifying the per ckt-km, per MVA and per feeder bay norms for Transmission for first year of the Control Period. Further, escalation factor has been determined based on five years average of annual increase in CPI for Industrial Workers (All India) as per Labour Bureau, Government of India and WPI as per Office of Economic Advisor of Government of India in the ratio of 50:50.

5.7.5 The actual O&M Expenses during the previous two years i.e., from FY 2015-16 and FY 2016-17 are lower than normative O&M expenses. However, this does not include the impact of 7th Pay Commission, which is likely to come in next Control Period. Hence, it may not be appropriate to substantially reduce the norms of O&M expenses with respect to applicable O&M norms for FY 2018-19.

5.7.6 However, in case of Transmission, existing norms includes the provisioning towards terminal liabilities arising out of actuarial valuation, hence, the norm for FY 2018-19 also includes the impact of these terminal liabilities. The Commission while carrying out the truing up of RVPN for FY 2016-17 has approved the O&M expenses. Such approved O&M expenses approved for FY 2016-17 have been considered as base expenses and escalated by 5.85% per annum to arrive at revised O&M expenses for FY 2018-19. The revised O&M expenses for FY 2018-19 have been considered to derive the O&M norms for the next Control Period. In view of the above, the following has been proposed for the next Control Period:

"***65. Operation and Maintenance Expenses:***

The norms for O&M expenses have been fixed for the first year of the Control Period (i.e., FY 2019-20) on the basis of circuit kilometre of transmission lines, transformation capacity in MVA, and number of feeder bays in the substation, as given below:

(a) O&M expense per ckt-km

- 765 kV	*:*	*Rs. 0.1.03 lakh per ckt-km*
- 400 kV	*:*	*Rs. 0.65 lakh per ckt-km*
- 220 kV	*:*	*Rs. 0.26 lakh per ckt-km*
- 132 kV	*:*	*Rs. 0.15 lakh per ckt-km*

(b) O&M expense per MVA capacity : Rs. 0.40 lakh per MVA

(c) O&M expense per feeder bay

- 765 kV	*:*	*Rs. 60.16 lakh per feeder bay*
- 400 kV	*:*	*Rs. 40.10 lakh per feeder bay*
- 220 kV	*:*	*Rs. 5.59 lakh per feeder bay*
- 132 kV	*:*	*Rs. 3.80 lakh per feeder bay*

Note: *MVA capacity includes MVAr.*

O&M Expenses norms for each subsequent year shall be escalated by escalation factor determined based on previous five years average of annual increase in Consumer Price Index for Industrial Workers (All India) as per Labour Bureau, Government of India and Wholesale Price Index as per Office of Economic Advisor of Government of India in the ratio of 50:50.

Provided that terminal liabilities shall be allowed separately based on actuarial valuation, over and above the normative O&M Expenses, subject to prudence check shall be allowed separately."

5.8 SLDC Charges for System Operation and Load Despatch

5.8.1 In line with the existing RERC Tariff Regulations, 2014, it is proposed to retain the provision that the Commission shall determine SLDC fees and charges in accordance with RERC (Levy of fees and charges for State Load Despatch Centre) Regulations, 2004 as amended from time to time. The determination of SLDC fees and charges during each year of the Control Period shall be based on approved SLDC expenses as outlined under these Regulations.

5.8.2 The SLDC expenses shall contain:

(a) Operating expense components comprising the following:

(i) Employee expenses;

(ii) Administrative and General Expenses;

(iii) Repair and Maintenance Expenses;

(iv) Interest on Working Capital;

(v) RLDC Fee and Charges;

(b) Capital expense components comprising the following:

(i) Depreciation;

(ii) Interest and finance charges on term loan; and (iii)Return on equity.

5.8.3 The segregated Accounts pertaining to SLDC function, duly certified by an Auditor or a Chartered Accountant, shall form the basis for approval of SLDC expenses and determination of SLDC fees and charges thereof in the manner as stipulated by the Commission through Orders to be issued from time to time.

