Central Electricity Regulatory Commission

New Delhi

Explanatory Memorandum on

Draft Central Electricity Regulatory Commission

(Terms and Conditions of Tariff) Regulations, 2024

January, 2024

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1 Introduction

1.1 Background

1.1.1 The Central Electricity Regulatory Commission (hereinafter referred to as the 'CERC' or 'the Commission') was constituted under the erstwhile Electricity Regulatory Commissions Act (ERC), 1998 to discharge the duties and perform the functions specified under Section 13 of the ERC Act, 1998. Upon enactment of the Electricity Act, 2003 (hereinafter referred to as 'the Act'), CERC was deemed to be constituted under the Act.

1.1.2 The Commission has been vested with the functions of regulating the tariff of the generating companies owned or controlled by the Central Government; regulating the tariff of generating companies having a composite scheme for generating and sale of electricity in more than one State; regulating inter-state transmission of electricity and to determine the tariff for inter-State transmission in electricity under Section 79(1) of the Act, among other functions.

1.1.3 The Act provides a broader role to the Commission, which includes promoting competition, efficiency and economy in bulk power markets, improving the quality of supply, promoting investments and advising the Government on removal of institutional barriers to allow for bridging of the demand-supply gap and thus foster the interests of consumers.

1.1.4 Section 61 of the Act provides the guiding principles for the Central Commission while specifying the terms and conditions for the determination of tariff as follows:

"Section 61 (Tariff regulations):

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) *Multiyear 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:*

1.1.5 Section 178 (1) and (2) (s) of the Act further empowers the Commission to make regulations on the terms and conditions for the determination of tariffs under Section 61 of the Act.

1.2 Tariff Regulations Issued by CERC

1.2.1 The Commission, since its inception, has been issuing regulations based on multi-year tariff principles over the various Control Periods as follows:

Tariff Regulations	Issuance	Period	Provisions
CERC (Terms and Conditions of Tariff) Regulations, 2001 (hereinafter referred to as the Tariff Regulations, 2001)	December 2000	2001 - 2004	Section 28 of the erstwhile Electricity Regulatory Commissions Act, 1998
CERC (Terms and Conditions of Tariff) Regulations, 2004 (hereinafter referred to as the Tariff Regulations, 2004)	March 2004	2004 - 2009	Section 178 of the Electricity Act, 2003
CERC (Terms and Conditions of Tariff) Regulations, 2009 (hereinafter referred to as the Tariff Regulations, 2009)	January 2009	2009 - 2014	Section 178 of the Electricity Act, 2003
CERC (Terms and Conditions of Tariff) Regulations, 2014 (hereinafter referred to as the Tariff Regulations, 2014)	February 2014	2014 - 2019	Section 178 of the Electricity Act, 2003
CERC (Terms and Conditions of Tariff) Regulations, 2019 (hereinafter referred to as the Tariff Regulations, 2019)	March 2019	2019 - 2024	Section 178 of the Electricity Act, 2003

1.2.2 The present tariff period 2019-24 would end on 31.03.2024, and therefore the Commission proposes to specify the terms and conditions of the tariff for the next control period, i.e., for 2024-29.

1.3 Approach Paper for Tariff Regulations, 2024-29

1.3.1 The Staff of the Commission initiated the process of framing Tariff Regulations for the 2024-29 period by issuing Approach Paper on Terms and Conditions of Tariff Regulations for Tariff Period 01.04.2024 to 31.03.2029 in May 2023 (hereinafter referred to as the Approach Paper) and solicited comments of stakeholders on various options for regulatory framework to be considered while framing the new terms and conditions of Tariff Regulations for the Control Period 2024-29. The Approach Paper was issued to initiate discussions on the changes required, if any, on the existing tariff norms based on the analysis of earlier Tariff Regulations and their efficacy and the issues and challenges faced by various stakeholders in the past. The Approach Paper also analyzed the key macroeconomic and other indicators, along with problems and challenges that the power sector at large is likely to face going forward, which shall impact the tariff and its determination process under Section 62 of the Electricity Act, 2003. The Approach Paper was aimed at soliciting preliminary views of the stakeholders on different aspects of tariff setting during the Control Period 2024-29.

1.3.2 Various stakeholders including State Governments, State Electricity Regulatory Commissions (SERCs), Central Sector Utilities, State Sector Utilities, Private Sector Utilities, Consumer Representative Groups, Financial and Other Organizations, and Individual Experts submitted their comments on the Approach Paper.

1.3.3 The comments received on the Approach Paper have been uploaded on the website separately. The meeting of the Central Advisory Committee was also held on 26.09.2023 and the observations and suggestions by the members have been considered. While preparing the Draft Tariff Regulations for 2024-29, the Commission has taken a holistic view by taking into consideration the following aspects inherent to the process of formulation of tariff regulations;

a) issues raised in the Approach Paper and comments thereon;

b) issues otherwise raised by the stakeholders;

c) the last five to ten years of performance of the central sector generating stations and other interstate generating stations and interstate transmission systems;

d) the existing economic environment of the power sector in the country;

e) future needs of the power sector based on the anticipated generation mix and associated grid support; and

f) fostering energy security by promoting sustainable investments.

1.3.4 Approach Paper highlighted several issues and challenges that have direct or indirect impact on the tariff framework. Along with the problems and challenges, the Approach Paper also suggested alternatives for addressing such problems. It further sought various stakeholders' views and other probable solutions to address such issues/problems and challenges.

1.3.5 In response, several stakeholders have provided their suggestions, and the Commission has considered the comments/suggestions provided by the stakeholders on various issues. All the suggestions given by the stakeholders have been considered, and the Commission has attempted to summarise the relevant suggestions and the Commission's view thereon in the subsequent paragraphs, however, in case any suggestion is not specifically elaborated, it does not mean that the same has not been considered. Though the Approach Paper has touched upon the issues of a wider horizon, the Commission, in the Draft Tariff Regulations for 2024-29, has included only those issues that are relevant at this stage and which are needed to be addressed immediately considering the present scenario and strategic long-term view of the power sector.

1.3.6 In this explanatory memorandum, the Discom has the same meaning as "the Distribution Licensee". Similarly, Transco may be read as "the Transmission Licensee".

2 Definitions

2.1 Background

2.1.1 The Commission has updated certain definitions and has also introduced some new definitions to provide clarity to certain existing and new terms that are referred to in these regulations.

2.2 Proposed Definitions and Rationale:

(5) 'Annual Target Quantity' or 'ATQ' *in respect of an integrated mine(s) means the quantity of coal or lignite to be extracted during a year from such integrated mine(s) corresponding to 85% of the quantity specified in the Mining Plan;*

Rationale: It is observed that the ATQ is being used to compute the price of coal and in case of any shortfall in achieving 100% of the ATQ there is a shortfall in recovery of fixed charges. Several representations have been received from generating companies to reduce ATQ to 85% of the quantity specified in the mine plan so that the fixed charges incurred can be recovered, as is allowed in the case of generating stations where entire fixed cost is being allowed to be recovered if the station achieves availability of 85%. The Commission observes that the extraction of coal is affected by several extraneous factors which may prevent it from achieving 100% of ATQ, and therefore some margin is required so that the utility is able to at least recover its fixed charges. In this regard, it is further observed that as per Model Coal Supply Agreement under the New Coal Distribution Policy notified on 18.10.2007, the capacity utilization factor considered for computation of base price of coal is 85%. It is also observed that the Ministry of Coal vide Order dated 11.06.2009 has also recommended retaining the capacity utilization factor of 85% for lignite mine integrated with NLC stations.

Given the above, the definition of ATQ has been modified to 85% of the quantity specified in the mine plan.

(12) 'Capital Spares' *means spares individually costing above Rs. 20 lakh which is maintained by the generating company or the transmission licensee over and above the initial spares.*

Rationale: The Commission, in order to simplify the approval process has proposed to allow capital spares individually costing up to Rs. 20 lakh on a normative basis as part of O&M expenses and therefore the definition is proposed to be included as above.

(17) 'Cut-off Date" *shall be the last day of the financial year closing after thirty six months from the date of commercial operation of the project, except in case of integrated mine(s);*

Rationale: Comments were sought in the Approach Paper on extending the cut-off date to 5 years to enable closing of contracts and discharge of liabilities and to reduce the need of allowing additional capitalisation post cut-off date except due to change in law and force majeure. While various Generating Companies and Transmission Licensees have supported the idea, they have also submitted that all works may not get completed even if the cut-off date is extended to 5 years and have therefore requested to allow additional capitalisation beyond the cut-off date. Various consumer representatives, CEA and distribution companies have suggested not to extend the cut-off date.

The Commission is of the view that for projects whose construction period is 3-5 years, allowing a cut-off date of 5 years may be too long for completing the pending works, and therefore the Commission has proposed to keep the cut-off date as 36 months. However, the earlier provision to compute the cut-off date based on the calendar year is creating difficulties as well, as in most cases, it falls in between a financial year. In case where the cut-off date falls in between a financial year, it becomes difficult to ascertain whether a given asset has been capitalised within this date as the Utilities generally capitalize the asset at the end of the financial year. This difficulty in ascertaining the date of capitalisation of asset also leads to difficulty in computation of Initial Spares since the computation of spares is dependent on Plant and Machinery Cost up to Cut-off Date. In order to address such issues and considering the suggestions of various stakeholders, the modified definition has been proposed as per which the cut-off date shall be the last day of the financial year closing after thirty-six months from the date of commercial operation of the project.

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

Rationale:

Comments were sought in the Approach Paper on the possible approaches to recover or refund the impact of decommissioning costs in case the generating stations/transmission systems are decommissioned before the completion of their useful lives if such decommissioning is done in compliance with a statutory order or due to technological obsolescence duly approved by RPC.

Generating Companies submitted that specific regulations are required to address decommissioning, covering scenarios wherein such de-commissioning is carried out "before useful life" or "after useful life". Transmission Licensees submitted that one-time allowance of unrecovered depreciation along with dismantling or any other associated cost may be allowed. Differential treatment needs to be given depending upon the type & nature of the asset being decommissioned, including its salvage value. Suitable provisions may be provided for recovering the unrecovered depreciation.

The Commission observes that, due to upgradation of environmental norms, some of the old generating plants may fail to meet revised environmental regulations. Therefore, the Commission proposes to include “environmental concerns” in the existing definition of “De-commissioning”.

Further, the certification process by the Central Electricity Authority or other authorized agencies will ensure that the decision is made based on a thorough assessment and aligns with the broader goals of sustainable and responsible energy management.

(32) 'Force Majeure' *for the purpose of these regulations means the events or circumstances or combination of events or circumstances, including those stated below, which prevent the generating company or transmission licensee from completing or to operating the project, and only if such events or circumstances are* *not within the control of the generating company or transmission licensee and could not have been avoided, had the generating company or transmission licensee taken reasonable care or complied with prudent utility practices:*

(a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or

(b) Any act of war, invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, terrorist or military action; or

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

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

Rationale:

It is observed that in the existing Tariff Regulations, the definition of force majeure cover events occurring during the construction period preventing the utilities from completing a project. As such, the definition does not explicitly mention that the said force majeure events may also affect the project post commercial operation i.e., during the operational phase. Hence, the Commission has proposed to modify the definition of Force Majeure to also cover the operational period.

(53) 'Mining Plan' or' Mine Plan' *in respect of integrated mine(s) means a plan prepared in accordance with the Guidelines for Preparation, Formulation, Submission, Processing, Scrutiny, Approval and Revision of Mining Plan for the coal and lignite block issued by the Ministry of Coal, Government of India as amended from time to time or provisions of the Mineral Concession Rules, 1960, as amended from time to time and approved under clause (b) of sub-section (2) of section 5 of the Mines and Minerals (Development and Rehabilitation) Act, 1957 by the Central Government or by the State Government, as the case may be;*
957 by the Central Government or by the State Government, as the case may be;

Rationale:

The Commission has proposed to modify the definition of 'Mining Plan' in accordance with the mining guidelines issued by the Ministry of Coal for Preparation, Formulation, Submission, Processing, Scrutiny, Approval and Revision of Mining Plan for the coal and lignite block.

(67) 'Reference Rate of Interest' *means the one-year marginal cost of funds based lending rate (MCLR) of the State Bank of India (SBI) issued from time to time plus 325 basis points;*

Rationale:

A comprehensive analysis of associated risks, including liquidity risk premium, maturity risk premium, and default risk premium, has been conducted in the power industry. The findings reveal that the historical spread of 350 basis points is higher considering the various efficient financing instruments available today. Therefore, to align with the current market, the spread is proposed to be reduced to a more manageable 325 basis point.

By narrowing the spread, the power industry is expected to optimize its risk-return profile, fostering a more stable and predictable financial environment. This strategic decision reflects a commitment to prudent risk management practices, ensuring that the associated risks are accurately priced and balanced for sustainable growth in the power sector.

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

(a)	*Coal/Lignite based thermal generating station*	*25 years*
(b)	*Gas/Liquid fuel based thermal generating station*	*25 years*
(c)	*AC and DC sub-station*	*25 years*
(d)	*Gas Insulated Substation (GIS)*	*25 years*
(e)	*Hydro generating station including pumped storage hydro generating stations*	*40 years*
(f)	*Transmission line (including HVAC & HVDC) and OPGW*	*35 years*
(g)	*Communication system excluding OPGW, IT and SCADA*	*7 years*
(h)	*Integrated mine(s)*	*As per the Mining Plan*

Provided that in case of coal/lignite based thermal generating stations and hydro generating stations the Operational Life shall be 35 years and 50 years, respectively.

Rationale:

In the Approach Paper, it was proposed that the useful life of coal based thermal generating stations and transmission sub-stations may be increased to 35 years from the current specified useful life of 25 years.

The Commission has observed that various coal/lignite based thermal generating stations and hydro generating stations are operating beyond their stipulated useful life of 25 years and 40 years. To recognize the same, the operational life of these generating stations has been separately specified.

With regard to communication system, it is observed that the expected useful life of the communication system (except for OPGW) and SCADA is similar to that of the IT system. Therefore, the Commission has proposed to reduce the communication system's (excluding OPGW) useful life from 15 years to 7 years.

With regard to OPGW, the Commission is of the view that the life of OPGW is more or less equal to transmission lines. Therefore, the Commission has proposed to align the useful life of OPGW with that of transmission lines.

3 Date of Commercial Operation

3.1 Background

3.1.1 The Commission has updated the terms of COD as per the latest Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2023 and has proposed the sale of infirm power based on the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations, 2022.

3.2 Commission's Views

3.2.1 In the Approach Paper, it was proposed that the aspect of the Date of Commercial Operation (COD) and the manner in which COD shall be declared are being separately dealt with by the Commission in the CERC (Indian Electricity Grid Code) Regulations, 2023 and therefore, shall be considered as per the said Regulation. Accordingly, the proposed provisions in the Draft Tariff Regulations are reproduced below:

Provisions Proposed:

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

(2) The date of commercial operation in case of integrated mine(s), shall mean the earliest of: -

a) *the first date of the year succeeding the year in which 25% of the Peak Rated Capacity as per the Mining Plan is achieved; or*

b) *the first date of the year succeeding the year in which the value of production estimated in accordance with Regulation 7 of these regulations, exceeds total expenditure in that year; or*

c) *the date of two years from the date of commencement of production:*

Provided that on the earliest occurrence of any of the events under sub-clauses (a) to (c) of Clause (2) of this Regulation, the generating company shall declare the date of commercial operation of the integrated mine(s) under the relevant sub-clause with one week prior intimation to the beneficiaries of the end-use or associated generating station(s);

Provided further that in case the integrated mine(s) is ready for commercial operation but is prevented from declaration of the date of commercial operation for reasons not attributable to the generating company or its suppliers or contractors or the Mine Developer and Operator, the Commission, on an application made by the generating company, may approve such other date as the date of commercial operation as may be considered appropriate after considering the relevant reasons that prevented the declaration of the date of commercial operation under any of the sub-clauses of Clause (2) of this Regulation;

Provided also that the generating company seeking the approval of the date of commercial operation under the preceding proviso shall give prior notice of one month to the beneficiaries of the end-use or associated generating station(s) of the integrated mine(s) regarding the date of commercial operation.

6. Sale of Infirm Power: *Supply of infirm power shall be in accordance with the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations, 2022:*

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

7. Supply of Coal or Lignite prior to the Date of Commercial Operation of Integrated Mine: *The input price for the supply of coal or lignite from the integrated mine(s) prior to their date of commercial operation shall be:*

(a) *in the case of coal, the estimated price available in the investment approval, or the notified price of Coal India Limited for the corresponding grade of coal supplied to the power sector, whichever is lower; and*

(b) *in the case of lignite, the estimated price available in the investment approval or the last available pooled lignite price as determined by the Commission for the transfer price of lignite, whichever is lower:*

Provided that any revenue earned from the supply of coal or lignite prior to the date of commercial operation of the integrated mine(s) shall be applied in adjusting the capital cost of the said integrated mine(s).

4 Procedure for Tariff Determination

4.1 Background

4.1.1 As per the existing Regulations, the generating company or the transmission licensee may file a Petition within 60 days of the anticipated date of commercial operation. In case the transmission system comprises various elements, the transmission licensee may file an application for determination of tariff for a group of elements on incurring of expenditure of not less than 70% of the cost envisaged in the Investment Approval or Rs. 200 Crore, whichever is lower, as on the anticipated date of commercial operation. Further, there is a provision with regard to interim tariff wherein the Commission may allow interim tariff if the information furnished in the Petition is in accordance with the stipulated regulations.

4.2 Existing Provisions of the Tariff Regulations, 2019

9. Application for determination of tariff:

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

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

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

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

………

10. Determination of Tariff

(3) If the information furnished in the Petition is in accordance with these regulations and is adequate for carrying out prudence check of the claims made, the Commission may consider granting interim tariff in case of new projects.

……..

4.3 Issues discussed in the Approach Paper

4.3.1 In the Approach Paper for consultation, it was proposed that the Provision for Interim Tariff to be continued in the next control period.

4.4 Stakeholders' Response

4.4.1 Stakeholders have submitted the following suggestions on this issue.

a) NTPC, NHPC along with most of the Generator and Transmission Licensees, CEA, SRPC, APP proposed that the current provision for approval of interim tariff may be continued.

b) PGCIL proposed that an **Interim Tariff at 90%** of the claimed tariff may be approved.

c) THDCIL, MPERC, OTPC and many more companies have submitted that the utilities face hardship in cash flow until the tariff order is issued; hence, interim/provisional tariff up to 90% should be allowed.

d) SJVNL submitted to consider interim tariff / provisional tariff, post COD, considering around 85% of the capital cost as submitted by the Petitioner in the Petition.

e) Some Beneficiaries submitted that Petition for interim tariff may be filed within one month of commissioning, fresh filings were needed for projects not commissioned within 6 months of interim tariff notification, and hence the percentage of the interim tariff may be reduced to 70% instead of the 80% considered currently.

f) Tata Power and MPPMCL have submitted that the interim tariff may be allowed with additional provisions such as Petition for interim tariff may be filed within one month of commissioning, fresh filings were needed for projects not commissioned within 6 months of interim tariff notification, percentage of interim tariff may be reduced to 70% and time-bound determination of final tariff as per CBR regulations or following recent MoP guideline to dispose within 120 days.

4.5 Commission's View

4.5.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders.

4.5.2 It is observed that after the filing of the Petition based on anticipated COD, by the time matter is listed for hearing before the Commission, in most of the cases the project attains actual COD, and the information in the Petition needs revision based on actual COD, which results in regulatory overburden. Further, in cases where COD of the project is delayed, the petition requires multiple revisions. Therefore, the Commission proposes that the provision for the determination of Tariff for projects on an anticipated basis may be done away with, and all projects that have attained COD shall file the Petition for approval of Tariff based on the information as on actual COD within 90 days from the actual COD. The Commission further proposes to allow 90 days from actual COD for filing such Petition so that the financials of the asset are almost firmed up and taken into account while filing the Petition.

4.5.3 Further, taking into cognizance the difficulties that arise while preparing the petition on the basis of audited cost as on actual COD, the existing provision to file Petition on the basis of Auditor Certificate or management certificate is to be retained.

4.5.4 On the issue of interim tariff, the Commission is of the view that the same should be allowed so that the cash flow of utility is not affected and on the other hand the carrying cost that is being paid by the beneficiaries on delayed recoveries is also minimized. The Commission has therefore proposed to grant interim tariff of up to 90% of the tariff claimed during the first hearing. It is proposed that depending upon the time and cost overrun involved, the Commission may allow interim Tariff of up to 80% of the tariff claimed during the first hearing in case Time over-run or cost over-run is involved in the Project's implementation and in case there is no time and cost overrun involved the Commission may allow 90% of the tariff claimed as interim tariff.

4.5.5 The Commission in order to discourage higher claims by the utilities in case the interim tariff is higher than the final tariff by over 10%, the generating company or transmission licensees shall be charged at the rate of 1.20 times the rate of Carrying Cost.

4.5.6 On the issue of clubbing of elements for filing petition, in the past, it has been observed that the existing threshold limit of Rs. 200 Crore is resulting in delayed recoveries and there is a need to review the same. It is also observed that the transmission licensees while filing single Petition have been claiming tariff individually (Asset wise) for various elements based on a different date of commercial operation resulting in multiple AFC streams. The Commission in order to reduce delayed recoveries proposes to lower the specified threshold of expenditure to Rs. 100 Crore and in cases where investment approval is lower than Rs. 100 Crore, the transmission licensee may file Petition if 100% of the cost envisaged in the Investment Approval is incurred. The Commission, in order to avoid multiple AFC streams, proposes that Transmission Licensee shall declare single COD for the elements that have been approved under a single investment approval and have achieved commissioning during a given month. Further, the Transmission Licensee shall seek tariff for a single Asset so that multiple AFC streams of multiple assets can be avoided.

4.5.7 The Commission proposes that Carrying Cost may be provided from the Date of COD in case the Petition is filed within 90 days from the COD of the asset. Further, Carrying Cost may be provided from the Date of filing of the Petition in case the Petition is not filed within 90 days from the COD of the asset to promote prompt filing for Tariff by the Petitioners.

4.6 Proposed Provisions

4.6.1 In view of the above, the Commission proposes Regulation 9 and Regulation 10 in the Draft Tariff Regulations as follows:

9. "Application for determination of tariff"

(1) The generating company or the transmission licensee may make an application for determination of tariff for a new generating station or unit thereof or transmission system or element thereof in accordance with these Regulations within 90 days from the actual date of commercial operation:

Provided that where the transmission system comprises various elements, the transmission licensee shall file an application for determination of tariff for a group of elements on incurring of expenditure of not less than Rs. 100 Crore or 100% of the cost envisaged in the Investment Approval, whichever is lower, as on the actual date of commercial operation:

Provided further that transmission licensees shall combine all the elements of the transmission system in the Investment Approval, which are attaining commissioning during a particular month and declare a single COD for *the combined Asset, which shall be the date of the COD of the last element commissioned in that month and such Asset shall be treated as single Asset for tariff purposes.*

Provided further that the generating company or the transmission licensee, as the case may be, shall submit an Auditor Certificate and, in case of non-availability of an Auditor Certificate, a Management Certificate duly signed by an authorised person, not below the level of Director of the company, indicating the capital cost incurred as on the date of commercial operation and the projected additional capital expenditure for respective years of the tariff period 2024-29:

Provided that for a new generating station or unit thereof or transmission system or element thereof, the applicant, through a specific prayer in its application filed under Regulation 9(1) of these regulations, may plead for an interim tariff, and the Commission shall consider granting interim tariff from the date of commercial operation during the first hearing of the application.

Provided also that the generating company shall file an application for determination of supplementary tariff for the emission control system installed in coal or lignite based thermal generating station in accordance with these regulations not later than 90 days from the date of start of operation of such emission control system.

(2) In case of an existing generating station or unit thereof, or transmission system or element thereof, the application shall be made by the generating company or the transmission licensee, as the case may be, by 31.10.2024, based on admitted capital cost including additional capital expenditure already admitted and incurred up to 31.3.2024 (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure for the respective years of the tariff period 2024-29 along with the true up Petition for the period 2019-24 in accordance with the CERC (Terms and Conditions of Tariff) Regulations, 2019.

(3) In case an emission control system is required to be installed in the existing generating station or unit thereof to meet the revised emission standards, an application shall be made for the determination of supplementary tariff (capacity charges or energy charge or both) based on the actual capital expenditure duly certified by the Auditor.

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

Provided that a generating company with integrated mine(s) shall file a Petition for determination of the input price of coal or lignite from the integrated mine(s) not later than 90 days from the date of actual commercial operation of the integrated mine(s) in accordance with these regulations.

(5) In case the generating company or the transmission licensee files the application as per the timeline specified in sub-clause (1) to (4) of this Regulation, carrying cost shall be allowed from the date of commercial operation of the project:

Provided that in case the generating company or the transmission licensee delays in filing of application as per the timeline specified in sub-clause (1) to (4) of this Regulation, carrying cost shall be allowed to the generating company or the transmission licensee from the date of filing of the application as per Regulation 10(7) and 10(8) of these regulations.

10. "Determination of Tariff"

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

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

(3) If the information furnished in the Petition is in accordance with these regulations, the Commission may consider granting interim tariff of up to ninety per cent (90%) of the tariff claimed in case of new generating station or unit thereof or transmission system or element thereof during the first hearing of the

application:-

Provided that in case the final tariff determined by the Commission is lower than the interim tariff by more than 10%, the generating company or transmission licensee shall return the excess amount recovered from the beneficiaries or long term customers, as the case may be with simple interest at 1.20 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis points prevailing as on 1st April of the financial year in which such excess recovery was made

(4) In case of the existing projects, the generating company or the transmission licensee, as the case may be, shall continue to bill the beneficiaries or the long term customers at the capacity charges or the transmission charges respectively as approved by the Commission and applicable as on 31.3.2024 for the period starting from 1.4.2024 till approval of final capacity charges or transmission charges by the Commission in accordance with these regulations:

Provided that the billing for energy charges w.e.f. 1.4.2024 shall be as per the operational norms specified in these regulations.

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

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

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5 Carrying Cost

5.1 Background

5.1.1 The applicable rate of carrying cost, the manner in which such carrying cost shall be computed has been a point of contention and a matter of litigation for a long time, and hence, the Commission has proposed to simplify the provisions for same in the Draft Regulations.

5.2 Existing Provisions of the Tariff Regulations, 2019

5.2.1 The Existing Provisions in the Tariff Regulations, 2019 is as below:

"10. (7) The difference between the tariff determined in accordance with clauses (3) and (5) above and clauses (4) and (5) above, shall be recovered from or refunded to, the beneficiaries or the long term customers, as the case may be, with simple interest at the rate equal to the bank rate prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments.

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

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

5.3 Commission's View

5.3.1 The Commission is of the view that the Carrying Cost rate should not be enriching but offsetting in nature. Therefore, the Commission has proposed to revise the rate of carrying cost equivalent to the rate of 1 year SBI MCLR plus 100 basis points prevailing as on 1st April of the respective year of the tariff period.

5.3.2 To avoid compounding effect and to maintain simplicity, the Commission has proposed that the carrying cost shall be computed by taking a simple interest on the due amount.

5.3.3 The Commission has also proposed that the bills for this recovery may be issued by the generating company or the transmission licensees within 30 days from the issuance of the Order, and the carrying cost shall be payable till the date of issuance of the Order, and for simplicity purpose no interest shall be allowed or levied during the period of six-monthly instalments for payment of arrears.

5.3.4 The Commission has also proposed to introduce a late payment surcharge in case a utility delays in refunding the amount, to promote prompt refund to the Beneficiaries.

5.3.5 In case the projected additional capitalisation exceeds the actual trued up additional capitalisation by over 10%, the generating company or transmission licensees shall be charged at the rate of 1.20 times the Carrying Cost rate. The Commission has proposed to continue with this existing provision in the Draft Tariff Regulations to discourage the generating company or transmission licensees from projecting higher additional capitalisation, which leads to higher tariff.

5.4 Proposed Provisions

5.4.1 In view of the above, the Commission has proposed the following provisions in Regulation 10 in the Draft Tariff Regulations:

"(7) Subject to Sub-Clause (8) below, the difference between the tariff determined in accordance with clauses (3) and (5) above and clauses (4) and (5) above, shall be recovered from or refunded to, the beneficiaries or the long term customers, as the case may be, with simple interest at the rate equal to the 1 year SBI MCLR plus 100 basis points prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments.

Provided that the bills to recover or refund shall be raised by the generating company or the transmission licensees within 30 days from the issuance of the Order.

Provided further that such interest, including that determined as per sub-clause (8) of this regulation shall be payable till the date of issuance of the Order and no interest shall be allowed or levied during the period of six-monthly instalments.

Provided further that in case where money is to be refunded and there is a *delay in the raising of bills by the generating company or transmission licensees beyond 30 days from the issuance of the Order, it shall attract a late payment surcharge as applicable in accordance with these regulations.*

(8) Where the capital cost approved by the Commission on the basis of projected additional capital expenditure exceeds the actual trued up additional capital expenditure incurred on a year to year basis by more than 10%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term customers as the case may be, the tariff recovered corresponding to the additional capital expenditure not incurred, as approved by the Commission, along with simple interest at 1.20 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis points as prevalent on 1st April of the respective year."

6 Capital Cost

6.1 Background

6.1.1 The approval of capital cost is the basis for tariff determination in the cost-plus tariff regime. The capital cost, to a large extent, determines the extent of competitiveness of the tariff. The Commission admits the capital cost as per the actual capital expenditure incurred on the project, subject to a prudence check.

6.1.2 In the tariff determination process followed prior to the inception of the Electricity Regulatory Commission i.e. before 1992 and during the period 1992 to 1997 and 1997 to 2001, the project's capital cost was based on the gross book value as per the audited accounts. The changes in the capital cost by the way of capitalisation and foreign exchange rate variation (FERV) were also being accounted for and tariff was being adjusted retrospectively. During the control period 2004-09, the determination of capital cost was based on the actual cost incurred on the project. The project developer was to approach for tariff determination after declaration of commercial operation date. This premise was changed with effect from 1.4.2009, and the determination of capital cost was admitted based on the projected capital expenditure. This change facilitated the generating companies or transmission licensees to file their tariff application prior to commissioning of the project and thereby ensured recovery of tariff from the beginning of the commercial operation date as against delayed recovery during the previous period. The projected/actual capital expenditure to be submitted by the generating companies or transmission licensees needs to exclude the un- discharged liabilities for the purpose of capitalisation up to the date of commercial operation. Capital cost, apart from the hard cost of the project, also includes interest during construction, financing charges and FERV up to the date of commercial operation of the project. In the case of generation projects, any revenue generated on account of injection of infirm power through unscheduled interchange in excess of fuel cost is adjusted in the capital cost, whereas in the case of transmission projects, any revenue earned by using the assets before COD is adjusted in the capital cost.

In the Tariff Regulations, 2004, the concept of cut-off date was introduced with a view to allow capitalisation of all the necessary works and equipment up to the cut-off date, within the original scope of work, as a part of approved capital cost. The cut-off date was defined as the closing date of the financial year immediately after one year of the COD. Subsequently, in the case of projects commissioning in the last quarter of the financial year, the cut-off date was extended to the financial year closing after two years of the date of commercial operation of the generating station or the transmission system.

6.1.3 The Commission had specified various provisions regarding the Additional Capital Expenditure in past Tariff Regulations. The Tariff Regulations, 2001 and Tariff Regulations, 2004 had specified that 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. The Tariff Regulations, 2009 allowed additional capital expenditure incurred on new assets after the cut-off date for meeting liabilities of arbitration award, decree or order of the court; on account of a change in law; and deferred works relating to ash pond or ash handling system in the original scope of work. In Tariff Regulations, 2014 and Tariff Regulation, 2019, the Commission continued with the existing provisions for determination of tariff based on the capital expenditure incurred or projected to be incurred. As per the Act, the principles of tariff determination mandate balancing of consumer interests while allowing reasonable returns to the generating company or transmission licensee.

6.1.4 In Tariff Regulations, 2019 the Commission also added the provisions for the determination of tariffs for emission control system based on capital expenditure incurred or projected to be incurred.

6.2 Existing Provisions of the Tariff Regulations, 2019

6.2.1 The existing Tariff Regulations, 2019, allow capital cost for the new projects (to be commissioned in the control period 2019-24) based on the expenditure incurred as on the date of COD, duly certified by the Auditors after prudence check. For the existing projects, the capital cost admitted by the Commission during the preceding tariff period is being considered along with the additional capitalisation during the Control Period after due diligence. Relevant provisions of Tariff Regulations, 2019 are extracted below:

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

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

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

(b) Interest during construction and financing charges, on the loans (i) being

equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event of the actual equity less than 30% of the funds deployed;

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

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

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

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

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

(h) Adjustment of any revenue earned by the transmission licensee by using the assets before COD;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and

(b) Cost of the developers 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) and Deendayal Upadhyaya Gram Jyoti Yojana (DDUGJY) project in the affected area.

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

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

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

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

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

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

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

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

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

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

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

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

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

(3) Where the power purchase agreement entered into between the generating company and the beneficiaries provides for ceiling of actual capital expenditure, the Commission shall take into consideration such ceiling for prudence check

(4) The generating company or the transmission licensee, as the case may be, shall 48 furnish the capital cost for execution of the existing and new projects as per Annexure-I to these regulations along with tariff Petition for the purpose of creating a database of benchmark capital cost of various components.

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

(1) Interest during construction shall be computed corresponding to the loan from the date of infusion of debt fund, and after taking into account the prudent phasing of funds up to SCOD.

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

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

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

(4) If the delay in achieving the COD is not attributable to the generating company or the transmission licensee, IDC and IEDC beyond SCOD may be allowed after prudence 49 check and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be adjusted in the capital cost of the generating station or the transmission system, as the case may be

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

(6) For the purpose of Clauses (4) and (5) of this Regulation, IDC on actual loan and normative loan shall be considered in accordance with sub-clause (b) of clause (2) of Regulation 19 of these regulations.

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

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

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

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

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

a. *Force Majeure events;*

b. *Change in law; and*

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

23. Initial Spares: *Initial spares shall be capitalised as a percentage of the Plant and Machinery cost subject to following ceiling norms:*

(a) Coal-based/lignite-fired thermal generating stations	-	*4.0%*
(b) Gas Turbine/Combined Cycle thermal generating stations	-	*4.0%*
(c) Hydro generating stations including pumped storage hydro generating station.	-	*4.0%*
(d) Transmission system		
i. Transmission line	-	*1.00%*
ii. Transmission Sub-station		
- Green Field	-	*4.00%*
- Brown Field	-	*6.00%*
iii. Series Compensation devices and HVDC Station	-	*4.00%*
iv. Gas Insulated Sub-station (GIS)		
- Green Field	-	*5.00%*
- Brown Field	-	*7.00%*
v. Communication System	-	*3.50%*
vi. Static Synchronous Compensator	-	*6.00%*

Provided that:

i. Plant and Machinery cost shall be considered as the original project cost excluding IDC, IEDC, Land Cost and Cost of Civil Works. The generating 51 *company and the transmission licensee for the purpose of estimating Plant and Machinery Cost, shall submit the break-up of head wise IDC and IEDC in its tariff application;*

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

iii. where the emission control system is installed, the norms of initial spares specified in this Regulation for coal or lignite based thermal generating station as the case may be, shall apply.

6.3 Issues discussed in the Approach Paper

6.3.1 Following issues had been brought out in the Approach Paper:

For Capital Cost

(i) Move from investment approval as reference cost to benchmark/reference cost for prudence check. However, the challenge is the absence of credible benchmarking of technology and capital cost,

(ii) In new projects, restrict the fixed rate of return to the normative equity as envisaged in the investment approval or benchmark cost and allow a return on additional equity at the rate of a weighted average of interest rate of loan portfolio or rate of Risk-Free Return.

(iii) Introduce incentive for early completion and disincentive for slippage from the scheduled commissioning date

(iv) Capital cost of Hydro Generating Stations- As the expenses towards the advancement of the Local Area are required for the development of the project and for reducing public resistance and delays, such expenses may be allowed as part of the capital cost with certain limits. Alternatively, these expenses may be met through Budgetary support for funding the enabling infrastructure, i.e., roads and bridges, on a case-to-case basis, which could be (i) as per actuals, limited to Rs. 1.5 crore per MW for up to 200 MW projects, and (ii) Rs. 1.0 crore per MW for above 200 MW projects, as per the Ministry of Power guidelines dated 28.09.2021, for Budgetary support for Flood Moderation and for Budgetary Support for Enabling Infrastructure.

(v) Projects Acquired post NCLT Proceedings-Historical Cost or Acquisition Value, whichever is lower, should be considered for the determination of tariff post approval of the Resolution Plan. Tariff provisions to be included to address the issue of the cost of debt servicing, including repayments, that were allowed as a part of the tariff during the CIRP process.

For Computation of IDC

(vi) Existing mechanism wherein the deduction (based on delay not condoned) is made on IDC beyond SCOD (Option-1). Alternatively, other Option was proposed to Pro-rate IDC considering the total implementation period wherein the actual IDC till the implementation of the project is pro-rated considering the period up to SCOD and a period of delay condoned over the total implementation period. IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay.

(vii) Delays on account of forest clearances can also be considered for inclusion as an uncontrollable factor.

(viii) To encourage the rigorous pursuit of approvals from statutory authorities, even if delay beyond SCOD on account of any reasons is condoned, some part of the cost impact (Say 20%) corresponding to the delay condoned may be disallowed. Alternatively, RoE on Equity corresponding to cost and time overrun allowed over and above project cost, as per investment approval may be allowed at the weighted average rate of interest on loan instead of fixed RoE. The current mechanism of treating time overrun may be continued, considering that utilities are automatically disincentivised if the project gets delayed.

Capital spares

(ix) Single norm for Initial Spares can be considered for each of the following classes of transmissions assets:

(a) Transmission Lines including HVDC lines

(b) Substations (including HVDC S/s)

(c) Dynamic Reactive Compensation devices

(d) Communication Systems

(e) Underground cable

Price variation

Suggestions were sought from the stakeholders in the Approach Paper wherein it was proposed that for allowing price variation, the utilities may be mandated to submit the statutory auditor certificate along with the petition duly certifying the price variation corresponding to delay and the same may be allowed on pro rata basis corresponding to the delay condoned. Further, a separate form may also be specified to submit the relevant information pertaining to price variation.

6.4 Stakeholders' Response

6.4.1 In response to the issues brought out in the Approach Paper, the stakeholders submitted their comments/suggestions on various issues. The summary of comments/suggestions as submitted by the stakeholders is as follows:

Reference Cost—Benchmark Cost V/s Investment Approval:

6.4.2 The comments and suggestions of the stakeholders received are as below:

a) NTPC, NHPC, PGCIL, CEA, along with most of the Generators and Transmission Licensees, proposed that Capital Costs may be approved with reference to the Investment Approval/ Costs discovered through a transparent bidding process.

b) Some Consumer Representatives suggested that the benchmark costs may be considered for prudence checks of the actual costs.

c) Few Beneficiaries suggested that the discovery of tariffs through Section 63 may be promoted since it is more economical than the current method of Tariff determination under Section 62.

d) Some Beneficiaries proposed that the process and methodology for Benchmarking the Capital Costs to be discussed in detail so that the stakeholders may be able to comment on the same.

e) GE Power India Ltd submitted that for new projects, benchmarking Cost may not be a true representation for all the plants and hence actual cost (through competitive bidding) may be considered.

f) HMEL has submitted that the benchmark cost may not be an accurate indicator for determining capital cost. The benchmarking cost may only be used as a thumb rule in prudence check of capital cost and in guiding the new investor/ developers in the sector to set their own targets in accomplishing the desired level of cost and therefore target returns.

g) JSW has submitted that capital cost as mentioned in the original investment approval, i.e. Project Detailed project report (DPR), may be considered as DPRs are more site-specific. Further, Designated Independent Agency (DIA) of the Commission's panel are vetting the DPRs.

Capital Cost – Hydro Generating Stations:

6.4.3 The comments and suggestions of the stakeholders received are as under:

a) NHPC, THDCIL, along with most Generators, have welcomed the option to allow the expenses towards the advancement of the Local Area for alleviating public resistance and delays and requested to allow the expenses on various local area development activities as part of the Capital Cost for tariff determination.

b) Some Beneficiaries submitted that the expenses should be funded by GoI through budgetary support.

c) Most of the Generators submitted that timely competition may be incentivized by increasing the RoE by 0.5%-1%.

d) THDCIL has submitted that to expedite hydro projects and curb delays due to land and forest clearances, a SPV may be created for obtaining essential approvals involving both central and state officials. Higher equity returns may be provided (e.g., 0.5%) for projects finished ahead of schedule. Encourage developers to make investments and tariff reductions through a government policy facilitating soft loans from financial institutions for renewable projects. Further, expenses towards the advancement of the Local Area are required for the development of the project and for alleviating public resistance and delays, which form part of the capital cost may be included in budgetary support as per the Ministry of Power guidelines. The present practice of approval of capital cost, including time and cost over-run after prudence check, may be continued.

e) APP submitted that Hydropower plant development in different states and areas requires different policies and local development plans. It is inappropriate to set limits on such expenses on a pan-India basis and should be allowed independently. Further, to expedite hydro station development and increase commercial viability, nodal agency, centrally appointed Geological Survey report and data repository to intercept site-specific geological surprises may be considered. Extend project life based on independent expert studies while ensuring that plant life doesn't hinder recovery of depreciation and ROE. Useful life should be limited to technical design life, not exceeding the project's useful life.

Capital Cost – Projects Acquired post NCLT Proceedings:

6.4.4 The comments and suggestions of the stakeholders received are as below:

a) PGCIL supported the proposed approach and requested to continue the existing tariff until the CIRP process ends.

b) SRPC, CEA, along with some Generators and Transmission Licensees, submitted that the lower of the Historical Cost or the Acquisition cost may be considered for Tariff Purpose. However, the expenses made by the Developer to bring the project to running condition and the cost of servicing of debt should also be considered.

c) Some generators, such as NTPC and Adani, have opposed the tariff determination on acquired value.

d) NHPC has suggested that the Tariff based on historical cost may continue till the CIRP process is complete.

e) Some Generators and Transmission Licensees submitted that limiting the project cost to the lower of the Historical Cost or the Acquisition cost may discourage the purchase through NCLT. One of the generators suggested that an additional RoE of 0.5% to 1% may be provided to encourage entities to acquire such assets.

f) Beneficiaries and Consumer Representatives welcomed the proposal to consider the lower of the Historical cost and the Acquisition cost.

g) TSSPDCL has suggested that the Tariff under Section 62 needs to be determined on the cost-plus principle. But in the interest of the consumer, it is imperative that the lower of Historical cost or acquisition value may be considered for the determination of tariff.

Computation of IDC:

6.4.5 The comments and suggestions of the stakeholders received are as under:

a) NTPC, NHPC and PGCIL requested that the Option 2 may be considered where the pro rata IDC is allowed considering the total implementation period.

b) Some Generators and Transmission Licensees proposed that the IDC should be allowed based on actuals subject to prudence check by the Commission. In case the actual IDC is lower than the IDC as per the Investment Approval, the actual IDC may be considered, irrespective of delay.

c) Some Beneficiaries such as GRIDCO, PSPCL, KSEBL and Consumer Representatives proposed that the existing methodology for IDC may be continued and any IDC beyond SCOD may be partially/fully disallowed.

d) Some Generators and CEA have suggested considering allowing IDC on the basis of Investment approval plus the IDC corresponding to the delay condoned.

e) NHDC has submitted that the approved IDC, as per the original investment approval may be considered as a reference. In case the actual/ evaluated IDC is lower than the said approved IDC, the actual IDC may be allowed even if the project is delayed, which in turn will encourage Utilities to go for prudent phasing of funds. Further, in case of delay in project completion and higher IDC, capitalisation of IDC may be allowed as per option 2 i.e. the actual IDC till implementing the project is pro-rated considering the period up to SCOD and period of delay condoned over total implementation period which appears to be more realistic compared to other option.

Treatment of LD:

6.4.6 The comments and suggestions of the stakeholders received are as below:

a) NTPC, along with most of the stakeholders, agrees, with the LD adjustment done as per APTEL Judgment in Appeal No. 72/2010 and has suggested that the same should be considered.

b) PGCIL and SRPC proposed that the forms may be revised to include the value of LD recovered to be declared separately.

c) DVC proposed that the LD deduction is limited to 5% as a ceiling as the IDC and IEDC against the delay are already disallowed.

d) MSEDCL has submitted that the LD amount shall be passed on to the beneficiary/Discom as compensation for the delay.

e) MESCOM submitted that delays in a project would result in a pro rata deduction of IDC, with utilities retaining the LD for adjustment in additional capitalisation. Adjustments in LD made during the project may be accounted for separately.

Price Variation:

6.4.7 The comments and suggestions of the stakeholders received are as below:

a) NTPC, NHPC and PGCIL have proposed that the existing treatment for price variation may be continued. Disallowance on hard cost may not be implemented as the IDC & IEDC are already disallowed and the price variation is as per the contract, and the developer is already penalised for the delay through delayed cash flow.

b) SRPC, GRIDCO, along with other Beneficiaries and Consumer Representatives, supported the proposal and requested that a new form may be introduced for the same and may be certified by the Statutory Auditor. They also submitted that the price variation may be allowed based on the delay condoned.

c) CEA submitted that the impact of calculating price variation cost on the condoned period is very complex, which includes various indices and are not same during the entire period of delay. In view of this, the price variation should be calculated on a pro rata basis.

d) OTPC suggested that contractors are chosen through a competitive bidding route and that too much meddling in the contracts by the Regulator may not be fair and equitable.

e) GMR Energy Ltd has submitted that if a project gets delayed, there may be price variations of the materials used. Price variation of materials, i.e. Copper, Aluminum, Steel, Cement etc, should also be allowed.

f) THDCIL has submitted that the Commission has proposed a reduction of hard cost of delay periods not condoned, while the Commission is already reducing capital costs by reducing IDC and IEDC for delay periods not condoned. Further submitted that the proposed micro-level approach makes the process more complex instead of simplifying it, therefore price variation corresponding to delay should be allowed.