5.8.4 Further, existing Regulations, do not provide either the norms or principles for determination of O&M Expenses for SLDC. In view of the O&M expenses proposed for other Licensees, the following principle has been proposed for SLDC:

"

(1) *The O&M Expenses as approved by the Commission for FY 2018-19 shall be considered as base O&M Expenses.*

(2) *O&M Expenses for each subsequent year shall be calculated by escalating base O&M expenses with the escalation factor determined based on previous five years average of annual increase in Consumer Price Index for Industrial Workers (All India) as per Labour Bureau, Government of India and Wholesale Price Index as per Office of Economic Advisor of Government of India in the ratio of 50:50:*

Provided that terminal liabilities shall be allowed separately based on actuarial valuation, over and above the normative O&M Expenses, subject to prudence check. "

6 Norms and Principles for Determination of ARR and Tariff for Distribution Business

6.1 Components of ARR of Distribution Licensee

6.1.1 It is proposed that for the next Control Period, retail supply tariff of a Distribution Licensee shall provide for recovery of the Aggregate Revenue Requirement of the Distribution Licensee for the financial year, as reduced by the amount of non-tariff income, income from wheeling, income from Other Business and receipts on account of cross-subsidy surcharge and additional surcharge, as approved by the Commission, and subsidy from the State Government, if any, and shall comprise the following:

(a) Cost of power purchase, cost of power generation for self and partnership projects;
(b) Transmission charges;
(c) NLDC/RLDC/SLDC Charges;
(d) Operation and Maintenance expenses;
(e) Interest and finance charges on loan capital;
(f) Depreciation;
(g) Amortisation of Regulatory assets;
(h) Interest on working capital and on consumer security deposits and deposits from Distribution System Users;
(i) Provisioning for Bad debts, if any; and
(j) Return on equity.

Net Revenue Requirement from sale of electricity = Aggregate revenue requirement, as above, minus:

(a) Non-tariff income;
(b) Income from wheeling charges recovered from open access consumers;
(c) Income from Other Business, to the extent specified in these Regulations;
(d) Receipts on account of cross-subsidy surcharge from open access consumers; and
(e) Receipts on account of additional surcharge on charges of wheeling from open access consumers:

Provided that any revenue grant received from the State Government other than the subsidy under Section 65 of the Act shall be treated in the manner as indicated by the State Government. If no such manner is indicated, the grant shall be used to reduce the overall gap between the ARR and revenue of Discoms.

6.2 Operation & Maintenance Expenses

6.2.1 The O&M expenses comprise Employee Expenses, R&M Expenses and A&G expenses, and constitute a significant part of the Aggregate Revenue Requirement of the distribution licensee.

6.2.2 In this context, the FOR Report on MYT framework and distribution margin has recommended as under:

"2.5.14 O&M expenditure should be allowed on a normative basis by prescribing this in the regulations."

6.2.3 In the existing Tariff Regulations, the Commission has specified norms for Employee Expenses, A&G Expenses and R&M Expenses in terms of paise per unit of sale. While developing the framework for the components of O&M Expenses, the State Regulatory Commissions have adopted different approaches after duly considering the State-specific requirements. The Regulatory Commissions have mainly adopted the following approaches:

- Actual O&M expenses for previous year with certain escalation factor for ensuing years
- O&M expenses based on certain performance benchmarks

6.2.4 In the traditional approach, the Commissions have specified the O&M expenses based on the actual expenditure incurred during the previous year and the ensuing years' O&M expenses are based on certain escalation factors.

6.2.5 The Commission, in its existing Tariff Regulations, considered the merits and demerits of the available approaches, and decided that employee expenses, A&G expenses and R&M expenses would be specified separately, rather than as consolidated O&M expenses. It is proposed to continue with the mechanism of specifying separate norms for each O&M component.

6.2.6 Regulation 83 of RERC Tariff Regulations, 2014 specifies O&M expenses for Transmission Licensees as under:

"***83. Operation and Maintenance expenses***
The norms for O&M expenses for Distribution Licensees to recover O&M expenses have been fixed for the first year of the Control Period (i.e. FY 2014-15), as given below:

Employee Expenses : 38 paise per unit of sale
A&G Expenses : 4 paise per unit of sale
R&M Expenses : 8 paise per unit of sale"

6.2.7 In the Tariff Order for respective year, the Commission has approved the O&M expenses based on the norms specified above and projected energy sales. Further, the Commission has also undertaken the Truing up till FY 2016-17, wherein normative O&M Expenses are approved based on the norms and actual energy sales. The comparison of actual and normative O&M Expenses Distribution Licensees is shown in the following Table:

Table 10 Actual O&M Expenses vis-à-vis normative O&M Expenses for Distribution

Sr. No.	Particulars	Normative (in Rs. Crore)			Actual (in Rs. Crore)			
		JVVNL	AVVNL	JdVVNL	JVVNL	AVVNL	JdVVNL	Total
	FY 2014-15							
1	Employee Expenses	457.25	472.17	423.24	394.53	455.08	315.93	1,165.54
2	A&G Expenses	48.84	46.96	48.73	86.23	72.56	54.23	213.02

Sr. No.	Particulars	Normative (in Rs. Crore)			Actual (in Rs. Crore)			
		JVVNL	AVVNL	JdVVNL	JVVNL	AVVNL	JdVVNL	Total
3	R&M Expenses	139.95	102.93	126.67	100.10	101.43	101.25	302.78
4	Total O&M Expenses	646.04	622.06	598.64	580.86	629.07	471.41	1,681.34
	FY 2015-16							
1	Employee Expenses	494.69	510.34	468.50	428.69	513.43	360.48	1,302.60
2	A&G Expenses	50.39	51.32	51.41	93.63	79.49	55.68	228.80
3	R&M Expenses	151.17	111.36	140.22	85.30	108.36	91.11	284.77
4	Total O&M Expenses	696.25	673.02	660.13	607.62	701.28	507.27	1,816.17
	FY 2016-17							
1	Employee Expenses	658.78	567.58	632.83	520.80	543.08	435.49	1,499.37
2	A&G Expenses	71.55	56.40	67.24	128.85	103.78	63.34	295.97
3	R&M Expenses	167.75	123.57	158.94	111.23	128.58	88.97	328.78
4	Total O&M Expenses	898.08	747.55	859.01	760.88	775.44	587.80	2,124.12

6.2.8 The computation of Norms for O&M Expenses based on actual O&M expenses, is shown in the following Table:

Table 11 Computation of norms for O&M Expenses for Distribution

Particulars	Actual Norms		
	FY 15	FY 16	FY 17
Employee expenses (paise per unit sale)	25.23	27.39	29.85
A&G Expenses expenses (paise per unit sale)	4.61	4.81	5.89
R&M Expenses (paise per unit sale)	6.55	5.99	6.55
R&M Expenses as % of Opening GFA	1.30%	1.12%	1.21%

6.2.9 From the above, it is observed that actual O&M expenses for JVVNL and JdVVNL are lower than normative in all three years, however, it is higher for AVVNL. Since, common norms are specified for all three distribution licensees, there is gain to two distribution licensees and loss to one distribution licensee.

6.2.10 For the next Control Period, it is proposed to continue with the same approach of specifying uniform norms for first year of the Control Period for all the Distribution Licensees. Further, escalation factor has been determined based on five years average of annual increase in CPI for Industrial Workers (All India) as per Labour Bureau, Government of India and WPI as per Office of Economic Advisor of Government of India. The escalation factor for employee expenses has been linked to increase in CPI, for A&G expenses linked to increase in CPI and WPI in the ratio of 50:50, and for R&M Expenses linked to increase in WPI only.

6.2.11 Further, R&M Expenses are linked to R&M of distribution system. Hence, instead of energy sale, gross fixed asset would be the appropriate parameter for computation of norms for R&M Expenses. Hence, it is proposed to specify the norm for R&M expenses linked to Gross Fixed Assets instead of energy sale. However, the per unit sale norms have been continued for Employee Expenses and A&G expenses.

6.2.12 It is noted that the actual O&M Expenses for 2 Discoms during the previous three years, i.e., from FY 2014-15 to FY 2016-17 are lower than normative O&M expenses. However, this does not include the impact of 7th Pay Commission, which is likely to come in next Control Period. Hence, it may not be appropriate to substantially reduce the norms of O&M expenses with respect to applicable O&M norms for FY 2018-19. Hence, O&M Expenses norm for FY 2019-20 have been kept equivalent to norm of FY 2018-19 as there will be impact of 7th Pay Commission in the next Control Period.