Controllable & Uncontrollable Parameters:

6.4.8 The comments and suggestions of the stakeholders received are as under:

a) NTPC, NHPC, PGCIL and various other companies supported the proposal to include forest clearance along with land acquisition as an uncontrollable parameter. Some of them further proposed that the contractual delays not attributable to the Generators and R&R delays may also be included as an uncontrollable parameter.

b) PGCIL further submitted that Statutory clearances like Railway Clearance/ NHAI clearance, delay in grant of Shutdowns by RPCs/RLDCs/SLDCs etc. also need to be covered under uncontrollable factors as they are beyond the control of Transmission licensees.

c) Some Beneficiaries and Consumer Representatives submitted that delay due to forest clearance may not be included in uncontrollable factor as it is the responsibility of the developer to get it approved before the zero date and may lead to laxity from the side of the developer.

d) CEA submitted that forest clearance and land clearance may be included as a controllable factor as it provides certain responsibility and liability of developer towards the project. However, application for delay to be allowed on merit on a case to case basis.

e) WBSEDCL has submitted that delays in land acquisition, forest clearance, and right of way are major causes of cost and time overruns in power projects, particularly hydro and pump storage. To ensure the availability of electricity to consumers at reasonable and competitive rates, the developers should consider incorporating afforestation and R&R works in the government program to reduce uncertainty, ensure timely completion, and reduce project costs.

Differential Norms–Servicing Impact of Delay:

6.4.9 The comments and suggestions of the stakeholders received are as below:

a) NTPC, NHPC, CEA and PGCIL have proposed to continue with the existing approach for approval of time over-run and servicing of the impact of time overrun. They have submitted that they are already penalised by the delay in terms of reduced IRR, and further penalising them by servicing such costs at WAROI is unwarranted.

b) DVC submitted that the component of delay may be considered being funded through loans and provide returns on it at WAROI.

c) Some Beneficiaries have supported levying a penalty of 20-30% of time overrun condoned. However, generators and transmission utilities have opposed the same, stating it as unjustified.

d) MSETCL has submitted that proposal to treat delay due to forest clearance as uncontrollable while disallowing some portion of cost impact corresponding to delay condoned defeats the very purpose of citing 'delay on account of forest clearance' as an uncontrollable factor.

e) MSPGCL has submitted that delays due to uncontrollable factors like lack of timely clearances and forest approvals require constant follow-up. Deducting even a small portion of the cost impact is not justified, as certain operating processes must be followed. The Commission may not be able to determine if sufficient efforts are made at the senior level to obtain necessary clearances. Disadvantaging generators/licensees' sincere efforts in cases where project delays occur due to uncontrollable factors is counterproductive. Disallowing a portion of the cost that corresponds to the condoned delay is inappropriate, as the delay has already been excused.

Initial Spares:

6.4.10 The comments and suggestions of the stakeholders received are as under:

a) NTPC submitted that the cut-off date may be increased from 3 to 5 years and spares may be allowed post cut-off date subject to the ceiling norms where the same are not received due to delay from the OEMs.

b) NHPC submitted that 2% of Plant and Machinery cost may be considered as a limit for initial spares for the cases where segregation of spares provided with the mother plant is not available.

c) PGCIL and some Consumer Representatives proposed that spare requirements for AIS & GIS Substation may remain separate, common norms for greenfield and brownfield may be specified in line with the spare requirement of brownfield assets only. Further suggested that HVDC Substations may be clubbed with AIS substations and Initial Spare with a ceiling limit of 3% may be allowed for HV Underground cables.

d) Some Transmission Licensees and Generators proposed higher ceiling norms for initial spares and consideration for certain spares over and above the ceiling due to certain special conditions.

e) Teesta Valley PTL has submitted that a 1% limit of initial spares is not sufficient for TPTL as it is a single-asset company. Further submitted that being a single-asset company, TPTL is bound to maintain the spares for the transmission line, as against a company with multiple assets can maintain the same spares for the multiple assets, which would lead to balancing out of the spare cost across the assets, therefore coming under the limit of 1% as specified by the CERC Regulations, 2019.

f) NLCIL submitted that the Commission may consider 7% initial spares for generators with GIS SS in proposed new regulations for new projects.

6.5 Commission's View

6.5.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders. The important changes made to the provisions related to Capital Cost are as follows:

<u>New Components of Capital Expenses:</u>

6.5.2 Taking into consideration the need for promoting absorption of renewable generation, timely execution of projects and the Policies of the Government of India, the Commission has proposed inclusion of the following capital cost components:

a) Expenses incurred for flexible operation of the Generating Stations at lower loads to improve Grid Security and promotion of RE Integration.

b) Expenses incurred towards biomass handling equipment and facilities to promote co-firing. and

c) Expenditure incurred towards developing local infrastructure in the vicinity of the hydel power plant that is not provided for under "Budgetary Support for Flood Moderation and for Budgetary support for enabling infrastructure" in the Capital Cost of the Hydel Stations.

Separate Provisions for Projects Acquired through NCLT:

6.5.3 The Commission has proposed separate provisions for allowing capital cost related to projects acquired through NCLT. This initiative aims to enhance transparency in approving capital cost for the purpose of Tariff Determination of such projects and to ensure regulatory consistency for these projects.

6.5.4 The Commission has considered the proposal of the stakeholders for considering the expenses incurred towards making the acquired project operational, which shall be considered as Additional Capitalisation and shall be subject to prudence check by the Commission as per the provisions of Additional Capitalisation proposed in this Regulation.

De-capitalisation of Assets:

6.5.5 The Commission has proposed that assets may be excluded from the capital cost in case they are decapitalized due to obsolescence/upgradation or in case such asset is permanently shifted from one project to another. In such cases tariff shall not be allowed to be recovered corresponding to such de-captialised assets. However, in case such an asset is recommended for further utilisation by the Regional Power Committee in consultation with CTU, such asset shall be de-capitalised from the original project only after its redeployment and till the time of its redeployment the tariff for the asset shall continue to be serviced through the tariff or the original project.

IDC, IEDC and LD:

6.5.6 The Commission observes that, as per the existing provisions, the equity in excess of 30% is considered as normative Loan. It is observed that in cases where in the initial stages of project development; the expenses are met through equity and no actual debt is drawn, there is no provision to provide normative interest on equity over and above 30%. In view of the APTEL Judgement in Appeal No. 231 of 2017 (Powerlinks V/s CERC &. Ors.) wherein Hon’ble APTEL has held that every fund has cost, the Commission in the recent past has allowed normative interest on normative loan. Hence, the Commission has provided that IDC on normative loans corresponding to excess equity over 30% of the funds deployed on a parri-passu basis shall be allowed at the rate of 1 year SBI MCLR till the actual loan is infused and post infusion of actual loan, the interest shall be allowed on the basis of Weighted Average Rate of Interest applicable for the quarter.

6.5.7 The computation of IDC in case of delay will be condoned considering the total implementation period wherein the actual IDC till the implementation of the project is pro-rated considering the period up to SCOD and the period of delay condoned over the total implementation period.

[Note: For example, in case a project was scheduled to be completed in 48 months and is actually completed in 60 months. Out of 12 months of time overrun, if only 6 months of time overrun is condoned, the allowable IDC and IEDC shall be computed by considering the total IDC and IEDC incurred for 60 months and allowed in the proportion of 54 months over 60-month period.]

6.5.8 In case of activities like obtaining forest clearance, NHAI Clearance, approval of Railways, and acquisition of government land, where the delay is on account of delay in the approval of concerned authority, in such cases, in order to promote rigorous follow ups, it is proposed that the maximum condonation shall be allowed up to 90% of the delay associated with obtaining such approvals or clearances.

[Note: For example: A project is delayed by 10 months due to delay in getting forest clearance or NHAI Clearance or approval of Railway or due to delay in acquisition of government land, or due to combination of these reasons, in such cases maximum delay that shall be condoned shall be 90% of total delay i.e., 9 months.]

6.6 Proposed Provisions

6.6.1 The Commission, after considering various aspects and taking into account comments and suggestions of the stakeholders, has proposed Regulation 19 to Regulation 23 in the Draft Tariff Regulations as follows:

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

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

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

(b) Interest during construction and financing charges, on the loans (i) being equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed on pari-passu basis, by treating the excess equity over and above 30% of the funds deployed as normative loan, or (ii) being equal to the actual amount of loan in the event of actual equity being less than 30% of the funds deployed;

(c) Any gain or loss on account of foreign exchange risk variation pertaining to the

loan amount availed during the construction period;

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

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

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

(g) Adjustment of revenue due to the sale of infirm power in excess of fuel cost prior to the date of commercial operation as specified under Regulation 6 of these regulations;

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

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

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

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

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

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

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

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

(p) Expenditure required to enable flexible operation of the generating station at lower loads.

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

(a) Capital cost admitted by the Commission prior to 1.4.2024 duly trued up by excluding liability, if any, as on 1.4.2024;

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

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

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

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

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

(g) Expenditure required to enable flexible operation of the generating station at lower loads; and

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

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

(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and

(b) cost of the developer's 10% contribution towards the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) and Deendayal Upadhyaya Gram Jyoti Yojana (DDUGJY) project in the affected area.

(c) Expenditure incurred towards developing local infrastructure not exceeding Rs. 10 lakh/MW in the vicinity of the power plant approved in original scheme if funding is not provided for under "Budgetary Support for Flood Moderation and for Budgetary support for enabling infrastructure".

Provided that such funds shall be allowed only if the funds are spent through Indian Governmental Instrumentality;

(5) For Projects acquired through NCLT proceedings, the following shall be considered while approving Capital Cost for determination of tariff:

(a) For projects already under operation, historical GFA of the project acquired or

the acquisition value paid by the generating company, whichever is lower;

(b) For considering the historical GFA for the purpose of Sub-Clause (a) above, the same shall be the capital cost approved by the appropriate commission till the date of acquisition;

Provided that in the absence of any prior approved cost of an Appropriate Commission, the Commission shall consider the same on the basis of audited accounts subject to prudence check;

Provided further, that in case additional capital expenditure is required post acquisition of an already operational project, the same shall be considered under the provisions of Chapter 7 of these Regulations;

(c) In case any under construction project is acquired which is yet to achieve commercial operation, the acquisition value or the actual audited cost incurred till the date of acquisition, whichever is lower, shall be considered. and;

(d) any additional capital expenditure incurred post acquisition of such project up to the date of commercial operation of the project in line with the investment approval of the Board of Directors of the generating company or the transmission licensees shall also be considered on a case to case basis subject to prudence check.

Provided that post commercial operation, any additional capital expenditure shall be allowed under the provisions of Chapter 7 of these Regulations.

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

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

(b) De-capitalised Assets after the date of commercial operation on account of obsolescence;

(c) De-capitalised Assets on account of upgradation or shifting from one project to another project:

Provided that in case such an asset is recommended for further utilisation by the Regional Power Committee in consultation with CTU, such asset shall be de-capitalised from the original project only after its redeployment;

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

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

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

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

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

(1) In case of the thermal generating station and the transmission system, prudence check of capital cost shall include scrutiny of the capital expenditure, in the light of capital cost of similar projects based on past historical data, wherever available, reasonableness of financing plan, interest during construction, incidental expenditure during construction, use of efficient technology, cost over-run and time over-run, procurement of equipment and materials through competitive bidding as given in Regulation 100 below and such other matters as may be considered appropriate by the Commission:

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

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

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

(3) Where the power purchase agreement entered into between the generating company and the beneficiaries provides for the ceiling of actual capital expenditure, the Commission shall take into consideration such ceiling for prudence check.

(4) The generating company or the transmission licensee, as the case may be, shall furnish the capital cost for the execution of the existing and new projects as per Annexure-I to these regulations along with tariff petition for the purpose of creating

a database of benchmark capital cost of various components.

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

(1) Interest during construction (IDC) shall be computed considering the actual loan and normative loan after taking into account the prudent phasing of funds up to actual COD:

Provided that IDC on normative loan corresponding to excess equity over 30% of funds deployed shall be allowed only in case the actual infusion of equity on a quarterly basis is more than 30% of total funds deployed on a pari-passu basis.

Provided further that in case IDC on normative loan is to be allowed prior to infusion of actual loan, rate of interest for computing such IDC shall be equal to 1-year SBI MCLR as prevailing on 1st April of the respective year.

Provided further that IDC on normative loan, post infusion of actual loan shall be computed based on WAROI for that respective quarter.

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

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

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

(4) If the delay in achieving the COD is not attributable to the generating company or the transmission licensee, such additional IDC and IEDC may be allowed after prudence check and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be adjusted in the capital cost of the generating station or the transmission system, as the case may be

(5) If the delay in achieving the COD is attributable either in entirety or in part to the generating company or the transmission licensee or its contractor or supplier or

agency, in such cases, IDC and IEDC due to such delay may be disallowed after prudence check either in entirety or on pro-rata basis corresponding to the period of delay not condoned vis-à-vis total implementation period and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be retained by the generating company or the transmission licensee, in the same proportion of delay not condoned vis-à-vis total implementation period.

[Note: For e.g.: In case a project was scheduled to be completed in 48 months and is actually completed in 60 months. Out of 12 months of time overrun, if only 6 months of time overrun is condoned, the allowable IDC and IEDC shall be computed by considering the total IDC and IEDC incurred for 60 months and allowed in the proportion of 54 months over 60 month period.]

Provided that in case of activities like obtaining forest clearance, NHAI Clearance, approval of Railways, and acquisition of government land, where delay is on account of delay in approval of concerned authority, in such cases maximum condonation shall be allowed up to 90% of the delay associated with obtaining such approvals or clearances.

(6) For the purpose of Clauses (4) and (5) of this Regulation, IDC on actual loan and normative loan shall be considered in accordance with the normative debt-equity ratio specified under clause (1) of Regulation 18 of these regulations.

22. Controllable and Uncontrollable factors: *The following shall be considered as controllable and uncontrollable factors for deciding time overrun, cost escalation, IDC and IEDC of the new projects:*

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

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

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

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

a. Force Majeure events;

b. Change in Law; and

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

***23. Initial Spares**: Initial spares shall be capitalised as a percentage of the Plant and Machinery cost, subject to the following ceiling norms:*

	(a) Coal-based/lignite-fired thermal generating station		*4.0%*
	(b) Gas Turbine/ Combined Cycle thermal generating-Stations -		*4.0%*
	(c) Hydro generating stations including pumped storage –hydro generating station		*4.0%*
	(d) Transmission System		
(i)	*Transmission line including UG Cable*	*-*	*1.00%*
(ii)	*Transmission Sub-station*		
	-Green Field	*-*	*4.00%*
	-Brown Field	*-*	*6.00%*
(iii)	*Series Compensation devices and HVDC Static*	*-*	*4.00%*
(iv)	*Gas Insulated Sub-station (GIS)*	*-*	*6.00%*
	-Green Field	*-*	*5.00%*
	-Brown Field	*-*	*7.00%*
(v)	*-Communication system*	*-*	*3.50%*
(vi)	*Static Synchronous Compensator*	*-*	*6.00%*

Provided that:

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

ii. *where the generating station has any transmission equipment forming part of the generation project, the ceiling norms for initial spares for such equipment shall be as per the ceiling norms specified for the transmission system under these regulations.*

iii. *where the emission control system is installed, the norms of initial spares specified in this Regulation for coal or lignite based thermal generating stations,* *as the case may be, shall apply.*

7 Additional Capitalisation and Special Compensation

7.1 Background

7.1.1 The Commission in the Tariff Regulations, 2019, had clearly segregated provisions to allow additional capitalisation under the following categories:

- Additional Capitalisation within the original scope and up to the cut-off date
- Additional Capitalisation within the original scope and after the cut-off date
- Additional Capitalisation beyond the original scope
- Additional Capitalisation on account of Renovation and Modernisation
- Additional Capitalisation on account of Revised Emission Standards

7.2 Existing Provisions of Tariff Regulations, 2019

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

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

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

(b) Works deferred for execution;

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

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

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

(f) Force Majeure events

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

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

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

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

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

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

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

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

(e) Force Majeure events;

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

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

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

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

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

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

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

26. Additional Capitalisation beyond the original scope:

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

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

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

(c) Force Majeure events;

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

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

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

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

(2) In case of de-capitalisation of assets of a generating company or the transmission licensee, as the case may be, the original cost of such asset as on the date of de-capitalisation shall be deducted from the value of gross fixed asset

and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place with corresponding adjustments in cumulative depreciation and cumulative repayment of loan, duly taking into consideration the year in which it was capitalised:

27. Additional Capitalisation on account of Renovation and Modernisation

(1) generating company or the transmission licensee, as the case may be, intending to undertake renovation and modernization (R&M) of the generating station or unit thereof or transmission system or element thereof for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff, shall file a petition before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee:

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

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

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

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

Provided that any expenditure included in the renovation and modernization (R&M) on consumables and cost of components and spares which is generally covered in the O&M expenses during the major overhaul of gas turbine shall be suitably deducted from the expenditure to be allowed after prudence check.

(4) After completion of the renovation and modernisation (R&M), the generating company or the transmission licensee, as the case may be, shall file a petition

for determination of tariff. Expenditure incurred or projected to be incurred and admitted by the Commission after prudence check, and after deducting the accumulated depreciation already recovered from the admitted project cost, shall form the basis for determination of tariff.

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

(1) In case of coal-based/lignite fired thermal generating stations, the generating company, instead of availing renovation and modernization (R&M) may opt to avail a 'special allowance' in accordance with the norms specified in this Regulation, as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof and in such an event, upward revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the Special Allowance shall be included in the annual fixed cost:

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

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

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

(3) In the event of a generating station availing Special Allowance, the expenditure incurred upon or utilized from Special Allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed.

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

29. Additional Capitalization on account of Revised Emission Standards:

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

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

(3) Where the generating company makes an application for approval of additional capital expenditure on account of implementation of revised emission

standards, the Commission may grant approval after due consideration of the reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.

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

(5) Un-discharged liability, if any, on account of emission control system shall be allowed as additional capital expenditure during the year it is discharged, subject to prudence check."

7.3 Issues Discussed in Approach paper

7.3.1 Following issues were brought out in the Approach Paper for comments and suggestions:

(i) In order to have an enabling provision under which additional capitalisation can be allowed with prior approval, a provision may be introduced to existing Regulation 26 to allow such expenses if they are found to be beneficial/essential for continued operations.

(ii) For generating stations that have already crossed the cut-off date as on 31.03.2024, the additional capitalisation may be allowed as per the following:

(a) Thermal Generating Stations – Based on the analysis of actual additional capitalisation incurred by such generating stations in the past (15-20 years) and co-relating such expenses to different unit sizes such as 200/210 MW series, 500/660 MW Series and different vintages (5-10, 10-15, 15-20, 20-25 years post-COD) a special compensation in the form of yearly allowance may be allowed based on unit sizes and vintage which shall not be subject to any true up and shall not be required to be capitalized.

(b) Hydro Generating Stations–As each hydro generating station is unique owing to various factors, additional capitalisation of such generating stations may not be benchmarked as can be done for thermal generating stations. However, in the case of a specific hydro generating station, the additional capitalisation is recurring in nature, and hence, station-wise normative additional capitalisation may be approved in the form of special compensation which shall not be subject to any true up and shall not be required to be capitalized.

(c) While determining such special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulation 26 to Regulation 29, wherever applicable, may not be included as these expenses may be allowed separately.

(d) Any items that cost below Rs. 20 lakhs that may be in the nature of minor items such as tools and tackles and those pertaining to Capital Spares may be allowed only as part of O&M expenses and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations.

(e) Discharge of liabilities of works already admitted by the Commission as of 31.03.2024 may be allowed as and when such liability is discharged.

(iii) For Generating Companies whose cut-off date falls in the next tariff block (2024-29), or are expected to achieve COD after 31.03.2024, the following approach may be adopted:

(a) By extending the cut-off date from the current 3 years to 5 years which shall allow time to close contracts and discharge liabilities and eliminate the need to allow additional capitalisation post cut-off date unless in the case of Change in Law and Force Majeure.

(b) However, based on past data of similar existing generating stations, if there is a need to allow additional capitalisation that may be legitimately required post cut-off date other than those presently allowed under Regulations 26 to 29, the same may be allowed as special compensation as proposed in the case of the existing stations that have crossed the cutoff date.

(c) While determining such special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulations 26 to Regulation 29, wherever applicable, may not be included as these expenses but may be allowed separately.

(d) Further, any item that costs below Rs. 20 lakh that is in the nature of minor assets, including Capital Spares below Rs 20 lakh, can be allowed only as part of O&M expenses and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations. Further, any major capital spares costing above Rs. 20 lakh may form part of the special compensation.

(e) Further, discharge of liabilities of works already admitted by the Commission as of 31.03.2024 may be allowed as and when such liability is discharged.

(iv) For Transmission Systems, additional capitalisation post cut-off date may be allowed on technological obsolescence, change in law, force majeure, or due to replacement as presently allowed under Regulations 26 and 27 of the CERC Tariff Regulations, 2019.

7.4 Stakeholders' Response

7.4.1 Stakeholders have submitted the following suggestions.

Additional capitalisation towards better fuel management and efficient operations

a) NTPC, MSEDCL, GRIDCO, JP submitted that the expenses towards smooth fuel transportation up to the receiving end of the station, water supply to the Generating Companies, and ash disposal and utilization as per MOEF Notifications / Statutory Notifications may be included in the existing provisions of additional capitalisation.

b) Some Transmission Licensees submitted that additional capitalisation post cut-off date should be allowed on account of Technological Obsolescence, Change in Law, Force Majeure or due to replacement.

c) Some Beneficiaries – MSEDCL, GRIDCO and a few Consumer Representatives submitted that the additional capitalisation post cut-off date shall be allowed only after the cost-benefit analysis of the proposal and based on a prudence check of the Commission for redundant capitalisation.

d) Sikkim Urja Ltd has submitted that an additional provision may be introduced to the existing Regulation 26 of Tariff Regulations, 2019, to allow additional capitalisation if they are found to be beneficial/essential for continued operations.

e) CESC Ltd. submitted that agreement to allow capital costs related to Railway Infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station and towards any works that would lead to better fuel management, reduce operating costs, or have any tangible benefits is a welcome step and should be allowed for existing power projects as well, considering some of them have limited infrastructure not envisaged at development stage and may lead to definitive tangible benefits.

Normative Additional Capitalisation - Generating Station:

a) NTPC, NHDC, SRPC, etc., have supported the inclusion of minor items that cost below Rs. 20 lakh under O&M expenses.

b) NHPC along with most of the Generating Companies and Beneficiaries have suggested that proposal of normative additional capitalisation be approved based on prudence check of the capitalisation proposed by the Petitioners.

c) Some Generating Companies proposed that capitalisation on account of Change in Law, Force Majeure and, other large, unexpected expenses that affect the operation of the generating station may be allowed on a case-to-case basis in addition to the normative capitalisation. It was further proposed that the normative capitalisation may be approved considering the inflation factor.

d) Some Generating Companies questioned the basis for considering the expenses below Rs. 20 lakh as O&M expenses.

e) MB Power Ltd supported the proposal that for the existing thermal generating stations, in lieu of the actual additional capitalisation, a normative yearly allowance may be allowed based on the unit sizes and vintage, which shall not be subject to any true-up and shall not be capitalized. Further, such an annual allowance be over and above the additional capitalisation incurred by a thermal generating station on account of Regulation 26 to Regulation 29 of the CERC Tariff Regulations, 2019.

f) HMEL submitted that if there is some balance requirement of additional capitalization, it may be allowed through special allowance. For the special compensation for Generating Stations, costs incurred towards works presently covered under Regulations 26 to 29, wherever applicable, may not be included and these expenses may be allowed separately. Any expenditure below Rs. 20 lakh may be separately allowed under O&M expenses and should not form part of additional capitalization. Discharge of liabilities of works already admitted by the Commission as of 31.03.2024 may be allowed as and when such liability is discharged.

Normative Additional Capitalisation - Transmission System:

a) Transmission Licensees have suggested that additional capitalisation post cut-off date may be allowed only on account of technological obsolescence, due to Change in Law and Force Majeure.

b) MSEDCL submitted that additional capitalisation may be allowed on a case-to-case basis only after a prudence check with cost benefit-analysis.

c) MPPMCL has submitted that since additional capitalisation post cut-off date is rarely required in the case of transmission systems. Hence, the existing approach may be continued.

7.5 Commission's View

7.5.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders.

New Components of Additional Capitalisation:

7.5.2 The Commission observes that due to recent developments such as the need for flexible operations, biomass firing and for projects acquired through the NCLT process, certain provisions to include such costs need to be carried out. The Commission with regard to hydro generating station further observes that there may be delays in receiving funds under the GoI Scheme for "Budgetary Support for Flood Moderation and for Budgetary support for enabling infrastructure" and therefore to enable a generating company to carry out certain works which may result in faster execution of work, the Commission proposes to allow additional capitalization of Rs. 10 lakh/MW. Such funds shall be available to generating companies in case it does not receive fund under the Scheme.

7.5.3 The Commission, in view of the above, proposes to include the following capital cost components:

a) Expenses incurred for flexible operation of the Generating Stations at lower loads to improved Grid Security and promotion of RE Integration.

b) Expenses incurred towards biomass handling equipment and facilities to promote co-firing.

c) Expenditure that has become necessary for efficient operation of assets acquired through NCLT proceedings and

d) Expenditure incurred towards developing local infrastructure in the vicinity of the hydel power plant that is not provided for under "Budgetary Support for Flood Moderation and for Budgetary support for enabling infrastructure" in the Capital Cost of the Hydel Stations.

Additional Capital Expenditure on Individual Assets (up to Rs. 20 Lakh):

7.5.4 In the Approach paper suggestions were sought on inclusion of minor works valuing up to Rs. 20 lakh as a part of the O&M Expenses. The Commission based on various suggestions received has decided to include these costs under O&M expenses and has suitably modified the definition of O&M expenses to include such expenses. Hence, in line with the above discussions, the Commission has proposed to not consider any expenditure individually costing up to Rs. 20 lakh to be approved as additional capitalisation.

Assumed Deletion:

7.5.5 The Commission has introduced separate provisions that shall govern cases wherein the historical value of assets is not available as per the books as it was purchased as a part of a scheme. The proposed methodology is in line with the current practice being followed by the Commission in its various Orders.

Emission Control System:

7.5.6 The Commission has proposed to continue with the existing provisions of emission control system without any change.

7.6 Proposed Provisions

7.6.1 The Commission, in view of the above discussions, and after considering various aspects and taking into account comments and suggestions of the stakeholders, has proposed Regulation 24 to 26 in the Draft Tariff Regulations as follows:

*"**24. Additional Capitalisation within the original scope and up to the cut-off date***

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

(a) Payment made towards admitted liabilities for works executed up to the cut-off date;

(b) Works deferred for execution;

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

(d) Payment against the award of arbitration or for compliance with the directions or order of any statutory authority or order or decree of any court of law;

(e) Change in law or compliance with any existing law which is not provided for in the original scope of work;

(f) In the case of the hydro generating station, expenditure incurred towards developing local infrastructure in the vicinity of the power plant not exceeding Rs. 10 lakh/MW if funding is not provided for under "Budgetary Support for Flood Moderation and for Budgetary support for enabling infrastructure";

Provided that such funds shall be allowed only if the funds are spent through Indian Governmental Instrumentality; and

(g) Force Majeure events.

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

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

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

(1) The additional capital expenditure incurred or projected to be incurred in

respect of an existing project or a new project on the following counts within the original scope of work and after the cut-off date may be admitted by the Commission, subject to prudence check:

(a) Payment made against award of arbitration or for compliance with the directions or order of any statutory authority, or order or decree of any court of law;

(b) Change in law or compliance with any existing law which is not provided for in the original scope of work;

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

(d) Payment made towards liability admitted for works within the original scope executed prior to the cut-off date;

(e) Force Majeure events;

(f) Works within original scope executed after the cut-off date and admitted by the Commission, to the extent of actual payments made; and

(2) In case of replacement of assets deployed under the original scope of the existing project after the 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) Assets whose useful life is not commensurate with the useful life of the project and such assets have been fully depreciated in accordance with the provisions of these regulations;

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

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

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

Provided that any claim of additional capitalisation with respect to the replacement of assets under the original scope and on account of obsolescence of technology, less than Rs. 20 lakhs shall not be considered as part of Capital cost and shall be met by Generating company and Transmission licensee through normative O&M charges only

26. Additional Capitalisation beyond the original scope

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

(a) Payment made against award of arbitration or for compliance of order or directions of any statutory authority, or order or decree of any court of law;

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

(c) Force Majeure events;

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

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

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

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

(g) Works required towards biomass handling system to enable biomass co-firing and towards enabling flexible operation of the generating station as may be required.

(h) Works pertaining to Railway Infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station (excluding any transportation cost and any other appurtenant cost paid to railways) that are not covered under Regulation 24, 25 and 27, but shall result in better fuel management and can lead to a reduction in operation costs, or shall have other tangible benefits:

Provided that the generating company shall have to mandatorily seek prior approval of the Commission before implementing such works based on a detailed cost-benefit analysis of such schemes; and

(i) Any additional capital expenditure which has become necessary for efficient operation of generating station or transmission system as the case may be, including the works required towards projects acquired through NCLT process. The claim shall be substantiated with the technical justification and cost benefit analysis.

(2) Any claim of additional capitalisation less than Rs. 20 lakhs shall not be considered under Clause (1) of this regulation.

(3) In case of de-capitalisation of assets of a generating company or the transmission licensee, as the case may be, the original cost of such asset as on the date of de-capitalisation shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place with corresponding adjustments in cumulative depreciation and cumulative repayment of loan, duly taking into consideration the year in which it was capitalised.

Provided that in cases where an asset forming part of a scheme is de-capitalised and wherein the historical value of such asset is not available, the value of de-capitalisation shall be computed by de-escalating the value of the new asset by 5% per year until the year of capitalisation of the old asset subject to a minimum of 10% of the replacement cost of the asset.

27. Additional Capitalisation on account of Renovation and Modernisation

(1) The generating company intending to undertake renovation and modernization (R&M) of the generating station or unit thereof for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff, shall file a petition before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis,

estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee:

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

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

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

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

Provided that any expenditure included in the renovation and modernisation (R&M) on consumables and cost of components and spares, which is generally covered in the O&M expenses during the major overhaul of gas turbines shall be suitably deducted from the expenditure to be allowed after prudence check.

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

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

(1) In the case of coal-based/ lignite fired thermal generating stations, the generating company, instead of availing renovation and modernization (R&M), may opt to avail of a 'special allowance' in accordance with the norms specified in this Regulation, as compensation for meeting the requirement of expenses towards any additional capital expenditure covered in Regulation 24, 25, 26 and 27 except for capital expenditure arising out of change in law, award of arbitration or for compliance of the directions or order of any statutory authority, or order or decree of any court of law, and force majeure after completion of 25 years from the date of Commercial operation of the generating station or a unit thereof and in such an event, an upward revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the Special Allowance shall be included in the annual fixed cost:

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

Provided further that special allowance shall also be available for a generating station which has availed the Special Allowance during the tariff period 2009-14 or 2014-19 or 2019-24 as applicable from the date of completion of the useful life.

(2) The Special Allowance admissible to a generating station shall be @ Rs 10.75 lakh per MW per year for the control period.

(3) In the event of a generating station availing of Special Allowance, the expenditure incurred upon or utilized from Special Allowance shall be maintained separately by the generating station, and details of the same shall be made available to the Commission as and when directed.

(4) The Special Allowance allowed under this Regulation shall be transferred to a separate fund for utilization towards Renovation & Modernisation and additional capitalisation.

29. Additional Capitalization on account of Revised Emission Standards:

(1) A generating company requiring to incur additional capital expenditure in the existing generating station for compliance with the revised emissions standards shall share its proposal with the beneficiaries and file a petition for undertaking such additional capitalization.

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

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

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

(5) Un-discharged liability, if any, on account of the emission control system shall be allowed as additional capital expenditure during the year it is discharged, subject to prudence check."

8 Renovation and Modernisation

8.1 Background

8.1.1 As per the Tariff Regulations, 2019, the generating companies and the transmission licensees are allowed to undertake Renovation and Modernisation (R&M) for an extension of life beyond the useful life of the generating station or a unit thereof or a transmission system. The admissibility of the R&M claim is required to be supported by a Project Report containing information about the reference date, financial package, phasing of expenditure, schedule of completion, useful life, reference price level, estimated completion cost, record of consultation with beneficiaries, etc. In the Tariff Regulations, 2009, the Commission introduced an alternative provision in the form of Special Allowance, in lieu of R&M for coal/lignite- based thermal power stations. This provision enabled coal/lignite-based thermal power stations to meet the requirement of expenses relating to R&M on completion of 25 years of useful life without resetting of capital base. The provision of Special Allowance continued in the Tariff Regulations, 2014 and Tariff Regulations, 2019, which has been opted by many generating stations and there has been no fresh Petition filed before the Commission seeking additional capital expenditure for R&M of a thermal generating station in the entire control period 2019-24.

8.2 Existing Provisions of the Tariff Regulations, 2019

"27. Additional Capitalisation on account of Renovation and Modernisation

(1) generating company or the transmission licensee, as the case may be, intending to undertake renovation and modernization (R&M) of the generating station or unit thereof or transmission system or element thereof for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff, shall file a petition before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee:

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

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

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

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

Provided that any expenditure included in the renovation and modernization (R&M) on consumables and cost of components and spares which is generally covered in the O&M expenses during the major overhaul of gas turbine shall be suitably deducted from the expenditure to be allowed after prudence check.

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

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

(1) In case of coal-based/lignite fired thermal generating stations, the generating company, instead of availing renovation and modernization (R&M) may opt to avail a 'special allowance' in accordance with the norms specified in this Regulation, as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof and in such an event, upward revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the Special Allowance shall be included in the annual fixed cost:

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

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

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

(3) In the event of a generating station availing Special Allowance, the expenditure incurred upon or utilized from Special Allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed.

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

8.3 Issues discussed in the Approach Paper

8.3.1 Following issues were brought out in the Approach Paper for consultation.

a) In view of the inherent benefits of undertaking R&M as against going for fresh capital investment, the current provisions may be continued. Further, utilities that opt for a special allowance for the first year of the tariff period shall have to continue with the same for the rest of the tariff period.

b) As the need for higher repairs will still be required, the current dispensation of allowing a special allowance or provision of R&M may be continued after 25 years.

8.4 Stakeholders' Response

8.4.1 Stakeholders have submitted the following suggestions on this issue.

a) NTPC has proposed that the existing norms may be continued for R&M Expenses and special allowance. Further flexibility is to be provided to shift from special allowance to R&M within the control/tariff period.

b) CEA submitted that the option for Special Allowance once exercised should be valid for the useful life of the plant and the power plant must submit the details of benefits accrued due to such "Special Allowance" availed by the power plants at least every 10 years.

c) NHPC proposed that R&M expenses of hydro stations may be considered being funded through debt and equity in the ratio of 50:50.

d) PGCIL submitted that R&M may not be made applicable for transmission systems, however, Special Allowance on 'per km'/ 'per MVA' / 'per bay' basis may be provided for AC assets beyond 20 years. Further, an outage availed to carry out any refurbishment/ replacement works under special allowance may be considered as deemed available.

e) KSEBL, BRPL along with some beneficiaries and consumer representatives have submitted that the Special Allowance and R&M may be approved based on a prudence check by the Commission that it shall improve the operating parameters of the generating units.

f) Some Generating Companies have suggested the option to change their selection between Special Allowances and R&M within the control period.

g) GE Power India Ltd has submitted that incentives for undertaking R&M should not only be continued but also be increased for mass adoption by the Generating Companies. Current incentives are not yielding the expected results, with only a few units adopting the same. Further suggested that R&M for older & inefficient units is a must for supporting power generation (ever-increasing future demand) & easing out constraints in capacity addition.

h) Some Generating Companies submitted that the Special Allowances may be continued, however, additional allowances may be allowed in view of the flexible operations expected from plants.

i) DVC submitted that the amount of special allowance in lieu of R&M may be increased to Rs.25 Lakh/MW per year with provision for year-wise escalation. As special allowance provision is on a yearly basis, year-wise escalation needs to be provided. Further, provision for special allowance requires to be kept for the 'Transmission & Distribution' project as well .

8.5 Commission's View

8.5.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders.

<u>Renovation and Modernisation</u>

8.5.2 The Commission has considered the proposal of the Stakeholders wherein it is suggested that the R&M Expenses may not apply for Transmission Licensees. Hence, the Commission has proposed to exclude the Transmission Licensees from the purview of Renovation & Modernization.

8.5.3 The Commission has also observed that there is a delay in the approval of Renovation & Modernization Expenses by the Beneficiaries. Hence, the Commission has proposed modification to the existing provisions wherein the Generating Company proposing to undertake R&M has to obtain consent from the Beneficiaries before an application is made by the Generating Company before the Commission for approval. Commission has proposed that the generating station should submit the response of the beneficiaries on its R&M proposal and the Commission shall decide the same on merits. This modification is proposed for the swift implementation of R&M activities.

<u>Special Allowance for Coal-based/Lignite-fired Thermal Generating stations</u>

8.5.4 The Commission proposes to continue with the provision of Special Allowance for the coal-based/ lignite-based thermal power plants that have completed 25 years of operation in lieu of Renovation and Modernization and additional capital expenditure required for efficient operation of the generating stations except for capital expenditures arising out of a change in law, award of arbitration, compliance of directions/ orders of any statutory authority, order/ decree of any court of law and force majeure conditions. The Commission further clarifies that no additional capitalization is admissible once this special allowance is claimed by the Generating Company except under the conditions listed above.

8.5.5 The value of Special Allowance is proposed to be increased from Rs. 9.5 Lakh/MW per annum to Rs. 10.75 Lakh/MW per annum based on the actual escalation derived in the process of normalization of O&M expenses from FY 2018-19 to FY 2022-23.

8.6 Proposed Provisions

8.6.1 The Commission, after considering various aspects and taking into account comments and suggestions of the stakeholders, has proposed Regulation 27 to 29 in the Draft Tariff Regulations as follows:

"27. Additional Capitalisation on account of Renovation and Modernisation

(1) The generating company intending to undertake renovation and modernization (R&M) of the generating station or unit thereof for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff, shall file a petition before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee:

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

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

(2) Where the generating company, as the case may be, makes an application for approval of its proposal for renovation and modernisation (R&M), approval may be granted after due consideration of the reasonableness of the proposed cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, expected

duration of life extension, the response of the beneficiaries or long term customers, and such other factors as may be considered relevant by the Commission.

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

Provided that any expenditure included in the renovation and modernisation (R&M) on consumables and cost of components and spares, which is generally covered in the O&M expenses during the major overhaul of gas turbines shall be suitably deducted from the expenditure to be allowed after prudence check.

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

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

(1) In the case of coal-based/ lignite fired thermal generating stations, the generating company, instead of availing renovation and modernization (R&M), may opt to avail of a 'special allowance' in accordance with the norms specified in this Regulation, as compensation for meeting the requirement of expenses towards any additional capital expenditure covered in Regulation 24, 25, 26 and 27 except for capital expenditure arising out of change in law, award of arbitration or for compliance of the directions or order of any statutory authority, or order or decree of any court of law, and force majeure after completion of 25 years from the date of Commercial operation of the generating station or a unit thereof and in such an event, an upward revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the Special Allowance shall be included in the annual fixed cost:

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

Provided further that special allowance shall also be available for a generating station which has availed the Special Allowance during the tariff period 2009-14 or 2014-19 or 2019-24 as applicable from the date of completion of the useful life.

(2) The Special Allowance admissible to a generating station shall be @ Rs 10.75 lakh per MW per year for the control period.

(3) In the event of a generating station availing of Special Allowance, the expenditure incurred upon or utilized from Special Allowance shall be maintained separately by the generating station, and details of the same shall

be made available to the Commission as and when directed.

(4) The Special Allowance allowed under this Regulation shall be transferred to a separate fund for utilization towards Renovation & Modernisation and additional capitalisation.

9 Depreciation

9.1 Background

9.1.1 Depreciation is a major component of the annual fixed cost. Para 5.8.2 of the National Electricity Policy, 2006, provides that *"depreciation reserve is created so as to fully meet the debt service obligation.*" The regulatory principle evolved over time stipulates that there should be enough cash flow available to meet the repayment obligations of the generating company or transmission licensee during the first 12 years of operation. Historically, the depreciation rate has been considered based on the above principle.

9.1.2 The Tariff Policy, 2016 also provides that the Central Commission may notify the rates of depreciation in respect of generation and transmission assets and the rates so notified would be applicable for the purpose of tariffs as well as accounting.

9.1.3 Depreciation depends on three factors, viz., gross fixed assets on which the rate of depreciation is applied, which includes subsequent additions, a method of depreciation and useful life.

9.1.4 Straight Line Method (SLM) of depreciation has been used in all the previous five tariff periods. In the context of tariff setting, useful lives of all types of generating stations (excluding hydro) and transmission systems, except gas-based generating stations, have remained the same in all the tariff periods. For gas-based stations, the life of 15 years was used in tariff periods 2001-04 and 2004-09, which was extended to 25 years in the tariff period 2009-14 and has continued till 2019-24. For hydro stations, the useful life of plants has been increased to 40 years in the previous control period.

9.1.5 In the Tariff Regulations, 2001 and the Tariff Regulations, 2004, the Commission adopted the provision of Advance Against Depreciation (AAD) to ensure that the project has enough cash flows to meet its loan repayment obligations. Over the period, this regulatory definition of depreciation viz., "enough cash flow to meet the repayment obligations of the Generating Companies during loan repayment period" has gained precedence in a tariff setting.

9.1.6 Subsequently, in line with the erstwhile Tariff Policy, 2006 and to have uniformity in depreciation rates for accounting as well as tariff setting; the Tariff Regulations, 2009 dispensed with the provision of Advance Against Depreciation (AAD). As a result, the rate of depreciation was increased so that the utilities were able to meet loan repayment obligations.

9.1.7 The depreciation rate was worked out by considering the normative repayment period of 12 years to repay long-term loan corresponding to 70% of the capital cost.

9.2 Existing Provisions of the Tariff Regulations, 2019

*"**33. Depreciation:***

(1) Depreciation shall be computed from the date of commercial operation of a generating station or unit thereof or a transmission system or element thereof including communication system. In case of the tariff of all the units of a generating station or all elements of a transmission system including communication system for which a single tariff needs to be determined, the depreciation shall be computed from the effective date of commercial operation of the generating station or the transmission system taking into consideration the depreciation of individual units:

Provided that effective date of commercial operation shall be worked out by considering the actual date of commercial operation and installed capacity of all the units of the generating station or capital cost of all elements of the transmission system, for which single tariff needs to be determined.

(2) The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission. In case of multiple units of a generating station or multiple elements of transmission system, weighted average life for the generating station of the transmission system shall be applied. Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the year, depreciation shall be charged on pro rata basis.

(3) The salvage value of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the capital cost of the asset:

Provided that the salvage value for IT equipment and software shall be considered as NIL and 100% value of the assets shall be considered depreciable.

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

Provided also that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciated value shall correspond to the percentage of sale of electricity under long-term power purchase agreement at regulated tariff:

Provided also that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life or the extended life.

(4) Land other than the land held under lease and the land for reservoir in case of hydro generating station shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing depreciable value of the asset.

(5) Depreciation shall be calculated annually based on Straight Line Method and at

rates specified in Appendix-II to these regulations for the assets of the generating station and transmission system:

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

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

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

(8) In case of de-capitalization of assets in respect of generating station or unit thereof or transmission system or element thereof, the cumulative depreciation shall be adjusted by taking into account the depreciation recovered in tariff by the decapitalized asset during its useful services.

(9) Where the emission control system is implemented within the original scope of the generating station and the date of commercial operation of the generating station or unit thereof and the date of operation of the emission control system are the same, depreciation of the generating station or unit thereof including the emission control system shall be computed in accordance with Clauses (1) to (8) of this Regulation.

(10) Depreciation of the emission control system of an existing or a new generating station or unit thereof where the date of operation of the emission control system is subsequent to the date of commercial operation of the generating station or unit thereof, shall be computed annually from the date of operation of such emission control system based on straight line method, with salvage value of 10%, over a period of –

a) twenty five years, in case the generating station or unit thereof is in operation for fifteen years or less as on the date of operation of the emission control system; or

b) balance useful life of the generating station or unit thereof plus fifteen years, in case the generating station or unit thereof is in operation for more than fifteen years as on the date of operation of the emission control system; or

(c) ten years or a period mutually agreed by the generating company and the beneficiaries, whichever is higher, in case the generating station or unit thereof has completed its useful life."

9.3 Issues discussed in the Approach Paper

9.3.1 Following issues were brought out in the Approach Paper for consultation:

i) Depreciation rate may be specified considering a loan tenure of 15 years instead of the current practice of 12 years.

ii) Additional provisions may also be specified that allow a lower rate of depreciation to be charged by the Generating Companies in the initial years, if mutually agreed upon with the beneficiaries.