6.2.13 In view of the above, the following have been proposed for O&M Expenses for Distribution Licensee for the next Control Period:

"The norms for O&M expenses for Distribution Licensees to recover O&M expenses have been fixed for the first year of the Control Period (i.e., FY 2019-20), as given below:

(1) *Employee Expenses and Administrative and General Expenses:*

(a)Employee Expenses: - 48 paise per unit of sale
(b)Administrative and General Expenses:- 5 per unit of sale

Employee Expenses norms for each subsequent year shall be escalated by escalation factor determined based on previous five years average of annual increase in Consumer Price Index for Industrial Workers (All India) as per Labour Bureau, Government of India.

Administrative and General Expenses norms for each subsequent year shall be escalated by escalation factor determined based on previous five years average of annual increase in Consumer Price Index for Industrial Workers (All India) as per Labour Bureau, Government of India and Wholesale Price Index as per Office of Economic Advisor of Government of India, in the ratio of 50:50.

Provided that terminal liabilities shall be allowed separately based on actuarial valuation, over and above the normative O&M Expenses computed above, subject to prudence check.

(2) *Repairs and Maintenance Expenses:*

R&M Expenses for each year of Control Period: $k \times GFA_{n-1} \times (WPI_n/WPI_{n-1})$

Where,
K' is a constant (expressed in %) governing the relationship between R&M expenses and Gross Fixed Assets (GFA) for the (n-1)th year And shall be considered as 1.2%.

'GFA' is the average value of the Gross Fixed Assets of the (n-1)th year;

'WPI_n' means the annual average Wholesale Price Index as per Office of Economic Advisor of Government of India for the n^{th} year; "

6.3 Loss Reduction Trajectory

6.3.1 In the multi – year tariff regime, the Commission is required to set year-wise benchmarks for loss reduction, which may be in terms of percentage reduction with respect to the opening loss level or by stipulating absolute numbers. The issues that need to be addressed for the next Control Period are the criteria for determining the base level loss determination and loss reduction trajectory.

6.3.2 The FOR report on MYT framework and distribution margin recommends as under:

"6.1.12 The loss levels may be considered at actual level at the start of the first control period and an achievable trajectory may be given under the MYT framework. However, the loss level at the start of the subsequent control periods may be fixed keeping in view the targets set in the previous control period, actual performance and efforts at achievement. The norms should be revised after every MYT period with prospective effect."

6.3.3 Regulation 76 of RERC Tariff Regulation specifies as under:

*"**76. Distribution Losses & Collection Efficiency***
(1) The Distribution Licensee shall give information of total and voltage-wise distribution losses in the previous year and current year and the basis on which such losses have been worked out.

(2) The Distribution Licensee shall give information of total and category-wise collection efficiency in the previous year and current year and the basis on which such collection efficiency has been worked out.

(3) The Distribution Licensee shall also propose a target for loss reduction and improvement in collection efficiency for the ensuing year as well as for the subsequent years of Control Period giving details of the measures proposed to be taken for achieving the targets proposed, along with the Tariff Petition for the first year of the Control Period.

(4) Based on the information furnished and the target for loss reduction and improvement in collection efficiency proposed by the Distribution Licensee, the Commission shall fix a target for reduction of distribution losses and improvement in collection efficiency for the ensuing years of the Control Period.

(4) The gains arising on account of distribution losses being lower or the losses arising on account of distribution loss being higher than the target fixed for any year by the Commission, shall be shared in the ratio of 50:50 between the distribution licensee and the consumers."
Provided that the gains on account of distribution losses to be shared with the consumers shall be considered net of income tax as follows:

Gain to be shared with consumers = 50% of total Gain X (1-t)

Where "t" is the effective tax rate applicable for the year at the time of truing up."

6.3.4 It is proposed to continue with the existing approach of determination of the distribution loss trajectory for the licensees for the entire Control Period based on the Tariff Petition for the first year of the Control Period.

6.3.5 Further, it is proposed that the gains arising out of higher distribution loss reduction than the target fixed for any year by the Commission and the losses on account of the distribution licensee's failure to achieve the target set by the Commission shall be shared in the ratio of 50:50 between the distribution licensee and the consumers.

6.4 Wheeling Charges

6.4.1 In this context, RERC Tariff Regulations, 2014 specifies as under:

"86. Wheeling charges

(1) Wheeling charges of a distribution licensee shall be computed by deducting the following amounts from its aggregate revenue requirement worked out under regulation 77 (1):

(a) Cost of power purchase as per regulation 79,
(b) Interest payable on security deposits of consumers,
(c) Transmission charges and
(d) 10% of O&M expenses

(2) Wheeling charges so worked out shall be apportioned supply voltage wise on the basis of fixed asset at each voltage level, as submitted by the distribution licensee.