9.4 Stakeholders' Response

9.4.1 Stakeholders have submitted the following suggestions on the above issues:

i. Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff / continue with the existing policy of charging depreciation / to keep the tariff on the lower side, the depreciation rate for hydro stations could be spread over the entire useful life i.e. 35 years.

a) NTPC, NHPC, Teesta Valley PTL and APP submitted that the existing loan tenure of 12 years may be continued while allowing depreciation.

b) PGCIL submitted that the depreciation rate may be specified considering loan tenure of 15 years for projects whose investment approval is done post 31.03.2024.

c) Beneficiaries, CEA and Consumer Representatives suggested that considering the increased life of the assets, the rate of depreciation should be allowed by taking the loan tenure as 15 or 18 years, so that the depreciation is not front-loaded.

d) DVC submitted that the depreciation may be allowed as per the DVC Act.

e) OTPCL submitted that it is a welcome step to increase the spread of depreciation and will lead to a reduction in tariffs for beneficiaries. However, the lending institutions are not offering loans for 15 years and the same may be made available to Generating Companies to enable such provisions in the Regulations.

f) Tata Power-DDL submitted that the existing 12-year provision should be continued, as procurement of loans with 15-year tenure is still a challenge from private banks and lenders. Changing the depreciation rates would affect the cash flow of the Utilities.

g) THDCIL submitted that the depreciation rate can be specified considering the actual project loan tenure, instead of 12 years. Further, additional provisions may also be specified that allow Generating Companies to charge lower depreciation rates in initial years if mutually agreed upon with beneficiaries. Depreciation rate can be maintained considering loan repayment within tenure as specified by the Commission.

ii. Extended useful life of coal-based thermal generating stations and transmission sub-stations may be increased to 35 years from the current specified useful life of 25 years and at the same time bring in corresponding changes in the treatment of depreciation.

a) NTPC proposed that the existing norm of useful life for 25 years may be continued for thermal generating stations.
b) PGCIL supported the extension of the life of substations for 35 years. However, it sought Special Allowances from the 20th year so that the life of the asset may be extended.
c) Most of the Beneficiaries and CEA have supported for extension of the life of the plants. However, they have proposed that R&M may be approved on a case-to-case basis based on the Residual Life Assessment, Environmental Impact Assessment and Cost Benefit Analysis.
d) Some Generating Companies submitted that a useful life of 25 years at present can be increased to 35 years subject to the following provisions which need to be considered:
   (i) Capex for replacements due to obsolescence in technology
   (ii) Capex for replacements/modifications for efficiency improvement
   (iii) Capex due to replacements of Boiler/Turbine/Generator components due to creep/fatigue and other requirements
   (iv) Capex required due to replacements/modifications on account of Flexible Operations of Coal Plants.
   (v) Any other change-in-law requirements, etc.

9.5 Commission's View

9.5.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders.

Rate of Depreciation:

9.5.2 The Commission observes that long term loans are available for a tenure of 15-18 years and therefore there is merit in revising the rate of depreciation. However, as the funding of existing projects have already been materialized, it is proposed to reduce the rate of depreciation for all new projects which shall achieve commissioning post 31.03.2024. The Commission has proposed to maintain the old rates of depreciation for existing projects to ensure regulatory certainty for existing projects. The Commission also proposes an enabling clause allowing hydel stations to charge reduced depreciation with the consent of the beneficiaries to reduce front loading of tariff.

9.5.3 The Commission has also clarified the methodology for recovery of depreciation pertaining to additional capital expenditure incurred at the fag end of the useful life of an asset. The Commission observes that for a thermal or hydro generating stations, the actual operational life is higher than the useful life and therefore it is proposed that for a generating station, depreciation shall be approved by equally spreading the depreciable value of such additional capital expenditure over the balance operational life or 15 years, whichever is lower. With regard to transmission system, as the useful and operational life has been considered as same, the depreciable value shall be spread over the balance useful life of the Asset.

Depreciation of Emission Control System

9.5.4 The Commission has revised the existing depreciation methodology for the Emission Control System based on the suggestions provided by the stakeholders. As discussed above, the operational life of thermal generating station is higher than the useful life and therefore, the Commission has proposed that in the case the commissioning of ECS is subsequent to the commissioning of the generating station and where generating station is yet to complete the useful life, depreciation shall be as per the Straight-Line Method (SLM) for the first 12 years and the remaining depreciation may be spread over 13 years or balance operational life of the station, whichever is lower. The Commission has proposed to continue with the existing methodology to allow depreciation for the Emission Control System that is installed in the generating station that has completed its useful life.

9.6 Proposed Provisions

9.6.1 In view of the above, the Commission proposes Regulation 33 in the Draft Tariff Regulation as follows:

"33. Depreciation: *(1) Depreciation shall be computed from the date of commercial operation of a generating station or unit thereof or a transmission system or element thereof including communication system. In the case of the tariff of all the units of a generating station or all elements of a transmission system including the communication system for which a single tariff needs to be determined, the depreciation shall be computed from the effective date of commercial operation of the generating station or the transmission system taking into consideration the depreciation of individual units:*

Provided that the effective date of commercial operation shall be worked out by considering the actual date of commercial operation and installed capacity of all the units of the generating station or capital cost of all elements of the transmission system, for which a single tariff needs to be determined.

(2) The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission. In case of multiple units of a generating station or multiple elements of a transmission system, the weighted average life

for the generating station or the transmission system shall be applied. Depreciation shall be chargeable from the first year of commercial operation. In the case of commercial operation of the asset for a part of the year, depreciation shall be charged on a pro rata basis.

(3) The salvage value of the asset shall be considered as 10%, and depreciation shall be allowed up to the maximum of 90% of the capital cost of the asset:

Provided that the salvage value for IT equipment and software shall be considered as NIL and 100% value of the assets shall be considered depreciable;

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

Provided also that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciated value shall correspond to the percentage of the sale of electricity under long-term power purchase agreement at regulated tariff:

Provided also that any depreciation disallowed on account of lower availability of the generating station or unit or transmission system, as the case may be, shall not be allowed to be recovered at a later stage during the useful life or the extended life.

(4) Land other than the land held under lease and the land for a reservoir in case of a hydro generating station shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing the depreciable value of the asset.

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

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

Provided further that in the case of an existing hydro generating station, the generating company, with the consent of the beneficiaries, may charge depreciation at a rate lower than that specified in Appendix I and Appendix II to these Regulations to reduce front loading of tariff.

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

Provided that the remaining depreciable value as on 31st March of the *year closing after a period of 15 years from the effective date of commercial operation of the station shall be spread over the balance useful life of the assets.*

Provided further that in the case of a new hydro generating stations, the generating company, with the consent of the beneficiaries, may charge depreciation at a rate lower than that specified in Appendix II to these Regulations to reduce front loading of tariff.

(7) In the case of the existing projects, the balance depreciable value as on 1.4.2024 shall be worked out by deducting the cumulative depreciation as admitted to by the Commission up to 31.3.2024 from the gross depreciable value of the assets.

(8) The generating company or the transmission licensee, as the case may be, shall submit the details of capital expenditure proposed to be incurred during five years before the competition of useful life along with proper justification and proposed life extension. The Commission, based on prudence check of such submissions, shall approve the depreciation by equally spreading the depreciable value over the balance Operational Life of the generating station or unit thereof or fifteen years, whichever is lower, and in case of the transmission system shall equally spread the depreciable value over the balance useful life of the Asset.

(9)In case of de-capitalization of assets in respect of generating station or unit thereof or transmission system or element thereof, the cumulative depreciation shall be adjusted by taking into account the depreciation recovered in tariff by the de-capitalised asset during its useful service.

(10) Where the emission control system is implemented within the original scope of the generating station and the date of commercial operation of the generating station or unit thereof and the date of operation of the emission control system are the same, depreciation of the generating station or unit thereof including the emission control system shall be computed in accordance with Clauses (1) to (9) of this Regulation.

(11) Depreciation of the emission control system of an existing generating station that is yet to complete its useful life or a new generating station or unit thereof where the date of operation of the emission control system is subsequent to the date of commercial operation of the generating station or unit thereof, shall be computed annually from the date of operation of such emission control system based on the straight line method at rates specified in Appendix- I to these regulations;

Provided that the remaining depreciable value as on 31st March of the year closing after a period of 12 years from the date of operation of such emission control system shall be spread over the balance period of thirteen years or balance operational life of generating station, whichever is lower.

(12) In case the date of operation of the emission control system is subsequent to the date of completion of the useful life of generating station commercial operation of the generating station or unit thereof, depreciation of ECS shall be computed annually from the date of operation of such emission control system based on the straight line method, with a salvage value of 10% and recovered over ten years or a period mutually agreed by the generating company and the beneficiaries, whichever is higher."

10 Gross Fixed Assets Approach Versus Modified GFA Approach

10.1 Background

10.1.1 The Commission had adopted the Gross Fixed Asset approach for all generating stations and transmission assets for the primary reason that it provides internal resources for capacity replacement/addition through return on equity, which is allowed even when the cumulative depreciation on the assets goes beyond the debt component. While framing CERC Tariff Regulations, 2019, the Commission adopted a modified GFA approach for a few specific generating and transmission assets having equity greater than 30% and having either completed or are about to complete their useful life in the control period 2019-24.

10.2 Existing Provisions of the Tariff Regulations, 2019

"18. Debt-Equity Ratio: *(1) For new projects, the debt-equity ratio of 70:30 as on date of commercial operation shall be considered. If the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan: Provided that:*

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

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

(2) The generating company or the transmission licensee, as the case may be, shall submit the resolution of the Board of the company or approval of the competent authority in other cases regarding infusion of funds from internal resources in support of the utilization made or proposed to be made to meet the capital expenditure of the generating station or the transmission system including communication system, as the case may be.

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

period ending 31.3.2019 shall be considered:

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

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

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

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

(6) Any expenditure incurred for the emission control system during the tariff period as may be admitted by the Commission as additional capital expenditure for determination of supplementary tariff, shall be serviced in the manner specified in clause (1) of this Regulation."

10.3 Issues discussed in the Approach Paper

10.3.1 The following issue was brought out in the Approach Paper for consultation:

i) Increasing the Investors' confidence by ensuring assured returns is important, and further considering the recent spikes in power tariffs in power exchanges indicating a shortage of power availability, investment in Power sector needs a boost, and therefore the existing GFA approach, being a balanced approach may be continued.

10.4 Stakeholders' Response

10.4.1 Stakeholders have submitted the following suggestions on the above issue.

a) Most of the Generating Companies and Transmission Licensees have proposed to continue with the GFA approach.

b) Some of the Beneficiaries (APDISCOMS & KSEBL, MSEDCL, GRIDCO) have proposed shifting to the NFA approach as it is beneficial to the end consumers.

c) NHDC submitted that the existing GFA approach may be continued to ensure assured returns, boost investor confidence in investing in hydro-power stations, and have policy consistency.

d) MESCOM submitted that the NFA approach is suitable due to its weighted average cost of capital, reducing the tariff burden on consumers, as end consumers are a key source of income for the power sector.

10.5 Commission's View

10.5.1 The Commission, considering the views and suggestions of various stakeholders and the macroeconomic indicators pointed out in the approach paper, proposes to continue with the existing approach.

10.6 Proposed Provisions

10.6.1 In view of the above, the Commission proposes Regulation 18 in the Draft Tariff Regulation, which is reproduced below:

18. Debt-Equity Ratio: *(1) For new projects, the debt-equity ratio of 70:30 as on date of commercial operation shall be considered. If the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan:*
Provided that:

i. *where equity actually deployed is less than 30% of the capital cost, actual equity shall be considered for determination of tariff:*

ii. *the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment:*

iii. *any grant obtained for the execution of the project shall not be considered as a part of capital structure for the purpose of debt: equity ratio.*

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

(2) The generating company or the transmission licensee, as the case may be, shall submit the resolution of the Board of the company or approval of the competent authority in other cases regarding the infusion of funds from internal resources in support of the utilization made or proposed to be made to meet the capital expenditure of the generating station or the transmission system including

communication system, as the case may be.

(3) In the case of the generating station and the transmission system, including the communication system declared under commercial operation prior to 1.4.2024, the debt-equity ratio allowed by the Commission for the determination of tariff for the period ending 31.3.2024 shall be considered:

Provided that in the case of a generating station or a transmission system, including a communication system which has completed its useful life as on 1.4.2024 or completing its useful life during the 2024-29 tariff period, if the equity actually deployed as on 1.4.2024 is more than 30% of the capital cost, equity in excess of 30% shall not be taken into account for tariff computation;

Provided further that in case of projects owned by Damodar Valley Corporation, the debt: equity ratio shall be governed as per sub-clause (ii) of clause (2) of Regulation 96 of these regulations.

(4) In the case of the generating station and the transmission system, including communication system declared under commercial operation prior to 1.4.2024, but where debt: equity ratio has not been determined by the Commission for determination of tariff for the period ending 31.3.2024, the Commission shall approve the debt: equity ratio in accordance with clause (1) of this Regulation.

(5) Any expenditure incurred or projected to be incurred on or after 1.4.2024 as may be admitted by the Commission as additional capital expenditure for determination of tariff, and renovation and modernisation expenditure for life extension shall be serviced in the manner specified in clause (1) of this Regulation.

(6) Any expenditure incurred for the emission control system during the tariff period as may be admitted by the Commission as additional capital expenditure for determination of supplementary tariff, shall be serviced in the manner specified in clause (1) of this Regulation."

11 De-Commissioning

11.1 Background

11.1.1 With the rapid changes in the technology sector and introduction of new environmental standards, the Generating Companies and Transmission Licensees are mandated to change/upgrade their assets before completion of their life. In order to address the financial impact arising due to decommissioning of assets on account of environmental concerns, safety issues or system upgradation or combination of factors before completion of their life, the Commission proposed to introduce appropriate provisions that shall govern decommissioning of assets.

11.2 Issues Discussed in the Approach Paper

11.2.1 Following issue was brought out in the Approach Paper for consultation:

i) Possible approaches to recover or refund the impact of decommissioning costs in case the generating stations/transmission systems are decommissioned before the completion of their useful lives, if such decommissioning is done in compliance of a statutory obligation or due to technological obsolescence duly approved by RPC.

11.3 Stakeholders' Response

11.3.1 Stakeholders have submitted the following suggestions on this issue.

a) NTPC proposed that formulation of specific regulations that address decommissioning, covering both " before useful life" and "after useful life" scenarios, is required.

b) PGCIL submitted that a one-time allowance of unrecovered depreciation along with dismantling or any other associated cost may be allowed.

c) Some Beneficiaries submitted that the benefit of the decommissioning of asset should be passed on to the beneficiaries.

11.4 Commission's View

11.4.1 The Commission has proposed a new Regulation that shall govern decommissioning of assets. The Commission proposes to allow utilities to recover unrecovered depreciation if such de-commissioning is on account of environmental concerns or safety issues or a combination of these factors not attributable to the generating company or a Transmission Licensee.

11.5 Proposed Provisions

11.5.1 In view of the above, the Commission proposes Regulation 35 in the Draft Tariff Regulations as follows:

"35. ***De-Commissioning***

(1) In case a generating station or unit thereof, or a transmission system including communication systems or element thereof after it is certified by CEA or CTU or any other statutory authority, that any asset cannot be operated or needs to be replaced on account of environmental concerns or safety issues or system upgradation or a combination of these factors not attributable to generating company or a transmission licensee, the unrecovered depreciable value may be allowed to be recovered on a case-to-case basis after duly adjusting the actual salvage value post disposal of such project.

Provided that the manner of recovery, including a number of instalments in which such unrecovered depreciation will be allowed, shall be specified by the Commission on a case-to-case basis.

Provided further that no carrying cost shall be allowed on any delay associated with such recovery."

12 Return on Equity (RoE) and Tax on RoE

12.1 Background

12.1.1 The Commission had specified a post-tax RoE rate of 16% based on the recommendations of the study assigned to review the cost of capital for the Tariff Period 2001-04 and reduced the post-tax RoE rate to 14% for the Tariff Period 2004-09. However, for Tariff Regulations, 2009, the Commission decided to revise the RoE to 15.5% on pre-tax basis considering the rise in the prevailing prime lending Rates of the public sector banks, 10-year G-Sec rates then, and other macro-economic conditions and to help the entities to build up sufficient internal accruals for investment towards capacity addition. For storage-type generating stations, including pumped storage hydro stations and the run of river generating stations with pondage, the pre-tax RoE was increased to 16.50%. The Commission in its Tariff Regulations, 2009, provided additional Return on Equity at the rate of 0.5% to the projects that are completed within the specified time. In view of this, the Central Commission notifies, from time to time, the rate of RoE for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital, and the same acts as a guiding principle for the SERCs.

12.1.2 In the case of equity, any cash resources available to the company from its share premium account or from its internal resources that are used to meet the equity commitments of the project are treated as equity subject to the limitation of the specified debt-equity ratio.

12.1.3 The Commission for the Tariff Period 2001-04 and 2004-09 specified post- tax Return on Equity and allowed income tax, in respect of income from core businesses only, as pass through to be recovered separately on an actual basis. However, since the Tariff Regulations, 2009, considering the views of various stakeholders, the Commission has been allowing pre-tax Return on Equity to the utilities.

12.2 Existing Provisions of the Tariff Regulations, 2019

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

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

of river generating station with pondage:

Provided that return on equity in respect of additional capitalization after cut-off date beyond the original scope, excluding additional capitalization on account of emission control system, shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system or in the absence of actual loan portfolio of the generating station or the transmission system, the weighted average rate of interest of the generating company or the transmission licensee, as the case may be, as a whole shall be considered, subject to ceiling of 14%

Provided that:

i. *In case of a new project, the rate of return on equity shall be reduced by 1.00% for such period as may be decided by the Commission, if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO) or Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the respective RLDC;*

ii. *in case of existing generating station, as and when any of the 61 requirements under (i) above of this Regulation are found lacking based on the report submitted by the concerned RLDC, rate of return on equity shall be reduced by 1.00% for the period for which the deficiency continues;*

iii. *in case of a thermal generating station, with effect from 1.4.2020:*
    a) *rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate of 1% per minute;*
    b) *an additional rate of return on equity of 0.25% shall be allowed for every incremental ramp rate of 1% per minute achieved over and above the ramp rate of 1% per minute, subject to ceiling of additional rate of return on equity of 1.00%:*

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

(3) The return on equity in respect of additional capitalization on account of emission control system shall be computed at the base rate of one year marginal cost of lending rate (MCLR) of the State Bank of India as on 1st April of the year in which the date of operation (ODe) occurs plus 350 basis point, subject to ceiling of 14%;

31. Tax on Return on Equity:

(1) The base rate of return on equity as allowed by the Commission under Regulation 30 shall be grossed up with the effective tax rate of the respective financial year. For this purpose, the effective tax rate shall be considered on the basis of actual tax paid in the respect of the financial year in line with the provisions of the relevant Finance Acts by the concerned generating company or the transmission licensee, as the case may be. The actual tax paid on income from other businesses including deferred tax liability (i.e. income from business other than business of generation or transmission, as the case may be) shall be excluded for the

calculation of effective tax rate.

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

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

Where "t" is the effective tax rate in accordance with Clause (1) of this regulation and shall be calculated at the beginning of every financial year based on the estimated profit and tax to be paid estimated in line with the provisions of the relevant Finance Act applicable for that financial year to the company on pro-rata basis by excluding the income of non-generation or non-transmission business, as the case may be, and the corresponding tax thereon. In case of generating company or transmission licensee paying Minimum Alternate Tax (MAT), "t" shall be considered as MAT rate including surcharge and cess.

Illustration.-

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

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

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

(a) *Estimated Gross Income from generation or transmission business for FY 2019- 20 is Rs 1000 crore.*

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

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

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

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

12.3 Issues discussed in the Approach Paper

12.3.1 Following issues were brought out in the Approach Paper for consultation:

i) Whether there is a need for the RoCE approach, or the RoE approach, may continue.

ii) Review of the rate of RoE to be allowed, including that to be allowed on additional capitalisation that is carried out on account of Change in Law and Force Majeure.

iii) Whether the revised rate of RoE to be made applicable to only new projects or to both existing and new projects?

iv) Merit behind approving different rate of RoE to thermal, hydro generation, and transmission projects with further incentives for dam/reservoir-based projects including PSP.

v) Merit in allowing RoE by linking the rate of return from market interest rates, such as G-SEC rates/MCLR/RBI Base Rate.

vi) The Base Rate of RoE may be grossed up as follows:

(a) At MAT rate (If not opted for Section 115 BAA)
(b) At effective tax rate (if not opted for Section 115BAA) subject to a ceiling of Corporate Tax Rate; or
(c) At reduced tax rate under Section 115BAA of the Income Tax Act, 1961 or any other relevant categories notified from time to time subject to a ceiling of the rate specified in the relevant Finance Act.

vii) Tax shall be allowed only in cases where the company has actually paid taxes as under no circumstances tax can be allowed to be recovered if the company has not paid any tax for the year under consideration.

12.4 Stakeholders' Response

12.4.1 Stakeholders have submitted the following suggestions on the issues flagged in the Approach Paper.

a) Almost all (NTPC, NHPC, PGCIL, CEA, etc.) stakeholders have suggested that the RoE approach may be continued.

b) CEA, along with several other Stakeholders comprising consumer representatives, distribution companies suggested reducing RoE for transmission and generating companies.

c) ASCI submitted that selection between the RoE and RoCE approaches is difficult and should be done on a case-to-case basis.

d) NEEPCO proposed to continue with the present RoE approach, which provides assured returns to the Generating Companies, particularly in the

Hydro Sector, which has a long gestation period.

e) MPERC submitted to continue with the ROE approach, as volatility in financial market makes benchmarking of the debt-equity ratio and cost of debt challenging and therefore shifting to the ROCE approach might not sufficiently incentivize investment in the Power Sector.

12.5 Commission's View

12.5.1 Clause (d) of Section 61 of the Act provides that the Commission while specifying the terms and conditions for the 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"*.

12.5.2 The Commission had adopted the Capital Asset Pricing Model (CAPM) to determine the cost of equity, as was done in the Tariff Regulations, 2014 and the Tariff Regulations, 2019. This was done because it was felt that out of the various scientific models such as the Dividend Growth Model/Discounted Cash Flow Model, Price/Earning Ratio Method, Risk Premium Approach, and CAPM, the CAPM was more suitable for determining the cost of equity for investments in the Indian power sector. Further, CAPM is also the most popular and widely accepted method for determining the cost of equity. However, as this model relies on assumptions about the data used as input, it may not provide a precise rate of return on equity. For e.g. market return data taken for 5 years, 10 years or more would give different rates for return on equity. Risk-Free rate taken as Government/Sovereign Bonds yield for 1 year, 5 years, or 10 years will also impact the rate of return on equity. However, the CAPM gives an approximate rate of return on equity, which can be used to make an informed decision on the rate of return on equity.

12.5.3 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.

12.5.4 The Commission has worked out the cost of equity considering the risk-free rate as the average of the yield on 10-year government securities yield (Source – RBI Notification) for the period April 2022 to March 2023. The following graph shows the trend of monthly government securities yield for FY 2022-23. For the estimation of risk-free, the average yield on 10-year zero coupon bonds for the period April 2022 to March 2023 has been considered as 7.35%.

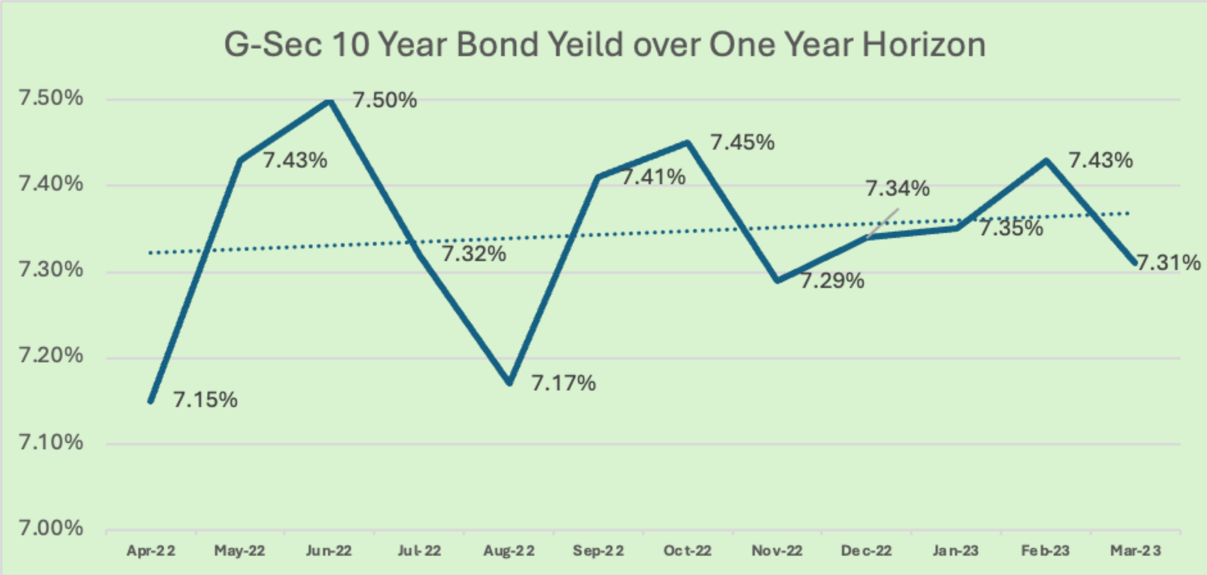

Figure 7: Ten-Year Government Securities Yield Trend

12.5.5 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. For determining the market return, the Commission has considered the returns provided by the BSE Sensex over the period from April 1992 to March 2023 as a proxy for the historical returns provided by the Indian equity market. The average annual growth rate of the BSE Sensex over the period FY 1992-93 to FY 2022-23 is as shown below.

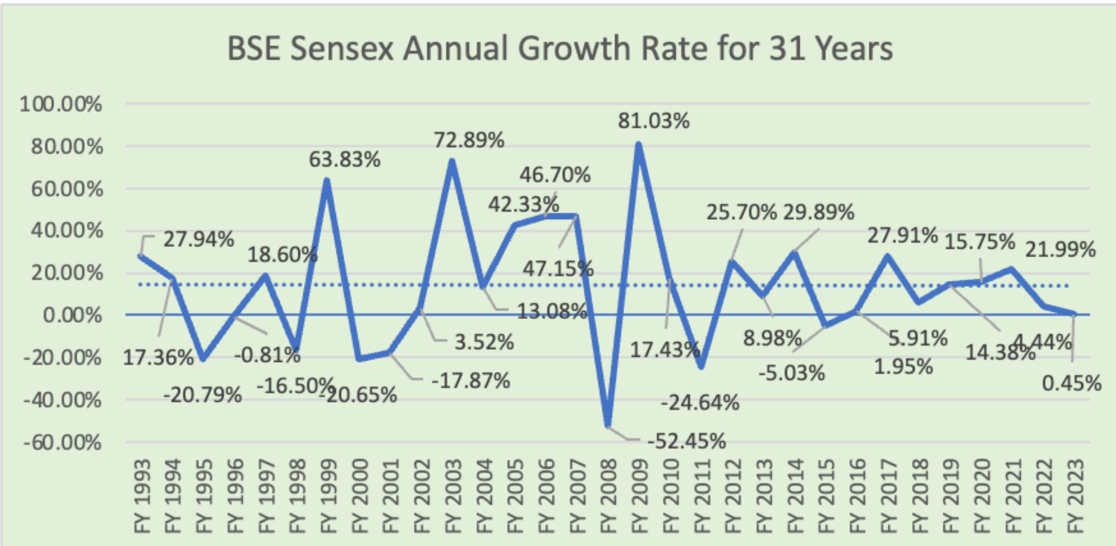

Figure: Yearly Market Return Trend

12.5.6 The Beta is a measure of the volatility, or systematic risk, of a security or a portfolio in comparison to the market as a whole. 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. A stock that swings more than the market over time has a beta greater than 1.0. If a stock moves less than the market, the stock's beta is less than 1.0. High-beta stocks tend to be riskier but have the potential for higher returns; low-beta stocks pose less risk but typically yield lower returns. Unlevered Beta (i.e. Asset Beta) is the Beta of a company without the impact of debt. It is also known as the volatility of returns for a company, without taking into account its financial leverage. It compares the risk of an unlevered company to the risk of the market. It is also commonly referred to as “Asset Beta” because the volatility of a company without any leverage is the result of only its asset financed from its equity. Then the levered Beta is converted to unlevered Beta considering the actual debt: equity ratio and effective tax rate to gauge the business risk. In the next step, the composite Beta based on the weighted average of market capitalisation separately for Regulated entities and IPPs has been computed to estimate the business risk of the concerned companies. For computing the levered Beta, it has been considered that the actual debt- equity ratio till now will remain same in the future.

12.5.7 If the daily data on the BSE Power Index for the latest 5 years is considered for computing the levered Beta, then the average Cost of Equity works out to around 15.52%.

Regulatory Certainty for Existing Projects:

12.5.8 To maintain the Regulatory Certainty and considering that aggressive capacity addition is required in near future as also was highlighted in the Approach Paper, the Commission is of the view that the RoE of existing Assets may be retained at the rates provided in Tariff Regulations, 2019.

Differential RoE for New Transmission Assets, Pumped Hydro Generation, and Additional Capitalisation due to CIL, FM & ECS:

12.5.9 The Commission observes that there is a difference between the risks involved in the commissioning and operationalization of generating and transmission assets. It is also observed that for the same Rate of Return, the effective IRR (Internal Rate of Return) is different for projects with different gestation period. The Commission has carried out a detailed analysis of effective IRR for projects with different gestation period ranging from 3 to 10 years. It is observed that, with an increase in gestation period, the effective IRR reduces and, therefore, in order to have uniformity, the Commission has proposed a differential Rate of Return. The gestation period of a typical transmission project is around 2-3 years as compared to around 4-5 years for a thermal generating station and around 7 years for storage based hydro station. The Commission therefore proposes to allow RoE of 15% for new Transmission Projects, 15.50% for thermal generating stations and ROR based hydro generating stations and 17% for storage based hydro generating stations, including PSPs.

12.5.10 Further, the Commission has proposed RoE for Additional Capitalisation beyond the original scope on account of the Emission Control System, Change in Law and Force Majeure at the rate of one-year marginal cost of funds based lending rate (MCLR) of the State Bank of India plus 350 basis points, subject to a ceiling of 14%.

Income Tax:

12.5.11 In the 2014 Tariff Regulations, the Commission decided to allow pre-tax rate of return on equity with grossing up with the effective tax rate of the financial year or Minimum Alternate Tax (MAT) rate under Section 115JB of the Income Tax Act, 1961 and the tax on other income stream will not be considered for the calculation of the effective tax rate. In the existing 2019 Tariff Regulations same provisions were retained for the purpose of grossing up of RoE. However, the Commission observed that with the introduction of Section 115BAA of the Income Tax Act, 1961, there is a need to bring in more clarity for computing effective tax rate in case a generating company or transmission licensee is paying Minimum Alternate Tax (MAT) or opted for Section 115BAA. Accordingly, the Commission has proposed that the in case a generating company or transmission licensee is paying MAT, the effective tax rate shall be the MAT rate. Similarly, in case a generating company or transmission licensee has opted for Section 115BAA, the effective tax rate shall be tax rate as specified under Section 115BAA of the Income Tax Act, 1961.

Illustration-

In case a generating company or a transmission licensee is paying Minimum Alternate Tax (MAT) @ 17.47% including surcharge and cess:

Rate of return on equity = 15.50/(1-0.1747) = 18.781%

In case a generating company or a transmission licensee is paying tax under normal corporate tax or under any other category applicable from time to time, including surcharge and cess:

Estimated Gross Income from generation or transmission business for FY 2024-25 is Rs 1,000 crore;

Estimated Advance Tax for the year on above is Rs 280 crore;

Effective Tax Rate for the year 2024-25 = Rs 280 Crore/Rs 1000 Crore = 28%

Rate of return on equity = 15.50/ (1-0.28) = 21.528%.

In case a generating company or a transmission licensee is paying tax at a special rate @ 25.17% including surcharge and cess under Section 115BAA of the Income Tax Act, 1961:

Rate of return on equity = 15.50/(1-0.2517) = 20.713%

12.6 Proposed Provisions

12.6.1 In view of the above, the Commission proposes Regulation 30 to 31 in the Draft Tariff Regulations as follows:

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

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

(3) Return on equity for new project achieving COD on or after 01.04.2024 shall be computed at the base rate of 15.00% for the transmission system, including the communication system, at the base rate of 15.50% for Thermal Generating Station and run-of-river hydro generating station and at the base rate of 17.00% for storage type hydro generating stations, pumped storage hydro generating stations and run-of-river generating station with pondage;

Provided that return on equity in respect of additional capitalization beyond the original scope, including additional capitalization on account of the emission control system, Change in Law, and Force Majeure shall be computed at the base rate of one-year marginal cost of lending rate (MCLR) of the State Bank of India plus 350 basis points as on 1st April of the year, subject to a ceiling of 14%;

Provided further that:

i. *In case of a new project, the rate of return on equity shall be reduced by 1.00% for such period as may be decided by the Commission if the generating station or* *transmission system is found to be declared under commercial operation without commissioning of any of the Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the respective RLDC;*

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

iii. *in the case of a thermal generating station:*

a) *rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate as specified under Regulation 45(9) of IEGC Regulations, 2023.*

b) *an additional rate of return on equity of 0.25% shall be allowed for every incremental ramp rate of 1% per minute achieved over and above the ramp rate specified under Regulation 45(9) of IEGC Regulations, 2023, subject to the ceiling of additional rate of return on equity of 1.00%:*

31. Tax on Return on Equity. *(1) The rate of return on equity as allowed by the Commission under Regulation 30 of these regulations shall be grossed up with the effective tax rate of the respective financial year. The effective tax rate 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 concerned generating company or the transmission licensee by excluding the income of non-generation or non-transmission business, as the case may be, and the corresponding tax thereon.*

Provided that in case a generating company or transmission licensee is paying Minimum Alternate Tax (MAT) under Section 115JB of the Income Tax Act, 1961, the effective tax rate shall be the MAT rate, including surcharge and cess;

Provided further that in case a generating company or transmission licensee has opted for Section 115BAA, the effective tax rate shall be tax rate including surcharge and cess as specified under Section 115BAA of the Income Tax Act, 1961.

(2) *The 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)

(3) The generating company or the transmission licensee, as the case may be, shall true up the effective tax rate for every financial year based on actual tax paid together with any additional tax demand, including interest thereon, duly adjusted for any refund of tax including interest received from the income tax authorities pertaining to the tariff period 2024-29 on actual gross income of any financial year.

Further, any penalty arising on account of delay in deposit or short deposit of tax amount shall not be considered while computing the actual tax paid for the generating company or the transmission licensee, as the case may be.

Provided that in case a generating company or transmission licensee is paying Minimum Alternate Tax (MAT) under Section 115JB, the generating company or the transmission licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year with the applicable MAT rate including surcharge and cess.

Provided that in case a generating company or transmission licensee is paying tax under Section 115BAA, the generating company or the transmission licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year with the tax rate including surcharge and cess as specified under Section 115BAA.

Provided that any under-recovery or over recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries or the long term customers, as the case may be, on a year to year basis."

13 Interest on Loan

13.1 Background

13.1.1 In the Tariff Regulations, 2001 and the Tariff Regulations, 2004, the Commission had considered the actual repayment for arriving at outstanding loans at the beginning of the Tariff period for the purpose of interest on the debt. To simplify the approach, the Commission, while finalising the Tariff Regulations, 2009, considered the repayment as equal to the depreciation. Since then, the repayment for each of the years has been considered equal to the depreciation allowed for the corresponding year/period. In the case of de-capitalisation of assets, the repayment has been adjusted considering the cumulative repayment on a pro rata basis.

13.2 Existing Provisions of the Tariff Regulations, 2019

13.2.1 The existing Tariff Regulations, 2019, consists of the following provision regarding Interest on Loan Capital.

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

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

(3) The repayment for each of the year of the tariff period 2019-24 shall be deemed to be equal to the depreciation allowed for the corresponding year/period. In case of decapitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment on a pro rata basis and the adjustment should not exceed cumulative depreciation recovered up to the date of decapitalisation of such asset.

(4) Notwithstanding any moratorium period availed by the generating company or the transmission licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the depreciation allowed for the year or part of the year.

(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after providing appropriate accounting adjustment for interest capitalized:

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

Provided further that if the generating station or the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered.

(5a) The rate of interest on loan for installation of emission control system shall be the weighted average rate of interest of actual loan portfolio of the emission control system or in the absence of actual loan portfolio, the weighted average rate of interest of the generating company as a whole shall be considered.

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

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

13.3 Issues discussed in the Approach Paper

13.3.1 Following issue was brought out in the Approach Paper for consultation:

(i) To simplify the approval of interest on loan, the weighted average actual rate of interest of the generating company or transmission licensee may be considered instead of project specific interest on loan. Further, the cost of hedging related to foreign loans be allowed on an actual basis, without allowing any actual FERV.

13.4 Stakeholders' Response

13.4.1 Stakeholders have submitted the following suggestions on the above issue.

a) NTPC and NHPC have proposed that the normative interest rate of SBI MCLR+(250BP, 450 BP) may be considered.

b) Most of the beneficiaries and consumer representatives have proposed that WAROI of the Company may be considered and that the lower of the cost of hedging/ FERV may be approved.

c) CEA has proposed that computing interest on loans on the basis of the actual weighted average rate of interest for a company as a whole will simplify the process. However, if a company has taken a specific loan for a particular project, the same may be considered.

d) Some Beneficiaries have proposed that the complete benefit on restructuring/ refinancing of loans may be passed on to Discoms.

e) CESC Ltd. submitted that the determination of the cost of debt based on the weighted average rate of the actual loan portfolio may be continued to recognise the actual interest payment/ finance cost obligation by the generating companies.

Further submitted that the hedging involves de-risking foreign currency loans for a specific period, which entails some costs towards risk premiums and margins for financial institutions. Repeated hedging through the project life cumulatively often surpasses the overall FERV variation that would have otherwise impacted the capital cost. Therefore, suggested that for efficient financial planning and management, both choices may be allowed to the Generating Companies.

f) DVC agreed on a proposal for allowing the weighted average actual rate of interest of the generating or transmission company as a whole instead of project-specific interest on loans. However, DVC submitted to consider normative 'Interest during construction (IDC)' in case of equity infusion is higher than the normative 30%.

g) APPC and APDISCOMS submitted that the present practice of admission of interest on debt does not incentivise the utility to go for a better loan portfolio by making use of various avenues available in the market.

13.5 Commission's View

13.5.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders.

13.5.2 The Commission, in order to simplify the approval of interest on loan, has proposed that the Interest on Loan for new projects shall be allowed on the basis of WAROI of the actual loan portfolio of the generating company/ transmission licensee. In cases when there is no actual loan for a generating company or transmission licensee, the Commission has proposed considering the rate of interest equal to one-year MCLR of SBI for approving the interest cost.

13.5.3 The Commission has also proposed to consider the interest rate of the actual loan portfolio for the Emission Control System for new projects and, in case there is no loan portfolio specific to that of the Emission Control System; the Commission has proposed considering the actual loan portfolio of the generating company as a whole subject to a ceiling of 14%.

13.5.4 The Commission, however, for the sake of continuity, has not proposed any change in computing rate of interest for existing projects.

13.6 Proposed Provisions

13.6.1 In view of the above, the Commission proposes provisions in Regulation 32 in the Draft Tariff Regulations as follows:

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

(2) The normative loan outstanding as on 1.4.2024 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2024 from the gross normative loan.

(3) The repayment for each of the years of the tariff period 2024-29 shall be deemed to be equal to the depreciation allowed for the corresponding year/period. In case of de-capitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment on a pro rata basis, and the adjustment should not exceed cumulative depreciation recovered up to the date of de-capitalisation of such asset.

(4) Notwithstanding any moratorium period availed of by the generating company or the transmission licensee, as the case may be, the repayment of the loan shall be considered from the first year of commercial operation of the project and shall be equal to the depreciation allowed for the year or part of the year.

(5) For the Existing Project(s), the rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio or allocated loan portfolio;

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

Provided further that if the generating station or the transmission system, as the case may be, does not have any actual loan, then the weighted average rate of interest of the loan portfolio of the generating company or the transmission licensee as a whole shall be considered.

Provided that the rate of interest on the loan for the installation of the emission control system shall be the weighted average rate of interest of the actual loan portfolio of the emission control system, and in the absence of the actual loan portfolio, the weighted average rate of interest of the generating company as a whole shall be considered.

(6) In the case of New Project(s), the rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio of the generating company or the transmission licensee, as the case may be;

Provided further that if the generating station or the transmission system, as the case may be, does not have any actual loan, then the rate of interest for a loan shall be considered as 1-year MCLR of the State Bank of India as applicable as on April 01, of the relevant financial year.

Provided that the rate of interest on the loan for installation of the emission control system shall be the weighted average rate of interest of the actual loan portfolio of the emission control system, and in the absence of the actual loan portfolio, the weighted average rate of interest of the generating company as a whole shall be *considered subject to a ceiling of 14%.*

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

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

14 Interest on Working Capital

14.1 Background

14.1.1 Working Capital is one of the key cost components of the Annual Fixed Cost (AFC) for power sector utilities. In 1990, the K. P. Rao Committee Report discussed at length the need for the provision of working capital in the power sector. At that time, one view was not to allow interest on working capital separately, as the tariff payable includes non-cash expense items like returns and depreciation, besides additional recoveries, which would provide enough funds to meet the working capital requirements for operation. The contrary view was that the resources from returns and depreciation are used as internal resources for capacity addition programs and hence, are not available for meeting the working capital requirements. The Committee concluded in favour of the inclusion of interest on working capital in the determination of the cost of power supply.

14.1.2 Accordingly, the Commission since the Tariff Regulations, 2001 has approved separate norms for interest on working capital of coal and lignite-fired stations, gas-based stations, hydro generating stations and transmission systems. The components for computation of working capital considered are primary fuel and secondary/liquid fuel cost and stock (for coal/lignite/gas-based generating stations only), O&M expenses, maintenance spares (initially as a percentage of historical capital cost, but subsequently linked to O&M expenses) and receivables.

14.2 Existing Provisions of the Tariff Regulations, 2019

14.2.1 The Tariff Regulations, 2019, consists of the following provision regarding Interest on Working Capital.

"34. Interest on Working Capital :*(1) The Working Capital shall cover:(a) For Coal-based/lignite-fired thermal generating stations:*

(i) Cost of coal or lignite and limestone towards stock, if applicable, for 10 days for pit-head generating stations and 20 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower;

(ii) Advance payment for 30 days towards cost of coal or lignite and limestone for generation corresponding to the normative annual plant availability factor;

(iii)Cost of secondary fuel oil for two months for generation corresponding to the

normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil;

(iv) Maintenance spares @ 20% of operation and maintenance expenses, including water charges and security expenses;

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

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

(aa) For emission control system of coal or lignite based thermal generating stations: (i) Cost of limestone or reagent towards stock for 20 days corresponding to the normative annual plant availability factor;

(ii) Advance payment for 30 days towards cost of reagent for generation corresponding to the normative annual plant availability factor; (iii) Receivables equivalent to 45 days of supplementary capacity charge and supplementary energy charge for sale of electricity calculated on the normative annual plant availability factor;

(iv) Operation and maintenance expenses in respect of emission control system for one month;

(v) Maintenance spares @20% of operation and maintenance expenses in respect of emission control system

(b) Open-cycle Gas Turbine/Combined Cycle thermal generating stations:

(i) Fuel cost for 30 days corresponding to the normative annual plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel;

(ii) Liquid fuel stock for 15 days corresponding to the normative annual plant availability factor, and in case of use of more than one liquid fuel, cost of main liquid fuel duly taking into account mode of operation of the generating stations of gas fuel and liquid fuel;(iii) Maintenance spares @ 30% of operation and maintenance expenses including water charges and security expenses;

(iv) Receivables equivalent to 45 days of capacity charge and energy charge for sale of electricity calculated on normative plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel; and

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

(c) Hydro generating station including pumped storage hydro-electric generating station and transmission system:

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

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

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

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

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

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

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

(4) Interest on Working Capital shall be payable on normative basis not withstanding that the generating company or the transmission licensee has not taken loan for Working Capital from any outside agency."

14.3 Issues discussed in the Approach Paper

14.3.1 Following issues were brought out in the Approach Paper for consultation:

a) It is observed that the working capital norms are efficient, so the existing norms may be retained. However, comments and suggestions are invited on any modification that may be required in the norms.

b) Any modification that may be required in the norms of old gas generating stations to factor in the actual generation while allowing for the working capital requirement for gas based generating stations.

c) As per the existing Regulations, the Bank Rate for the purpose of computing the

Interest on Working Capital (IoWC) is defined as a one-year MCLR plus 350 bps. Whether the same may be continued or may suggest any better alternative to the same.

d) Ways to determine IoWC along with any other alternatives, if any, so that the same may not require periodic truing up.

14.4 Stakeholders' Response

14.4.1 Stakeholders have submitted the following suggestions on the above mentioned issue.

a) NTPC has submitted the following:

i) To consider the fuel cost and gross calorific value of fuel on the actual weighted average for the preceding Financial Year rather than only considering the last quarter.

ii) While approving the deterrent charges, the following factors, such as reasons for lower plant availability, coal shortage, obligations of adequate Coal stock, Force Majeure events, etc., are to be considered.

iii) PLF of Gas Stations has increased substantially due to flexible operation and therefore, IoWC may be computed based on the NAPAF – Existing approach to be adopted.

iv) Bank rate as on April 1st may be considered for arriving at the interest rate.

v) Receivables for 45+6 days may be considered due to delay in the preparation of Regional Energy Account (REA).

vi) Water cess/water usage charges based on design energy, or any other statutory charges or taxes levied on a monthly basis reimbursable to the generating company under working capital.

vii) Price escalation of 3-5% may be considered for fuel cost.

viii) IoWC annual adjustment on account of variation in the interest rate and fuel cost may be allowed on the automatic basis as done for ECR.

b) OTPC, GRIDCO, NETCL, MB Power and ASCI have proposed to continue with the existing approach.

c) Some Beneficiaries submitted that the interest rate on the working capital may be reduced. Further, the cost of coal as per the coal stock may be reduced based on the actual stock observed in the previous year.

d) Prayas Energy Group submitted that CERC's current Regulations adopt the normative rate of 1-year SBI MCLR plus 3.50% for IoWC. This is more relaxed than the IoWC norm adopted by GERC (1-year SBI MCLR plus 2.50%) and MERC (1-year SBI MCLR plus 1.50%).

e) CEA has submitted that the existing methodology for Interest for Working Capital may be followed.

f) Torrent Power submitted that the change in norms of Interest on Working Capital as proposed will adversely impact important arrangements like fuel supply & transportation, Manpower & Service Contracts, Spares and will disturb the complete cycle of receivables and payables. Further, the existing norms have already gone through scrutiny & deliberation over almost five tariff periods (over 20 years) and should be continued to maintain the sanctity of all such rationales and decisions. It is also necessary to provide regulatory certainty in terms of principle and approach, specifically if the approach has been in place for more than 20 years and is very important (for availability) in the present & future situation due to high renewable energy integration.

14.5 Commission's View

14.5.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders.

Limestone Stock for Thermal Generating Stations:

14.5.2 The Commission observed that limestone stock is independent of whether the generating station is pit head or non-pit head based and therefore having separate norms for pit head and non-pit head stations do not appear to be logical and therefore the Commission has proposed to consider stock of 15 days for computing working capital requirement.

Working Capital of Gas Based Generating Stations:

14.5.3 The Commission has observed that the gas-based generating stations do not have to pay for fuel (gas) in advance, however there is some take or pay obligation for minimum take-off. The Commission has therefore proposed to modify the existing norm of 30 days' fuel cost to 15 days.

14.5.4 Further, the Commission has included a provision clarifying that 15 days liquid fuel stock shall be allowed to only those generating stations that have the facilities for storage of liquid fuel.

14.5.5 With regard to the suggestion to consider the fuel cost based on the entire year actuals rather than considering only the third quarter data, the Commission has proposed to consider the cost of fuel for working capital using the weighted average fuel cost of the entire previous year.

14.6 Proposed Provisions

14.6.1 In view of the above, the Commission proposes provisions in Regulation 34 in the Draft Tariff Regulations as follows:

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

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

(i) Cost of coal or lignite, if applicable, for 10 days for pit-head generating stations and 20 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity, whichever is lower;

(ii) Limestone towards stock for 15 days corresponding to the normative annual plant availability.

(iii) Advance payment for 30 days towards the cost of coal or lignite and limestone for generation corresponding to the normative annual plant availability factor;

(iv) Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil;

(v) Maintenance spares @ 20% of operation and maintenance expenses, including water charges and security expenses;

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

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

(b) For emission control system of coal or lignite based thermal generating stations:

(i) Cost of limestone or reagent towards stock for 20 days corresponding to the

normative annual plant availability factor;

(ii) Advance payment for 30 days towards the cost of reagent for generation corresponding to the normative annual plant availability factor;

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

(iv) Operation and maintenance expenses in respect of the emission control system for one month;

(v) Maintenance spares @20% of operation and maintenance expenses in respect of emission control system.

(c) For Open-cycle Gas Turbine/Combined Cycle thermal generating stations:

(i)Fuel cost for 15 days corresponding to the normative annual plant availability factor, duly taking into account the mode of operation of the generating station on gas fuel and liquid fuel;

(ii) Liquid fuel stock for 15 days corresponding to the normative annual plant availability factor, and in case of use of more than one liquid fuel, cost of main liquid fuel duly taking into account mode of operation of the generating stations of gas fuel and liquid fuel;

Provided that the above shall only be allowed to generating stations that have facilities to store liquid fuel.

(iii) Maintenance spares @ 30% of operation and maintenance expenses, including water charges and security expenses;

(iv) Receivables equivalent to 45 days of capacity charge and energy charge for the sale of electricity calculated on the normative plant availability factor, duly taking into account the mode of operation of the generating station on gas fuel and liquid fuel;

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

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

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

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

security expenses; and

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

(2) The cost of fuel in cases covered under sub-clauses (a) and (c) of clause (1) of this Regulation shall be based on the landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 59 of these regulations) by the generating station and gross calorific value of the fuel as per actual weighted average for the preceding financial year in case of each financial year for which tariff is to be determined:

Provided that in the case of a new generating station, the cost of fuel for the first financial year shall be considered based on landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 59 of these regulations) and gross calorific value of the fuel as per actual weighted average for three months, as used for infirm power, preceding date of commercial operation for which tariff is to be determined.

(3) Rate of interest on working capital shall be on a normative basis and shall be considered at the Reference Rate of Interest as on 1.4.2024 or as on 1st April of the year during the tariff period 2024-29 in which the generating station or a unit thereof or the transmission system including communication system or element thereof, as the case may be, is declared under commercial operation, whichever is later:

Provided that in case of truing-up, the rate of interest on working capital shall be considered at Reference Rate of Interest as on 1st April of each of the financial year during the tariff period 2024-29.

(4) Interest on working capital shall be payable on a normative basis, notwithstanding that the generating company or the transmission licensee has not taken a loan for working capital from any outside agency."

15 O&M Expenses – Generating Stations

15.1 Background

15.1.1 The Commission during the course of formulation of Tariff Regulations, 2001 had laid down that the regulated entities should include in their tariff petitions, the details of year-wise actual O&M expenses (excluding abnormal expenses including water charges) for the previous 5 years duly certified by the statutory auditor. The average O&M expenses based on the actuals for FY 1995-96 to FY 1999-2000 would correspond to the FY 1997-98 (third year). This average O&M expense was escalated @ 10% per annum to arrive at the base year's O&M expenses of FY 1999-2000. Thereafter, the escalation factor applied was @ 6% per annum for the tariff period 2001-2004. In the case of new thermal stations, which had not completed five years of operation, the base O&M expenses were fixed at 2.5% of the capital cost for the first year of operation, duly escalated @ 10% per annum to bring it to the base year's O&M expenses of FY 1999-2000. Thereafter, the escalation factor was applied @ 6% per annum. A deviation of the escalation factor computed from the actual data that lies within 20% of the above notified escalation factor (which works out to 1.2% on either side of 6%) was to be absorbed by the generating stations. Deviations beyond this limit were to be adjusted on the basis of the actual escalation factor.

15.1.2 The Commission in the Tariff Regulations, 2004 approved normative O&M expenses for thermal stations on the basis of unit sizes of 200/210/250 MW based on the past years' actual data, besides approving norms for unit sizes of 500 MW and above. The Commission in the Tariff Regulations, 2009, continued with its earlier approach of approving O&M norms on the basis of unit sizes in the case of coal-based generating stations and on the basis of actual O&M expenses for past years for hydro generating stations. Further, in the Tariff Regulations, 2009, the Commission also specified norms for supercritical units and added another class of unit size of 300/330/350 MW with regard to coal-based generating stations. The Commission in the Tariff Regulations, 2004 and the Tariff Regulations, 2009, also approved separate norms for some of the generating stations of NTPC and DVC. In Tariff Regulations, 2014 & Tariff Regulations, 2019, the Commission continued with the approach of approving O&M norms on the basis of unit sizes in case of coal based generating stations. Further, in the Tariff Regulations 2014 the Commission for the first time on the basis of the analysis of actual O&M expenses for the past five years specified station-wise O&M

norms for hydro generating stations. The Commission also, for the first time, introduced the norms for thermal generating stations based on coal rejects and continued the approach while formulating Tariff Regulations, 2019.

15.2 Existing Provisions of the Tariff Regulations, 2019

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

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

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

(in Rs Lakh/MW)

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

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

Provided further that operation and maintenance expenses of generating station and the transmission system of Bhakra Beas Management Board (BBMB) and Sardar Sarovar Project (SSP) shall be determined after taking into account provisions of the Punjab Reorganization Act, 1996 and Narmada Water Scheme, 1980 under Section 6-A 71 of the Inter-State Water Disputes Act, 1956 respectively;

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

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

(in RsLakh/MW)

Year	***Talcher TPS***	***Chandrapura TPS (Units 3), Tanda TPS, pur TPS (Unit 1)***
2019-24	*56.34*	*46.16*

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

(in Rs Lakh/MW)

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

(4) Lignite-fired generating stations:

(in Rs Lakh/MW)

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

(5) Generating Stations based on coal rejects:

Year	***O&M Expenses (in Rs Lakh/MW)***
2019-20	*31.15*

2020-21	*32.24*
2021-22	*33.37*
2022-23	*34.54*
2023-24	*35.76*

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

Provided that water charges shall be allowed based on water consumption depending upon type of plant, type of cooling water system, subject to prudence check. and considering the norms of specific water consumption notified by the Ministry of Environment, Forest and Climate Change. The details regarding the same shall be furnished along with the petition:

Provided further that the generating station shall submit the details of year wise actual capital spares consumed at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not funded through compensatory as per Regulation 17 of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 or Special Allowance or claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.

(7) The operation and maintenance expenses on account of emission control system in coal or lignite based thermal generating station shall be 2% of the admitted capital expenditure (excluding IDC and IEDC) as on its date of operation, which shall be escalated annually @3.5% during the tariff period ending on 31st March 2024:

Provided that income generated from sale of gypsum or other by-products shall be reduced from the operation and maintenance expenses.

***(2)** Hydro Generating Station*

(a) Following operations and maintenance expense norms shall be applicable for hydro generating stations which have been operational for three or more years as on 01.04.2019:

(in Rs Lakh/MW)

Sr. No.	***Name of Station***	***2019-20***	***2020-21***	***2021-22***	***2022-23***	***2023-24***
1	*Bairasul*	*8,292.11*	*8,687.36*	*9,101.45*	*9,535.28*	*9,989.78*

Sr. No.	Name of Station	2019-20	2020-21	2021-22	2022-23	2023-24
2	Loktak	9,538.27	9,992.91	10,469.23	10,968.25	11,491.06
3	Salal	19,207.75	20,123.29	21,082.48	22,087.39	23,140.19
4	Tanakpur	10,520.33	11,021.79	11,547.15	12,097.55	12,674.18
5	Chamera – I	11,773.57	12,334.77	12,922.71	13,538.68	14,184.00
6	Uri	9,865.77	10,336.03	10,828.70	11,344.85	11,885.61
7	Rangit	5,336.17	5,590.53	5,857.00	6,136.18	6,428.66
8	Chamera – II	10,670.68	11,179.30	11,712.17	12,270.44	12,855.31
9	Dhauliganga	8,813.40	9,233.50	9,673.61	10,134.71	10,617.79
10	Dulhasti	18,563.04	19,447.85	20,374.84	21,346.02	22,363.49
11	Teesta- V	12,186.58	12,767.46	13,376.02	14,013.60	14,681.56
12	Sewa-II	7,079.34	7,416.78	7,770.31	8,140.68	8,528.71
13	THDC Stage I	27,788.87	29,113.44	30,501.14	31,955.00	33,478.15
14	TLDP III	7,539.76	7,899.14	8,275.66	8,670.12	9,083.39
15	Chamera III	9,078.72	9,511.46	9,964.83	10,439.81	10,937.43
16	Chutak	3,536.67	3,705.25	3,881.86	4,066.89	4,260.74
17	Nimmo Bazgo	3,527.43	3,695.57	3,871.72	4,056.27	4,249.61
18	Uri II	7,058.82	7,395.28	7,747.78	8,117.08	8,503.99
19	Parbati III	6,618.29	6,933.76	7,264.26	7,610.51	7,973.27
20	Maithon	2,892.40	3,030.26	3,174.70	3,326.03	3,484.56
21	KHEP	13,452.46	14,093.68	14,765.46	15,469.26	16,206.61
22	Naptha Jhakari	33,326.11	34,914.62	36,578.84	38,322.39	40,149.04
23	Rampur	12,267.22	12,851.94	13,464.54	14,106.33	14,778.72
24	Koldam	12,659.94	13,263.39	13,895.59	14,557.93	15,251.84
25	Karcham Wangtoo	11,710.14	12,268.31	12,853.09	13,465.74	14,107.59
26	Indira Sagar	11,728.40	12,287.44	12,873.12	13,486.73	14,129.58
27	Omkareshwar	7,198.97	7,542.12	7,901.62	8,278.25	8,672.84

Sr. No.	*Name of Station*	*2019-20*	*2020-21*	*2021-22*	*2022-23*	*2023-24*
28	*Kopili I*	*9,044.47*	*9,475.58*	*9,927.24*	*10,400.43*	*10,896.17*
29	*Ranganadi*	*12,095.88*	*12,672.44*	*13,276.47*	*13,909.30*	*14,572.30*
30	*Doyang*	*5,654.57*	*5,924.10*	*6,206.47*	*6,502.31*	*6,812.24*
31	*Khandong*	*2,261.12*	*2,368.90*	*2,481.81*	*2,600.11*	*2,724.04*
32	*Kopili II*	*1,130.56*	*1,184.45*	*1,240.90*	*1,300.05*	*1,362.02*
33	*Panchet*	*2,191.37*	*2,295.83*	*2,405.26*	*2,519.90*	*2,640.02*
34	*Tilaiya*	*900.17*	*943.08*	*988.03*	*1,035.13*	*1,084.47*
Note: The impact in respect of revision of minimum wage and GST, if any, will be considered at the time of determination of tariff.						

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

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

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

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

15.3 Issues discussed in the Approach Paper

15.3.1 Following issues were brought out in the Approach Paper for consultation:

(i) In the case of employee expenses, onetime impact, mostly related to pay revision, is required to be given, and as in the forthcoming tariff period, wage/salary revision is also anticipated, so O&M norms may be specified separately under the following two categories.

(a) Employee Expenses

(b) Other O&M Expenses comprise of Repair and Maintenance and Administrative & General Expenses.

(ii) Alternatively, to give effect to the impact of pay/wage revision, 50% of the actual wage can be allowed as the impact of wage revision on a normative basis.

(iii) Considering the actual expenses incurred in the past, one norm for all HVDC schemes in terms of per MW basis may be specified.

(iv) Additional O&M expenses can be given for transmission assets being operated in the North Eastern and Hilly Regions and the manner in which such additional costs can be considered.

(v) Possibility of allowing recurring and low value spares below Rs. 20 lakh as a part of normative O&M expenses, while for capital spares with a value in excess of Rs. 20 lakh, utilities may submit the same on a case-to-case basis for reimbursement with appropriate justification for the Commission's consideration.

(vi) Inclusion of provisions with regard to allowing the impact of a change in the law on O&M expenses.

15.3.2 Accordingly, the comments from the stakeholders were sought on the following:

(i) Segregation of O&M expenses under 2 categories, i.e. Employee Expenses and Other O&M Expenses

(ii) impact of pay/wage revision, 50% of the actual wage may be allowed as impact on a normative basis.

(iii) One norm for all HVDC schemes in terms of per MW is considering the actual expenses incurred.

(iv) Additional O&M Expenses for Transmission Line operation in the North Eastern and Hilly Region.

(v) Low value spares below Rs. 20 lakh may be made a part of normative O&M expenses, and the current practice of approval of capital spares continues for spares costing above Rs. 20 lakh.

15.4 Stakeholders' Response

15.4.1 In response to the issues brought out in the Approach Paper for consultation, the stakeholders have submitted the following comments/suggestions.

a) Some Generators have submitted that the O&M norms may be increased to recover the actual expenses incurred or that the actual O&M expenses may be approved subject to prudence checks by the Commission.

b) Some Consumer Representatives have submitted that if actual O&M Expenses are less than normative O&M Expenses, the Surplus may be used to compensate for the Pay revision impact and the rest of the balance (Surplus – Pay revision impact) may be reimbursed back to the beneficiaries.

c) Various Central Generating Stations have supported the proposal to allow 50% of pre-revision wage as wage impact on a Normative basis. As regards change in law events, it was suggested that a provision to deal with the change in law events might be provided in the O&M expenses, so that any change in law event impacting O&M can be dealt by the Commission.

d) Various Utilities suggested not to split O&M expenses and in case they are to be segregated, it has been proposed to provide separate escalating factors for both the components. It was further suggested that the expenses towards the contractual employees should be considered as part of other O&M Expenses as they are hired for some specific works as per the agreement with the third party.

e) Some Consumer Representatives submitted that the choice of the price index may be based on a single index or a weighted composite index calculated on the basis of the proportion of different cost sub-components of the O&M cost i.e., wages & salary (W&S), repair & maintenance (R&M) and administrative & general (A&G) expenses. The W&S component may be linked to the CPI (industrial worker), R&M to the WPI of electrical equipment or weighted sum of electrical equipment and machinery & equipment and the A&G expenses to be linked to the CPI applicable to white-collar workers (CPI urban & clerical workers). Such a sub-component based application of price index could be feasible if costs under the respective heads can be apportioned reliably.

f) Some Beneficiaries submitted that the Commission may allow the employee expenses for the private sector based on actual expenses. Further, it was suggested to continue the existing provisions for allowing separate other expenses, i.e., Water Charges, Ash Transportation, etc.

g) Some Beneficiaries submitted that in O&M Expenses, the lower of the normative and actual may be approved.

h) DVC has submitted that a special provision may be specified for DVC towards consideration for top up in the P&G Fund. Further, it is suggested to allow the impact of pay revision whenever it arises. As regards R&M expenses, it was suggested that the Commission may consider normative R&M expenses based on the size and vintage of the generating unit. As regards A&G expenses, it was suggested that ash evacuation costs may be allowed separately, in addition to security charges and water charges.

i) In addition to the above, DVC submitted that an adequate add-cap provision is required to cover up the capital expenditure on the ground of 'replacement of asset' for various reasons like efficient operation, achieving PAT, replacement of existing drives, etc.

j) NLCIL submitted that O&M Expenses may be approved based on the ageing factor of the stations. Higher O&M expenses may be considered for CFBC boilers due to increased maintenance expenses and increased downtime between shutdown and startup.

15.5 Analysis of Actual O&M Expenses

15.5.1 The Commission, through its Order dated March 29, 2023 directed various Central sector generating companies, joint venture companies, independent power producers and Central/ inter-State transmission licensees whose tariff is being regulated by the Commission to submit details of actual annual O&M expenses incurred from FY 2017-18 to FY 2021-22 in the prescribed format. Subsequently, similar information was also sought for FY 2022-23.

Normalisation of O&M Expenses

15.5.2 The Central sector generating stations submitted the O&M expenses for FY 2017-18 to FY 2022-23 in the prescribed format with actual break up of expenses incurred under various sub- heads. The O&M expenses incurred by these generating stations can be broadly classified into three heads, namely, employee expenses, repair and maintenance expenses, and administrative and general expenses. Each of these major heads of the O&M expenses incurred by generating stations has further been segregated under various sub-heads, and these have been evaluated by the Commission. Based on the detailed analysis, the Commission has followed a systematic approach for arriving at the actual normalised O&M expenses to be considered for the preparation of norms.

a) Some of the employee related expenses, namely ex gratia, incentives, productivity linked incentives and performance related pay, are linked to the efficient operation of the generating station. These types of expenses are contingent upon the actual performance of the individual generating station and are payable only when the generating station achieves targeted operational norms. The Commission has been consistently following the principle that such incentives and performance related pay should be paid by the generating company from the increase in revenue due to reduced downtime and efficient operations of the generating stations. Therefore, for computing O&M expenses norms, these types of expenses are excluded from the actual O&M expenses. Further, some of the expenses such as donations, provisions, community development expenses, CSR expenses, and loss of stores are expenses, which don't form part of O&M expenses for determination of norms and thus have been excluded while computing the O&M expenses norms.

b) Some of the expenses, such as security charges, water charges, RLDC fees, filing fees, etc. are allowed separately by the Commission based on actual data. Therefore, such expenses have not been considered for computing the O&M expense norms.

c) Further, some of the expenses, like prior period expenses, arrears, etc., booked under the head O&M expenses are onetime expenses. Therefore, such expenses of a non-recurring nature have not been considered for computing the O&M expenses norms.

d) Expense on account of ash transportation are allowed by the Commission on case-to case basis after due prudence, as transportation of ash is not a constant and predictable operational activity and may differ significantly by factors such as distance between the plant and the beneficiaries and the diverse nature of beneficiaries, such as Cement Industries, Traders, Brick Manufactures, among others. Further, the costs associated with handling and transporting ash are treated separately. Therefore, due to the variable and irregular nature of ash disposal activities, such expenses have not been considered for computing the O&M expense Norms.

e) The Commission has determined the average escalation rate for FY 2017-18 to FY 2022-23, which works out to be 5.93% (WPI) (as per 2011-12 base year series) and 5.84% (CPI). The following table provides the summary of the computation of average WPI and average CPI.

Table 1: Summary computation of Average WPI and Average CPI

Year	Average CPI	% Change	Average WPI	% Change
FY 2017-18	284.42	3.08%	114.88	2.92%
FY 2018-19	299.92	5.45%	119.79	4.28%
FY 2019-20	322.50	7.53%	121.80	1.68%
FY 2020-21	338.69	5.02%	123.38	1.29%

Year	Average CPI	% Change	Average WPI	% Change
FY 2021-22	356.06	5.13%	139.41	13.00%
FY 2022-23	377.62	6.05%	152.53	9.41%
Total		**5.84%**		**5.93%**

f) Further, as the Commission has proposed to consider allowing water charges and security expenses at actuals for each of the generating stations separately, the same has not been considered as a part of O&M expenses for thermal generating stations. However, water cess being a statutory charge payable to the respective State Pollution Control Board for discharge of effluent, has been considered while computing the O&M expenses norms.

g) Where steep year-on-year increases in expenses under various heads were observed, the Commission normalised the same, depending upon the nature of expenses, in the preceding year's corresponding expense figure.

15.5.3 The Commission has thus derived the normalised O&M expenses actually incurred by the generating stations to approve the norms for thermal generating stations.

15.5.4 Further, the COVID-19 pandemic during FY 2020-21 and FY 2021-22 had a significant impact on the O&M expenses of power plants, especially in FY 2020-21. The stringent lockdown measures reduced workforce availability and caused disruptions in the supply chain, which led to deferment of activities pertaining to maintenance, repairs, and procurement of critical spare parts. In FY 2021-22, as the pandemic's initial shock abated, power plants experienced a somewhat moderated impact on O&M Expenses. In view of the impact of the COVID-19 pandemic on actual O&M expenses, it is felt that before proceeding with the determination of norms; the impact needs to be nullified. In order to do the same, the O&M expenses for FY 2020-21 have been recomputed by escalating normalized O&M expenses of FY 2019-20 by a 5-year CAGR of O&M expenses for thermal power station (NTPC) i.e. 2.94%. Similarly, O&M Expenses for FY 2021-22 have been computed by escalating the derived O&M Expenses for FY 2020-21 by 2.94%.

Table 2: CAGR of O&M Expenses for FY 2018-19 to FY 2022-23

Particulars	FY 2018-19	FY 2019-20	FY 2020-21*	FY 2021-22*	FY 2022-23	5-year CAGR
Total O&M Expenses	12,35,022	12,95,544	13,33,574	13,72,720	13,86,546	**2.94%**

Derived based on CAGR of Normalised O&M expenses for FY 2018-19 to FY 2022-23

15.5.5 In case of hydropower plants, normalized O&M expenses of FY 2019-20 have been escalated by a 5-year CAGR of O&M expenses for hydropower stations, i.e. 3.05%, to calculate the O&M Expenses for FY 2020-21. Similarly, O&M Expenses for FY 2021-22 have been determined by escalating the computed O&M Expenses pertaining to FY 2020-21 by a CAGR of 3.05%.

Table 3: CAGR of O&M Expenses for FY 2018-19 to FY 2022-23

Particulars	FY 2018-19	FY 2019-20	FY 2020-21*	FY 2021-22*	FY 2022-23	5-year CAGR
Total O&M Expenses	1,85,102	1,92,655	1,98,523	2,04,570	2,08,703	**3.05%**

**** Derived based on CAGR of Normalised O&M expenses (NHPC) for FY 2018-19 to FY 2022-23***

15.5.6 In the case of the transmission system, normalized O&M expenses of FY 2019-20 have been escalated by 5-year CAGR of O&M expenses for the transmission system, i.e. 3.35%, to calculate the O&M Expenses for FY 2020-21. Similarly, O&M Expenses for FY 2021-22 shall be determined by escalating the computed O&M Expenses pertaining to FY 2020-21 by CAGR of 3.35%.

Table 4: CAGR of O&M Expenses for FY 2018-19 to FY 2022-23

Particulars	FY 2018-19	FY 2019-20	FY 2020-21*	FY 2021-22*	FY 2022-23	5-year CAGR
Total O&M Expenses	3,16,294	2,90,536	3,00,263	3,10,314	3,60,821	**3.35%**

****Derived based on CAGR of Normalised O&M expenses (PGCIL) for FY 2018-19 to FY 2022-23***

Impact of Wage Revision

15.5.7 The Commission has reviewed the suggestions received regarding allowing impact of wage revision. The Commission observes that there is no data suggesting the future impact of wage revision and therefore the impact cannot be anticipated and therefore the Commission has proposed to allow the same at the time of truing up of tariff.

Change in Law

15.5.8 The Commission has reviewed the suggestions received regarding allowing impact of change in law events affecting O&M expenses. The Commission observes that while a certain change in law events may have a substantial impact on O&M expenses, there may be certain events that may have a minor impact on O&M expenses and revisiting norms for allowing such minor impacts will erode the normative structure of O&M expenses. The Commission has therefore proposed to revisit the O&M expenses only in case the overall impact of a change in law event(s) is more than 5% of the normative O&M expenses allowed for the given year.

A. Thermal Generating Stations

15.5.9 The Commission in Tariff Regulations, 2019 notified norms of O&M expenses based on the unit sizes. These unit sizes were classified as 200/210/250 MW Series, 300/330/350 MW Series, 500 MW Series (sub-critical), 600 MW Series and 800 MW Series and above (super-critical). The Commission has analysed the actual O&M expenses from FY 2018-19 to FY 2022-2023, and for stations where FY 2022-23 data was not available, O&M expenses for FY 2017-18 to FY 2021-22 have been considered. The Commission has observed that several generating stations, for which O&M expense data have been submitted, have a combination of different unit sizes. Therefore, the Commission has separately analysed the O&M expense data of the generating stations having single unit type configuration and considered the same for computing O&M expenses norms for respective unit sizes. For this purpose, the stage-wise O&M expenses of a thermal generating station have been derived by applying the weighted average sum-product of installed capacity and existing O&M expense norms (in Rs. Lakh per MW).

15.5.10 For 200/210/250 MW units, the Commission has considered the O&M expenses of the following stations.

a) Dadri Coal Stage 1
b) Unchahar
c) Ramakundam Stage 1
d) Korba Stage 1
e) Kahalgaon Stage 1
f) Farraka I
g) Kanti Bijli
h) Chandrapura Unit 7-8
i) NLC TPS II

15.5.11 Accordingly, in line with the above, the actual O&M expenses for these 200/210/250 MW Series stations for FY 2018-19 to FY 2022-23 are as shown below:

Table 5: Actual O&M expenses for 200 / 210 / 250 MW Series Thermal Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2018-19 (a)	FY 2019-20 (b)	FY 2020-21 (c) = (b)*(1+2.94%)	FY 2021-22 (d) = (c)*(1+2.94%)	FY 2022-23 (e)	Five Year Average
Dadri Coal Stage 1	28.46	31.14	32.05	32.99	32.99	31.53
Unchahar	30.64	31.95	32.89	33.86	31.99	32.27
Ramagundam Stage 1	30.57	30.10	30.99	31.90	31.10	30.93
Korba Stage 1	34.72	35.18	36.21	37.28	35.90	35.86
Kahalgaon Stage 1	31.58	33.17	34.15	35.15	36.67	34.14
Faraaka I	37.31	39.28	40.43	41.62	38.77	39.48
Kanti Bijli	32.87	35.66	36.71	37.79	48.25	38.26
Chandrapura Unit 7-8	22.44	27.03	27.82	28.64	22.68	25.72
NLC TPS – II	35.96	35.94	36.99	38.08	37.23	36.84

15.5.12 Stations with only 500 MW sized units are as stated below:

a) Simhadri TPS
b) Talcher STPP
c) Rihand TPS
d) Sipat TPP Stage 2
e) Dadri TPP Stage 2
f) Ramakundam Stage 2
g) Korba Stage 2
h) Kahalgaon Stage 2
i) Mauda Stage 1
j) Farakka Stage 2

15.5.13 The actual O&M expenses for these stations for FY 2018-19 to FY 2022-23 are as shown below:

Table 6: Actual O&M expenses for 500 MW Series Thermal Generating Stations

(INR in Lakh)

Generating Stations	FY 2018-19 (a)	FY 2019-20 (b)	FY 2020-21 (c) = (b)*(1+2.94%)	FY 2021-22 (d)= (c)*(1+2.94%)	FY 2022-23 (e)	Five Year Average
Simhadri TPS	21.55	22.01	22.66	23.32	23.65	22.64

Generating Stations	FY 2018-19 (a)	FY 2019-20 (b)	FY 2020-21 (c) = (b)*(1+2.94%)	FY 2021-22 (d)= (c)*(1+2.94%)	FY 2022-23 (e)	Five Year Average
Talcher STPP	20.52	21.68	22.31	22.97	24.10	22.31
Rihand TPS	18.63	19.00	19.56	20.14	20.46	19.56
Sipat TPP Stage 2- 2x500MW	19.10	20.05	20.64	21.25	21.64	20.53
Dadri Coal Stage 2 - 2x490MW	19.06	21.26	21.89	22.53	22.53	21.45
Ramagundam Stage 2	20.47	20.56	21.16	21.78	21.24	21.04
Korba Stage 2	23.25	24.03	24.73	25.46	24.52	24.40
Kahalgaon Stage 2	21.15	22.65	23.32	24.00	25.05	23.30
Mauda Stage 1	18.33	19.28	19.85	20.43	21.72	19.92
Farakka Stage 2	24.99	26.83	27.61	28.42	26.48	26.87

15.5.14 Stations with 600 / 660 MW sized units are as stated below:

a) Mauda STPS Stage 2

b) Sipat STPP Stage 1

c) Barh Stage 2

Table 7: Actual O&M expenses for 600 / 660 MW Series Thermal Stations

(INR Lakh per MW)

Generating Station	FY 2018-19 (a)	FY 2019-20 (b)	FY 2020-21 (c) = (b)*(1+2.94%)	FY 2021-22 (d) = (c)*(1+2.94%)	FY 2022-23 (e)	Five Year Average
Mauda STPS Stage 2	16.49	17.35	17.86	18.39	19.54	17.93
Sipat STPP Stage 1	17.18	18.05	18.58	19.12	19.47	18.48
Barh Stage 2	23.03	25.91	26.67	27.45	31.11	26.83

15.5.15 Tanda TPS has a smaller sized unit of 110 MW, for which separate norms have been provided for them under the previous Tariff Regulations.

15.5.16 The actual O&M expenses for Tanda TPS for FY 2018-19 to FY 2022-23 is shown below:

Table 8: Actual O&M expenses for small sized Thermal Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2018-19 (a)	FY 2019-20 (b)	FY 2020-21 (c) = (b)*(1+2.94%)	FY 2021-22 (d) = (c)*(1+2.94%)	FY 2022-23 (e)	Five Year Average
Tanda TPS	57.39	50.81	34.03	29.01	34.24	41.10

15.5.17 Further, Tanda-II TPS unit 1 (660 MW) was commissioned in 7.11.2019 and unit 2 (660 MW) was commissioned in 1.7.2021, accordingly the O&M expenses have been allocated to these two units from their effective COD.

15.5.18 For lignite fired stations, the Commission had approved separate norms for Barsingsar TPS. The actual expenses are as shown below:

Table 9: Actual O&M expenses for Lignite Fired Generating Station

(INR Lakh per MW)

Generating Stations	FY 2018-19 (a)	FY 2019-20 (b)	FY 2020-21 (c) = (b)*(1+2.94%)	FY 2021-22 (d) = (c)*(1+2.94%)	FY 2022-23 (e)	Five Year Average
Barsingsar TPS	38.35	41.15	42.36	43.60	44.18	41.93

15.5.19 For gas based stations other than small gas turbines, the actual O&M expenses are as shown below:

Table 10: Actual O&M expenses for NTPC Gas based Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2018-19 (a)	FY 2019-20 (b)	FY 2020-21 (c) = (b)*(1+2.94%)	FY 2021-22 (d) = (c)*(1+2.94%)	FY 2022-23 (e)	Five Year Average
Anta	18.59	20.34	20.94	21.55	22.57	20.80
Aurayia	11.32	11.42	11.76	12.10	14.88	12.30
Dadri	11.94	12.54	12.91	13.29	10.26	12.19
Faridabad	15.58	13.49	13.89	14.29	14.88	14.43
Gandhar	13.13	14.56	14.99	15.43	13.47	14.31
Kawas	15.61	16.01	16.48	16.96	14.87	15.98
Kayamkulam GPP	18.19	15.69	16.15	16.63	9.87	15.31
Average	**14.91**	**14.86**	**15.30**	**15.75**	**14.40**	**15.04**

15.5.20 For small gas turbine power generating station i.e. Assam GPS, Tripura GPS and Agartala GPS, the actual normalized O&M expenses are as shown below.

Table 11: Actual O&M expenses for NEEPCO Gas based Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2017-18 (a)	FY 2018-19 (b)	FY 2019-20 (c)	FY 2020-21 (d) = (c)* (1+2.94%)	FY 2021-22 (e) = (d)*(1+2.94%)	Five Year Average
Assam GPS	36.24	36.36	34.48	35.49	36.53	35.82
Agartala GPS	35.59	35.25	34.64	35.66	36.70	35.57
Tripura GPS	28.09	27.89	26.17	26.93	27.72	27.36

15.5.21 For advance class gas power stations, actual normalized O&M expenses of

OTPC have been considered out of a total of three such generating stations, as RGPPL and Sugen Power have not submitted their O&M data. The actual normalized O&M expenses for OTPC are shown below:

Table 12: Actual O&M expenses for OTPC Gas based Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2018-19 (a)	FY 2019-20 (b)	FY 2020-21 (c) = (b)*(1+2.94%)	FY 2021-22 (d) = (c)*(1+2.94%)	FY 2022-23 (e)	Five Year Average
OTPC	17.77	21.40	22.03	22.68	18.55	20.49

B. <u>Hydro Generating Stations</u>

15.5.22 The Commission in the Tariff Regulations, 2009 specified the approach for approving the O&M expenses for the hydro generating stations after considering the actual O&M expenses based on the Audited Accounts. However, no specific station-wise norms were specified. For tariff periods 2014-19 and 2019-24, the Commission decided to specify station-wise O&M norms based on the actual normalised O&M expenses.

15.5.23 In response to the Commission's Order No. L-1/268/2022/CERC, dated 26 March 2023, NEEPCO has submitted their actual O&M expenses for the period from FY 2017-18 to FY 2021-22. Subsequently, NHPC, NTPC, THDCIL, SJVNL, NHDC and DVC have submitted their actual O&M expenses for FY 2022-23 as well.

15.5.24 The actual normalised O&M expenses of hydro generating stations (NEEPCO), for which FY 2022-23 data was not available, the actual O&M expenses from FY 2017-18 to FY 2021-22 have been considered, which is as shown under.

Table 13: Actual O&M expenses for Hydro Stations for NEEPCO

(INR Lakhs)

Particulars	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22
	a	b	c	d = c*(1+3.05%)	e = d*(1+3.05%)
NEEPCO					
Kopili	9,804.45	9,179.52	9,377.74	9,663.35	9,957.66
Doyang	6,343.23	6,112.32	5,551.44	5,720.52	5,894.74
Panyor	12,213.86	12,853.12	13,188.82	13,590.51	14,004.42
Pare Hydro		11,940.64	12,839.36	13,230.40	13,633.35
Turial	4,824.25	5,977.61	4,458.85	4,594.65	4,734.59
Khandong	2,447.78	2,247.40	2,233.43	2,301.45	2,371.55
Khandong Stage II	1,233.57	1,128.74	1,079.62	1,112.50	1,146.39

15.5.25 For NHPC's hydro generating stations, NTPC – Koldam, NHDC, THDCL, SJVNL and DVC generating station for which actual O&M expenses for FY 2022-23 was available, the actual normalised O&M expenses from FY 2018-19 to FY 2022-23 has been considered and is shown as under.

Table 14: Actual O&M expenses for other Hydro Generating Stations

(INR Lakhs)

Particulars	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23
	a	b	c = b* (1+3.05%)	d = c*(1+3.05%)	e
NHPC					
Bairasiul Power Station	6,414.42	6,510.90	6,709.19	6,913.53	7,609.19
Chamera I	12,507.48	12,089.15	12,457.34	12,836.75	14,582.00
Chamera II	11,464.56	11,245.64	11,588.14	11,941.07	11,076.56
Chamera III	8,406.29	8,342.69	8,596.77	8,858.60	9,354.15
Chutak Power Station	3,847.24	3,762.46	3,877.05	3,995.13	4,213.37
Dhauliganga Power Station	9,857.14	9,979.46	10,283.39	10,596.59	11,070.34
Dulhasti Power Station	14,919.39	16,461.33	16,962.68	17,479.30	17,653.00
Kishanganga Power Station	11,292.02	13,455.22	13,865.02	14,287.29	13,619.15
Loktak Power Station	7,166.69	7,962.22	8,204.72	8,454.60	7,832.39
Nimmo-bazgo Power Station	4,156.54	3,859.85	3,977.41	4,098.55	4,068.25
Parbati-III Power Station	8,480.31	9,823.33	10,122.52	10,430.81	9,353.67
Rangit Power Station	5,150.96	5,533.76	5,702.29	5,875.97	6,258.47
Salal Power Station	14,333.99	15,443.05	15,913.39	16,398.05	19,501.37
Sewa II Power Station	6,586.31	6,843.41	7,051.84	7,266.61	8,689.57
Tanakpur Power Station	9,231.26	10,243.50	10,555.48	10,876.96	11,289.27
Teessta Vally Power	14,010.13	13,741.09	14,159.59	14,590.84	14,147.48
Tldp-III Power Station	8,611.73	8,298.50	8,551.24	8,811.68	7,966.24
Tldp-IV Power Station	9,759.94	9,441.11	9,728.65	10,024.95	9,013.84
Uri-I Power Station	11,447.78	11,533.00	11,884.26	12,246.21	12,779.87
Uri-II Power Station	7,458.20	8,086.21	8,332.49	8,586.26	8,625.62
NTPC					
Koldam	11,866.57	11,140.07	11,479.35	11,828.97	11,585.83
NHDC					
Omkareshwar	8,039.50	8,477.03	8,735.21	9,001.25	9,806.71
Indira Sagar	11,534.41	12,974.35	13,369.50	13,776.68	13,868.74
THDC					
Tehri HPP	32,315.62	34,328.17	35,373.68	36,451.03	36,135.83
KHEP	18,058.02	16,214.94	16,708.78	17,217.67	18,385.83
SJVNL					
Naptha Jhakari	42,473.69	41,311.95	42,570.16	43,866.69	47,403.19
Rampur	16,229.94	15,068.34	15,527.27	16,000.17	17,273.65
Teesta Urja Ltd	22,938.98	23,839.09	24,565.14	25,313.31	25,162.49
Karcham Wangtoo	10,299.08	11,207.14	11,548.47	11,900.19	14,663.14
DVC					
Maithon	1,725.69	1,887.13	1,944.61	2,003.84	2,249.12

Particulars	**FY 2018-19**	**FY 2019-20**	**FY 2020-21**	**FY 2021-22**	**FY 2022-23**
	a	**b**	**c = b* (1+3.05%)**	**d = c*(1+3.05%)**	**e**
Panchet	1,745.64	1,998.15	2,059.01	2,121.72	2,931.94
Tilaya	519.29	466.64	480.85	495.49	567.30

15.6 Commission's View – Thermal Generating Stations

15.6.1 After examining and reviewing comments/suggestions of stakeholders received, the Commission proposes the following.

<u>Escalation Rate:</u>

15.6.2 The Escalation rate computed based on the five-year average of WPI for FY 2018-19 to FY 2022-23 works out to 5.93% per annum, while that of CPI for the same period works out to 5.84% per annum. Considering the 60:40 weightages for WPI and CPI, respectively, the escalation rate works out to 5.89% per annum. The Commission observes that actual O&M expenses after normalisation during the period from FY 2018-19 to FY 2022-23 have increased by approximately 3.22% per annum for coal-based generating stations of NTPC. However, in the case of gas-based power generating stations, it is observed that the plants were not in continuous operation from FY 2018-19 to FY 2022-23, leading to a notably low PLF. This low PLF has consequently contributed to considerable variability in the growth rates of individual plants. Therefore, the Commission has considered the annual growth rate of approx. 3.22%, same as for coal-based generating stations operated by NTPC for gas-based generating stations, as the PLF for gas-based generating stations may show an upward trend in the upcoming control period. The normalised O&M expenses escalation rate is lower than the weighted average escalation rate of 5.89% per annum. The Commission is of the view that average CPI and WPI indices are a fair indicator of inflation. In this context, for the purpose of escalation till FY 2023-24, the Commission proposes to consider the annual escalation rate of 3.22% for coal and gas generating stations and thereafter for projecting O&M expenses norms for the period from FY 2024-25 to FY 2028-29, the weighted average annual escalation rate of 5.89% is applied for all thermal generating stations.

<u>Determination of Norms</u>:

15.6.3 The Commission, based on the actual O&M expenses for FY 2018-19 to FY 2022-23 (for FY 2017-18 to FY 2021-22 for stations not having FY 2022-23 data), has recomputed the O&M expenses for FY 2020-21 (FY 2019-20 for stations not having FY 2022-23 data) by taking average of five-year O&M expenses after escalating annual normalised O&M expenses by 3.22% per annum for coal based and gas based generating stations till FY 2023-24. O&M expenses, thus computed for FY 2023-24, have been escalated further considering an escalation rate of 5.89% per annum to arrive at the O&M expenses for FY 2024-25 to FY 2028- 29.

15.6.4 The Commission proposes to approve the norms based on the actual normalised O&M expenses incurred by the generating station. For the purpose of determining norms for 200/210/250 MW units, the Commission has considered the actual O&M expenses for the following stations:

a) Dadri Coal Stage 1
b) Unchahar TPP
c) Ramakundam Stage 1
d) Korba Stage 1
e) Kahalgaon Stage 1
f) Farraka Stage I
g) Kanti Bijli
h) Chandrapura Unit 7-8
i) NLC TPS II

15.6.5 The O&M expenses for the above generating stations are shown as below.

Table 15: Projected O&M expenses for 200/210/250 MW Series Thermal Stations

(INR Lakh per MW)

Generating Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
Actuals						**Derived**	**Projected**				
Dadri Coal Stage 1	28.46	31.14	32.05	32.99	32.99	34.67	36.71	38.88	41.17	43.60	46.16
Unchahar TPP	30.64	31.95	32.89	33.86	31.99	35.49	37.58	39.79	42.14	44.62	47.25
Ramagundam Stage 1	30.57	30.10	30.99	31.90	31.10	34.02	36.02	38.14	40.39	42.77	45.29
Korba Stage 1	34.72	35.18	36.21	37.28	35.90	39.43	41.76	44.22	46.83	49.58	52.51
Kahalgaon Stage 1	31.58	33.17	34.15	35.15	36.67	37.55	39.76	42.11	44.59	47.22	50.00
Faraaka I	37.31	39.28	40.43	41.62	38.77	43.42	45.98	48.69	51.56	54.60	57.82
Kanti Bijli	32.87	35.66	36.71	37.79	48.25	42.07	44.55	47.18	49.96	52.90	56.02
Chandrapura Unit 7-8	22.45	27.03	27.83	28.64	22.68	29.20	29.96	31.72	33.59	35.57	37.67
NLC TPS - II	36.13	36.33	37.39	38.49	38.65	41.13	43.56	46.12	48.84	51.72	54.77
Average	**31.64**	**33.32**	**34.29**	**35.30**	**35.22**	**37.44**	**39.54**	**41.87**	**44.34**	**46.95**	**49.72**

Generating Stations (200 MW)	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29

15.6.6 For determining the norms for 500 MW units based on sub critical technology, the Commission has considered the following stations:

a) Simhadri TPS
b) Talcher STPP
c) Rihand TPS
d) Sipat TPP Stage 2
e) Dadri TPP Stage 2
f) Ramakundam Stage 2
g) Korba Stage 2
h) Kahelgaon Stage 2
i) Mauda Stage 2
j) Farakka II

15.6.7 The O&M expenses for the above generating stations are shown as below:

Table 16: Projected O&M expenses for 500 MW Series Thermal Stations

(INR Lakh per MW)

Generating Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
	Actuals					**Derived**	**Projected**				
Simhadri TPS	21.55	22.01	22.66	23.32	23.65	24.90	26.36	27.92	29.56	31.31	33.15
Talcher STPP	20.52	21.68	22.31	22.97	24.10	24.54	25.99	27.52	29.14	30.86	32.68
Rihand	18.63	19.00	19.56	20.14	20.46	21.51	22.78	24.12	25.54	27.05	28.64
Sipat TPP Stage 2	19.10	20.05	20.64	21.25	21.64	22.58	23.91	25.32	26.82	28.40	30.07
Dadri Stage 2	19.06	21.26	21.89	22.53	22.53	23.60	24.99	26.46	28.02	29.67	31.42
Ramagundam Stage 2	20.47	20.56	21.16	21.78	21.24	23.14	24.51	25.95	27.48	29.10	30.81
Korba Stage 2	23.25	24.03	24.73	25.46	24.52	26.83	28.41	30.09	31.86	33.74	35.72
Kahalgaon Stage 2	21.15	22.65	23.32	24.00	25.05	25.55	27.06	28.65	30.34	32.13	34.02
Mauda Stage 1	18.33	19.28	19.85	20.43	21.72	21.91	23.20	24.57	26.01	27.55	29.17
Farakka II	24.99	26.83	27.61	28.42	26.48	29.55	31.29	33.13	35.08	37.15	39.34
Average (500 MW)	**20.70**	**21.73**	**22.37**	**23.03**	**23.14**	**24.41**	**25.85**	**27.37**	**28.99**	**30.69**	**32.50**

15.6.8 For determining the norms for 600/660 MW units based on super critical technology, the Commission has considered the following stations:

a) Mauda Stage 2

b) Sipat Stage 1

c) Barh STPS Stage 2

15.6.9 Solapur STPS, Khargone STPS and Raghunathpur STPS have not been considered due to low PLF.

Table 17: Projected O&M expenses for 600/660 MW Series Thermal Stations

(INR Lakh per MW)

Generating Station	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
	Actuals					**Derived**	**Projected**				
Mauda STPS Stage 2	23.25	24.03	24.73	25.46	24.52	26.83	28.41	30.09	31.86	33.74	35.72
Sipat 1	17.18	18.05	18.58	19.12	19.47	20.32	21.52	22.79	24.13	25.55	27.06
Barh STPS Stage 2	23.03	25.91	26.67	27.45	31.11	29.51	31.25	33.09	35.04	37.11	39.30
Average 600 / 660 MW	**21.15**	**22.66**	**23.33**	**24.01**	**25.03**	**25.56**	**27.06**	**28.66**	**30.34**	**32.13**	**34.03**

15.6.10 The Commission, for determining the O&M expenses for 300/330/350 MW units, in continuation with its earlier approach, proposes to consider average O&M expenses norms for 200/210/250 MW and 500 MW units.