(3) Payment of wheeling charges:
Wheeling charges may consist of the following or any one or combination thereof:

(a) Fixed charge in Rs. per month per KW of contracted power.
(b) A charge in Rs. per KWh of energy wheeled separately for
(i) Wire business
(ii) Installation, operation and maintenance of meters, metering system and any other equipment at consumer's premises.
(iii) Billing & collection of payment
(iv) Consumer services.
(c) Connectivity fee.
(d) Reactive energy charge / incentive

(4) While determining wheeling charges for open access customers, the total electricity wheeled on the licensees distribution system including his own shall be taken into account.

(5) The average technical losses for each voltage level shall be determined and considered in the determination of wheeling charges and distribution losses as applicable and be applicable in kind to the users of the distribution system of that voltage level.

(6) The distribution licensee shall work out the voltage wise asset allocation and losses within one year of coming into force of these regulations. This period could be extended by one more year, if commission, based on petition of licensee, is satisfied that such extension be given. The distribution licensee shall also give the basis of allocation of fixed costs to the different voltage levels,

energy supplied at each voltage level and prevalent distribution losses at each voltage level in the petition for determination of wheeling charges:

Provided that for the first year of the control period or the extended period, as above, the Commission may determine the wheeling charges based on its assessment of the voltage-wise costs and losses."

6.4.2 It is observed that the Distribution Licensees are yet to work out the voltage-wise cost of supply and are also yet to work out the voltage-wise losses. The distribution licensees are unable to provide the details of allocation of fixed costs to the different voltage levels, energy supplied at each voltage level and prevalent distribution losses at each voltage level in the petition for determination of wheeling charges.

6.4.3 In view of the above, it is proposed that till the time the Distribution Licensee submits the appropriate details, the alternative method shall be adopted for computation of wheeling charges for different voltage levels based on distribution line length and transformation capacity. Accordingly, the following clauses have been proposed under sub-regulation (2):

"Provided that the distribution licensee shall work out the voltage wise asset allocation and losses within one year of coming into force of these regulations. This period could be extended by one more year, if Commission, based on petition of licensee, is satisfied that such extension be given. The distribution licensee shall also give the basis of allocation of fixed costs to the different voltage levels, energy supplied at each voltage level and prevalent distribution losses at each voltage level in the petition for determination of wheeling charges.

Provided further that till the time Distribution Licensee submits the actual allocation of fixed assets at each voltage level, the Commission shall apportion fixed assets at each voltage level on the basis of length of distribution lines in ckt. km and transformation capacity in MVA as furnished by the Distribution Licensee or any other methodology which it feels appropriate."

6.5 Fuel Surcharge

6.5.1 Regulation 88 of RERC Tariff Regulations, 2014 specifies the mechanism for Fuel Surcharge, which allows the recovery of variation in fuel cost on quarterly basis. Further, it is observed that there is no adjustment of under-recovery or over-recovery of Fuel Surcharge in subsequent Quarters. This would affect cash flow of Licensee. Hence, it is proposed that under-recovery or over-recovery of the previous (n-1) quarter shall also be considered for determining the fuel surcharge for a respective quarter (n).

6.5.2 Further, considering the increase in fuel prices in past years, it has been noted that there should be review of ceiling of Fuel Surcharge. The existing limit of 10% would not be sufficient for meeting the gap in approved and actual fuel cost.

Hence, it is proposed to increase the ceiling limit to 20% of average power purchase cost.

6.5.3 Accordingly, the following Regulation for Fuel Surcharge has been proposed for next Control period:

"

(1) *The Fuel Surcharge (FS) chargeable by the Distribution Licensee from its consumers for any quarter, shall be computed as per the following formula:*

$$FS_n = \frac{C + I_{n-1}}{E} \quad (Rs./\ kWh)$$

Where

C (in Rs. Lakh) = {(Weighted Average Variable Cost of all sources of power purchase during previous quarter in Rs/kWh – Base Weighted Average Variable Cost of all sources of power purchase as approved under Tariff Order for the year under operation in Rs/kWh) x Corresponding Power Purchase from all sources during previous quarter in LU}

E (in Lakh Units) = Energy sold (metered plus estimated) during previous quarter.