15.6.11 The Commission proposes to approve norms for stations having smaller-sized units, based on the actual normalised O&M expenses.

15.6.12 Since actual O&M expenses data for 800 MW ultra-supercritical technology is available from only FY 2019-20 to FY 2022-23, that too when the plants were operating at low PLF, the Commission proposes to specify the norms for these stations at slightly lower levels (at 0.9 times the norms projected for 600 MW series) compared to 600 MW units.

15.6.13 For stations with 100/110/130/140/ units, the Commission proposes to approve norms based on the actual performance of the plant since only Tanda TPS comprises 110 MW units, the actual normalised O&M expenses have been considered for approving norms for similar- sized units.

15.6.14 The O&M expenses norms of Tanda TPS are significantly high. Taking into account relaxed O&M expense norms as well as Operational Norms, the Commission is not inclined to further escalate the O&M expense norms for the station. Therefore, the Commission proposes to freeze the O&M expense norms worked out for FY 2024-25, which shall be applicable during the entire tariff period.

Table 18: Projected O&M expenses for small sized Thermal Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24	FY 2024-25 to FY 2028-29
Tanda TPS	57.39	50.81	34.03	29.01	34.24	45.20	**41.78**

15.6.15 For 125 MW lignite-fired station, the Commission has observed that there is a significant variation in O&M expenses allowed vide Order dated 06.10.2023 in Petition No. 366/GT/2020 after truing up vis-à-vis the O&M expenses submitted for Barsingsar Thermal Power Station. Therefore, the Commission has decided to consider the O&M expenses norms for FY 2023-24 as the base figure, and escalated the same by 5.89% (escalation factor for thermal generating stations) to arrive at the base figure for FY 2024-29. Thereafter, it is escalated by 5.89% for deriving the figures for the remaining years of the tariff period.

Table 19: Projected O&M expenses for 125 MW Generating Station

(INR Lakh per MW)

Generating Stations	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
	Existing Norm	**Projected**				
125 MW Sets	35.76	37.87	40.10	42.46	44.96	47.61

15.6.16 The Commission, for generating stations based on coal rejects, in line with its earlier approach, proposes to approve the norms for O&M expenses as approved for 125 MW lignite-fired stations.

15.6.17 For determination of O&M expenses norms for gas-based stations other than small gas turbines for FY 2024-25 to FY 2028-29, the Commission has considered actual normalised O&M expenses for FY 2018-19 to FY 2022-23 of all the gas-based generating stations of NTPC.

Table 20: Projected O&M expenses for NTPC gas based Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
	Actuals					**Derived**	**Projected**				
Anta	18.59	20.34	20.94	21.55	22.57	22.16	23.47	24.85	26.32	27.87	29.51
Aurayia	11.32	11.42	11.76	12.10	14.88	13.52	14.32	15.16	16.06	17.00	18.00
Dadri	11.94	12.54	12.91	13.29	10.26	12.98	13.75	14.56	15.42	16.33	17.29
Faridabad	15.58	13.49	13.89	14.29	14.88	15.37	16.28	17.23	18.25	19.33	20.46
Gandhar	13.13	14.56	14.99	15.43	13.47	15.25	16.15	17.10	18.11	19.18	20.31
Kawas	15.61	16.01	16.48	16.96	14.87	17.03	18.03	19.10	20.22	21.41	22.68
Kyakulam GPP	18.19	15.69	16.15	16.63	9.87	16.31	17.27	18.29	19.36	20.51	21.71
Average	**14.91**	**14.86**	**15.30**	**15.75**	**14.40**	**16.09**	**17.04**	**18.04**	**19.10**	**20.23**	**21.42**

15.6.18 For small gas turbine stations, the Commission has considered Assam GPS and Tripura GPS for determination of O&M norms. For Agartala Gas based stations, the Commission has considered the actual normalised O&M expenses for FY 2018-19 to FY 2022-23.

Table 21: Projected O&M expenses for NEEPCO Gas based Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
	Actuals					**Derived**	**Projected**				
Assam GPS	36.24	36.36	34.48	35.49	36.53	40.67	43.25	45.79	48.49	51.35	54.38
Tripura GPS	28.09	27.89	26.17	26.93	27.72	31.06	33.08	35.02	37.09	39.27	41.59
Average	**32.17**	**32.12**	**30.32**	**31.21**	**32.13**	**35.86**	**38.16**	**40.41**	**42.79**	**45.31**	**47.98**
Agartala GPS	35.59	35.25	34.64	35.66	36.70	40.38	42.76	45.28	47.94	50.77	53.76

15.6.19 For gas based advance F Class machines, the Commission observed that RGPPL and Sugen Power have not submitted their O&M data. Therefore, it would not be appropriate to consider the actual O&M expenses of a single power plant to determine the norm for the new tariff period. Accordingly, the Commission has decided to consider the O&M expenses norms for FY 2023-24 as the base figure.

Table 22: Projected O&M expenses for Advance F Class Machines

(INR Lakh per MW)

Generating Stations	FY 2023-24	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
	Existing Norm	**Projected**				
Advance F Class Machines	30.24	32.02	33.91	35.91	38.02	40.26

However, in case complete data is not provided by Sugen Power and RGPPL, the O&M expenses may be allowed on an actual basis.

Inclusion of Capital Spares and Additional Capitalisation below Rs. 20 Lakh

15.6.20 The Commission has gone through the suggestions provided by various stakeholders on the issue of whether to include capital spares below Rs. 20 Lakh as part of the normative O&M expenses and is of the view that incorporating such spares into normative O&M expenses will simplify the approval process. Therefore, to streamline the process, the capital spares below Rs. 20 lakhs are being made part of normative O&M expenses.

15.6.21 For determining the capital spares below Rs. 20 Lakh, the same units have been taken into account, as were considered for determining O&M norms for distinct MW series.

15.6.22 The Commission, based on the actual capital spares consumed for FY 2017-18 to FY 2022-23, has computed the capital spares consumed below Rs. 20 Lakh for FY 2019-20 by taking an average of six-year capital spares consumed below Rs. 20 Lakh after escalating the same by 3.51% (escalation rate approved by the Commission for the Control Period of 2019-24) per annum till FY 2023-24. Capital spares, thus computed for FY 2023-24, have been escalated further considering the escalation rate of 5.89% per annum to arrive at the capital spares for FY 2024-25 to FY 2028- 29 and have been added to the O&M norms.

15.6.23 With regard to the inclusion of additional capitalisation below Rs. 20 Lakh after the cut-off date, the Commission vide letter No. L-1/268/2022/CERC dated 01.08.2023 directed the thermal generating companies to submit the additional capitalisation data (Annexure I) wherein a detailed breakup of year-wise additional capitalisation claimed and approved was sought from the generating company. It is observed that the data provided by the generating utilities is not detailed enough to sort out the year-wise additional capitalisation below Rs. 20 Lakhs. As mentioned in paragraph 15.5.4 above, the Commission, for the determination of O&M norms, has excluded

O&M data from the COVID-affected years (FY 2020-21 and FY 2021-22). Nevertheless, the Commission has factored in the surge in inflation during the COVID-affected years to ascertain the escalation factor for the tariff period FY 2024-25 to FY 2028-29, thereby compensating for the inclusion of additional capitalisation below Rs. 20 Lakh under normative O&M expenses.

15.7 Commission's View–Hydro Generating Stations

<u>Escalation Rate</u>:

15.7.1 The Commission has worked out the escalation rate of 5.86% based on the five years average CPI and WPI indices for FY 2018-19 to FY 2022-23 by considering the weightage of 75% CPI and 25% WPI. It is observed that, post normalisation in the overall increase in the O&M Expenses from FY 2018-19 to FY 2022-23 (FY 2017-18 to FY 2021-22, in the case of NEEPCO) was around 5.10%. While for some of the hydro generating stations, the y-o-y growth was on a higher side, for others, the actual growth was on the lower side. Thus, while the average of CPI and WPI indices are an indicator of inflation, the average increase in actual normalised O&M expenses for hydro generating stations has been marginally lower than the escalation rate of 5.86%. Therefore, for the purpose of escalation till FY 2023-24, the Commission proposes to consider the escalation rate of 5.10% for deriving the projected O&M Expenses for the tariff period FY 2024-25 to FY 2028-29 in the case of hydro generating stations.

<u>Norms</u>:

15.7.2 The Commission has worked out O&M expense for the base year i.e. FY 2023-24, by taking the five-years average of actual normalised O&M expenses of FY 2018-19 to FY 2022-23 (FY 2017-18 to FY 2021-22, in case of NEEPCO) and thereafter escalating it with 5.10% per annum. The derived O&M expense for the base year FY 2023-24 is further escalated with an escalation factor of 5.86% for deriving the projected O&M Expenses for the tariff period FY 2024-25 to FY 2028-29.

15.7.3 Thus, for hydro generating stations having completed more than three years of operation after CoD as on 01 April 2024, the O&M expenses are as shown below.

Table 23: Actual O&M expenses for NEEPCO Hydro Stations

(INR Lakh)

Particulars	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	Average	Derived Base Year (FY 2023-24)
NEEPCO							
Kopili	9,804.45	9,179.52	9,377.74	9,663.35	9,957.66	**9,596.55**	**11,671.72**
Doyang	6,343.23	6,112.32	5,551.44	5,720.52	5,894.74	**5,924.45**	**7,205.56**
Panyor	12,213.86	12,853.12	13,188.82	13,590.51	14,004.42	**13,170.15**	**16,018.08**
Pare Hydro		11,940.64	12,839.36	13,230.40	13,633.35	**12,910.94**	**15,702.82**
Turial	4,824.25	5,977.61	4,458.85	4,594.65	4,734.59	**4,917.99**	**5,981.47**
Khandong I	2,447.78	2,247.40	2,233.43	2,301.45	2,371.55	**2,320.32**	**2,822.07**
Khandong II	1,233.57	1,128.74	1,079.62	1,112.50	1,146.39	**1,140.16**	**1,386.71**

Table 24: Actual O&M expenses Hydro Stations except NEEPCO

(INR Lakh)

Particulars	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Average	Derived Base Year (FY 2023-24)
NHPC							
Bairasiul	6,414.42	6,510.90	6,709.19	6,913.53	7,609.19	**6,831.45**	**7,911.84**
Chamera I	12,507.48	12,089.15	12,457.34	12,836.75	14,582.00	**12,894.54**	**14,933.82**
Chamera II	11,464.56	11,245.64	11,588.14	11,941.07	11,076.56	**11,463.19**	**13,276.10**
Chamera III	8,406.29	8,342.69	8,596.77	8,858.60	9,354.15	**8,711.70**	**10,089.45**
Chutak Power Station	3,847.24	3,762.46	3,877.05	3,995.13	4,213.37	**3,939.05**	**4,562.01**
Dhauliganga Power Station	9,857.14	9,979.46	10,283.39	10,596.59	11,070.34	**10,357.38**	**11,995.40**
Dulhasti Power Station	14,919.39	16,461.33	16,962.68	17,479.30	17,653.00	**16,695.14**	**19,335.48**
Kishanganga Power Station	11,292.02	13,455.22	13,865.02	14,287.29	13,619.15	**13,303.74**	**15,407.73**
Loktak Power Station	7,166.69	7,962.22	8,204.72	8,454.60	7,832.39	**7,924.12**	**9,177.32**
Nimmo-bazgo Power Station	4,156.54	3,859.85	3,977.41	4,098.55	4,068.25	**4,032.12**	**4,669.80**
Parbati-III Power Station	8,480.31	9,823.33	10,122.52	10,430.81	9,353.67	**9,642.13**	**11,167.03**
Rangit Power Station	5,150.96	5,533.76	5,702.29	5,875.97	6,258.47	**5,704.29**	**6,606.42**
Salal Power Station	14,333.99	15,443.05	15,913.39	16,398.05	19,501.37	**16,317.97**	**18,898.66**
Sewa II Power Station	6,586.31	6,843.41	7,051.84	7,266.61	8,689.57	**7,287.55**	**8,440.08**
Tanakpur Power Station	9,231.26	10,243.50	10,555.48	10,876.96	11,289.27	**10,439.30**	**12,090.27**
Teessta Vally Power	14,010.13	13,741.09	14,159.59	14,590.84	14,147.48	**14,129.83**	**16,364.46**
Tldp-III Power Station	8,611.73	8,298.50	8,551.24	8,811.68	7,966.24	**8,447.88**	**9,783.91**

Particulars	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Average	Derived Base Year (FY 2023-24)
Tldp-IV Power Station	9,759.94	9,441.11	9,728.65	10,024.95	9,013.84	**9,593.70**	**11,110.95**
Uri-I Power Station	11,447.78	11,533.00	11,884.26	12,246.21	12,779.87	**11,978.22**	**13,872.58**
Uri-II Power Station	7,458.20	8,086.21	8,332.49	8,586.26	8,625.62	**8,217.76**	**9,517.40**
NTPC							
Koldam	11,866.57	11,140.07	11,479.35	11,828.97	11,585.83	**11,580.16**	**13,411.56**
NHDC							
Omkareshwar	11,534.41	12,974.35	13,369.50	13,776.68	13,868.74	**13,104.74**	**15,177.25**
Indira Sagar	8,039.50	8,477.03	8,735.21	9,001.25	9,806.71	**8,811.94**	**10,205.55**
THDC							
THDC Stage I	32,315.62	34,328.17	35,373.68	36,451.03	36,135.83	**34,920.87**	**40,443.60**
KHEP	18,058.02	16,214.94	16,708.78	17,217.67	18,385.83	**17,317.05**	**20,055.74**
SJVNL							
Naptha Jhakari	42,473.69	41,311.95	42,570.16	43,866.69	47,403.19	**43,525.14**	**50,408.64**
Rampur	16,229.94	15,068.34	15,527.27	16,000.17	17,273.65	**16,019.88**	**18,553.42**
Karcham Wangtoo	10,299.08	11,207.14	11,548.47	11,900.19	14,663.14	**11,923.60**	**13,809.32**
DVC							
Maithon	1,725.69	1,887.13	1,944.61	2,003.84	2,249.12	**1,962.08**	**2,272.38**
Panchet	1,745.64	1,998.15	2,059.01	2,121.72	2,931.94	**2,171.29**	**2,514.68**
Tilaya	519.29	466.64	480.85	495.49	567.30	**505.91**	**585.93**
Teesta Urja Ltd	22,938.98	23,839.09	24,565.14	25,313.31	25,162.49	**24,363.80**	**29,632.26**

Table 25: Proposed O&M expenses for Hydro Generating Stations

(INR Lakh)

Particulars	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
THDC					
THDC Stage I	42,813.62	45,322.53	47,978.45	50,790.02	53,766.35
KHEP	21,231.02	22,475.17	23,792.23	25,186.47	26,662.41
NHPC					
Bairasiul	8,375.48	8,866.29	9,385.86	9,935.87	10,518.12
Chamera I	15,808.95	16,735.36	17,716.06	18,754.24	19,853.25
Chamera II	14,054.08	14,877.66	15,749.50	16,672.43	17,649.45

Particulars	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
Chamera III	10,680.70	11,306.60	11,969.17	12,670.57	13,413.08
Chutak	4,829.34	5,112.35	5,411.93	5,729.08	6,064.80
Dhauliganga	12,698.34	13,442.47	14,230.21	15,064.11	15,946.87
Dulhasti	20,468.55	21,668.02	22,937.78	24,281.94	25,704.88
Kishanganga	16,310.63	17,266.44	18,278.27	19,349.38	20,483.27
Loktak	9,715.12	10,284.43	10,887.11	11,525.10	12,200.47
Nimmo-bazgo	4,943.45	5,233.14	5,539.81	5,864.44	6,208.10
Parbati-III	11,821.43	12,514.17	13,247.51	14,023.82	14,845.62
Rangit	6,993.56	7,403.39	7,837.23	8,296.50	8,782.68
Salal	20,006.13	21,178.50	22,419.58	23,733.38	25,124.17
Sewa II	8,934.67	9,458.25	10,012.51	10,599.24	11,220.37
Tanakpur	12,798.77	13,548.79	14,342.75	15,183.25	16,072.99
Teesta V	17,323.43	18,338.59	19,413.24	20,550.87	21,755.16
TLDP-III	10,357.25	10,964.19	11,606.70	12,286.86	13,006.88
TLDP-IV	11,762.05	12,451.32	13,180.97	13,953.38	14,771.06
Uri-I	14,685.52	15,546.10	16,457.11	17,421.51	18,442.42
Uri-II	10,075.12	10,665.53	11,290.53	11,952.17	12,652.57
NHDC					
Indira Sagar	16,066.65	17,008.16	18,004.85	19,059.94	20,176.87
Omkareshwar	10,803.60	11,436.70	12,106.90	12,816.37	13,567.42
SJVNL					
Naptha Jhakari	53,362.62	56,489.70	59,800.03	63,304.35	67,014.02
Rampur	19,640.66	20,791.62	22,010.02	23,299.82	24,665.20
Karcham Wangtoo	14,618.56	15,475.21	16,382.07	17,342.07	18,358.32
NTPC					
Koldam	14,197.49	15,029.47	15,910.20	16,842.55	17,829.53
NEEPCO					
Kopili	12,355.69	13,079.74	13,846.22	14,657.61	15,516.56
Doyang	7,627.81	8,074.81	8,548.00	9,048.91	9,579.19
Panyor	16,956.75	17,950.42	19,002.33	20,115.88	21,294.68
Pare Hydro	16,623.01	17,597.13	18,628.33	19,719.96	20,875.57
Turial	6,331.98	6,703.04	7,095.84	7,511.66	7,951.85
Khandong I	2,987.44	3,162.51	3,347.84	3,544.02	3,751.70
Khandong II	1,467.98	1,554.00	1,645.07	1,741.47	1,843.52
DVC					

Particulars	**FY 2024-25**	**FY 2025-26**	**FY 2026-27**	**FY 2027-28**	**FY 2028-29**
Maithon	2,405.54	2,546.51	2,695.74	2,853.71	3,020.94
Panchet	2,662.04	2,818.04	2,983.18	3,157.99	3,343.05
Tilaya	620.26	656.61	695.09	735.82	778.94
Teesta Urja Ltd	31,368.73	33,206.96	35,152.91	37,212.89	39,393.59

15.7.4 The Commission observes that the Man-MW ratio for all the stations has reduced considerably from FY 2018-19 to FY 2022-23. However, some rationalisation is required in some of the stations where the Man/MW ratio is still on the higher side. The Man/MW ratio of hydro generating stations for comparison purposes is shown below:

Table 26: Summary of Man/MW Ratio in Hydro Generating Stations

Generating Stations	**Man/MW Ratio**				
	FY 2018-19	**FY 2019-20**	**FY 2020-21**	**FY 2021-22**	**FY 2022-23**
NHPC					
Bairasiul	1.27	1.16	0.99	0.85	0.60
Chamera I	0.51	0.46	0.42	0.39	0.36
Chamera II	0.88	0.82	0.75	0.67	0.61
Chamera III	0.80	0.74	0.65	0.61	0.51
Chutak Power Station	1.11	1.11	0.98	0.95	0.91
Dhauliganga Power Station	0.73	0.68	0.64	0.60	0.53
Dulhasti Power Station	1.03	0.92	0.81	0.69	0.57
Kishanganga Power Station	-	0.41	0.38	0.36	0.31
Loktak Power Station	2.44	2.01	1.51	1.20	0.79
Nimmo-bazgo Power Station	1.31	1.09	1.07	0.96	1.00
Parbati-III Power Station	0.29	0.27	0.25	0.21	0.19
Rangit Power Station	2.08	1.97	1.62	1.52	1.38
Salal Power Station	0.85	0.70	0.55	0.42	0.35
Sewa II Power Station	1.57	1.49	1.35	1.19	1.08
Tanakpur Power Station	3.82	3.40	3.15	2.96	2.68
Teessta Vally Power	0.48	0.44	0.40	0.36	0.32
Tldp-III Power Station	0.98	0.86	0.74	0.64	0.50
Tldp-IV Power Station	1.05	0.93	0.79	0.68	0.58
Uri-I Power Station	0.43	0.43	0.41	0.42	0.40
Uri-II Power Station	0.73	0.67	0.61	0.56	0.52

Generating Stations	Man/MW Ratio				
	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23
NEEPCO					
Kopili	0.83	0.71	0.62	0.54	0.50
Doyang	3.47	3.29	3.23	3.13	2.99
Tuiral	1.88	1.67	1.47	1.37	1.23
Khandong	0.82	0.70	0.62	0.54	0.48
Khandong Stage II	0.84	0.72	0.60	0.52	0.52

15.7.5 Although for the tariff period 2024-29, the Commission proposes to approve the O&M expenses norms on the basis of actual O&M expenses incurred during the past years, the Commission desires that the generating companies should further rationalise the Man/MW ratios.

15.7.6 The Commission, with regard to the increase in insurance premium for hydro generating stations, is of the view that the hydro generating stations are at utmost risk on account of an increased occurrence of natural calamities in their vicinity which may result in a substantial increase in their insurance premium. Therefore, the Commission proposes to allow the increase, if any, in insurance premiums for hydro generating station on a case-to-case basis after due prudence check.

Inclusion of Capital Spares and Additional Capitalisation of up to Rs. 20 Lakh

15.7.7 As discussed, the Commission is of the view that incorporating such expenses as a part of normative O&M expenses will simplify the approval process, as in the past; it has been observed that considerable effort is required by the Commission to map these expenses, to streamline the process, the capital spares and additional capital expenditure of up to Rs. 20 lakhs are being made part of normative O&M expenses.

15.7.8 In order to implement the same, the Commission vide letter No. L-1/268/2022/CERC dated 01.08.2023 directed the hydro generating companies to submit the additional capitalisation data (Annexure II) wherein a detailed breakup of year-wise additional capitalisation claimed and approved was sought from the generating company. The Commission, after analysing the data, proposes to include the approved additional capitalisation up to Rs. 20 Lakh (after escalating the same by applicable escalation rates approved by the Commission for different control periods) under normative O&M expenses projected for the tariff period from FY 2024-25 to FY 2028-29.

15.8 Proposed Provisions

15.8.1 The Commission, after considering various aspects and taking into account comments and suggestions of the stakeholders, has proposed Regulation 36 in the Draft Tariff Regulations as follows:-

"36. Operation and Maintenance Expenses:

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

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

(in Rs Lakh/MW)

Year	*200/210/ 250 MW Series*	*300/330/ 350 MW Series*	*500 MW Series*	*600 MW Series*	*800 MW Series and above*
FY 2024-25	*39.96*	*33.09*	*26.22*	*24.81*	*22.33*
FY 2025-26	*42.32*	*35.04*	*27.77*	*26.27*	*23.64*
FY 2026-27	*44.81*	*37.11*	*29.41*	*27.82*	*25.04*
FY 2027-28	*47.45*	*39.29*	*31.14*	*29.46*	*26.51*
FY 2028-29	*50.25*	*41.61*	*32.97*	*31.20*	*28.08*

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

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

(2) *Tanda TPS:*

(in Rs Lakh/MW)

Year	*Tanda TPS (Unit 1)*
FY 2024-25 to FY 2028-29	*41.78*

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

(in Rs Lakh/MW)

Year	*Gas Turbine Combined Cycle generating stations other than small gas turbine power generating stations*	*Small gas turbine power generating stations*	*Agartala GPS*	*Advance F Class Machines*
FY 2024-25	*17.22*	*38.16*	*42.76*	*32.02*
FY 2025-26	*18.24*	*40.41*	*45.28*	*33.91*
FY 2026-27	*19.31*	*42.79*	*47.94*	*35.91*
FY 2027-28	*20.45*	*45.31*	*50.77*	*38.02*
FY 2028-29	*21.66*	*47.98*	*53.76*	*40.26*

(4) *Lignite-fired generating stations:*

(in Rs Lakh/MW)

Year	*125 MW Sets*
FY 2024-25	*39.04*
FY 2025-26	*41.34*
FY 2026-27	*43.77*
FY 2027-28	*46.35*
FY 2028-29	*49.08*

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

(in Rs Lakh/MW)

Year	*O&M Expenses*
FY 2024-25	*39.04*
FY 2025-26	*41.34*
FY 2026-27	*43.77*
FY 2027-28	*46.35*
FY 2028-29	*49.08*

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

Provided that water charges shall be allowed based on water consumption depending upon type of plant and type of cooling water system or water agreement with state govt./utilities, and the norms specified by the Ministry of Environment, Forest and Climate Change subject to prudence check. The details regarding the same shall be furnished along with the petition;

Provided further that the generating station shall submit the assessment of *the security requirement and estimated expenses along with the petition seeking the determination of tariff;*

Provided also that the generating station shall submit the details of year-wise actual capital spares consumed individually costing above Rs. 20 Lakh at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not funded through compensatory allowance as per Regulation 17 of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 or Special Allowance or claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.

(7) *Any additional O&M expenses incurred by the generating company or transmission licensee due to any change in law or Force Majeure event shall be considered at the time of truing up of tariff.*

Provided that such impact shall be allowed only in case the overall impact of such change in law event in a year is more than 5% of normative O&M expenses allowed for the year.

(8) *In the case of a generating company owned by the Central or State Government, the impact on account of implementation of wage or pay revision shall be allowed at the time of truing up of tariff.*

(9) *The operation and maintenance expenses on account of emission control systems in coal or lignite based thermal generating stations shall be 2% of the admitted capital expenditure (excluding IDC and IEDC) as on its date of operation, which shall be escalated annually @ 5.89% during the tariff period ending on 31st March 2029:*

Provided that income generated from the sale of gypsum or other by-products shall be reduced from the operation and maintenance expenses.

(2) Hydro Generating Station:

a) *Following operations and maintenance expense norms shall be applicable for hydro generating stations which have been operational for three or more years as on 1.4.2024:*

(in Rs Lakh)

Particulars	*FY 2024-25*	*FY 2025-26*	*FY 2026-27*	*FY 2027-28*	*FY 2028-29*
THDC Stage I	*42,847.30*	*45,358.18*	*48,016.19*	*50,829.97*	*53,808.64*
KHEP	*21,264.04*	*22,510.13*	*23,829.24*	*25,225.64*	*26,703.88*

Particulars	*FY 2024-25*	*FY 2025-26*	*FY 2026-27*	*FY 2027-28*	*FY 2028-29*
Bairasul	*8,500.75*	*8,998.90*	*9,526.24*	*10,084.48*	*10,675.44*
Loktak	*9,788.20*	*10,361.79*	*10,969.00*	*11,611.79*	*12,292.24*
Salal	*20,486.34*	*21,686.85*	*22,957.72*	*24,303.05*	*25,727.23*
Tanakpur	*12,864.33*	*13,618.19*	*14,416.22*	*15,261.02*	*16,155.32*
Ch.amera-1	*16,184.76*	*17,133.20*	*18,137.22*	*19,200.07*	*20,325.21*
Uril	*15,019.58*	*15,899.74*	*16,831.47*	*17,817.81*	*18,861.94*
Rangit	*7,035.32*	*7,447.59*	*7,884.03*	*8,346.04*	*8,835.12*
Chamera-II	*14,262.87*	*15,098.68*	*15,983.48*	*16,920.12*	*17,911.65*
Dhauliganga	*12,893.21*	*13,648.76*	*14,448.58*	*15,295.28*	*16,191.59*
Dulhasti	*20,739.97*	*21,955.35*	*23,241.94*	*24,603.93*	*26,045.74*
Teesta-V	*17,678.36*	*18,714.33*	*19,811.00*	*20,971.93*	*22,200.90*
Sewa-II	*9,018.18*	*9,546.66*	*10,106.10*	*10,698.32*	*11,325.25*
TLDP III	*10,449.12*	*11,061.44*	*11,709.65*	*12,395.84*	*13,122.25*
Chamera III	*10,841.47*	*11,476.79*	*12,149.33*	*12,861.29*	*13,614.97*
Chutak	*4,859.97*	*5,144.76*	*5,446.25*	*5,765.40*	*6,103.26*
NimmoBazgo	*4,974.77*	*5,266.30*	*5,574.90*	*5,901.60*	*6,247.43*
Uri II	*10,409.18*	*11,019.16*	*11,664.89*	*12,348.46*	*13,072.09*
Parbati III	*12,183.32*	*12,897.27*	*13,653.06*	*14,453.14*	*15,300.10*
Kishanganga	*16,540.30*	*17,509.57*	*18,535.64*	*19,621.84*	*20,771.69*
TLDP IV	*11,873.41*	*12,569.20*	*13,305.76*	*14,085.48*	*14,910.90*
Indira Sagar	*16,099.67*	*17,043.12*	*18,041.86*	*19,099.12*	*20,218.34*
Omkareshwar	*10,837.28*	*11,472.35*	*12,144.64*	*12,856.32*	*13,609.71*
Napthajhakari	*53,396.29*	*56,525.35*	*59,837.77*	*63,344.30*	*67,056.31*
Rampur	*19,673.68*	*20,826.57*	*22,047.02*	*23,338.99*	*24,706.67*
Koldam	*14,317.21*	*15,156.21*	*16,044.37*	*16,984.58*	*17,979.89*
Karcham Wangtoo	*14,618.56*	*15,475.21*	*16,382.07*	*17,342.07*	*18,358.32*
Kopili	*12,355.69*	*13,079.74*	*13,846.22*	*14,657.61*	*15,516.56*
Khandong I	*2,987.44*	*3,162.51*	*3,347.84*	*3,544.02*	*3,751.70*
Khandong II	*1,467.98*	*1,554.00*	*1,645.07*	*1,741.47*	*1,843.52*
Doyang	*7,627.81*	*8,074.81*	*8,548.00*	*9,048.91*	*9,579.19*
Panyor	*16,956.75*	*17,950.42*	*19,002.33*	*20,115.88*	*21,294.68*
Pare	*16,623.01*	*17,597.13*	*18,628.33*	*19,719.96*	*20,875.57*
Turial	*6,331.98*	*6,703.04*	*7,095.84*	*7,511.66*	*7,951.85*
Maithon	*2,526.20*	*2,674.24*	*2,830.95*	*2,996.85*	*3,172.46*
Panchet	*2,795.57*	*2,959.39*	*3,132.81*	*3,316.39*	*3,510.74*
Tilaiya	*651.37*	*689.54*	*729.95*	*772.73*	*818.01*
Teesta Urja Ltd.	*31,368.73*	*33,206.96*	*35,152.91*	*37,212.89*	*39,393.59*

b) *In the case of the hydro generating stations declared under commercial operation on or after 1.4.2024, operation and maintenance expenses of the first year shall be fixed at 3.5% and 5.0% of the original project cost (excluding the cost of rehabilitation & resettlement works, IDC and IEDC) for stations with installed capacity exceeding 200 MW and for stations with installed capacity less than 200 MW, respectively.*

c) *In the case of hydro generating stations which have not completed a period of three years as on 1.4.2024, operation and maintenance expenses for 2024-25 shall be worked out by applying an escalation rate of 5.86% on the applicable operation and* *maintenance expenses as on 31.3.2024. The operation and maintenance expenses for subsequent years of the tariff period shall be worked out by applying an escalation rate of 5.86% per annum.*

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

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

Provided further that the value of capital spares exceeding Rs. 20.00 lakh shall only be considered for reimbursement at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.

e) Any additional O&M expenses incurred by the generating company due to any change in law or Force Majeure event shall be considered at the time of truing up of tariff.

Provided that such impact shall be allowed only in case the overall impact of such change in law event in a year is more than 5% of normative O&M expenses for the year.

f) In the case of a generating company owned by the Central or State Government, the impact on account of implementation of wage or pay revision shall be allowed at the time of truing up of tariff."

16 O&M Expense – Transmission

16.1 Background

16.1.1 The Commission, vide its Order dated 29th March 2023, directed transmission licensees, namely Power Grid Corporation of India Limited (PGCIL), Powerlinks Transmission Ltd., Jaypee Power Grid Ltd., Torrent Power Grid Pvt. Ltd., Parbati Koldam Transmission Company Ltd., North East Transmission Company Ltd., Adani Transmission Limited and others to furnish details of actual performance / operational data and O&M expenditure for the period FY 2017-18 to FY 2021-22. Similar information was also sought for FY 2022-23. In response, PGCIL, Parbati Koldam Transmission Company Ltd., North East Transmission Company Ltd. and others have submitted the information.

16.1.2 For the tariff period 2009-14, the gradation of O&M expenses for the Sub-stations was done based on the voltage and per km basis with additional gradation based on circuit configuration for AC and HVDC lines. For the Transmission lines, gradation was done based on the sub-conductor.

16.1.3 In the Tariff Regulations, 2014, O&M expenses for the transmission system have been specified on a per bay basis and in the Tariff Regulations, 2019, O&M expenses for the transmission system have been specified on a per bay and per MVA basis.

16.1.4 For working out the total allowable O&M expenses for the transmission system during FY 2024-29, the number of bays, transformer capacity and circuit km of line length are multiplied with the applicable O&M norms specified in terms of per bay, per MVA and per km, respectively.

16.2 Existing Provisions of the Tariff Regulations, 2019

16.2.1 Relevant provisions of the Tariff Regulations, 2019 is extracted as below:

(1) *Transmission system*

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

Norms for sub-stations Bays (in Rs Lakh per bay)	***2019-20***	***2020-21***	***2021-22***	***2022-23***	***2023-24***
765 kV	*45.01*	*46.60*	*48.23*	*49.93*	*51.68*

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

±800 kV, Bishwanath-Agra HVDC bipole scheme (Rs Lakh) (3000 MW)	*2,563*	*2,653*	*2,746*	*2,842*	*2,942*

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

Provided further that:

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

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

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

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

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

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

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

(c) The Security Expenses and Capital Spares for transmission system shall be allowed

separately after prudence check:

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

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

16.3 Issues discussed in the Approach Paper

16.3.1 Following issues specific to O&M norms of transmission system have been brought out in the Approach Paper for the tariff period commencing from 1.4.2024.

(i) Considering the actual expenses incurred in the past, one norm for all HVDC schemes in terms of per MW basis may be specified.

(ii) Additional O&M expenses can be given for transmission assets being operated in the North Eastern and Hilly Regions and the manner in which such additional costs can be considered.

16.4 Stakeholders' Responses

16.4.1 In response to the issues summarised in the Approach Paper, the stakeholders submitted the following comments/suggestions as below:

a) Various Transmission Licensees have supported the proposal to allow 50% of pay revision wage as wage Impact on a Normative basis. As regards change in law events, it has been suggested that a provision to deal with change in law events may be provided in the O&M expenses so that any change in law impact can be appropriately dealt with.

b) Some Transmission Licensees submitted that if the impact of expense on account of change in law are one-time and the same may be allowed. Furthermore, the impact of a change in law, which is recurring in nature, needs to be incorporated in actual expense and allowed. The Commission should determine a suitable mechanism to capture such impacts effectively.

c) DVC submitted that, in the case of the Transmission system, normative O&M expense is to be based on a number of bays and line length only.

d) PGCIL has supported the views of notifying one norm for all HVDC stations in terms of per MW, considering the actual expenses incurred in the past. Further, PGCIL has submitted that Regulations should provide for pass-through of Wage revision impact as it is a Change in Law event in the subsequent year as and when the decision of a pay revision is finalized. Actual Pay revision impact may not be compared with normative O&M charges allowed for the same control period or Financial Year. Appropriate Carrying costs should be allowed on Wage revision impact.

e) In addition, PGCIL submitted that Performance Related Pay (PRP) may be included as part of employee cost in the normalized O&M expenditure for FY 2018-19 to FY 2022-23 to arrive at the normative O&M norms for 2024-29.

f) MSETCL submitted that additional O&M norms may be allowed during a useful life and post useful life for transmission assets passing through hilly regions. These norms may be based on a special pro rata basis, such as 'per km', if a certain portion of the transmission line passes through the hilly region. However, PGCIL has opposed the same, citing an increase in complexity.

g) CEA and NETCL have supported the proposal for additional O&M Expenses for the Hilly Region.

h) ASSOCHAM has suggested to approve norms for O&M cost of bays & ICTs for greenfield substation and brownfield substations, separately.

i) CEA has also suggested to consider both transformer and reactor capacity rather than MVA capacity alone to arrive at O&M expenses for transformers. Further, with regard to the HVDC station, CEA suggested dividing the O&M expenses into two categories i.e. (i) HVDC system up to 2500 MW and (ii) above 2500 MW HVDC system.

16.5 Analysis of Actual O&M Expenses

16.5.1 The actual O&M expenses as submitted by PGCIL for various regions are as under:

Table 27: AC System - Actual Regional O&M expenses as submitted by PGCIL, including HVDC stations

(INR in Lakh)

Region	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23
	a	b	c=b*(1+3.35%)	d=c*(1+3.35%)	e
NR	1,72,087	1,33,583	1,38,054	1,42,676	1,75,407
ER	81,499	84,832	87,672	90,607	93,494
SR	74,344	1,00,569	1,03,936	1,07,415	1,27,907
NER	31,432	33,938	35,074	36,248	37,861
WR	1,04,775	1,00,986	1,04,367	1,07,861	1,16,881
TOTAL	**4,64,137**	**4,53,908**	**4,69,103**	**4,84,806**	**5,51,550**

Table 28: HVDC System - Actual Regional O&M expenses as submitted by PGCIL

(INR in Lakh)

Region	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23
	a	b	c=b*(1+3.35%)	d=c*(1+3.35%)	e
NR	15,606	14,493	14,978	15,480	16,816
ER	6,140	6,094	6,298	6,509	5,462
SR	4,728	4,688	4,845	5,007	11,587
NER	3,036	2,901	2,998	3,099	2,526
WR	4,201	7,170	7,410	7,658	7,622
TOTAL	**33,711**	**35,346**	**36,529**	**37,752**	**44,012**

16.5.2 For normalisation of the actual O&M expenses, the Commission has factored the following expenses heads as below:

(a) Electricity charges have been apportioned in the ratio of electricity consumption in the sub-station and that in the colony. Only the former electricity charges have been considered for the process of normalization;

(b) Security Expenses (Normal and Special) are not considered for arriving at norms of operation and maintenance expenses since the same shall be allowed separately, post prudence check taking into account actual expenditure;

(c) Self-Insurance Reserves have been considered at 0.09% of the gross fixed asset value of the AC transmission system as considered for the tariff period 2019-24 for the purpose of arriving at the base value of O&M expenses for the

AC transmission system.

(d) Rebate to customers, donations, ex gratia, productivity linked incentives, performance related pay have not been considered;

(e) Expenditures on Corporate Social Responsibility (CSR) have not been considered;

(f) Filing fees have not been considered since the same are being allowed separately;

(g) Prior period adjustments have been excluded, as these pertain to past periods and include expenses of nature other than O&M expenses as well.

16.5.3 The normalize O&M expenses have been worked out as follows.

Table 29: Normalised Regional O&M Expenses for PGCIL Transmission System

(INR in Lakh)

Region	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23
NR	1,06,345	96,451	99,680	1,03,016	1,17,563
ER	61,962	60,299	62,318	64,404	70,277
SR	52,874	47,192	48,772	50,405	69,701
NER	21,604	22,842	23,606	24,397	24,706
WR	73,508	63,752	65,887	68,092	78,574
TOTAL	**3,16,294**	**2,90,537**	**3,00,263**	**3,10,314**	**3,60,821**

Table 30: Normalised O&M Expenses of Transmission System excluding HVDC stations

(INR in Lakh)

Region	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23
NR	95,710	87,174	90,092	93,108	1,06,562
ER	57,778	56,399	58,287	60,238	66,704
SR	49,652	44,191	45,671	47,200	62,121
NER	19,535	20,985	21,687	22,413	23,054
WR	70,646	59,163	61,144	63,191	73,588
TOTAL	**2,93,321**	**2,67,912**	**2,76,881**	**2,86,150**	**3,32,029**

16.5.4 Regarding details of network parameters, since information for the period from 1st April, 2017 to 1st April, 2023 is available, average values for a year have been calculated by considering values as on the 1st day and last day of the respective year.

16.5.5 For S/c twin conductor lines, ckt-kms have been used as base and ckt-kms of all other circuit and conductor configurations have been converted to equivalent ckt-kms of S/C twin conductor ckt-km. Further, in continuation with the present approach, no differentiation has been made between triple and twin conductors for the same circuit configuration. Weightage factor for conversion has been used based on our estimate of the ratio of O&M expenditure for a particular conductor and circuit configuration vis-à-vis S/C twin conductor. The weightage factor for a bundled conductor with four or more (Quad and Hexa) conductors is taken as 1.5, and for a single conductor, it is taken as 0.5. Additionally, the ratio between O&M expenditure of 1 km of D/C line is estimated to be 1.5 times that of 1 km of S/C line for a single conductor and 1.75 times of 1 km of S/C for the bundled conductor. The table below gives the details of ckt-kms based on the gradation and equivalent S/C twin conductor ckt-kms.

Table 31: Circuit Kms of AC Lines and HVDC Lines

Actual average Ckt-km in operation						Weightage Factor	Equivalent Ckt-km (Twin Conductor) in operation				
Lines	**FY 19**	**FY 20**	**FY 21**	**FY 22**	**FY23**		**FY 19**	**FY 20**	**FY 21**	**FY 22**	**FY23**
S/C Hexa	332	333	334	335	334	1.50	499	500	502	503	501
S/C Quad	14556	14679	14679	14679	14679	1.50	21834	22018	22018	22018	22018
S/C Triple	2	2	9	16	16	1.00	2	2	9	16	16
S/C Twin	16338	16446	16553	16553	16553	1.00	16338	16446	16553	16553	16553
S/C Single	3024	3238	3404	3404	3404	0.50	1512	1619	1702	1702	1702
D/C Hexa	18309	20862	23564	25810	26154	1.31	24040	27392	30939	33889	34340
D/C Quad	25800	26351	27346	28614	29307	1.31	33876	34599	35905	37571	38480
D/C Triple	5805	6054	6464	6674	6674	0.88	5080	5297	5656	5840	5840
D/C Twin	58881	59677	60221	60750	60994	0.88	51521	52218	52693	53156	53370
D/C Single	8773	9063	9196	9215	9282	0.38	3290	3399	3449	3456	3481
M/C Quad	407	407	407	407	407	1.15	469	469	469	469	469
M/C Twin	351	406	406	466	526	0.77	269	312	312	357	403
DC on MC Quad	0	0	0	0	0	1.15	0	0	0	0	0
DC on MC Twin	159	159	159	159	159	0.77	122	122	122	122	122
Total	**1,52,738**	**1,57,677**	**1,62,741**	**1,67,082**	**1,68,487**		**1,58,851**	**1,64,391**	**1,70,328**	**1,75,651**	**1,77,294**

16.5.6 Further, the voltage has been retained as the basis for the gradation of norms for O&M expenditure for sub-station. However, bays at various voltage levels have been converted to equivalent 400 kV bays. The weightage factors for such conversion are considered in line with the approach followed in the Tariff

Regulations, 2019. The table below gives the details of a number of bays on the gradation and equivalent 400 kV bays.

Table 32: Number of AIS Substation Bays

Average No. of AIS sub-station bays in Commercial Operation						Weightage Factor	Eq. No. of Bays (400KV) in Commercial Operations				
Lines	**FY 19**	**FY 20**	**FY 21**	**FY 22**	**FY 23**		**FY 19**	**FY 20**	**FY 21**	**FY 22**	**FY 23**
765 kV	480	527	534	568	571	1.40	672	737.8	747.6	795.2	799.4
400 kV	2140	2202	2236	2305	2343	1.00	2140	2202	2236	2305	2343
220 kV	918	936	956	995	1024	0.70	642.6	655.2	669.2	696.5	716.8
Up to 132 kV	217	220	221	192	192	0.50	108.5	110	110.5	96	96
Total	**3755**	**3885**	**3947**	**4060**	**4130**		**3563**	**3705**	**3763**	**3893**	**3955**

Table 33: Number of GIS Substation Bays

Average No. of GIS sub-station bays in Commercial Operation						Weightage Factor	Eq. No. of Bays (400KV) in Commercial Operations				
Lines	**FY 19**	**FY 20**	**FY 21**	**FY 22**	**FY 23**		**FY 19**	**FY 20**	**FY 21**	**FY 22**	**FY 23**
765 kV	102	122	128	128	128	0.98	100	120	125	125	125
400 kV	287	303	344	380	396	0.70	201	212	241	266	277
220 kV	128	151	159	174	199	0.49	63	74	78	85	98
Up to 132 kV	19	37	37	68	70	0.35	7	13	13	24	25
Total	**536**	**613**	**668**	**750**	**793**		**370**	**419**	**457**	**501**	**525**

16.5.7 With regard to transformer capacity and reactor capacity of AC Sub-station, instead of voltage-specific norms for transformer capacity (MVA), a single norm is proposed to be determined for transformer capacity (MVA) based on total transformer capacity (MVA) of the AC Sub-station. A similar approach has also been considered for the determination of the norm for reactor capacity (MVAR)

16.5.8 The allocation of normalized O&M expenses, which were previously apportioned between substations and AC transmission lines at a ratio of 75:25, has been revised to a ratio of 65:35. It is observed that many transmission lines are getting old, unlike substations wherein modernization/automation is a continuous process through additional capitalisation, augmentation, extension etc., transmission lines have not undergone major modification/modernization in the past. Further, stringent environmental norms and pollution control measures require additional measures like replacement of Insulators, installation of bird diverters, Transmission Line Arrestors (TLA), etc. Thus, transmission lines will require a higher level of maintenance for reliable operation and desired availability, thereby warranting a realignment in the apportionment of O&M expenses between substations and transmission lines. CAGR of O&M expenses per equivalent (400 kV) AC bays for the period FY 2017-18 to FY 2022-23 works out to around 4.35%. Further, the CAGR of O&M expenses per equivalent (S/C twin conductor) for the period FY 2017-18 to FY 2022-23 works out to 6.45%. Thus, by applying the same ratio of 65:35 between sub-stations and transmission lines, the effective CAGR of increase in O&M expenses for the period FY 2017-18 to FY 2022-23 works out to 4.88%.

Table 34: CAGR of increase in O&M Expenses from FY 2017-18 to FY 2022-23

Particulars	**Unit**	**FY 2017-18**	**FY 2018-19**	**FY 2019-20**	**FY 2020-21**	**FY 2021-22**	**FY 2022-23**
Total Normalized O&M Expenses (A)	Rs. Lakh	2,06,066	2,93,321	2,67,912	2,76,881	2,86,150	3,32,029
Normalized O&M expenses allocated to S/S (65% of A)	Rs. Lakh	1,33,943	1,90,659	1,74,143	1,79,973	1,85,997	2,15,819
Equivalent No. of sub-station bays	No. of Bays	3,590	3,933	4,124	4,220	4,393	4,480
O&M expenditure per equivalent (400 kV) AC Bay	Rs. Lakh /Bay	37.31	48.47	42.23	42.64	42.34	48.18
CAGR	**%**	**4.35%**					
Normalized O&M expenses allocated to AC and HVDC lines (35% of A)	Rs. Lakh	72,123	1,02,662	93,769	96,908	1,00,152	1,16,210
Equivalent ckt-km in commercial operation	Ckt Km	1,49,860	1,58,851	1,64,391	1,70,328	1,75,651	1,77,294
O&M expenditure per equivalent (S/C. twin conductor) ckt-km	(Rs. Lakh /ckt-km)	0.42	0.65	0.57	0.57	0.57	0.61
CAGR	**%**	**6.45%**					

16.5.9 The Tariff Regulations, 2019, specified transmission O&M norms for transmission lines in terms of 'per km' and for transmission substations in terms of 'per bay' and 'per MVA' basis. Accordingly, O&M expenses are allowed for transmission utilities based on the length of the transmission line as well as the transformer bays and transformer capacity in a transmission substation. For every km addition of the transmission line, number of bays and MVA capacity in the transmission system, the transmission licensee is entitled to incremental O&M expenses in accordance with the specified norms. The basic premise for adopting such norms linked to the transmission system is to enable recovery of O&M expenses in proportion to the increase in the asset base of the transmission licensee. Reactor capacity is measured in terms of MVAr of the transmission system. The O&M expenses for a substation and the associated asset base, including bays and MVA capacity, also have a significant correlation with the

MVAr capacity of the substation as well. Therefore, the Commission is of the view that, while determining O&M expense norms for substation, MVAr capacity should be considered as a parameter along with MVA capacity. Accordingly, in the Draft Tariff Regulations, the Commission has proposed O&M expense norms for substations in terms of a number of bays and transformer/reactor capacity in terms of MVA along with MVAr. Further, in line with Tariff Regulations, 2019, the O&M expense norms for the HVDC bi-pole line shall be considered as a Double Circuit quad AC line.

16.5.10 To arrive at O&M expenses norms per equivalent bay, per MVA or MVAr, the normalized O&M expenses are further escalated with an escalation factor derived from CPI & WPI Indices, where the employee expenses are linked to CPI, R&M expenses are linked to WPI and A&G expenses are linked to the ratio of WPI: CPI.

16.5.11 In cases where abnormal year-on-year increases were observed, the Commission has normalized the same, depending upon the nature of expenses, in the preceding year's corresponding expense figure. Further, the Commission has determined the escalation rate for FY 2018-19 to FY 2022-23, which works out to be 5.93% (WPI) (as per the 2011-12 base year series) and 5.84% (CPI).

16.5.12 The following table shows the process of arriving at the average O&M expenditure per equivalent of 400 kV bay, per MVA/MVAr and per equivalent ckt- km of S/C twin at 2022-23 price level. The O&M expenditure per equivalent bay, per MVA/MVAr and ckt-km for FY 2018-19 to FY 2022-23 have been escalated to FY 2023-24 level with an escalation rate of 3.51% of effective CAGR. For projecting the norms for the Tariff Period 2024-29, the escalation rate has been computed based on the five-year average of WPI for FY 2018-19 to FY 2022-23, which works out to be 5.93%, while that of CPI for the same period works out to be 5.84%. Considering the 60:40 weightages for WPI and CPI respectively, the escalation rate works out to 5.89% to arrive at norms for 2024-29.

16.5.13 The arrived normative expenses have been apportioned between sub- stations and transmission lines (AC lines) in 65:35 ratio. Further, O&M expenses allocated for the substation is proposed to be divided in the ratio of 50:50 for Bays and Transformers/Reactors in the absence of adequate information in this regard.

Table 35: Computation of per Bay O&M Expenses Norms for AC Substation

Particulars	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Average
Total actual Normalized O&M Expenses (Rs. Lakh) (A)	2,93,321	2,67,912	2,76,881	2,86,150	3,32,029	
Actual Normalized O&M expenses allocated to S/S Bay (Rs. Lakh) (B)	95,329	87,072	89,986	92,999	1,07,909	
Equivalent No. of sub-station bays	3,933	4,124	4,220	4,393	4,480	
O&M expenditure per equivalent (400 kV) AC bay (Rs. Lakh/bay)	**24.24**	**21.12**	**21.32**	**21.17**	**22.47**	**22.06**

Table 36: Computation of per MVA+MVAR O&M Expenses Norms for AC Substation

Particulars	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Average
Actual Normalized O&M expenses allocated to S/S Transformer/Reactor (Rs. Lakh)	95,329.43	87,071.54	89,986.33	92,998.70	1,07,909.36	
Capacity in MVA+MVAR	4,20,465	4,62,404	4,84,989	5,07,079	5,28,765	
O&M expenditure per Transformer/Reactor (Rs. Lakh/MVA or Rs Lakh/MVAr)	**0.227**	**0.188**	**0.186**	**0.183**	**0.190**	**0.195**

Table 37: Computation of per Ckt-km O&M Expenses Norms for AC Lines

Particulars	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Average
Actual Normalized O&M expenses allocated to AC lines (Rs. Lakh)	1,02,662	93,769	96,908	1,00,152	1,16,210	
Equivalent ckt-km in commercial operation	1,58,851	1,64,391	1,70,328	1,75,651	1,77,294	
O&M expenditure per equivalent (S/C. twin conductor) ckt-km (Rs. Lakh/ckt-km)	**0.646**	**0.570**	**0.569**	**0.570**	**0.611**	**0.593**

16.5.14 The average O&M expenses for FY 2020-21 have been further escalated @ 3.51% per annum to reach FY 2023-24 level. The O&M expenses thus arrived for FY

2023-24 are given in Table below:

Table 38: O&M Expenses Norms for AC Transmission System for Base Year

Particulars	**Average FY 2020-21**	**Escalated @ 3.51 % to FY 2023-24 level**
O&M expenditure per equivalent (400 kV) AC bay	22.06	24.47
O&M expenditure per MVA or per MVAr	0.195	0.216
O&M expenditure per equivalent (S/C. twin conductor) ckt-km	0.593	0.658

16.5.15 The norms for AC sub-station bays and transmission lines (AC and HVDC) for equivalent 400 kV bay and for equivalent S/C twin conductor ckt-km so arrived are then converted to various voltage levels (for sub-stations bays) and various circuit and conductor configuration (for transmission lines) by applying weightage factors as stated above. The norms for Transformer/Reactor capacity have arrived based on the total transformer capacity (MVA) and total reactor capacity (MVAr). The escalation rate of 5.89% per annum is applied to the norms for FY 2023-24 to arrive at norms for each year of the tariff period 2024-29.

<u>HVDC Lines and Stations</u>

16.5.16 The Commission in the Tariff Regulations, 2019, had approved normative O&M expenses for HVDC schemes wherein specific norms have been specified for some of the schemes and for the rest of the schemes, formulation of normative O&M expenses have been specified linking it with similar nature schemes for which specific O&M expenses were approved. In the approach paper it was observed that there is a need to simplify the normative O&M expenses for HVDC schemes and therefore has proposed one norm for all HVDC schemes in terms of per MW considering the actual expenses incurred in the past may be specified. PGCIL has also supported the views presented in the Approach paper regarding the notification of one norm for HVDC stations in terms of per MW considering the actual expenses incurred in the past. Further, CEA has advised for determination of distinct norms for HVDC stations with a capacity below 2500 MW and a separate norm for HVDC stations exceeding 2500 MW.

16.5.17 The Commission has gone through the suggestions of various stakeholders and is of the view that in order to simplify the normative O&M expenses for HVDC schemes, O&M expenses on a per MW basis are proposed to be allowed separately for the following.

a) For all HVDC Bi-pole schemes,

b) For HVDC Back to Back stations (BTB) except Gazuaka

c) For Gazuwaka BTB

16.5.18 In order to arrive at norms for HVDC stations, average normalized expenses (per MW) for the period FY 2018-19 to FY 2022-23 have been escalated @ 3.51% per annum to reach FY 2023-24 level. The O&M expenses for FY 2023-24 level is escalated @ 5.89% per annum to reach FY 2024-25 level.

Table 39: Computation of Base Norms for HVDC Bipole Schemes

(INR in Lakh/MW)

Particulars	**Normalised O&M Expenditure**					**5-yrs Average**	**Escalated to 2024-25 Level @ 5.89%**		
HVDC Stations	**FY 2018-19**	**FY 2019-20**	**FY 2020-21**	**FY 2021-22**	**FY 2022-23**	**(FY 2020-21)**	**FY 2023-24**	**Scheme Total**	**FY 2024-25**
Rihand-Dadri Scheme									
Rihand (Rs. lakh/MW)	0.44	0.36	0.37	0.38	0.41	0.39	0.44		
Dadri (Rs. Lakh/MW)	0.44	0.48	0.50	0.52	0.48	0.48	0.54	0.97	1.03
Talcher-Kolar Scheme									
Talchar (Rs. Lakh/MW)	0.85	0.76	0.78	0.81	0.69	0.78	0.86		
Kolar (Rs. Lakh/MW)	0.69	0.75	0.78	0.80	0.74	0.75	0.84	1.70	1.80
Balia-Bhiwadi									
Bhiwadi (Rs. Lakh/MW)	0.53	0.48	0.50	0.51	0.55	0.52	0.57		
Balia (Rs. Lakh/MW)	0.42	0.37	0.38	0.39	0.33	0.38	0.42	0.99	1.05
Bishwanath-Agra									
Bishwanath (Rs. Lakh/MW)	0.34	0.31	0.32	0.33	0.28	0.32	0.35		
Agra (Rs. Lakh/MW)	0.47	0.41	0.43	0.44	0.47	0.44	0.49	0.84	0.89
Alipurduar-Agra									
Alipurduar (Rs. Lakh/MW)	0.52	0.54	0.56	0.58	0.43	0.52	0.58	0.58	0.61
Champa-Kurushetra									
Champa (Rs. Lakh/MW)	0.51	0.57	0.58	0.60	0.61	0.58	0.64		
Kurushetra (Rs. Lakh/MW)	0.68	0.50	0.52	0.54	0.80	0.61	0.67	1.31	1.39
Average								**1.07**	**1.13**

"Illustration-

The O&M expense of a HVDC bi-pole scheme of 2500 MW for FY 2024-25:

*O&M Expenses for the bi-pole scheme = 2500*1.13 = 2825 Lakh"*

Table 40: Normalised O&M Expenses for HVDC Back to Back Schemes except Gazuwaka BTB

(INR in Lakh/MW)

HVDC Station	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	5-yrs Average (FY 2020-21)	FY 2023-24	FY 2024-25
Vindhyachal BTB (Rs. Lakh per MW)	1.59	1.29	1.33	1.37	1.81	1.48	1.64	1.74
Chandarpur - Bhadravti BTB (Rs. Lakh per MW)	1.33	2.89	2.99	3.09	1.27	2.31	2.57	2.72
Sasaram BTB (Rs. Lakh per MW)	1.86	1.54	1.59	1.65	1.82	1.69	1.88	1.99
Average (Rs. Lakh per MW)	**1.59**	**1.91**	**1.97**	**2.04**	**1.63**	**1.83**	**2.03**	**2.15**

Table 41: Normalised O&M Expenses for Gazuwaka BTB

(INR in Lakh/MW)

HVDC Station	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	5-yrs Average (FY 2020-21)	FY 2023-24	FY 2024-25
Gazuwaka BTB (2x500 MW)	1.84	1.49	1.54	1.60	1.58	1.61	1.79	1.89

16.5.19 Computation of base norms at FY 2024-29 price level for HVDC back-to-back schemes has been done as follows:

Table 42: O&M Expense Norms for HVDC Back to Back Schemes

(INR in Lakh/MW)

Norms for HVDC	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
HVDC BTB stations (Rs. Lakh per MW)	2.15	2.27	2.41	2.55	2.70
Gazuwaka BTB stations (Rs. Lakh per MW)	1.89	2.00	2.12	2.25	2.38

16.5.20 The O&M expenses for the GIS bays shall be allowed as worked out by multiplying by a factor of 0.70 of the normative O&M expenses for bays.

Communication Systems

16.5.21 It is observed that the O&M expenses for OPGC, PMUs and STATCOM are already included under the O&M expenses submitted for transmission lines and bays, and as such, expenses have not been maintained separately; no separate norms have been proposed for OPGC links, PMUs and STATCOM. Therefore, the norms for communication systems have been proposed for the ULDC scheme only.

16.5.22 To arrive at norms for the ULDC scheme, 2% of the original project cost related to such a communication system will be considered. Further, the transmission licenses will submit the actual operational and maintenance expenses at the time of true up.

Approval of O&M Expenses for UNMS Scheme

The Commission, with regard to whether O&M expenses can be provided for the UNMS scheme observes that the UNMS scheme is relatively new, and no baseline data has been submitted by the Petitioner for the same. The Commission, therefore, proposes to consider O&M expenses for the UNMS scheme on actuals after due prudence check for the tariff period 2024-29.

Approval of O&M Expenses for North East/Hilly Regions

16.5.23 The Commission, with regard to whether additional O&M expenses can be given for transmission assets being operated in the North Eastern and Hilly Regions, based on the actual data submitted, observes that the actual expenses incurred in the NER region are higher than compared to other regions and therefore, the Commission acknowledges the elevated costs associated with transmission projects in hilly terrains. Factors such as increased logistic, erection, labour, and transportation costs contribute to higher O&M expenses in these regions compared to mainland projects. The Commission, therefore, proposes to allow O&M expenses by applying a factor of 1.5 to the O&M expenses determined under Regulation 36. As the O&M norms have been worked out considering the actual O&M expenses of all the regions of PGCIL which includes NE, NER and other hilly regions, therefore it is clarified that the factor of 1.50 shall be applicable only to those transmission licensees whose transmission assets are located solely in NE Region, States of Uttarakhand and

Himachal Pradesh, the Union Territories of Jammu and Kashmir and Ladakh.

16.6 Proposed Provisions

16.6.1 The Commission, after considering various aspects and taking into account comments and suggestions of the stakeholders, has proposed Regulation 36 (3) in the Draft Tariff Regulations as follows:

"36. Operation and Maintenance Expenses:

. . . .

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

Particulars	*2024-25*	*2025-26*	*2026-27*	*2027-28*	*2028-29*
Norms for sub-station Bays (Rs Lakh per bay)					
765 kV	*36.28*	*38.41*	*40.68*	*43.07*	*45.61*
400 kV	*25.91*	*27.44*	*29.06*	*30.77*	*32.58*
220 kV	*18.14*	*19.21*	*20.34*	*21.54*	*22.81*
132 kV and below	*12.96*	*13.72*	*14.53*	*15.38*	*16.29*
Norms for Transformers/Reactors (Rs Lakh per MVA or MVAR)					
O&M expenditure per MVA or per MVAr (Rs Lakh per MVA or per MVAr)	*0.229*	*0.242*	*0.257*	*0.272*	*0.288*
Norms for AC and HVDC lines (Rs Lakh per km)					
Single Circuit (Bundled Conductor with six or more sub-conductors)	*1.220*	*1.292*	*1.368*	*1.448*	*1.534*
Single Circuit (Bundled conductor with four or more sub-conductors)	*1.045*	*1.107*	*1.172*	*1.241*	*1.315*
Single Circuit (Twin & Triple Conductor)	*0.697*	*0.738*	*0.782*	*0.828*	*0.876*
Single Circuit (Single Conductor)	*0.348*	*0.369*	*0.391*	*0.414*	*0.438*
Double Circuit (Bundled Conductor with four or more sub-conductors)	*1.830*	*1.938*	*2.052*	*2.173*	*2.301*
Double Circuit (Twin & Triple Conductor)	*1.220*	*1.292*	*1.368*	*1.448*	*1.534*
Double Circuit (Single Conductor)	*0.523*	*0.554*	*0.586*	*0.621*	*0.657*
Multi Circuit (Bundled Conductor with four or more sub-conductor)	*3.212*	*3.401*	*3.601*	*3.814*	*4.038*
Multi Circuit (Twin & Triple Conductor)	*2.138*	*2.264*	*2.398*	*2.539*	*2.689*
Norms for HVDC stations					

HVDC Back-to-Back stations (Rs Lakh per MW)	*2.15*	*2.27*	*2.41*	*2.55*	*2.70*
Gazuwaka BTB (Rs Lakh/MW)	*1.89*	*2.00*	*2.12*	*2.25*	*2.38*
HVDC bipole scheme (Rs Lakh/MW)	*1.13*	*1.20*	*1.27*	*1.34*	*1.42*

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

Provided that the O&M expenses of ±500 kV Mundra-Mohindergarh HVDC bipole scheme (2500 MW) shall be allowed as worked out by multiplying 0.80 of the normative O&M expenses for HVDC bipole scheme;

Provided further that the O&M expenses for Transmission Licensees whose transmission assets are located solely in NE Regions, State of Uttarakhand and Himachal Pradesh, the Union Territories of Jammu and Kashmir and Ladakh shall be worked out by multiplying 1.50 to the normative O&M expenses prescribed above.

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

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

(d) The Security Expenses and Capital Spares for the transmission system and associated communication system shall be allowed separately after prudence check:

Provided that the transmission licensee shall submit the assessment of the security requirement and estimated security expenses, the details of year-wise actual capital spares consumed at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.

(e) On the occurrence of any change in law event affecting O&M expenses, the impact

shall be allowed to the transmission licensee at the time of truing up of tariff.

Provided that such impact shall be allowed only in case the overall impact of such change in law event in a year is more than 5% of normative O&M expenses for the year.

(f) In case of a transmission licensee owned by the Central or State Government, the impact on account of implementation of wage or pay revision shall be allowed at the time of truing up of tariff."

17 Normative PAF for Thermal Generating Stations

17.1 Background

17.1.1 The plant availability factor of a generating station is the percentage of time it is available to provide energy to the grid. The availability of a plant is the factor of its reliability and the periodic maintenance it requires. The Commission, in the Tariff Regulations, 2001 and Tariff Regulations, 2004, specified separate norms to be achieved for recovery of full AFCs and in order to qualify to receive incentive in case the station performs above such specified norm. However, the Commission in the Tariff Regulations, 2009, changed the norm and specified a single norm (except for a few stations) as the target availability for recovery of full fixed charges and incentives. To be eligible for incentives, a separate norm, i.e., Plant Load factor (PLF) was prescribed for the generating stations in the Tariff Regulations, 2014. The generating station was allowed incentive only in the case when it generated power in excess of the target PLF. Similar norms were prescribed for the generating stations in the Tariff Regulations, 2019.

17.2 Existing Provisions of the Tariff Regulations, 2019

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

(A) Normative Annual Plant Availability Factor (NAPAF)

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

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

TPS-I	*72%*

(c) *For following Thermal Generating Stations of DVC:*

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

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

Assam GPS	*72%*

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

1. *First Three years from COD – 75%*
2. *For next year after completion of three years of the date of commercial operation – 80%*

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

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

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

TPS –I	*75%*

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

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

17.3 Issues discussed in the Approach Paper

17.3.1 Following issue was brought out in the Approach Paper for consultation: -:

(a) Historically, the target availability has been determined based on the data available for the past few years. The recovery of fixed charges was linked to the Plant Availability Factor (PAF). The Normative Annual Plant Availability Factor (NAPAF) has been specified considering the past years’ data and best industry practices. However, due to changing dynamics, such as technological improvement, better O&M practices, and shorter shutdowns and outages, the PAF has improved.

(b) As the shortage of domestic fuel affects the availability of the plants and their scheduling, the existing norm for availability may require review. In the event of using e-auction or imported coal (other than the fuel arrangement agreed in the purchase agreement), the issue of the need for prior consent of the beneficiary and the maximum permissible limit of blending also needs to be deliberated.

17.4 Stakeholders' Response

17.4.1 In response to the issues brought out in the Approach Paper for consultation, the stakeholders submitted the following comments/suggestions on various issues:

a) A few Generators have proposed revising NAPAF based on past performance while other Generators have proposed retaining the existing norm.
b) Most of the Hydro Generators proposed continuing with the existing mechanism for recovery of AFC.
c) Most of the Distribution and Transmission Licensees have proposed to revise the norm for NAPAF based on the recent performance.
d) Few Distribution Licensees have proposed that NAPAF may be determined at the time of the Petition being filed by the generator for Determination of Tariff. Further, NAPAF may also be reviewed at the time of the truing-up petition filed by the generator so that a balanced view of the same may be taken.
e) Some beneficiaries suggested that revision in norms may be applicable to new developers only.

17.5 Actual Availability of Generating Station

17.5.1 The Commission has reviewed the suggestions and comments received from various stakeholders and sought the actual data for FY 2018-19 to FY 2022-23 from central generating stations to assess actual performance vis-à-vis norms. The actual availability achieved by the generating stations for FY 2018-19 to FY 2022-23 is given in the Table below:

Table 43: Actual Average PAF of NTPC Stations as submitted by NTPC

Generating Station	Station Type	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	5- Year Avg.
Barauni-2	Non-Pit- Head	-	93.43	94.37	88.11	91.57	**91.87**
Barh-2	Non-Pit- Head	90.14	85.23	96.00	89.14	97.93	**91.69**
Bogaigaon	Non-Pit- Head	86.26	94.34	95.30	92.67	94.24	**92.56**
Dadri Thermal Power Station Stage-I	Non-Pit-Head	90.28	99.49	97.78	81.07	98.71	**93.47**
Dadri Thermal Power Station Stage-II	Non-Pit-Head	91.35	90.09	100.27	92.93	95.45	**94.02**
Darlipali	Pit-Head	-	64.20	70.16	83.42	82.73	**75.13**
Farakka STPS Stage-I&II	Non-Pit-Head	87.68	80.98	94.12	83.73	91.49	**87.60**

Generating Station	Station Type	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	5- Year Avg.
Farakka STPS Stage-III	Non-Pit-Head	90.17	77.87	97.54	87.98	80.71	**86.85**
Gadarwara	Non-Pit-Head	-	97.03	92.58	85.79	99.34	**93.69**
Kahalgaon STPS Stage-I	Pit-Head	91.31	88.66	79.46	90.18	89.38	**87.80**
Kahalgaon STPS Stage-II	Pit-Head	88.96	87.73	70.34	89.28	96.59	**86.58**
Kanti MTPS Stage-II	Non-Pit-Head	83.98	92.65	92.69	90.03	97.33	**91.34**
Khargone	Non-Pit-Head	-	98.83	88.67	86.50	89.44	**90.86**
Korba STPS Stage-I&II	Pit-Head	87.60	88.72	95.47	95.79	97.61	**93.04**
Korba STPS Stage-III	Pit-Head	92.69	87.57	101.49	98.59	88.66	**93.80**
Kudgi	Non-Pit-Head	79.15	92.71	95.79	83.74	89.79	**88.24**
Lara	Pit-Head	-	86.35	80.44	91.01	94.43	**88.06**
Mouda Stage-I	Non-Pit-Head	85.03	100.14	95.66	92.01	95.42	**93.65**
Mouda Stage-II	Non-Pit-Head	78.31	89.25	97.85	89.44	98.42	**90.65**
Nabinagar	Non-Pit-Head	-	88.14	92.00	92.42	89.34	**90.48**
Ramagundam STPS Stage-I&II	Non-Pit-Head	89.99	90.68	88.19	86.37	86.94	**88.43**
Ramagundam STPS Stage-III	Non-Pit-Head	86.51	91.98	81.01	101.91	84.83	**89.25**
Rihand STPS Stage-I	Pit-Head	88.35	87.91	84.31	95.73	88.46	**88.95**
Simhadri STPS Stage-I	Non-Pit-Head	88.68	89.40	93.57	89.93	93.95	**91.11**
Simhadri STPS Stage-II	Non-Pit-Head	85.11	90.94	95.88	87.82	93.67	**90.68**
Singrauli STPS Stage- I&II	Pit-Head	87.37	87.85	84.89	83.47	89.34	**86.59**
Sipat STPS Stage-I	Pit-Head	92.57	87.83	94.21	79.17	87.31	**88.22**
Sipat STPS Stage-II	Pit-Head	91.51	90.58	90.12	98.68	96.65	**93.51**
Solapur	Non-Pit-Head	86.45	94.68	96.10	91.21	93.63	**92.41**
Talcher STPS Stage- I	Pit-Head	78.77	74.12	92.13	87.74	90.54	**84.66**
Talcher STPS Stage- II	Pit-Head	83.67	81.21	90.82	90.40	96.29	**88.48**
Tanda TPS-I	Non-Pit-Head	91.84	92.74	95.65	91.90	93.22	**93.07**
Tanda TPS-II	Non-Pit-Head	-	91.41	93.48	93.66	97.03	**93.89**
Unchahar Thermal Power Station Stage-I	Non-Pit-Head	96.85	95.28	100.50	86.00	90.94	**93.91**
Unchahar Thermal Power Station Stage-II	Non-Pit-Head	95.97	98.69	95.27	93.59	93.32	**93.37**
Unchahar Thermal Power Station Stage-III	Non-Pit-Head	92.91	102.97	95.02	96.16	101.75	**97.76**
Unchahar Thermal Power Station Stage-IV	Non-Pit-Head	22.16	95.63	88.49	90.01	101.13	**79.48**
Vindhayanchal Stage I	Pit-Head	90.70	86.93	90.73	91.62	88.00	**89.59**
Vindhayanchal Stage II	Pit-Head	90.92	84.82	93.69	87.61	96.26	**90.66**
Vindhayanchal Stage III	Pit-Head	94.42	90.46	99.06	89.94	91.73	**93.12**
Vindhayanchal Stage IV	Pit-Head	95.89	92.12	87.85	92.26	102.02	**94.03**
Vindhayanchal Stage V	Non-Pit-Head	92.77	98.54	96.56	90.63	97.68	**95.24**

Table 44: Actual Average PAF of DVC Stations as submitted by DVC

Generating Station	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	5- Year Avg.
Bokaro TPS	72.42	75.70	90.35	78.89	92.01	**81.87**
Mejia TPS (Unit 1-3)	59.01	83.35	98.79	85.63	85.30	**82.42**
Mejia TPS (Unit 4)	55.67	88.6	85.13	96.17	95.17	**84.15**
Mejia TPS (Unit 5-6)	73.13	90.50	94.61	93.21	87.53	**87.79**
Mejia TPS (Unit 7-8)	71.01	75.34	91.98	89.94	91.12	**83.88**
Chandrapur TPS (Unit 7-8)	83.41	87.98	90.27	96.31	84.44	**88.48**
Koderma TPS	77.01	90.03	98.53	89.79	89.28	**88.93**
RTPS	31.59	69.88	91.42	75.05	59.93	**65.58**
DSTPS	78.00	88.93	93.08	89.09	88.50	**87.58**

Table 45: Actual Average PAF of NLC Stations as submitted by NLC

Generating Station	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	5- Year Avg.
NLC TPS-1 EXP	81.59	96.15	78.07	92.16	87.71	**87.14**
NLC TPS-2 Stage-1	87.58	93.38	76.08	85.41	59.46	**80.38**
NLC TPS-2 stage 2	90.57	89.93	44.86	76.67	67.08	**73.82**
NLC TPS-2 EXP	44.35	38.11	48.42	46.37	45.03	**44.45**
NLC Barsingsar Thermal Power Station	62.35	70.56	67.51	75.50	80.38	**71.26**
NLCIL Neyveli New Thermal Power Station	-	51.24	68.64	73.25	86.92	**70.02**

Table 46: Actual Average PAF of Gas Based Generating Stations as per the submissions of Generating Companies

Generating Station	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	5- Year Avg.
NTPC						
Anta	96.06	88.20	97.01	89.31	87.56	**91.63**
Auraya	94.04	94.95	95.02	89.38	90.37	**92.75**
Gandhar	85.65	95.66	93.57	86.16	86.98	**89.60**
Kawas	95.81	94.35	97.17	87.81	93.60	**93.75**
Faridabad	93.46	97.99	97.02	88.03	89.05	**93.11**
Dadri Gas	90.22	92.03	95.39	90.91	86.50	**91.01**
KayamKulam Rajiv Gandhi Combined Cycle Power Station	0.06	0.00	5.23	0.00	96.03	**20.26**
Ratnagiri Gas and Power Private Limited	66.55	59.28	64.90	66.98	65.47	**64.64**

Generating Station	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	5- Year Avg.
PRAGATI POWER						
Pragati Power Corporation Ltd. PPS-III Bawana	71.99	89.26	92.54	93.12	NA	**86.73**
NEEPCO						
Assam Gas	64.20	69.44	64.62	71.52	73.35	**68.63**
Agartala Gas	58.05	75.27	83.45	80.37	81.69	**75.77**
Tripura Gas	79.27	87.53	63.30	84.38	86.50	**80.18**

17.6 Commission's View

17.6.1 As can be seen, the average availability during FY 2018-19 to FY 2022-23 for most of the stations of NTPC was above 90%, with few stations in the range of 85% to 90% and only two stations i.e. Unchahar TPS Stage-4 and Darlipalli STPS had actual average annual Availability factor of less than 85%. It is, however, observed that in the case of Unchahar TPS Stage-4, the actual availability in FY 2018-19 was abnormally low at 22.16% and if FY 2018-19 is not considered the 4-year average works out to be 93.82% which is well above the existing NAPAF. With regard to Darlipalli STPS, the station has been able to achieve PAFY (plant availability factor for the year) of 82%-83% in FY 2021-22 and FY 2022-23 and should be able to improve further.

17.6.2 For DVC stations, the actual performance levels were higher than the norms specified (85%) for Mejia TPS (Unit 5-6) (87.79%), Chandrapura TPS (Unit 7-8) (88.48%), Koderma TPS (88.93%), Durgapur Steel TPS (87.58%). The rest of the stations except RTPS, such as Bokaro TPS, Mejia TPS Unit 1-3, Mejia TPS Unit 4, Mejia TPS Unit 7-8, have achieved 5-year average availability in the range of 80-85%. It is further observed that the lower availability is attributable to poor availability achieved in FY 2018-19, and in case FY 2018-19 is not considered, these stations have achieved 4-year average availability of around 85%.

17.6.3 It is observed that the current Regulation specifies NAPAF as 85% for most of the coal-based generating stations, and CEA has also recommended the NAPAF of 85% for coal-based generating stations, with some exceptions, for the next tariff period. As also discussed earlier, the Commission also observes that the actuals achieved by most of the existing NTPC and DVC stations are around the current norms and that recommended by CEA, and therefore the Commission proposes to continue with the existing norm of 85% for coal-based generating stations.

17.6.4 With regard to Lignite based generating stations, the Commission observes that, for NLC, the actual availability of all the stations is more than the norms, except in the case of NLC TPS-II Expansion, NLC BTPS and NLC NNTPS. The target availability for these stations was 72%, and the five-year average for these stations mentioned above is only 44.45%, 71.26% and 70.02%, respectively. All other stations have exceeded the specified target availability by around 10%, as specified in the Tariff Regulations, 2019. Further, CEA has recommended the Normative Availability for NLC Stations, as shown below:

Lignite-fired Thermal Generating stations of NLC India Ltd.	
TPS- II Stage- I & Stage- II	80%
Barsingsar (CFBC)	75%
TPS-II Expansion (CFBC)	50%

Since the norms achieved by NLC Stations are in line with the Norms Proposed by the CEA, the Commission proposes to adopt the norms for NLC stations as recommended by the CEA. Accordingly, the Commission proposes the target availability norm for NLC TPS-2 Stage 1 & 2, NLC BTPS and NLC TPS – II Expansion at 80%, 75% and 50% respectively. Further, the target availability norm for NLC TPS-1 Expansion, NLC NNTPS shall be 80%.

17.6.5 With regard to gas-based generating stations of NTPC, it is observed that all the stations have achieved the current target availability of 85%, with a five-year average actual availability being close to 95%. CEA has recommended continuing with the Normative Availability of 85% for gas-based stations for the next tariff period. Based on the actuals achieved by the gas-based stations and the recommendations of CEA, the Commission proposes to retain the target availability of 85% for the next control period, i.e. 2024-29.

17.6.6 For NEEPCO's Assam Gas Stations, it is observed that the actual five-year average availability is 68.63% compared to the existing target availability of 72%. For Agartala Gas station, the actual five-year average availability is 75.77%, lower than the target norm of 85%. For Tripura Gas station, the actual five-year average availability is 80.18% which is lower than the target norm of 85%.

17.6.7 It is observed that in the case of the Tripura Gas plant; the station has been able to achieve 85% availability in two years, i.e., FY 2019-20 and FY 2022-23 and has also managed to achieve an availability of 84.38% in FY 2021-22. With regard to Assam GPS, the Stations have been able to achieve the target availability of 72%

only once in FY 2022-23, while Agartala GPS has not been able to achieve the target availability in any of the past five years. Considering the actual performance and other technical considerations, CEA has recommended marginally lower availability for Assam Gas Station at 70% while retaining the target availability norm for Agartala and Tripura Gas Stations at 85%. The Commission, in view of the actuals achieved and recommendations of the CEA, proposes to adopt the CEA recommendations.

17.6.8 In the Approach Paper, suggestions were sought from various stakeholders on the need to incentivize old Thermal Generating Stations for higher generation. The Approach Paper also observed that these stations are vintage plants for which the approved capital base is around Rs. 1.5-2 Cr/MW and therefore, the equity component of these generating stations is comparatively low. Due to low equity base, the RoE in today's term may not be significant enough when compared to the risks associated with these plants. In this regard, the Commission observes that currently the older Thermal Generating Stations which have completed 30 years of operation carry higher operational risk without having much of an incentive to continue with the operations. Accordingly, in order to de-risk the Business risk involved and to encourage continued operations and higher generation from such old Thermal Generating Stations which have completed 30 years of life, the Commission has proposed to relax the Target Normative Annual Plant Availability Factor (NAPAF) and Normative Annual Plant Load Factor (NAPLF) for Incentive as 80% for coal and lignite based generating stations completing 30 years from COD as on 31.03.2024.

17.7 Proposed Provisions

17.7.1 In view of the above, the Commission proposes Regulation 70 of the Draft Tariff Regulations reproduced as below:

<u>"Norms of operation for thermal generating station</u>

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

(A) Normative Annual Plant Availability Factor (NAPAF)

(a) 85% for all thermal generating stations, except those covered under clauses (c), (c), (d) & (d)

(b) 80% for coal and lignite based generating stations completing 30 years from

COD as on 31.03.2024

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

Assam GPS	*70%*
Agartala GPS	*85%*
Tripura GPS	*85%*

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

1. *First Three years from the date of commercial operation – 68.50%*
2. *For next year after completion of three years of the date of commercial operation - 75%*

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

1. *NLC TPS-2 Stage-1 and Stage-2* *80%*
2. *Baringsagar TPS* *75%*
3. *TPS – II Expansion (CFBC)* *50%*
4. *TPS-1 Expansion* *80%*
5. *New Neyveli TPS* *80%*

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

(a) *85% for all thermal generating stations, except for those covered under clause (b) below*

(b) *80% for coal and lignite based generating stations completing 30 years from COD as on 31.03.2024"*

18 Gross Station Heat Rate

18.1 Background

18.1.1 The heat rate is the amount of energy required by an electrical generator or a power plant to produce one-kilowatt hour (kWh) of electricity. If the heat rate is low, the efficiency is higher. The Commission, in the Tariff Regulations, 2001, had approved a single norm for existing as well as new 200 MW and 500 MW units for all central generating stations and provided relaxed norms for new thermal stations during the stabilization period. In the Tariff Regulations, 2004, the Commission specified separate norms for 200 MW and 500 MW. For 200 MW units, the Commission retained the same norms, while for 500 MW units, the norms were slightly tightened, as these units are more efficient, resulting in lower SHR. In the Tariff Regulations, 2009, the Commission retained the norms for 200 MW and tightened the norms for 500 MW and provided a relaxation of 6.5% as an operating margin for thermal generating stations, which achieved COD on or after 1 April 2009. In the Tariff Regulations, 2014, the Commission tightened the norms for both 200 MW and 500 MW and reduced the operating margin to 4.5% from 6.5% for new thermal generating stations. In the Tariff Regulations, 2019, the Commission tightened the norms for 200 MW by 0.82% and relaxed the norms for 500 MW by 0.63% for new thermal generating stations after considering the actual data from FY 2013-14 to FY 2017-18 and also increased the operating margin to 5% for generating stations which achieved COD on or after 1 April 2009.

18.2 Existing Provisions of the Tariff Regulations, 2019

"49 (C) (a) "Existing Thermal Generating Stations

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

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

Note 1

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

Note 2

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

Note 3

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

Note 4

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

(i) *For following Thermal generating stations of NTPC Ltd:*

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

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

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

(iii) *For Lignite-fired Thermal Generating Stations: For lignite-fired thermal generating stations, except for TPS-I and TPS-II (Stage I & II) of NLC India Ltd, the gross station heat rates specified under sub-clause (i) for coal-based thermal generating stations shall be applied with correction, using multiplying factors as given below:*

(a) *For lignite having 50% moisture: 1.10*

(b) *For lignite having 40% moisture: 1.07*

(c) *For lignite having 30% moisture: 1.04*

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

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

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

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

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

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

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

1.05 X Design Heat Rate (kCal/kWh)

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

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

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

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

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

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

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

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

Provided also that in case of coal based generating station if one or more generating units were declared under commercial operation prior to 1.4.2019, the heat rate norms for those generating units as well as generating units declared under commercial operation on or after 1.4.2019 shall be lowest of the heat rate norms considered by the Commission during tariff period 2014-19 or those arrived at by above methodology or the norms as per the sub-clause (C)(a)(i) of this Regulation:

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

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

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

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

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

For RLNG = 1.071 X Design Heat Rate of the unit/block for Liquid Fuel (kCal/kWh) Where the Design Heat Rate of a unit shall mean the guaranteed heat rate for a unit at 100% MCR and at site ambient conditions; and the Design Heat Rate of a block shall mean the guaranteed heat rate for a block at 100% MCR, site ambient conditions, zero percent make up, design cooling water temperature/back pressure."

18.3 Issues discussed in the Approach Paper

18.3.1 The Approach Paper highlighted the following key issues with regard to Station Heat Rate, on which comments had been sought from stakeholders.

a) It is observed that the Central Generating Stations that used to operate at around 80%-85% PLF prior to FY 2013-14 have now been operating at part load and much below the target PLF due to the need for higher RE integration. As these generating stations are operating at a much lower PLF, the actual performance data will also have a degradation impact. Further, as the generating stations are separately allowed degradation impact due to low load operations, it is felt that the norms may be fixed considering the ideal loading of generating units.

b) For those generating stations that have not been operating efficiently in the past and for which the Commission has been considering actual achievements to fix relaxed norms, in the interest of limited resources, such relaxation of norms may need reconsideration. This is necessary as coal/lignite is a limited resource that needs to be consumed efficiently and can be reallocated to more efficient plants.

c) With regard to operational norms such as Heat Rate, Secondary Fuel Oil Consumption (SFOC), Auxiliary Consumption, and Boiler Efficiency, the revised norms that are superior to design parameters for the old generating stations may not be specified for such old generating stations.

18.4 Stakeholders' Response

18.4.1 In response to the issues brought out in the Approach Paper for consultation, the stakeholders submitted the following comments/suggestions.

a) Few of the Central Generating Companies submitted that achievement of operational norms at 85% PLF and any degradation due to part load operations may be allowed up to technical minimum only. Further suggested allowing the following operational norms.

- For units that have achieved COD after April 2009, a suitable margin of at least 6% over unit design heat rate irrespective of minimum Boiler Efficiency limit.
- Increase in Heat Rate required due to co-firing with biomass pellets should be taken care of in the Tariff Norms and should not be considered for Merit Order Scheduling.

b) Few of the Central Generating Companies submitted that the current compensation mechanism should be reviewed to compensate units having lower average loading than their norms than changing the operational norms itself.

c) A few of the State Generating companies suggested that it is not possible to fix the operational norms of thermal stations on an ideal loading basis as stations are backed down based on the MOD.

d) Some DISCOMs observed that the operating norms should be based on past performance of the units in the country, including State Utilities/IPPs of a relevant vintage of the units and should factor in operating constraints, like partial loading due to erratic load patterns of the beneficiaries and lower operating load factor due to shortfall of quantity and quality of fuel. Further, the operation of a generating unit under varying load conditions and with variations in the quality of fuel, the efficiency of the boiler and turbine tends to degrade over time. Hence, a margin for Design Heat Rate may be determined for generating stations completing every block of 5 years.

e) Some Private IPPs observed that norms may be fixed considering the ideal loading of the generating units. The impact of Change in Law (CIL) & Force Majeure (FM) may also be considered in operational norms. Allow GSHR based on three factors: Design turbine cycle Heat Rate, Design boiler efficiency and Operating Margin. Either existing Regulation 49(C)(a)(i) should be applied in cases specified in 49(C)(b)(i), i.e. GSHR of 2430/2390 for 200/500 MW sets respectively, or a provision for providing relaxation in such cases may be provided.

f) Some Private IPPs submitted that norms specifying margin in Design Heat Rate based on the date of placement of the order for the BTG package for each station every 5 years are needed. Benchmarking of SHR may be avoided.

18.5 Actual Gross Station Heat Rate

18.5.1 The Commission has reviewed the suggestions and comments received from various stakeholders. The Commission had sought the actual data for FY 2018-19 to FY 2022-23 from Central Generating Stations to assess actual performance vis-à-vis norms. The actual Station Heat Rate data as submitted by the Generating Stations after taking into account the degradation factor allowed for compensating the generating stations for lower loading in accordance with the provisions of Grid Code for FY 2018-19 to FY 2022-23 is given in the table below.

Table 47: Actual Gross SHR (kCal/kWh) for Coal based Generation Stations of NTPC

Generating Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
200 MW Series						
Dadri Stage-I	2470	2491	2526	2481	2486	2491
Kahalgaon-I	2441	2426	2419	2422	2423	2426
Unchahar-I	2506	2527	2540	2544	2584	2540
Unchahar-II	2501	2519	2538	2540	2550	2530
Unchahar-III	2478	2507	2560	2521	2553	2524
Vindhyachal-I	2462	2440	2411	2431	2410	2431
Barauni 2	-	2464	2398	2371	2358	2398
Bongaigaon	2453	2508	2547	2475	2426	2481
Average						**2477**
500 MW Series						
Dadri Stage-II	2415	2432	2463	2400	2414	2425
Farraka Stage-III	2503	2434	2400	2504	2424	2453
Kahalgaon-II	2399	2377	2375	2374	2376	2380
Korba Stage-III	2387	2346	2324	2341	2304	2340
Mouda Stage-I	2490	2504	2490	2430	2382	2459
Ramagundam- III	2352	2324	2327	2339	2286	2326
Rihand-I	2343	2329	2304	2370	2357	2340
Simhadri-I	2439	2445	2436	2439	2411	2434
Simhadri-II	2423	2383	2393	2412	2386	2400
Sipat -II	2409	2365	2387	2368	2343	2374
Talcher I	2386	2420	2430	2346	2398	2396
Talcher II	2376	2419	2427	2352	2397	2394
Vindhyachal-II	2381	2387	2373	2387	2366	2379
Vindhyachal-III	2376	2387	2361	2385	2365	2375
Vindhyachal-IV	2376	2358	2334	2355	2338	2352
Unchahar – IV	2411	2436	2465	2427	2418	2431
Vindhyachal-V	2354	2357	2331	2355	2335	2347
Average						**2388**

18.5.2 Actual Gross Station Heat Rate (kCal/kWh) for Kanti MTPS Stage-II and Tanda-I TPP are shown as under:

Table 48: Actual Gross SHR (kCal/kWh) for Kanti MTPS and Tanda Stations

Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
Kanti MTPS Stage-II	2631	2610	2558	2580	2527	2581
Tanda-I TPP	2844	2837	2873	2867	2964	2877

18.5.3 Actual Gross Station Heat Rate (kCal/kWh) for coal and lignite-based stations of NLC India Ltd are as under.

Table 49: Actual Gross SHR (kCal/kWh) for Lignite based Generating Stations

Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
TPS -1 EXP	2715	2712	2712	2719	2714	2714
TPS - 2 Stage 1	2893	2887	2885	2888	3051	2921
TPS - 2 Stage 2	2893	2888	2886	2889	3038	2919
TPS - 2 EXP	2589	2587	2565	2564	2568	2575
Barsingsar TPP	2546	2548	2513	2530	2540	2536
NNTPS	-	2728	2610	2642	2635	2654

18.5.4 Actual Gross Station Heat Rate (kCal/kWh) for gas based stations of NTPC and NEEPCO other than small gas turbine stations are as under.