I_{n-1} (In Rs. Lakh)= Under-recovery of fuel surcharge in (n-1) quarter

Note:

(i) Quarter referred under this formula shall correspond to financial quarter (s) viz. Q1 (Apr. to Jun), Q2 (Jul to Sept), Q3 (Oct to Dec), and Q4 (Jan to Mar).

(ii) The variation in power purchase cost due to Charges for Deviations incurred by Distribution Licensee as per Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014 amended from time to time and Hydro based generation and other unapproved purchases shall not be covered under fuel surcharge adjustment.

(iii) For the generation stations/power purchase sources, which have single part tariff, 1/3 of the tariff shall be considered as fixed charge and 2/3 of the tariff shall be considered as energy charge for adjustment under this formula.

(iv) The cost and quantum of power purchase shall be based on bills paid/credits received during the previous quarter irrespective of period to which it pertains and shall include arrears or refunds, if any, for previous period, not considered earlier.

(2) *The rate of Fuel Surcharge shall be worked out in Rs./kWh rounded off to the next second decimal place.*

(3) *The Fuel Surcharge per unit for any quarter shall not exceed 20% of weighted average power purchase cost per unit approved by the Commission, or such other ceiling as may be stipulated by the Commission from time to time.*

(4) *The total Fuel Surcharge recoverable, as per the formula specified above, shall be recovered from the actual sales and in case of un-metered consumers, it shall be recoverable based on estimated sales to such consumers, calculated in accordance with such methodology as may be stipulated by the Commission. "*

6.6 Cross-Subsidy surcharge

6.6.1 Regulation 90 of RERC Tariff Regulations, 2014 specifies the Cross-Subsidy Surcharge as under:

"90. Cross-subsidy Surcharge

The surcharge payable by consumers opting for open access on the network of the distribution licensee or transmission licensee will be determined by the Commission as per the following Formula:

S = T - [C /(1 - (L/ 100)) + D]

Where,

S is the surcharge

T is the Tariff payable by the relevant category of consumers;

C is the weighted average cost of power purchase of top 5% at margin excluding liquid fuel source and renewable energy sources

D is the wheeling charge

L is the system losses of distribution licensee for the applicable voltage level, as a percentage:

Provided that if S is computed to be negative as per above Formula, S shall be considered as zero."

6.6.2 Further, the Tariff Policy dated January 28, 2016 stipulates the formula for computation of Cross-Subsidy Surcharge. It is proposed to adopt the same formula for the next Control Period. Accordingly, the following has been proposed for computation of Cross-Subsidy Surcharge for next Control Period:

"90. Cross-subsidy Surcharge

The surcharge payable by consumers opting for open access on the network of the distribution licensee or transmission licensee will be determined by the Commission as per the following Formula:

S = T - [C /(1 - L/ 100) + D+R]

Where,

S is the surcharge

T is the Tariff payable i.e., Average Billing Rate *by the relevant category of consumers;*

C is the per unit weighted average cost of power purchase by the Licensee;

D is the aggregate of transmission, distribution and wheeling charges applicable to the relevant voltage level;

L is the aggregate transmission, distribution and commercial losses, expressed as percentage applicable to the relevant voltage level;

R is the per unit cost of carrying regulatory assets or unfunded gap recognised by the Commission:

:

Provided that if S is computed to be negative as per above Formula, S shall be considered as zero."

6.7 Additional Surcharge

6.7.1 It is proposed to retain the existing provision for Additional Surcharge, as under:

"Additional Surcharge shall be governed by the relevant provisions of RERC (Terms and Conditions for Open Access) Regulations, 2016, as amended from time to time."

6.8 Regulatory Assets

6.8.1 It is proposed to retain the existing provision of Regulatory Assets to deal with exceptional circumstances, and accordingly the following provisions are envisaged:

"Regulatory Asset shall be created only under exceptional circumstances:
Provided that as and when created, the Regulatory Asset shall be amortised in such a manner that it is co-terminus with the MYT Control Period as far as possible and carrying cost shall be allowed to be added to the revenue requirement of each year till such time the Regulatory Asset is fully amortised."