Table 50: Actual Gross SHR (kCal/kWh) for Gas based Generating Stations

Generating Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
NTPC						
Anta GPS	2205	2348	2233	2890	2252	2386
Auraiya GPS	2288	2361	2290	2413	2308	2332
Kawas GPP	2074	2096	2081	2397	2319	2194
Gandhar GPP	2334	2368	2137	2337	2197	2275
Faridabad GPP	2021	2035	2010	2086	2506	2132
Dadri GPP	2119	2152	2105	2163	2112	2130
NEEPCO						
Agartala GPS	2587	2606	2623	2589	2681	2617
Assam GPS	2467	2616	2670	2671	2708	2626
Tripura GPS	1981	2171	2025	2025	2032	2036

18.5.5 Actual Gross Station Heat Rate (kCal/kWh) for Advance F Class machines of OTPC and RGPPL are as under.

Table 51: Actual Gross SHR (kCal/kWh) for Advance F Class Machines

Generating Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
RGPPL	1833	1840	1855	1883	1895	1861
OTPC	1791	1757	1764	1801	1798	1782
Average						**1822**

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18.5.6 It is observed that in the case of 200 MW Units of NTPC, the actual SHR is below the normative SHR only for Kahalgaon-I and Barauni-2. For the rest of the Stations with 200 MW units, the actual SHR is above the normative SHR. In the case of 500 MW Units of NTPC, the actual SHR is below the normative SHR for Kahalgaon-II, Korba Stage-III, Ramagundam-III, Rihand-I, Sipat-II, Vindhyachal-II, Vindhyachal-III, Vindhyachal-IV and Vindhyachal-V. For the rest of the Stations with 500 MW units, the actual SHR is above the normative SHR. For NLC stations, the actual five-year average heat rate is slightly less than the current Heat Rate Norms for NLC TPS-1 Expansion station and higher than current Heat Rate Norms for NLC TPS-II stations.

18.5.7 For Agartala and Assam GPS, the actual five-year average heat rate has been slightly lower than the norm. However, the heat rate achieved by other gas stations is higher than the norms.

18.6 Commission's View

18.6.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders. It is observed that the stakeholders have mainly suggested that Station Heat Rate norms should factor in the current operating conditions. The Tariff Policy, 2016 provides as follows:

"f) Operating Norms

Suitable performance norms of operations together with incentives and disincentives would need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. Except for the cases referred to in para 5.11(h)(2), the operating parameters in tariffs should be at "normative levels" only and not at "lower of normative and actuals". This is essential to encourage better operating performance. The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipments, nature of operations, level of service to be provided to consumers etc. Continued and proven inefficiency must be controlled and penalized.

The Central Commission would, in consultation with the Central Electricity Authority, notify operating norms from time to time for generation and transmission. The SERC would adopt these norms. In cases where operations have been much below the norms for many previous years, the SERCs may fix relaxed norms suitably and draw a transition path over the time for achieving the norms notified by the Central Commission, or phase them out in accordance with the norms specified by the Authority in this regard."

18.6.2 The Commission has been following the consistent practice of formulating norms based on actual data of the past period. The Commission, therefore, is of the opinion that the norm should be based on the actual data for the past five years and taking into consideration CEA recommendations.

18.6.3 The Commission observes that, in the case of 200 MW Units of NTPC, the actual SHR is below the approved norms only for Kahalgaon-I and Barauni-2. For the rest of the Stations with 200 MW units, the actual SHR is above the approved norms of 2430 kCal/kWh as per the Tariff Regulations, 2019. In the case of 500 MW Units of NTPC, the actual SHR is below the normative SHR for Kahalgaon-II, Korba Stage-III, Ramagundam-III, Rihand-I, Sipat-II, Vindhyachal-II, Vindhyachal-III, Vindhyachal-IV and Vindhyachal-V. For the rest of the Stations with 500 MW units, the actual SHR is above the normative SHR. The five-year average for all the plants with 500 MW units works out to be 2388 kCal/kWh, which is lower than the approved Norm of 2390 kCal/kWh.

18.6.4 It is further observed that CEA for 200/210/250 MW sets has recommended the target SHR of 2400 kCal/kWh, which is lower than the existing norm of 2430 kCal/kWh by 30 kCal/kWh. Further, with regard to 500-600 MW sets (sub-critical) (TDBFP), CEA has recommended the target SHR at 2375 kCal/kWh, which is lower than the existing norm of 2390 kCal/kWh by 15 kCal/kWh. CEA vide its letter dated 19.12.2023 has also recommended new unit heat rate degradation factors for the purpose of compensation towards low load operations ranging from 14.20% for PLF ranging in between 40-45% to around 2.10% for PLF ranging between 80-85%.

18.6.5 The Commission observes that the average actual SHR has increased to around 2477 kCal/kWh from FY 2018-19 to FY 2022-23 vis-à-vis 2381 kCal/kWh recorded for the period from FY 2012-13 to FY 2016-17. This degradation of actual SHR can be attributable to the increased backing down of thermal generating stations to accommodate the rapid integration of renewable energy. The Commission, to negate the financial implications on the generators due to part load operations, had already specified a compensation mechanism for degradation in Norms due to part load operations under sub-clause (6) of Regulation 6.3B of the IEGC, 2010. The Commission, in accordance with IEGC, 2023 is also in the process of specifying a fresh compensation mechanism based on CEA's recommendations, which will be sufficient to compensate for the degradation of Norms due to increased part load operations.

18.6.6 In view of the above, the Commission accepts the recommendations made by the CEA for 200 MW and 500 MW sets.

18.6.7 The Commission had approved relaxed norms for some of the generating stations after taking due consideration of plant vintage. In the case of Tanda TPS, the Commission had approved a norm of 2,750 kCal/kWh, whereas the five-year average heat rate achieved by the station was 2,877 kCal/kWh. It is observed that Tanda TPS has achieved a lower average PLF of 40% during its operations from FY 2020-21 to FY 2022-23, which has resulted in a spike in the actual Heat Rate. Analyzing the data from FY 2013-14 to FY 2017-18, the Commission observes that Tanda TPS was operating at a PLF of over 85% and was able to almost achieve the Norms for SHR around the approved norm of 2,750 kCal/kWh. Since the increase in the SHR in case of Tanda TPS during FY 2018-19 to FY 2022-23 appears to be primarily on account of lower PLF, the Commission is of the view that Tanda TPS should make efforts to achieve norms of 2,750 kCal/kWh if operated optimally. Further, CEA, in its recommendations, has also proposed to retain the Existing Norms for Tanda TPS. Accordingly, the Commission proposes to retain the Heat Rate norms for Tanda to 2,750 kCal/kWh for the 2024-2029 Tariff Regulations.

18.6.8 Further, CEA has recommended separate Norms for Kanti MTPS Stage-II, which was commissioned on 1st July 2017. CEA has proposed the Station Heat Rate of 2500 kCal/kWh for Kanti MTPS Stage-II for the FY 2024-29 Control Period. The Commission observes that Kanti TPS is a relatively newer station which has achieved its COD on 01.07.2017. The said station has achieved an average SHR of 2555 kCal/kWh during its operations from FY 2020-21 to FY 2022-23. Since the Power Plant is relatively new and has 195 MW units and as the recommendations made by CEA are in line with the average SHR achieved by the station during the past 3 years of stable operations, CERC proposes to adopt the Station Heat Rate of 2500 kCal/kWh for Kanti MTPS Stage-II for FY 2024-29 Control Period.

18.6.9 For NLC TPS-1 expansion, the actual five-year average heat rate is 2,714 kCal/kWh, which is slightly less than the current Heat Rate Norms approved in the Tariff Regulations, 2019, i.e. 2750 kCal/kWh. CEA has recommended a Heat Rate of 2710 kCal/kWh for NLC TPS-1 Expansion. Since during all the five years, NLC TPS-1 expansion has achieved a heat rate of less than 2,750 kCal/kWh and is closer to 2710 kCal/kWh, the Commission proposes to adopt the norms recommended by CEA and accordingly revise the norm for NLC TPS-1 to 2710 kCal/kWh.

18.6.10 For NLC TPS – II Stage 1 & 2, the actual five-year average is 2892 kCal/kWh & 2893 kCal/kWh, respectively and are slightly above the current heat rate norm approved in the Tariff Regulation, 2019 i.e. 2890 kCal/kWh. The recommendation of CEA on operation norms for thermal generating stations suggests heat rate norms of 2880 kCal/kWh for these generating stations. The Commission observes that the said stations have achieved an average SHR 2886 kCal/kWh during their operations from FY 2019-20 to FY 2021-22, therefore; the Commission proposes the Heat Rate norm of NLC TPS – II Stage-1 &2 as 2880 kCal/kWh which is in line with the recommendations of CEA.

18.6.11 For gas-based generating stations, analysis of the actual data as submitted by the generating stations has been done. The five-year average of NTPC Gas power stations is higher than the norms given in the Tariff Regulations, 2019. It is observed that higher SHR achieved by Gas Stations have been on account of lower loading due to lesser scheduling of Gas Stations for which additional impact is being currently allowed based on the plant-specific characteristic curves. CEA has also recommended continuing with the existing norms, and therefore, the Commission proposes to retain the current norms along with retention of existing compensation mechanism based on plant specific characteristic curves.

18.6.12 With regard to Gas Stations based on advanced F-Class machines, the actual 5-year average data of Ratnagiri and OTPC is around the existing norms of 1820 kCal/kWh. Further, CEA has also recommended to retain the existing norms. Accordingly, the Commission proposes to retain the existing Heat Rate norms of 1820 kCal/kWh.

18.6.13 With regard to existing operating margin allowed over and above the design heat rate for coal based generating stations which have achieved COD after 1.4.2009, CEA based on the technical analysis carried out has recommended a margin of 4% over and above the design heat rate as against the existing operating margin of 5% except for 200/210/250 MW Sets for which CEA has proposed to retain 5% margin. Based on CEA's recommendations, the Commission proposes to adopt the same.

18.6.14 With regard to SHR Norms of the coal and lignite based generating stations or units thereof (except for the generating stations or units thereof for which relaxed norms have been specified) and commissioned till 31.3.2024 (before 2009 and after 2009), degradation of actual SHR in such generating stations is observed which is attributable to the increased backing down of thermal generating stations to accommodate the rapid integration of renewable energy. Further, CEA recommended that tightening SHR Norms for such stations would not be prudent in view of the degraded efficiency of such units on account of frequent backing down and the fact that the rated efficiency parameters of such units was specified based on older regulatory regime wherein the SHR Norms were relaxed. In view of the facts stated above and recommendations of CEA, the Commission is of the view that prevailing SHR Norms shall remain applicable for such generating stations or units thereof for the remaining operational life of the respective generating stations or units thereof. Furthermore, since new generating stations and units thereof achieving COD after 31.03.2024 will be more efficient in operations as such units are being designed keeping in view the current regulations. Therefore, tightened norms as proposed above shall be applicable for units achieving COD after 31.03.2024.

18.7 Proposed Provisions

18.7.1 The Commission proposes Regulations 70 in the Draft Tariff Regulations as reproduced below:

"*70. **Norms of Operation for thermal generating stations:***

(C) Gross Station Heat Rate

(a) Existing Thermal Generating Station achieving COD before 1.4.2009

(i) For Coal-based Thermal Generating Stations, other than those covered under clause (ii) below:

200/210/250 MW Sets	***500 MW Sets (Sub-critical)***
2,400 kCal/kWh	*2,375 kCal/kWh*

Note 1

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

Note 2

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

Note 3

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

Note 4

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

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

Tanda TPS	*2,750 kCal/kWh*

(iii) *For Lignite-fired Thermal Generating Stations: For lignite-fired thermal generating stations, except for TPS-I Expansion, TPS-II (Stage I & II) of NLC India Ltd, the gross station heat rates specified under sub-clause (i) for coal-based thermal generating stations shall be applied with correction, using multiplying factors as given below:*

a. *For lignite having 50% moisture: 1.10*

b. *For lignite having 40% moisture: 1.07*

c. *For lignite having 30% moisture: 1.04*

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

(iv) *TPS-I , TPS-II (Stage I & II) & Barsingsar (2x125 MW) of NLC India Ltd:*

TPS-II (Stg I & II) *: 2,880 kCal/kWh*

TPS-1 (Expansion) *: 2,710 kCal/kWh*

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

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

(c) Thermal Generating Station achieving COD on or after 1.4.2009:

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

For 200/210/250 MW Sets = 1.05 X Design Heat Rate (kCal/kWh)

For 500 MW Sets and above = 1.04 X Design Heat Rate (kCal/kWh)

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

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

Pressure Rating (Kg/cm2)	150	170	170
SHT/RHT (^{0}C)	535/535	537/537	537/565
Type of BFP	Electrical Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1955	1950	1935
Min. Boiler Efficiency			
Sub-Bituminous Indian Coal (%)	86	86	86
Bituminous Imported Coal (%)	89	89	89

Pressure Rating (Kg/cm2)	247	247	260	270	270
SHT/RHT (^{0}C)	537/565	565/593	593/593	593/593	600/600
Type of BFP	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1900	1850	1814	1810	1790
Min. Boiler Efficiency (%)					
Sub-Bituminous Indian Coal (%)	86.00	86.00	86.00	86.50	86.50
Bituminous Imported Coal (%)	89.00	89.00	89.50	89.50	89.50

** For lignite fired thermal generating station, the minimum boiler efficiency shall be 76% (for pulverized) and 80% (for fluidized bed) based boilers.*

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

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

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

Provided units based on dry cooling system, the maximum turbine cycle heat rate shall be considered as per the actual design or 6% higher than the values given in the table above, whichever is lower."

Provided also that in the case of coal based generating station, if one or more generating units were declared under commercial operation prior to 1.4.2024, the heat rate norms for those generating units as well as generating units declared under commercial operation on or after 1.4.2024 shall be lowest of the heat rate norms considered by the Commission during tariff period 2019-24 or those arrived at by above methodology or the norms as per the sub-clause (C)(a)(i) of this Regulation:

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

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

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

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

Kanti TPS	*2,5000 kCal/kWh*

(iii) *For following lignite generating stations of NLC India Ltd:*

*Barsingsar (2*125 MW)*	*2,525 kCal/kWh*

(c) For Gas-based / Liquid-based thermal generating unit(s)/ block(s) having COD on or after 1.4.2009:

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

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

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

(d) *The Gross Station Heat Rate norms as specified in sub-clauses (a) and (b) of this clause, in respect of the coal and lignite based generating stations or units thereof (except for the generating stations or units thereof for which relaxed norms have been specified) and commissioned till 31.3.2024 (before 2009 and after 2009) shall remain applicable for such generating stations or units thereof for the remaining operational life of the respective generating stations or units thereof .”*

19 Secondary Fuel Oil Consumption (SFC)

19.1 Background

19.1.1 Under the Tariff Regulations, 2014, the cost of Secondary Fuel oil consumption was made as part of the Energy Charge, wherein norms are defined as ml/kWh. The same was continued under Tariff Regulations, 2019.

19.2 Existing Provisions of the Tariff Regulations, 2019

19.2.1 The existing norms for the Secondary Fuel Oil Consumption is as below:

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

…….

(C) Secondary fuel oil consumption

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

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

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

(c) Coal-based generating stations of DVC:

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

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

19.3 Issues discussed in the Approach Paper

19.3.1 The Approach Paper highlighted the following key issues with regard to Specific Oil Consumption, on which comments had been sought from stakeholders.

a) It is observed that the Central Generating Stations that used to operate at around 80%-85% PLF prior to FY 2013-14 have now been operating at part load and much below the target PLF due to the need for higher RE integration. As these generating stations are operating at a much lower PLF, the actual performance data will also have a degradation impact. Further, as the generating stations are separately allowed degradation impact due to low load operations, it is felt that the norms may be fixed considering the ideal loading of generating units.

b) For those generating stations that have not been operating efficiently in the past and for which the Commission has been considering actual achievements to fix relaxed norms, in the interest of limited resources, such relaxation of norms may need reconsideration. This is necessary as coal/lignite is a limited resource that needs to be consumed efficiently and can be reallocated to more efficient plants.

c) With regard to operational norms such as Heat Rate, Secondary Fuel Oil Consumption (SFOC), Auxiliary Consumption, and Boiler Efficiency, the revised norms that are superior to design parameters for the old generating stations may not be specified for such old generating stations.

19.4 Stakeholders' Responses

19.4.1 In response to the issues brought out in the Approach Paper for consultation, the stakeholders submitted the following comments/suggestions.

a) Few of the Central Generating Companies submitted that achievement of operational norms at 85% PLF and any degradation due to part load operations may be allowed up to technical minimum only. It was suggested to allow the following operational norms.

- Additional Specific Oil Consumption norms of 1.50 ml/kWh may be allowed for Super Critical units.
- Additional SFOC of 0.5 ml/kWh may be allowed for front and rear-fired supercritical units in addition to the Specific Oil Consumption norm of 1.50 ml/kWh proposed for Super Critical units.

b) Few of the Central Generating Companies submitted that the current compensation mechanism should be reviewed to compensate units having lower average loading than their norms, rather than changing the operational norms itself.

c) A few of the State Generating companies suggested that it is not possible to fix the operational norms of thermal stations on an ideal loading basis as stations are backed down based on the Merit Order Dispatch.

d) Few State Generating companies suggested that periodic reviews of norms may be conducted to ensure relevance and effectiveness through necessary changes.

e) Some DISCOM's observed that the operating norms should be based on past performance of the units in the country, including State Utilities/IPPs of a relevant vintage of the units and should factor in operating constraints, like, partial loading due to erratic load patterns of the beneficiaries and lower operating load factor due to shortfall of quantity and quality of fuel. Further, operation of a generating unit under varying load conditions and with variations in the quality of fuel.

f) Some Private IPPs observed that norms may be fixed considering the ideal loading of the generating units. The impact of CIL & FM may also be considered in operational norms.

19.5 Actual Secondary Fuel Oil Consumption

19.5.1 The actual secondary fuel oil consumption for various generating stations is as shown below:

Table 52: Actual Secondary Fuel Oil Consumption for Thermal Stations

Generating Stations	Existing Norm (ml/kWh)	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
NTPC							
Barh 2	0.50	0.33	0.26	0.30	0.43	0.42	0.35
Bongaigaon 2	0.50	0.64	0.81	0.84	0.51	0.52	0.67
Dadri Stage I	0.50	0.50	1.17	3.11	1.93	0.43	1.43
Dadri Stage II	0.50	0.24	0.77	0.59	0.43	0.44	0.49
Darlipalli	0.50	-	2.19	1.59	1.19	0.62	1.40
Farakka Stage I & II	0.50	0.57	1.00	0.93	1.39	0.81	0.94
Farakka Stage III	0.50	0.37	0.96	0.46	0.99	0.58	0.67
Gadarwara	0.50		4.38	0.80	1.30	0.81	1.82
Kahalgaon Stage I	0.50	0.43	0.29	0.40	0.66	0.39	0.43
Kahalgaon Stage II	0.50	0.36	0.30	0.45	0.22	0.39	0.35
Kanti MTPS Stage-II	0.50	0.92	0.70	0.52	0.58	0.33	0.61
Korba Stage I & II	0.50	0.18	0.19	0.19	0.15	0.19	0.18
Korba Stage III	0.50	0.08	0.25	0.03	0.11	0.35	0.16
Kudgi	0.50	1.04	2.07	1.43	1.31	0.75	1.32
Lara	0.50	-	0.52	1.18	0.66	0.86	0.80
Mauda Stage 1	0.50	0.67	0.59	0.76	1.01	0.33	0.67
Mauda Stage 2	0.50	0.66	0.75	0.95	0.80	0.38	0.71
Nabinagar	0.50		0.92	0.59	0.35	0.42	0.57
Ramagundam Stage I & II	0.50	0.34	0.33	0.33	0.34	0.60	0.39
Ramagundam Stage III	0.50	0.32	0.10	0.33	0.00	0.42	0.24
Rihand Stage I	0.50	0.41	0.23	0.32	0.23	0.55	0.35
Simadhri Stage I	0.50	0.15	0.56	0.62	0.50	0.39	0.45
Simadhri Stage II	0.50	0.57	0.48	0.40	0.47	0.33	0.45
Singrauli Stage I & II	0.50	0.25	0.25	0.30	0.34	0.25	0.28
Sipat Stage I	0.50	0.21	0.23	0.29	0.26	0.30	0.26
Sipat Stage II	0.50	0.26	0.21	0.24	0.21	0.18	0.22
Solapur	0.50	2.51	7.79	1.07	0.96	1.00	2.66

Generating Stations	Existing Norm (ml/kWh)	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
Talcher STPS Stage I	0.50	0.59	1.25	0.65	0.69	0.46	0.73
Talcher STPS Stage II	0.50	0.38	0.37	0.48	0.30	0.27	0.36
Tanda I	0.50	0.68	0.55	0.81	0.97	1.53	0.91
Tanda II	0.50		3.35	0.79	1.22	0.56	1.48
Unchahar Stage I	0.50	0.36	1.90	0.92	2.24	0.96	1.27
Unchahar Stage II	0.50	0.75	1.09	1.25	0.97	1.32	1.08
Unchahar Stage III	0.50	0.66	0.96	0.51	1.34	0.16	0.73
Unchahar Stage IV	0.50	4.43	1.20	0.69	0.43	0.36	1.42
Vindhyachal Stage I	0.50	0.21	0.30	0.27	0.29	0.28	0.27
Vindhyachal Stage II	0.50	0.22	0.36	0.22	0.35	0.19	0.27
Vindhyachal Stage III	0.50	0.15	0.12	0.09	0.21	0.16	0.15
Vindhyachal Stage IV	0.50	0.12	0.19	0.23	0.14	0.07	0.15
Vindhyachal Stage V	0.50	0.30	0.07	0.20	0.16	0.19	0.19
NLC India							
TPS 1 Expansion	1.00	0.73	0.34	0.45	0.81	0.72	0.61
TPSII-Stage 1	1.00	0.93	0.70	1.09	0.88	1.43	1.01
TPSII-Stage 2	1.00	0.79	0.65	1.35	1.02	1.19	1.00
TPS-II-Exp	1.00	1.94	3.64	1.59	1.61	1.46	2.05
Barsingsar TPS	1.00	0.78	0.58	0.70	0.56	0.46	0.62
NNTPS	1.00	-	8.97	2.25	1.37	0.66	3.31

*****DVC has not submitted the actual data

19.5.2 The Commission, in 2019-24, has specified a specific secondary fuel oil consumption norm of 0.5ml/kWh. From the actual data, it is observed that, while some of the stations have been able to achieve the norm, there are also some stations where the actuals are higher than the norm. As also discussed while dealing with station heat rate, there has been significant degradation in the performance parameters mainly on account of the backing down of generating stations and low demand, resulting in lower PLF during certain years of operation. However, considering the fact that the impact of low-load operations on operating parameters including SFC, are allowed through compensation, CEA based on the analysis carried out on several such stations has proposed to continue with the existing norms with an additional 0.50 ml/kWh allowance to generating stations that have front-fired boilers.

19.5.3 With regard to lignite fired stations for NLCIL, it is observed that the actual five-year average secondary fuel consumption is within the Norms specified in Tariff Regulations, 2019 except for TPS-II Expansion and NNTPS on account of partial loading of power stations. CEA in its recommendations has recommended to retain the existing Norms of 1.00 ml/kWh. Since most of the stations have been able to achieve the SFC Norm approved under Tariff Regulations, 2019, the Commission proposes to retain the current norm of 1.00 ml/kWh for Lignite fired stations. Also, for stations based on CFBC technology, the Commission proposes to retain the current norm of 1.00 ml/kWh.

19.5.4 For Mejia TPS Unit 1-3 and Unit-4 of DVC, CEA, based on its analysis, has proposed the Norms of 1.0 ml/kWh. The Commission adopts the Norm of 1.00 ml/kWh for Mejia TPS Unit 1-3 and Unit-4 of DVC, as has been proposed by CEA.

19.6 Proposed Provisions

19.6.1 The Commission proposes provisions of Regulations 70 in the Draft Tariff Regulations which are reproduced below:

*"**70 Norms of Operation for thermal generating stations:***

(D) ***Secondary fuel oil consumption:***

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

(b) *For Coal-based generating stations with front fired boilers: 1.00 ml/kWh*

(c) *For Lignite-fired generating stations (Pulverised and CFBC): 1.00 ml/kWh*

(d) *For Coal-based generating stations of DVC:*

Mejia TPS (Unit 1 to 3)	*1.00 ml/kWh*
Mejia TPS (Unit 4)	*1.00 ml/kWh*

(e) *For Generating Stations based on Coal Rejects: 2.0 ml/kWh"*

20 Auxiliary Energy Consumption

20.1 Background

20.1.1 In a thermal power plant, a fraction of the power produced is consumed by the power-generating equipment and their auxiliaries such as fans, motors, etc. In the Tariff Regulations, 2001, the Commission separated norms for 200 MW and 500 MW series and for units with and without cooling towers. For 500 MW series, the Commission specified separate norms for electric boiler feed pump (BFP) and steam-driven BFP. Further, the Commission prescribed an additional 0.50% Auxiliary Energy Consumption (AEC) norm for units under stabilization. These norms were applicable to coal, lignite-fired and gas-based stations. Additionally, the Commission specified separate norms for Open-Cycle and Combined-Cycle Operations for gas-based stations.

20.1.2 The Commission, in the Tariff Regulations, 2004, stipulated separate norms for coal and lignite-based stations. Further, the Commission also specified relaxed norms for Talcher and Tanda TPS, taking cognizance of smaller- sized units and vintage of these stations. In the case of lignite fired stations of NLC, the Commission except for TPS-I (210 MW) and TPS-II (210 MW) specified additional AEC of 0.50% over and above the AEC norms specified for coal-fired stations. The Commission for TPS-I and TPS-II of NLC specified relaxed norms, taking cognizance of unit sizes and vintage of the units.

20.1.3 The Commission, in the Tariff Regulations, 2009, retained the norms for 200 MW and 500 MW. However, the Commission in the 2009 Tariff Regulations did not specify separate norms for the stabilization period. In the 2014 Tariff Regulations, the Commission retained the norms for 200 MW series but improved the norms for units with a capacity of 300 MW and above units by 0.50%.

20.1.4 The Commission, in the Tariff Regulations, 2019, retained the norms for 200 MW. However, the Commission in the Tariff Regulations, 2019, relaxed the norms for 500 MW and above units by 0.50%.

20.2 Existing Provisions of the Tariff Regulations, 2019

49 (E) Auxiliary Energy Consumption:

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

With Natural Draft cooling tower or without cooling tower

(i) 200 MW series	-	*8.50%*
(ii) 300 MW and above		
Steam driven boiler feed pumps	-	*5.75%*

Electrically driven boiler feed pumps - 8.00%

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

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

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

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

(b) For other Coal-based generating stations:

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

(c) Gas Turbine /Combined Cycle generating stations:

(i) Combined Cycle : 2.75%

(ii) Open Cycle : 1.0%

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

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

(d) Lignite-fired thermal generating stations:

(i) All generating stations with 200 MW sets and above:

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

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

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

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

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

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

Barsingsar : 0.056 kg/kWh

TPS-II (Expansion) : 0.046 kg/kWh

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

(E) ***Norms for consumption of reagent:*** *(1) The normative consumption of specific reagent for various technologies for reduction of emission of sulphur dioxide shall be as under:*

a. For Wet Limestone based Flue Gas De-sulphurisation (FGD) system: The specific limestone consumption (g/kWh) shall be worked out by following formula:

[K x SHR x S/CVPF] x [85/ LP]

Where,

S = Sulphur content in percentage,
LP = Limestone Purity in percentage,

SHR = Gross station heat rate, in kCal per kWh

CVPF = (a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal based thermal generating stations less 85 kCal/kg on account of variation during storage at generating station;

(b) Weighted Average Gross calorific value of lignite as received, in kCal per kg, as applicable for lignite based thermal generating stations:

Provided that value of K shall be equivalent to (35.2 x Design SO2 Removal Efficiency/96%) for units to comply with SO2 emission norm of 100/200 mg/Nm3 or (26.8 x Design SO2 Removal Efficiency/73%) for units to comply with SO2 emission norm of 600 mg/Nm3;

Provided further that the limestone purity shall not be less than 85%.

(b) For Lime Spray Dryer or Semi-dry Flue Gas Desulphurisation (FGD) system: The specific lime consumption shall be worked out based on minimum purity of lime (LP) as at 90% or more by applying formula [6 x 90 / LP] g/kWh;

(c) For Dry Sorbent Injection System (using sodium bicarbonate): The specific consumption

of sodium bicarbonate shall be 12 g per kWh at 100% purity.

(d) For CFBC Technology (furnace injection) based generating station: The specific limestone consumption for CFBC based generating station (furnace injection) shall be computed with the following formula:

[62.9 x S x SHR /CVPF] x [85/ LP]

Where,

S = Sulphur content in percentage, LP = Limestone Purity in percentage,

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

CVPF = (a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal based thermal generating stations less 85 kCal/kg on account of variation during storage at generating station;

(b) Weighted Average Gross calorific value of lignite as received, in kCal per kg as applicable for lignite based thermal generating stations;

(e) For Sea Water based Flue Gas Desulphurisation (FGD) system: The reagent used in sea water based Flue Gas Desulphurisation (FGD) system shall be NIL

(2) The normative consumption of specific reagent for various technologies for reduction of emission of oxide of nitrogen shall be as below:

(a) For Selective Non-Catalytic Reduction (SNCR) System: The specific urea consumption of SNCR system shall be 1.2 g per kWh at 100% purity of urea.

(b)For Selective Catalytic Reduction (SCR) System: The specific ammonia consumption of SCR system shall be 0.6 g per kWh at 100% purity of ammonia."

20.3 Issues discussed in the Approach Paper

20.3.1 The Approach Paper highlighted the following key issues on which comments were sought from stakeholders:

a) It is observed that the Central Generating Stations that used to operate at around 80%-85% PLF prior to FY 2013-14 have now been operating at part load and much below the target PLF due to need for higher RE integration. As these generating stations are operating at a much lower PLF, the actual performance data will also have a degradation impact. Further, as the generating stations are separately allowed degradation impact due to low load operations, it is felt that the norms may be fixed considering the ideal loading of generating units.

b) For those generating stations that have not been operating efficiently in the past and for which the Commission has been considering actual achievements to fix relaxed norms, in the interest of limited resources, such relaxation of norms may need reconsideration. This is necessary as the coal/lignite is a limited resource that needs to be consumed efficiently and can be reallocated to more efficient plants.

c) With regard to operational norms such as Heat Rate, Secondary Fuel Oil Consumption (SFOC), Auxiliary Consumption, and Boiler Efficiency, the revised norms that are superior to design parameters for the old generating stations may not be specified for such old generating stations.

20.4 Stakeholders' Response

20.4.1 In response to the issues brought out in the Approach Paper for consultation, the stakeholders submitted the following comments/suggestions.

a) Few Central Generating companies suggested that the Approach Paper proposes the operational norms at the ideal loading of generating units. However, the existing practice of fixing operational norms for SHR, SFOC and Auxiliary Consumptions at the normative level of 85% is well established and may be continued.

b) A few Central Generating companies submitted that Increase in Heat Rate, Auxiliary Consumption and O&M requirement due to co-firing with biomass pellets should be taken care of in the Tariff Norms and should not be considered for Merit Order Scheduling.

c) Few State Generating companies suggested that periodic reviews of norms may be conducted to ensure relevance and effectiveness through necessary changes.

d) Some private IPPs submitted that the provision for degradation impact on unit operation & performance is to be finalized and introduced in the system as a cost of flexibilization, which has also been emphasized in the Clause 45.12 of IEGC Regulation 2023.

e) Some private IPP submitted that separate operational norms for SHR, Auxiliary consumption, etc. may be defined based on the PLF.

20.5 Actual Auxiliary Energy Consumption (AEC)

20.5.1 The actual AEC for Coal based stations of NTPC from FY 2018-19 to FY 2022-23, considering correction factor as per Grid Code, are summarized below.

Table 53: Actual Auxiliary Energy Consumption for NTPC Generating Stations

Generating Stations	Type of Cooling System	Type of BFP	Existing Norms	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
200 MW Series									
Dadri Stage-I	NDCT	Electrical Driven BFP	8.50%	8.35	9.31	14.04	10.54	8.48	10.14
Kahalgaon-I	IDCT	Electrical Driven BFP	9.00%	9.24	9.48	9.62	9.21	9.88	9.49
Unchahar-I	IDCT	Electrical Driven BFP	9.00%	9.44	10.31	11.39	11.13	10.52	10.56
Unchahar-II	IDCT	Electrical Driven BFP	9.00%	9.36	10.04	10.88	10.73	10.20	10.24
Unchahar-III	IDCT	Electrical Driven BFP	9.00%	9.36	9.73	10.47	9.97	9.69	9.84
Vindhyachal-I	IDCT	Electrical Driven BFP	9.00%	8.64	8.66	8.81	8.81	8.76	8.74
Barauni 2	IDCT	Electrical Driven BFP	9.00%		9.10	10.35	9.27	9.28	9.50
Bongaigaon	IDCT	Electrical Driven BFP	9.00%	9.04	9.13	9.70	9.10	8.72	9.14
Average									**9.70**
500 MW Series									
Dadri Stage-II	NDCT	Steam Driven BFP	5.75%	5.02	6.23	6.29	6.02	6.07	5.93
Farraka Stage-III	IDCT	Steam Driven BFP	6.25%	6.25	6.17	6.44	6.51	6.43	6.36
Kahalgaon-II	IDCT	Steam Driven BFP	6.25%	5.85	6.08	6.42	5.73	5.83	5.98
Korba Stage-III	IDCT	Steam Driven BFP	6.25%	5.84	5.63	5.37	5.40	5.42	5.53
Mouda Stage-I	IDCT	Steam Driven BFP	6.25%	6.06	6.42	7.04	6.13	5.75	6.28
Ramagundam- III	IDCT	Steam Driven BFP	6.25%	5.25	6.09	5.98	6.29	7.55	6.23
Rihand-I	IDCT	Electrical Driven BFP	8.00%	7.80	8.05	7.60	7.82	8.21	7.89
Simhadri-I	NDCT	Steam Driven BFP	5.75%	5.93	6.40	6.87	5.95	5.88	6.21
Simhadri-II	NDCT	Steam Driven BFP	5.75%	5.95	6.49	6.47	5.97	5.90	6.16
Sipat -II	IDCT	Steam Driven BFP	6.25%	5.61	5.84	5.80	5.72	6.02	5.80
Talcher I	IDCT	Steam Driven BFP	6.25%	7.89	8.21	7.49	7.50	7.27	7.67
Talcher II	IDCT	Steam Driven BFP	6.25%	5.80	6.24	6.09	5.90	5.74	5.95
Vindhyachal-II	IDCT	Steam Driven & Tube Mill	7.05%	5.83	6.44	6.31	6.32	6.21	6.22
Vindhyachal-III	IDCT	Steam Driven	6.25%	5.25	5.47	5.37	5.61	5.58	5.46
Vindhyachal-IV	IDCT	Steam Driven	6.25%	5.56	5.67	5.44	5.56	5.48	5.54
Unchahar – IV	IDCT	Steam Driven BFP	6.25%	7.77	6.37	6.71	6.24	6.90	6.80
Average									**6.25**

20.5.2 The actual AEC for Kanti MTPS Stage II and Tanda generating stations of NTPC from FY 2018-19 to FY 2022-23, are summarized below:

Table 54: Actual AEC for Kanti and Tanda Generating Stations

Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
Kanti MTPS Stage-II	10.60	10.22	10.37	9.98	9.55	10.14
Tanda-I TPP	12.86	13.44	14.02	14.51	14.44	13.85

20.5.3 It is observed that, except for a few stations, most of the NTPC stations were able to achieve the AEC norms as specified in Tariff Regulations, 2019. As also discussed earlier, the generating stations are also entitled to compensation due to partial load, which compensates for degradation.

20.5.4 The actual AEC for Lignite based generating stations of NLC from FY 2018-19 to FY 2022-23, are summarized below.

Table 55: Actual Auxiliary Energy Consumption for NLC Generating Stations

Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average
TPS -1 EXP	8.21	8.44	9.10	8.65	9.05	8.69
TPS - 2 Stage 1	9.87	9.89	9.67	9.70	11.50	10.13
TPS - 2 Stage 2	9.75	9.93	10.06	9.56	10.22	9.90
TPS - 2 EXP	15.18	16.77	15.64	15.46	15.65	15.74
Barsingsar TPP	13.12	12.75	13.11	12.39	12.36	12.75
NNTPS	-	9.62	7.84	6.80	6.10	7.59

20.5.5 In the case of NLC, the actual AEC for the stations are almost at the same level as current norms, except in the case of Barsingsar TPP, where the actual five-year average AEC works out to around 12.75% as against the norm of 12.50% and for TPS-2 Expansion, the actual five-year average AEC works out to around 10.13% as against the current norm of 10.00%.

20.5.6 The AEC for gas based generating stations (other than small gas turbine stations) of NTPC and NEEPCO from FY 2018-19 to FY 2022-23, are summarized below:

Table 56: Actual AEC for Gas based Generating Stations

Generating Stations	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Five Year Average	Existing Norms
NTPC							
Anta GPS	3.69	6.73	4.78	9.85	6.70	6.35	3.30
Auraiya GPS	3.94	4.21	3.18	3.61	6.60	4.31	3.30
Kawas GPP	-	-	-	-	5.20	5.20	3.30
Gandhar GPP	2.84	4.36	4.31	4.55	5.50	4.31	3.30
Faridabad GPP	2.99	3.18	2.69	7.54	263.40	55.96	3.30
Dadri GPP	3.44	3.77	3.86	5.92	5.40	4.48	3.30
NEEPCO							
Agartala GPS	3.55	3.25	3.72	3.44	3.37	3.47	3.30
Assam GPS	2.56	2.52	2.49	2.13	2.37	2.41	3.30
Tripura GPS	4.25	3.88	4.41	3.40	3.50	3.89	3.30

20.5.7 For NTPC gas-based stations, the actual AEC ranges between 4.31% to 6.35% as against the current norm of 3.30%, on account of lower PLF. The Agartala GPS was converted to a Combined Cycle Power Plant with the addition of two Steam Turbine Generating units (STG) comprising a capacity of 25.5 MW, each with an effect from 29.7.2015 and 1.9.2015, respectively. The AEC for Agartala GPS and Tripura has been slightly higher than the AEC norms specified.

20.5.8 The Commission observed that complete data pertaining to AEC with respect to Thermal Generating stations was not submitted by the DVC. Therefore, the Commission has not considered the same for analysis.

20.6 Commission's View

20.6.1 As discussed in the preceding section, the Commission has carried out the analysis of actual performance achieved by various generating stations during FY 2018-19 to FY 2022-23 vis-à-vis existing norms.

20.6.2 The Commission has also referred to the following recommendations made by CEA with regard to AEC:

i. Coal-based Thermal Generating Stations except at (ii) & (iii) below:

(Auxiliary energy consumption as% of gross generation) with NDCT/Once-through	
200/210/250 MW sets	8.5%
500-600 MW sets with TDBFP (Sub-critical)	5.25%
660-800 MW sets with TDBFP (Super-critical)	5.25%

In the case of thermal units of 500 MW and above with electrically driven Boiler Feed Pumps, the auxiliary energy consumption allowed shall be 8.0%.

In the case of thermal generating stations provided with Induced Draft Cooling Tower (IDCT), the additional auxiliary energy consumption allowed shall be 0.5%.

In addition, thermal generating stations provided with tube and ball mills, the additional auxiliary energy consumption allowed shall be 0.8%.

In the case of thermal generating stations provided with Dry Cooling Systems, the additional auxiliary energy consumption allowed shall be as below:

Type of Dry Cooling System	**(% of Gross Generation)**
Direct cooling air-cooled condensers with Mechanical Draft Fans	1.0%
Indirect cooling system employing jet condensers with pressure recovery turbine and the Natural Draft Tower	0.5%

ii. NTPC's coal based thermal generating stations:

Tanda Thermal Power Station	12.00%

iii. DVC's coal based thermal generating stations:

Chandrapur Thermal Power Station (2x250 MW)	9.50%

Lignite based Thermal Generating Stations:

i. For all pulverized lignite fired thermal generating stations with 200 MW sets and above, the auxiliary energy consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations except at (ii) below

ii. M/s NLCIL's pulverized lignite fired generating stations:

TPS-II stage- I (630 MW)	10%
TPS- II stage- II (840 MW)	10%

iii. For lignite fired thermal generating stations using CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations except at (iv) below.

iv. M/s NLCIL's CFBC technology based lignite fired generating stations:

Barsingsar TPS (2x125 MW)	12.5 %
TPS-II Expansion (2x250 MW)	12.5 %

Gas Turbine/ Combined Cycle Generating Stations:

i. Gas turbine/ combined cycle generating stations, except those at (ii) below:

a) Combined cycle generating stations : 2.75%

b) Open cycle generating stations : 1.00%

In the case of Combine Cycle Generating Stations using electric motor driven Gas Booster Compressor, the Auxiliary Energy Consumption shall be 3.30% (including impact of air-cooled condensers for Steam Turbine Generators).

Further, additional Auxiliary Energy Consumption of 0.35% shall be allowed for stations having direct cooling air-cooled condensers with mechanical draft fans.

ii. a) NEEPCO's Tripura CCPP (101 MW) : 3.5%

b) OTPC Palatana CCPP (726.6 MW) : 3.5%

20.6.3 After examining and reviewing the comments/suggestions of stakeholders and the recommendations received from CEA, the Commission proposes to adopt CEA recommendations on auxiliary energy consumption.

20.7 Proposed Provisions

20.7.1 In view of the above analysis, the Commission therefore proposed the following Regulation in the Draft Tariff Regulation.

"70. ***Norms of Operation for thermal generating stations:***

….

(E) Auxiliary Energy Consumption

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

S. No.	***Generating Station***	***With Natural Draft cooling tower or without cooling tower***
(i)	*200 MW series*	*8.50%*
(ii)	*300/330/350/500 MW series*	
	Steam driven boiler feed pumps	*5.25%*
	Electrically driven boiler feed pumps	*8.00%*
(iii)	*600 MW and above*	
	Steam driven boiler feed pumps	*5.25%*
	Electrically driven boiler feed pumps	*8.00%*

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

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

Type of Dry Cooling System	***(% of gross generation)***
Direct cooling air cooled condensers with mechanical draft fans	*1.0%*
Indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower	*0.5%*

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

(b) For Other Coal-based generating stations:

(i)	*Tanda Thermal Power Station*	*12.00%*
(ii)	*Chandrapura TPS (Unit 7 to 8)*	*9.50%*

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

(i) *Combined Cycle* *: 2.75%*

(ii) *Open Cycle* *: 1.00%*

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

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

(iii) *Tripura CCPP: 3.50%*

(iv) *OTPC Palatana CCPP: 3.50%*

(d) For Lignite-fired thermal generating stations:

(i) *For all generating stations with 200 MW sets and above:*

The auxiliary energy consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (E) (a) Provided that for the lignite fired stations using CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (E) (a) above.

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

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

TPS-II Stage-I and Stage-II	*10.00%*
TPS-II (Expansion)	*12.50%*

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

(f) Norms of Auxiliary energy consumption for the emission control system (AUX_{en}) of thermal generating stations:

Name of Technology	**AUX_{en} (as % of grossgeneration)**
(1) For reduction of emission of Sulphur dioxide:	
a) Wet Limestone based FGD system (without Gas to Gas heater)	*1.0%*
b) Lime Spray Dryer or Semi dry FGD System	*1.0%*
c) Dry Sorbent Injection System (using Sodium bicarbonate)	*NIL*
d) For CFBC Power plant (furnace injection)	*NIL*
e) Sea water based FGD system (without Gas to Gas heater)	*1.00%*
(2) For reduction of emission of oxide of nitrogen:	

Name of Technology	***AUX_{en} (as % of grossgeneration)***
a) Selective Non-Catalytic Reduction system	*NIL*
b) Selective Catalytic Reduction system	*0.2%*

Provided that where the technology is installed with a "Gas to Gas" heater, AUX_{en} specified above shall be increased by 0.20% of gross generation."

(F) ***Norms of consumption of reagent:***

(1) The normative consumption of specific reagent for various technologies for reduction of emission of sulphur dioxide shall be as under:

(a) For Wet Limestone based Flue Gas De-sulphurisation (FGD) system: The specific limestone consumption (g/kWh) shall be worked out by following formula:

$$\frac{K \text{ x Normative heat rate (kcal/kWh) x Sulphur content of coal (\%) kg/kWh}}{\text{GCV of Coal (kcal/kg)}}$$

Where,

GCV = (a) Weighted Average Gross calorific value of coal in kCal per kg for coal based thermal generating stations computed in accordance with Regulation 60 of these regulations;

(b)Weighted Average Gross calorific value of lignite as received, in kCal per kg, as applicable for lignite based thermal generating stations:

Provided that value of K shall be equivalent to 35.2 for units to comply with SO_2 emission norm of 100/200 mg/Nm^3 or 26.8 for units to comply with SO_2 emission norm of 600 mg/Nm^3;

Provided further that the limestone purity shall not be less than 85%.

(b) For Lime Spray Dryer or Semi-dry Flue Gas Desulphurisation (FGD) system: The specific lime consumption shall be worked out based on minimum purity of lime (LP) as at 90% or more by applying formula [6] g/kWh;

(c)For Dry Sorbent Injection System (using sodium bicarbonate): The specific

consumption of sodium bicarbonate shall be 12 g per kWh at 100% purity.

(d)For CFBC Technology (furnace injection) based generating station: The specific limestone consumption for CFBC based generating station (furnace injection) shall be computed with the following formula:

[62.9 x S x SHR/ CVPF]

Where

S = Sulphur content in percentage,

LP = Limestone Purity in percentage,

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

CVPF = (a) Weighted Average Gross calorific value of lignite as received, in kCal per kg as applicable for lignite based thermal generating stations;

(e) For Sea Water based Flue Gas Desulphurisation (FGD) system: The reagent used in sea water based Flue Gas Desulphurisation (FGD) system shall be NIL

(2) The normative consumption of specific reagent for various technologies for reduction of emission of oxide of nitrogen shall be as below:

(a)For Selective Non-Catalytic Reduction (SNCR) System: The specific urea consumption of SNCR system shall be 1.2 g per kWh at 100% purity of urea.

(b)For Selective Catalytic Reduction (SCR) System: The specific ammonia consumption of SCR system shall be 0.6 g per kWh at 100% purity of ammonia."

21 Norms for Operation for Hydro Generating Stations

21.1 Background

21.1.1 Unlike thermal generating stations, in the case of hydro generating stations, unit sizes depend upon various factors, due to which there is less scope for standardization. Therefore, the operating norms are more specific and are based on the type, technology, and size of the power plant.

21.1.2 In the Tariff Regulations, 2009, the Commission replaced Capacity Index Mechanism with the concept of NAPAF. The Commission with an objective of equal sharing of the hydrological risk between the generating company and the beneficiaries, bifurcated the recovery mechanism for hydro generating stations into NAPAF linked Capacity Charge (50% of AFC) and Design Energy linked Energy Charge (balance 50% of AFC). The Commission specified NAPAF for the hydro generating stations, and the recovery of Capacity Charges was linked to actual availability. In the Tariff Regulations, 2014, as well as in the Tariff Regulations, 2019, the Operational Norms for hydro generating stations continue to include the norms for Auxiliary Consumption, Transformation Losses and NAPAF.

21.2 Existing Provisions of the Tariff Regulations, 2019

21.2.1 The existing Tariff Regulations, 2019, notified by the Commission, consists of the following provision regarding Operational Norms for Hydro Generating Stations are as under:

*"**50. Norms of operation for hydro generating stations:** The norms of operation as given hereunder shall apply to hydro generating station:*

(a) Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8%, and where plant availability is not affected by silt: 90%;

(b) In case of storage and pondage type plants with head variation between full reservoir level and minimum draw down level is more than 8% and when plant availability is not affected by silt, the month wise peaking capability as provided by the project authorities in the DPR (approved by CEA or the State Government) shall form basis of fixation of NAPAF;

(c) Pondage type plants where plant availability is significantly affected by silt: 85%. Run-of-river generating stations: NAPAF to be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant.

(2) A further allowance may be made by the Commission in NAPAF determination under special circumstances, e.g. abnormal silt problem or other operating conditions, and known plant limitations.

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

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

Station	***Type of Plant***	***Plant Capacity No. of Units x MW***	***NAPAF (%)***
THDC			
THDC Stage I	*Storage*	*4x250*	*80*
KHEP	*Storage*	*4x100*	*68*
NHPC			
Bairasul	*Pondage*	*3x60*	*90*
Loktak	*Pondage*	*3x35*	*88*
Salal	*ROR*	*6x115*	*64*
Tanakpur	*ROR*	*3x31.4*	*59*
Chamera-I	*Pondage*	*3x180*	*90*
Uri I	*ROR*	*4x120*	*74*
Rangit	*Pondage*	*3x20*	*90*
Chamera-II	*Pondage*	*3x100*	*90*
Dhauliganga	*Pondage*	*4x70*	*78*
Dulhasti	*Pondage*	*3x130*	*90*
Teesta-V	*Pondage*	*3x170*	*87*
Sewa-II	*Pondage*	*3x40*	*89*
TLDP III	*Pondage*	*4x33*	*77*
Chamera III	*Pondage*	*3x77*	*87*
Chutak	*ROR*	*4x11*	*48*
Nimmo Bazgo	*Pondage*	*3x15*	*70*
Uri II	*ROR*	*4x60*	*70*
Parbati III	*Pondage*	*4x130*	*43*
NHDC			
Indira Sagar	*Storage*	*8x125*	*87*
Omkareshwar	*Pondage*	*8x65*	*90*
NEEPCO			
Kopili I	*Storage*	*4x50*	*69*
Khandong	*Storage*	*2x25*	*67*
Kopili II	*Storage*	*1x25*	*69*
Doyang	*Storage*	*3x25*	*70*
Ranganadi	*Pondage*	*3x135*	*88*
NTPC			
Koldam	*Storage*	*4x200*	*90*
SJVNL			
Nathpa Jhakri	*ROR*	*6x250*	*90*
Rampur	*ROR*	*6x68.67*	*85*
DVC			
Panchet	*Storage*	*2x40*	*80*

Tilaya	*Storage*	*2x2*	*80*
Maithon	*Storage*	*3x20*	*80*
Teesta III	*Pondage*	*6x200*	*85*

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

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

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

(6) Auxiliary Energy Consumption (AUX):

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

21.3 Issues discussed in the Approach Paper

21.3.1 The following issues were highlighted in the Approach Paper for consultation:

"5.1.1 Review of Existing Norms

Historically, the target availability has been determined based on the data available for the past few years. The recovery of fixed charges was linked to the Plant Availability Factor (PAF). The Normative Annual Plant Availability Factor (NAPAF) has been specified considering the past years' data and best industry practices. However, due to changing dynamics, such as technological improvement, better O&M practices, and shorter shutdowns and outages, the PAF has improved. However, a shortage of domestic fuel affects PAF, and it has been an area of concern in recent years. In the event of bridging the gap through e-auction or imported coal (other than fuel arrangements agreed in PPA), the need for prior consent of beneficiaries, the maximum permissible limit of blending, etc. has also been deliberated under Section 5.9 of this Approach Paper.

Similarly, for Hydro generating stations, PAF is impacted due to changing hydrology, and restrictions imposed on the flow of water, and changes in the pattern of water usage in the case of multipurpose dam projects.

In view of the above, the existing norms of NAPAF may need review by considering past years' PAF, the procurement of coal from alternate sources, other than designated fuel supply agreements, changes in hydrology, etc.

Further, it is observed that current Regulations, although specifies the mechanism for computing PAF of storage-based hydro generating stations, do not specify a methodology for computing PAF of Run-of River (ROR) Plants. There is a need to specify a mechanism for the same, and based on such a specified mechanism, the current NAPAF value may need reconsideration.

One option can be to re-introduce the methodology that was being adopted in the Tariff Regulations 2004. Based on Regulation XI (b) under Chapter 3 of the Tariff Regulations, 2004, the methodology can be specified as follows:

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

Comments and suggestions are sought from stakeholders on the above suggested option and any other methodology that can be considered for the computation of plant availability for ROR based hydro generating plants."

21.4 Stakeholders' Response

21.4.1 In response to the issues brought out in the Approach Paper for consultation, the stakeholders submitted the following comments/suggestions.

a) NHPC has stated that DC of purely RoR Hydro Power Plants may be calculated based on average of maximum declarations for any 12-time blocks (3 hours) in a day, which is the current practice subject to the maximum of NAPAF presently fixed by CERC to avoid further stressing the plant. However, more clarity may be provided on whether that calculation of PAF shall be as per DC calculation as defined in the approach paper or the methodology of the Capacity index will be introduced for RoR plants. For recovery of energy charge for hydro generating stations, the Commission may continue with the existing mechanism of recovery of AFC.

b) THDCIL submitted that the Operation of Tehri PSP in turbine mode affects the daily pattern of the reservoir level and available head for Tehri HPP and Koteshwar HEP. Hence, past available PAF data may not be true representative for reviewing the NAPAF of these plants. Accordingly, the NAPAF of these plants may be revised to its Designed value. The same may be reviewed once plant' PAFs are available after the commissioning of Tehri PSP.

c) SJVN submitted that existing norms of NAPAF for existing hydro plants may be continued without revision. Declared Capacity of purely RoR Hydro Power Plants may be considered on an average of maximum declaration of any 12 time blocks (3 hours) in a day as per current practice.

21.5 Commission's View

21.5.1 The Commission, after reviewing the stakeholders' suggestions/comments and based on the actual five years' data for PAF (Annexure I) and AEC (Annexure II) has proposed as follows.

<u>NAPAF</u>

21.5.2 As regards the actual availability achieved by the hydro generating stations, it is observed that most of the generating stations achieved much higher PAF as compared to the current normative annual plant availability factor (NAPAF) norms. Based on the review of actual PAF achieved by the generating stations for the period FY 2018-19 to FY 2022-23, the Commission has proposed the NAPAF norms for the tariff period 2024-29 period and is as shown in the table below.

Table 57: Actual and Proposed NAPAF for Hydro Generating Stations

Generating Stations	PAF Actuals					Average	Existing NAPAF Norms	Proposed NAPAF Norms
	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23			
THDC								
THDC Stage I	84.52	82.77	86.09	83.73	84.09	84.24	80.00	80.00
KHEP	68.03	76.31	70.13	68.61	68.66	70.35	68.00	68.00
NHPC								
Bairasul	75.09	89.49	76.89	80.62	88.05	82.03	90.00	90.00
Loktak	97.87	90.64	90.52	97.42	95.19	94.33	88.00	88.00
Salal	**84.05**	**97.43**	**94.04**	**89.77**	**90.05**	**91.07**	**64.00**	**75.00**
Tanakpur	**74.07**	**84.41**	**73.90**	**81.21**	**86.21**	**79.96**	**59.00**	**70.00**
Chamera-I	99.49	95.19	97.37	89.80	93.08	94.98	90.00	90.00
Uri I	**89.22**	**93.61**	**91.29**	**95.17**	**91.26**	**92.11**	**74.00**	**80.00**
Rangit	95.68	95.35	86.73	95.82	90.31	92.78	90.00	90.00
Chamera-II	94.15	54.89	59.11	96.22	97.1	80.30	90.00	90.00
Dhauliganga	**91.39**	**98.99**	**96.05**	**99.56**	**98.16**	**96.83**	**78.00**	**85.00**
Dulhasti	89.58	79.75	101.44	100.55	92.01	92.67	90.00	90.00
Teesta-V	98.23	97.50	99.33	98.03	100.38	98.69	87.00	87.00

Generating Stations	PAF Actuals					Average	Existing NAPAF Norms	Proposed NAPAF Norms
	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23			
Sewa-II	103.34	104.04	53.39	6.69	99.84	73.46	89.00	89.00
TLDP III	**95.71**	**95.43**	**93.14**	**93.36**	**84.39**	**92.41**	**77.00**	**80.00**
Chamera III	90.96	93.16	97.40	99.40	96.32	95.45	87.00	87.00
Chutak	51.92	51.05	46.99	57.71	61.83	53.90	48.00	48.00
Nimmo Bazgo	71.42	75.02	72.70	87.38	92.24	79.75	70.00	70.00
Uri II	**90.29**	**97.91**	**100.71**	**95.49**	**90.91**	**95.06**	**70.00**	**80.00**
Parbati III	**51.76**	**61.83**	**56.08**	**59.73**	**54.31**	**56.74**	**43.00**	**45.00**
TLDP IV	93.64	89.42	94.46	95.61	86.64	91.95	90.00	90.00
NHDC								
Indira Sagar	92.42	94.05	94.05	90.61	97.37	93.70	87.00	87.00
Omkareshwar	96.71	94.85	96.29	96.85	97.51	96.44	90.00	90.00
NEEPCO								
Kopili I	74.16	87.06	93.44	NA	NA	84.89	69.00	69.00
Khandong	70.00	75.84	55.05	34.87	72.92	61.74	67.00	67.00
Kopili II	75.82	75.26	57.97	0.00	15.27	44.86	69.00	69.00
Doyang	**71.52**	**59.74**	**65.63**	**60.32**	**62.39**	**63.92**	**70.00**	**65.00**
Ranganadi	93.67	82.50	84.73	95.51	95.77	90.44	88.00	88.00
NTPC								
Koldam*	99.58	107.72	108.75	107.59	108.69	106.47	90.00	90.00
SJVNL								
Nathpa Jhakri	103.51	105.48	105.38	106.60	106.65	104.60	90.00	90.00
Rampur	103.26	104.88	104.80	106.41	106.09	104.28	85.00	85.00
DVC#								
Panchet	-	-	-	-	-	-	80.00	80.00
Tilaya	-	-	-	-	-	-	80.00	80.00
Maithon	-	-	-	-	-	-	80.00	80.00

* Data for FY 2022-23 not available (Average from FY 2017-18 to FY 2021-22)
#DVC did not submit the actual data

Auxiliary Energy Consumption (AEC)

21.5.3 The Commission has observed that, hydro generating stations with 'Surface – Static Excitation Field', having installed capacity below 200 MW, have higher actual AEC than the existing norm of 1.2% except for NHPC's TLDP IV which has achieved the Actual average AEC lower than the norms of 1.20%. Further, the actual AEC of all hydro generating stations of NEEPCO are much lower than the existing norms. Based on these observations, the Commission proposes to retain the following norms for the Control Period 2024-29.

Table 58: Existing and Proposed AEC Norms for Hydro Generating Stations

Type of Station	Existing AEC Norms (All Capacities)	Proposed AEC Norms	
		Installed Capacity above 200 MW	Installed Capacity up to 200 MW
Surface			
Rotating Excitation	0.7%	0.7%	0.7%

Type of Station	Existing AEC Norms (All Capacities)	Proposed AEC Norms	
		Installed Capacity above 200 MW	**Installed Capacity up to 200 MW**
Static	1.0%/1.20%	1.0%	1.2%
Underground			
Rotating Excitation	0.9%	0.9%	0.9%
Static	1.2%/1.3%	1.2%	1.3%

21.6 Proposed Provisions

The Commission, based on the above changes, has proposed provisions of Regulations 71 in the Draft Tariff Regulations which are reproduced below:

Norms of Operation for hydro generating stations

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

(A) Normative Annual Plant Availability Factor (NAPAF): (1) The following normative annual plant availability factor (NAPAF) shall apply to hydro generating station:

(a) *Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8%, and where plant availability is not affected by silt: 90%;*

(b) *In the case of storage and pondage type plants with head variation between full reservoir level and minimum draw down level is more than 8% and when plant availability is not affected by silt, the month wise peaking capability as provided by the project authorities in the DPR (approved by CEA or the State Government) shall form the basis of fixation of NAPAF.*

(c) *Pondage type plants where plant availability is significantly affected by silt: 85%.*

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

(2) *A further allowance may be made by the Commission in NAPAF determination under special circumstances, e.g. abnormal silt problem or other operating conditions, and known plant limitations.*

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

(4) *Based on the above, the Normative annual plant availability factor (NAPAF) of*

the hydro generating stations already in operation shall be as follows:

Station	***Type of Plant***	***Plant Capacity No. of Units x MW***	***NAPAF (%)***
THDC			
THDC Stage I	*Storage*	*4x250*	*80*
KHEP	*Storage*	*4x100*	*68*
NHPC			
Bairasul	*Pondage*	*3x60*	*90*
Loktak	*Pondage*	*3x35*	*88*
Salal	*ROR*	*6x115*	*75*
Tanakpur	*ROR*	*3x31.4*	*70*
Chamera-I	*Pondage*	*3x180*	*90*
Uri I	*ROR*	*4x120*	*80*
Rangit	*Pondage*	*3x20*	*90*
Chamera-II	*Pondage*	*3x100*	*90*
Dhauliganga	*Pondage*	*4x70*	*85*
Dulhasti	*Pondage*	*3x130*	*90*
Teesta-V	*Pondage*	*3x170*	*87*
Sewa-II	*Pondage*	*3x40*	*89*
TLDP III	*Pondage*	*4x33*	*80*
Chamera III	*Pondage*	*3x77*	*87*
Chutak	*ROR*	*4x11*	*48*
Nimmo Bazgo	*Pondage*	*3x15*	*70*
Uri II	*ROR*	*4x60*	*80*
Parbati III	*Pondage*	*4x130*	*45*
TLDP IV	*ROR*	*4x40*	*90*
NHDC			
Indira Sagar	*Storage*	*8x125*	*87*
Omkareshwar	*Pondage*	*8x65*	*90*
NEEPCO			
Kopili I	*Storage*	*4x50*	*69*
Khandong	*Storage*	*2x25*	*67*
Kopili II	*Storage*	*1x25*	*69*
Doyang	*Storage*	*3x25*	*65*
Ranganadi	*Pondage*	*3x135*	*88*
NTPC			
Koldam	*Storage*	*4x200*	*90*
SJVNL			
Nathpa Jhakri	*Pondage*	*6x250*	*90*
Rampur	*Pondage*	*6x68.67*	*85*
DVC			
Panchet	*Storage*	*2x40*	*80*

Station	***Type of Plant***	***Plant Capacity No. of Units x MW***	***NAPAF (%)***
Tilaya	*Storage*	*2x2*	*80*
Maithon	*Storage*	*3x20*	*80*

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

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

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

(C) Auxiliary Energy Consumption (AEC):

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

……..”

22 Norms of Operation for Transmission System

22.1 Background

22.1.1 The Commission has been specifying different NATAF for the purpose of recovery of transmission charges and for incentive purposes. During the Tariff Period 2014-19, Target Availability for recovery of full transmission charges for AC System (98% for Recovery of Annual Fixed Charges and 98.50% for Incentive Consideration) as well as HVDC System (95% for Recovery of Annual Fixed Charges and 96% for Incentive Consideration), were kept same as that of Tariff Regulations, 2009. During the Tariff Period 2019-24, the norms for Target Availability for recovery of full transmission charges for AC System as well as HVDC System were retained at 98% and 95% respectively. The norms for Target Availability for Incentive consideration for AC System were retained at 98.50% and were further tightened to 97.50% for the HVDC System during FY 2019-24 Tariff Period.

22.2 Existing Provisions of the Tariff Regulations, 2019

"***51. Normative Annual Transmission System Availability Factor (NATAF) shall be as under:***

a) For recovery of Annual Fixed Charges:

(1) AC system: 98.00%

(2) HVDC bi-pole links: 95.00% and HVDC back-to-back stations: 95%

b) For incentive NATAF shall be as under:

(1) AC system: 98.50%

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

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

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

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

***39. Auxiliary Energy Consumption in the sub-station**:*

(a) AC System

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

(b) HVDC sub-station

HVDC sub-station: For auxiliary energy consumption in HVDC sub-stations, the Central Government may allocate an appropriate share from one or more ISGS.

The charges for such power shall be borne by the transmission licensee from the normative operation and maintenance expenses"

22.3 Analysis of Actual Performance and Commission's Proposal

22.3.1 PGCIL has submitted region-wise transmission system availability from FY 2018-19 to FY 2022-23 for both AC and HVDC Systems, which is summarized below.

Table 59: Transmission System Availability of AC Transmission System (%)

Region	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Average
NR	98.96	99.65	99.61	99.43	99.66	**99.46**
WR	99.69	99.76	99.66	99.76	99.78	**99.73**
ER	99.92	99.15	99.91	99.90	99.92	**99.76**
SR	99.92	99.89	99.81	99.86	99.85	**99.87**
NER	99.90	99.87	99.87	99.86	99.85	**99.87**

Table 60: Transmission System Availability of HVDC Bipole Tx System (%)

Region	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	Average
HVDC Consolidated*	-	97.65	98.57	97.65	98.44	**98.07**

**HVDC Consolidated is a mix data provided by PGCIL consisting of Inter Regional Bi-Pole, BTB HVDC Systems and Northern Regional HVDC System.*

22.3.2 It is observed that the average transmission system availability for regional AC

Transmission System in five regions during FY 2018-19 to FY 2022-23 ranges from 99.46% to 99.87%. In the case of HVDC Transmission System and for HVDC bipole and back-to-back schemes, the average transmission availability is 98.07%.

22.3.3 In the case of HVDC sub-stations where the Central Government has allocated an appropriate share from one or more ISGS, the charges for such power are included in operation and maintenance expenses and therefore, the same shall be excluded from Auxiliary Energy Consumption norms.

22.3.4 In view of the above, the Commission proposes to continue with the existing norms with regard to the Normative Annual transmission System Availability Factor (NATAF) and auxiliary consumption.

22.4 Transmission System Availability Factor – Proposed Norms

22.4.1 The Commission proposes provisions of Regulations 72 in the Draft Tariff Regulations which are reproduced below:

"72. Normative Annual Transmission System Availability Factor (NATAF):

(a) For recovery of Annual Fixed Charges:

(1) *AC system: 98.00%;*

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

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

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

(1) *AC system: 98.50%;*

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

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

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

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

73. Auxiliary Energy Consumption in the sub-station:

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

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

23 Integrated Coal or Lignite Mine

23.1 Background

23.1.1 Government of India, on 21st October 2014, has notified "The Coal Mines (Special Provisions) Ordinance, 2014 [now "The Coal Mines (Special Provisions) Act, 2015 (11 of 2015) or "The Coal Mine Act"] which provides for the coal allocation through public auction or through allotment order. As per Section 5 of the Coal Mine Act, the allocation of mine through allotment order is allowed to a Government Company and to Case-2 generation projects.

23.1.2 The coal mines have been allotted to various Government Companies and entities such as NTPC Ltd., Damodar Valley Corporation (DVC) and THDC for the specified end use of power generation. Pakri-Barwadih coal mine was allotted to NTPC Ltd. prior to promulgation of the Coal Mine Act, while the remaining coal blocks namely, Chatti-Bariatu & Chatti-Bariatu (south), Kerandari, Dulanaga, Talaipalli, Benai, Bhalumuda and Mandakini-B have been allotted to NTPC Ltd. after promulgation of the Coal Mine Act, by the Government of India through Government dispensation route. All of these mines have been allotted by the Government of India through an Allotment Order, followed by a Coal Block Development and Production Agreement (CMDPA).

23.1.3 Unlike allocation by auction, the allocation by Allotment Order on the basis of Government dispensation, is without specifying any cost of coal mine or price of coal. The allotment documents and standard Coal Mine Development and Production Agreement (CMDPA) issued by the Ministry of Coal, GoI, do not provide any coal price for using coal in specified end use plants, except specifying the end use as power generation.

23.1.4 The Commission vide the second amendment dated 19.2.2021 to the Tariff Regulations, 2019, had notified the provisions for the determination of input price of coal and lignite from the integrated mine(s). The Commission, vide the Second Amendment to Tariff Regulations, 2019, has incorporated provisions with regard to the determination of the input price of coal and lignite, wherein such mines have been allocated to the generating stations. The Commission, before specifying the norms, had constituted a Working Group to suggest a regulatory framework for the determination of input price of the coal and lignite. The Commission, on the basis of the report submitted and after considering the suggestions received from various stakeholders, notified the second amendment to the Tariff Regulations, 2019 on 19.02.2021 which specified the terms of the determination of the input price of coal to be considered for the determination of energy charges for power stations with integrated mine.

23.2 Existing Provisions of the Tariff Regulations, 2019

23.2.1 The Tariff Regulations, 2019, for computation of input price of coal and lignite from integrated mine are as follows:

*"**36B. Run of Mine (ROM) Cost**: (1) Run of Mine Cost of coal in case of integrated mine(s) allocated through auction route under Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:*

ROM Cost = (Quoted Price of coal) + (Fixed Reserve Price)

Where,

(i) Quoted Price of coal is the Final Price Offer of coal in respect of the concerned coal block or mine, along with subsequent escalation, if any, as provided in the Coal Mine Development and Production

Provided that additional premium, if any, quoted by the generating company during auction, shall not be considered in the Run of Mine Cost;

(ii) Fixed Reserve Price is the fixed reserve price per tonne along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement: and

(iii) Capital cost under Regulation 36D and additional capital expenditure under Regulation 36E shall not be admissible for the purpose of ROM cost in respect of integrated mine(s) allocated through auction route.

(2) Run of Mine Cost of coal in case of integrated mine allocated through allotment route under Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:

ROM Cost = [(Annual Extraction Cost / ATQ) + Mining Charge] + (Fixed Reserve Price).

Where,

(i) Annual Extraction Cost is the cost of extraction of coal as computed in accordance with Regulation 36F of these regulations;

(ii) Mining Charge is the charge per tonne of coal paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable; and

(iii) Fixed Reserve Price is the fixed reserve price per tonne along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement.

(3) Run of Mine Cost of lignite in case of integrated mine(s) for lignite shall be worked out as under:

ROM Cost = [(Annual Extraction Cost / ATQ) + (Mining Charge)]

Where,

(i) Annual Extraction Cost is the cost of extraction of lignite as computed in accordance with Regulation 36F of these regulations; and

(ii) Mining Charge is the charge per tonne of lignite paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable.

(4) The generating company shall adhere to the Mining Plan for extraction of coal or lignite on annual basis and shall submit a certificate to that effect from the Coal Controller or the competent authority:

Provided that deviations from the Mining Plan shall be considered only if such deviations have been approved by the Coal Controller or the revised Mining Plan has been approved by the competent authority.

(5) Run of Mine Cost of coal and lignite shall be worked out in terms of Rupees per tonne.

……..”

*"**36P. Adjustment on account of Non-tariff income (NTI Adjustment):** (1) Adjustment on account of non-tariff income (NTI Adjustment) for any year, such as income from sale of washery rejects in case of integrated mine of coal and profit, if any, from supply of coal to the Coal India Limited or merchant sale of coal as allowed under the Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:*

NTI Adjustment = (All Non-tariff income during the year)/(Actual quantity of coal or lignite extracted during the year)

(2) The adjustment on account of non-tariff income worked out in accordance with this Regulation shall not be applicable in case of the integrated mine(s) allocated through auction route under Coal Mines (Special Provisions) Act, 2015.”

23.3 Issues discussed in the Approach Paper

23.3.1 Following issue was brought out in the Approach Paper for consultation:

Any modifications that may be required to current tariff provisions with regard to the determination of the input price of coal and lignite from integrated mines.

23.4 Stakeholders' Response

23.4.1 Stakeholders have submitted the following suggestions on this issue.

a) Some Central Generating Companies submitted that CUF of 80% with proportionate recovery of fixed cost in case the production is more than 80% is in line with the Tariff Policy. It was submitted that RoE needs to be revised for Integrated Mines up to 15.5% from the existing 14% and additional capex may be allowed to enhance production from such mines. It was further submitted that incentive may be provided in case a higher GCV is achieved. The Generating Companies also submitted that formula for adjustment due to stripping ratio variations may not be required and the provisions may be stipulated for coal procurement from commercial mines without competitive bidding.

b) Some Discoms submitted that mining charges including crushing, transportation, handling, or washing charges in the Run of Mine (ROM) cost of coal mined from coal mines allocated through auction under the Coal Mines (Special Provisions) Act, 2015 may be allowed to be recovered through appropriate changes in the Tariff Regulations. It is submitted that appropriate changes may be made in the Tariff Regulations to absorb the impact of additional capital expenditure incurred on account of Change in Law or Force Majeure events or any other similar reasons on the input price of coal from the coal mines allocated through auction under Coal Mines (Special Provision) Act, 2015. It was further submitted that the Commission may make appropriate changes in the Regulations to allow recovery of mine closure expenses for the coal mines allocated through auction under the Coal Mines (Special Provision) Act, 2015, in line with those allocated through the allotment route.

c) Some Generating Companies proposed that ATQ should be set at 85% capacity, instead of providing relaxation as per existing regulations. It is further submitted that tax paid by the Generating Company should be allowed on 100% Input Price.

d) Most of the beneficiaries proposed that the existing mechanism may be continued. However, the prices may be limited to notified prices by CIL.

e) Some Central Generating Companies have submitted:

(i) Regulation prohibits additional capitalisation for procurement of heavy earth-moving machines (HEMM) and other equipment after peak capacity. Capital addition shall be allowed throughout the mine's life, unlike the thermal station.

(ii) Since the Operating cycle for due realization in the case of linked thermal Power station takes 45 days and all fixed expenses, including statutory payments, have to be made on time irrespective of realization. Therefore, the O&M expenses for 2 months may be considered while computing the interest of working capital.

(iii) Since the store and spare consumption in mines is high therefore, 30% of 2 months O&M for IoWC may be allowed.

(iv) Overburden removal expenses depend on factors like unfavorable stripping ratio, geological surprises, and hard strata. Therefore, O&M expenses should be allowed separately on an actual basis, similar to the 2014-19 control period.

(v) Mine closure expenses are deposited annually in the Escrow Account and are maintained as a short-term deposit, auto-renewed with accrued interest. These should not be adjusted from mine closure costs.

(vi) The NTI Adjustment clause may be amended considering the contradiction with the Mines and Minerals (Development and Regulation) Amendment Act, 2021, and the risks and expenditures borne by miners.

23.5 Commission's View

23.5.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders.

23.5.2 The Commission, for reasons stated above in para 2.2, has already reasoned out to modify the definition of ATQ for the purpose of recovery of fixed charges and therefore for the sake of brevity, is not reiterating the same. The Commission however would like to clarify that in case the quantity extracted is more than the ATQ but less than the quantity specified in the mine plan there shall be no incentives that the generating company shall be entitled to and in such cases for computation of ROM price the higher of the ATQ and actual quantity extracted shall be considered.

23.5.3 With regard to adjustment of non-tariff income (NTI), it is observed that there is no sharing of non-tariff income as is allowed in case of generating station and transmission licensee. The Commission is of the view that there should be some incentives for the utilities to increase NTI as the same shall be mutually beneficial and therefore the Commission proposes to share the NTI among beneficiaries and the mine owner. The Commission further observes that as the cost of all the facilities, including mining equipment such as heavy earth-moving machines (HEMM) is borne by the beneficiaries and therefore the Commission proposes to share the NTI in between the beneficiaries and the mine owner in the ratio of 2:1.

23.5.4 Regarding other existing provisions, it is observed that so far; the Commission has received a couple of petitions for the determination of the input price of coal and therefore not much actual data is available to review the current operational norms and other provisions. In view of no compelling reasons to revisit the current terms and conditions for the determination of the input price of coal, it is proposed that the current provisions be continued.

23.6 Proposed Provisions

23.6.1 In view of the above, the Commission proposes Regulation 39 and Regulation 53 in the Draft Regulation, which is as follows:

"39. Run of Mine (ROM) Cost: *(1) Run of Mine Cost of coal in case of integrated mine(s) allocated through an auction route under the Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:*

ROM Cost = (Quoted Price of coal) + (Fixed Reserve Price)

Where,

(i) The Quoted Price of coal is the Final Price Offer of coal in respect of the concerned coal block or mine, along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement:

Provided that additional premium, if any, quoted by the generating company during auction shall not be considered in the Run of Mine Cost;

(ii) Fixed Reserve Price is the fixed reserve price per tonne along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement: and

(iii)Capital cost under Regulation 41 and additional capital expenditure under Regulation 42 shall not be admissible for the purpose of ROM cost in respect of integrated mine(s) allocated through the auction route.

(2) Run of Mine Cost of coal in case of integrated mine allocated through allotment route under Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:

ROM Cost = [(Annual Extraction Cost / (ATQ or Actual production whichever is higher) + Mining Charge] + (Fixed Reserve Price).

Where,

(i) Annual Extraction Cost is the cost of extraction of coal as computed in accordance with Regulation 43 of these regulations;

(ii) Mining Charge is the charge per tonne of coal paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable; and

(iii)Fixed Reserve Price is the fixed reserve price per tonne along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement.

(3) Run of Mine Cost of lignite in case of integrated mine(s) for lignite shall be worked out as under:

ROM Cost = [(Annual Extraction Cost / (ATQ or Actual production whichever is higher) + (Mining Charge)]

Where,

(i) Annual Extraction Cost is the cost of extraction of lignite as computed in accordance with Regulation 43 of these regulations; and

(ii) Mining Charge is the charge per tonne of lignite paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable.

(4) The generating company shall adhere to the Mining Plan for the extraction of coal or lignite on an annual basis and shall submit a certificate to that effect from the Coal Controller or the competent authority:

Provided that deviations from the Mining Plan shall be considered only if such deviations have been approved by the Coal Controller or the revised Mining Plan has been approved by the competent authority.

(5) Run of Mine Cost of coal and lignite shall be worked out in terms of Rupees per tonne.

53. Adjustment on account of Non-tariff income (NTI Adjustment): *(1) Adjustment on account of non-tariff income (NTI Adjustment) for any year, such as income from sale of washery rejects in case of integrated mine of coal and profit, if any, from supply of coal to the Coal India Limited or merchant sale of coal as allowed under the Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:*

NTI Adjustment = (2/3) x (Total Non-tariff income during the year)/(Actual quantity of coal or lignite extracted during the year)

(2) The adjustment on account of non-tariff income worked out in accordance with this Regulation shall not be applicable in case of the integrated mine(s) allocated through an auction route under the Coal Mines (Special Provisions) Act, 2015."

24 Blending of Coal

24.1 Background

24.1.1 The Commission in the current Tariff Regulations, in order to address domestic coal shortages, had allowed blending of imported coal without seeking consent from the beneficiaries till the weighted average price of fuel post blending do not exceed 30% of base energy charge rate as approved by the Commission for that year or exceeds by over 20% of energy charge rate as applicable for the previous month, whichever is lower.

24.2 Existing Provisions of the Tariff Regulations, 2019

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

(1) ..

(3) In case of part or full use of alternative source of fuel supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power purchase agreement for supply of contracted power on account of shortage of fuel or optimization of economical operation through blending, the use of alternative source of fuel supply shall be permitted to generating station:

Provided that in such case, prior permission from beneficiaries shall not be a precondition, unless otherwise agreed specifically in the power purchase agreement:

Provided further that the weighted average price of alternative source of fuel shall not exceed 30% of base price of fuel computed as per clause (5) of this Regulation:

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

24.3 Issues discussed in the Approach Paper

24.3.1 Staff of the Commission, in June 2022, published a paper analyzing the impact of blending of coal on the energy charges and noted that even when blending of coal is less than 10%, the 30% ECR threshold limit gets breached. In view of the same and considering that the shortage situation may recur, the issue needs a relook.

24.3.2 Linking the consent of beneficiaries with the percentage blending of imported coal instead of an increase in ECR may enable a swift response to an increase in demand by the generating company. Procurement of such coal (other than linkage coal) has to be done through a transparent competitive bidding process.

24.3.3 Comments and suggestions were sought from stakeholders on the above proposal and any other alternative, if any.

24.4 Stakeholders' Response

24.4.1 Stakeholders have submitted the following suggestions on the above issue.

a) NTPC submitted that proposal for taking consent of beneficiaries regarding percentage blending of coal may cause practical difficulties for implementation of the GoI direction and submitted that regulatory framework needs suitable enabling provisions to allow blending of imported coal based on guidelines / directions / advisory issued by the GOI from time to time.

b) Prayas Energy Group submitted that as imports are costly, blending of imported coal should be used as a last resort.

c) Adani Power Limited submitted that proposal is acceptable. However, in the case of a shortfall of domestic coal, such consent may be processed on onetime annual basis.

d) CEA submitted that the consent of Beneficiaries shall not be required for blending of imported coal up to 6% or the percentage as specified by GoI, whichever is higher.

e) MB Power Limited suggested that existing regulatory requirement may be suitably modified to allow a blending of domestic coal with up to 30% of imported coal without any prior consent of the beneficiary.

f) CSECL submitted that it may not be feasible for the beneficiary to specify the percentage of blending of imported coal to be adopted by the generating company. Therefore, the specific ratio of blending may best be left to be decided by the generating company itself.

g) GMR Energy Ltd submitted that Procurement of Alternative coal on a competitive bidding basis should not be made compulsory. The Competitive bidding condition for Procurement of Alternate coal must not be imposed in the regulations.

h) WBSEDCL suggested continuing the current practice of obtaining beneficiary consent for coal blending.

i) SRPC submitted that the existing clause of linking consent with ECR may be continued. However, any direction on% blending needs to be complied without the consent of beneficiaries.

j) MSPGCL submitted that either an alternative mechanism for obtaining consent from beneficiaries for coal blending should be devised, or the existing mechanism based on per unit impact (within 30%) should be maintained with some necessary modifications.

k) HEL submitted that linking of consent with the percentage of blending instead of an increase in ECR may be considered. Generators may be allowed to decide upon a blending ratio.

l) MSEDCL submitted that consent of the Distribution Licensee may be linked to an increase in ECR and not to the percentage of blending.

m) NTPL submitted that consent of beneficiaries may not be required for blending of imported coal up to 30% with domestic coal.

n) GRIDCO submitted that the existing provision of taking consent of beneficiaries for blending of coal and increase in ECR may be continued.

o) BRPL & BYPL submitted that Blending may not be allowed by weight at Genco level, but at individual station level.

p) Bajaj Energy submitted that the Coal blending may be allowed without taking consent from the beneficiary. The emergency procurement may not be restricted to procure through bidding, otherwise generator may be allowed to recover full capacity charges.

q) TANGEDCO submitted that approach paper may further provide the details of present coal availability in the country and the ceiling limit for blending of coal. A balanced approach may be needed so that even in the case of higher blending, the consumers may not be burdened with higher tariff.

r) MPPMCL submitted that existing provision of consent linked to increase in energy charge may be continued. If the proposed norm is considered then it is suggested that consent must be linked with both percentage blending of imported coal and an increase in ECR.

s) TATA POWER submitted that existing threshold limit of 30% of base energy charge rate as prescribed in 3rd proviso to Regulation 43(3) can be increased to 50% (considering blend of imported and domestic coal) and 20% of energy charge rate to 40% and for which no consent shall be required from the concerned beneficiaries. Further, deemed availability shall be considered, if consent for blending is denied by the beneficiary beyond these thresholds.

24.5 Commission's View

24.5.1 It is observed that during the current tariff period, due to domestic coal shortages, the Ministry of Power had to issue several directions to all domestic coal based power plants to import coal to meet the increased demand by blending domestic coal with imported coal. The percentage blending that was stipulated varied, reaching up to 10% by weight.

24.5.2 It is further observed that due to higher prices of imported coal, even for blending of up to 5%, the current price ceiling for seeking consent was getting breached and the generating companies had to seek the consent of beneficiaries time and again.

24.5.3 The generating companies reported to be facing problems complying with the above directions of the Ministry of Power on account of delays in securing permission required under Regulation 43(3) of the Tariff Regulations, 2019 from the concerned beneficiaries, which indirectly impacted beneficiaries in terms of increased short-term purchases at higher rates.

24.5.4 The Commission has therefore proposed that use of an alternative source of fuel supply shall be permitted to generating station without seeking consent of the beneficiaries up to a maximum of 6% blending by weight.

24.6 Proposed Provisions

24.6.1 In view of the above, the Commission proposes Regulation 64 in the Draft Tariff Regulations, which is as follows:

"64. Computation and Payment of Energy Charge for Thermal Generating Stations and Supplementary Energy Charge for Coal or Lignite based Thermal Generating Stations:

………..

(4) In case of part or full use of an alternative source of fuel supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power purchase agreement for the supply of contracted power on account of a shortage of fuel or optimization of economical operation through blending, the use of an alternative source of fuel supply shall be permitted to generating station up to a maximum of 6% blending by weight.

Provided that in such case, prior permission from beneficiaries shall not be a *precondition, unless otherwise agreed specifically in the power purchase agreement:*

Provided also that where a higher blending ratio than that specified under sub-clause (4) above of this Regulation is required, prior consultation with the beneficiary shall be made at least three days in advance."

25 Computation of Variable Cost

25.1 Background

25.1.1 The Commission in the Tariff Regulations, 2001, did not specify any norms with respect to transit and handling losses of primary fuel. However, the Commission in its subsequent Tariff Regulations, 2004, approved separate norms for pit head and non-pit head generating stations. The Commission in the Tariff Regulations, 2009, also determined separate norms for landed cost of primary fuel. In the Tariff Regulations, 2014, the Commission maintained the status quo on the transit and handling losses, while stating that in the case of imported coal, the transit and handling losses shall be 0.2%. In the Tariff Regulations, 2019, the Commission specified transit and handling losses for pit head generating stations as 0.20% and non-pit head stations as 0.80%, while in case of imported coal, the transit and handling losses have been specified as 0.20%.

25.1.2 The Commission in the Tariff Regulations, 2001, had defined “the heat produced in kCal by the complete combustion of one kilogram of solid fuel or one liter of liquid fuel or one standard cubic meter of gaseous fuel, gas the case may be” for Gross Calorific Value (GCV) in relation to thermal generation and had also specified that the gross calorific value for computation of energy charges shall be done in accordance with GCV on “as fired” basis and the same approach was adopted in the Tariff Regulations, 2004 and Tariff Regulations, 2009. In the Tariff Regulations, 2014, the Commission observed that there was considerable loss in the value of GCV on as fired basis vis-à-vis as received. The Commission further observed that the loss incurred while the coal was within the plant premises. The Commission considering recommendations of CEA and study carried out by CPRI specified that the gross calorific value for computation of energy charges shall be done in accordance with GCV on “as received” basis. Subsequently, a margin of 85 kCal/kWh was also permitted to compensate for storage loss, and the same approach was considered in the Tariff Regulations, 2019.

25.2 Existing Provisions of the Tariff Regulations, 2019

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

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

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

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

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

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

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

Provided that in case of pit-head stations, if coal or lignite is procured from sources other than the pit-head mines which is transported to the station through rail, transit and handling losses applicable for non-pit head station shall apply;

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

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

(2) The generating company shall provide to the beneficiaries of the generating station the details in respect of GCV and price of fuel i.e. domestic coal, imported coal, e-auction coal, lignite, natural gas, RLNG, liquid fuel etc. as per the Form 15 prescribed at Annexure-I(Part I) to these regulations:

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

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

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

(2) The normative consumption of specific reagent for the various technologies installed for meeting revised emission standards shall be as specified in Regulations 49 of these regulations."

25.3 Issues discussed in the Approach Paper

25.3.1 Following issue was brought out in the Approach Paper for consultation:

Ways to reduce the gap between GCV "as billed" and "as received".

25.4 Stakeholders' Response

25.4.1 Stakeholders have submitted the following suggestions on this issue.

a) NTPC expressed its inability to share any risk and suggested that Coal Companies may transfer the title of coal to the Generating Companies at the plant's end. However, this requires changes in Fuel Supply Agreements which may be achievable only after intervention at the level of the Ministry of Coal (GOI), and the Ministry of Power (GoI).

b) MB Power Limited, MSPGCL and MSEDCL proposed to continue with the existing mechanism.

c) CESCL submitted that passing on a part of the risk of grade slippage/loss of GCV on the generating company is against the principle of natural justice. The risk-sharing mechanism should be limited to the coal supplier and the Railways only. 'GCV as received' at the unloading end of a power station may be the basis of computation of fuel cost and energy charge of generating stations.

d) GMR Energy Ltd submitted that Generating Companies have a very limited role to play before the coal is actually delivered at its premise. Therefore, the efficiency of Generating Companies in preventing GCV loss may be measured by comparing as Received and as fired GCV.

e) HMEL submitted that provision for watch & ward expenses may be introduced to keep a continuous vigilance during the loading, transit, and unloading of coal in addition to taking up the matter with coal companies to restrict grade slippages.

f) APPC-APDISCOMS submitted that the onus on grade slippage or proper loading shall be looked after by the Generating Companies and risks, if any, are to be covered in FSA between Coal Supplier and Generating Companies and shall not be transferred to Discoms.

g) JP Power submitted that to avoid grade slippages, systematic implementation of proper sampling and testing procedures at the mine end is essential. The responsibility for remedial actions lies with coal companies.

h) AERC and MESCOM submitted that there is a need for fixing the responsibility of coal companies, railways, third parties and generating companies to relieve the consumers from this unwarranted burden.

i) Prayas Energy Group submitted that norms should be revised such that ECR is calculated based on GCV as billed with permitted transit and stacking losses.

j) HEL submitted risk sharing may be limited to coal vendors and Railways only. Existing CERC norm for considering GCV "as fired" basis may be relied upon. To avoid grade slippage, a transparent process is needed to re-validate the coal grading across mines and ensure adequate quality controls at the unloading end. The current methodology of heat value determination may be revised considering quality deterioration and ambient conditions.

k) NTPL submitted that GCV loss towards storage needs to be reviewed for non-pit head power stations.

l) GRIDCO submitted that the Commission may review the existing norms in terms of risk allocation to the Generating Companies regarding grade slippage of coal between the mine end and the generator end. The Generating Companies need to be given a target for reducing the GCV loss from the mine to the boiler.

m) PSPCL submitted that the determination of GCV at both the mine end and at the station end to be done by the same agency.

n) BYPL & BRPL submitted that the Commission may direct generating stations to share the test reports of the coal as submitted by the third-party agencies to the beneficiaries, as well as publish the same on their website. Moreover, involve the representatives of the beneficiaries to verify the independence and correctness of third-party sampling and formulate penalty mechanism for non-compliance by generating stations.

o) Individual Beneficiaries submitted that there is a need for fixing the responsibility of coal companies, railways, third parties, and generating companies with regard to loss in GCV and the Commission may allow a nominal loss of 50 – 100 kCal / kg in case of grade slippage.

p) Bajaj Energy has submitted that Transit loss may be considered as 3% for coal sourced through RCR mode. Transit Loss in the case of rail-fed stations is beyond the control of Generating Companies.

25.5 Commission's view

25.5.1 The Commission has carefully examined and reviewed the comments/suggestions received from the stakeholders.

Transit & Handling Losses:

25.5.2 The Commission has provided the transit & handling loss of Pit Head Stations at 0.2% and Non-Pit Head Stations at 0.8%. However, it is observed that due to coal shortage, coal is being transported through multiple modes of transport before reaching the Generating Stations and therefore, higher transit loss is required to be considered in such cases. Hence, the Commission has proposed to introduce a new norm for multi-mode transport of coal. The transit & handling loss proposed for such multi-mode transportation is proposed to be 1%.

GCV of Primary Fuel:

25.5.3 The Commission has observed that the GCV of fuel keeps on varying at different reference points due to various factors such as moisture content and grade slippages during transportation of coal or during storage at the plant end. The current Regulations specify that the GCV of fuel for the purpose of allowing energy charges shall be considered on an "as received" basis as other factors due to which there is a loss in GCV are not under the control of the generating stations.

25.5.4 However, it is observed that the variation in GCV "as billed" and "as received" is significant. Though the magnitude of such losses has reduced in the past, they are still significant and may need to be accounted for in terms of risk sharing between the coal company, the railways, and the generating station. At present, the Generating Companies pay for the coal based on GCV "as billed" and the quantum of coal at the loading point. It is observed that currently the loss in GCV from "as billed" to "as received" has been allowed on an actual basis, however, in order to increase the accountability towards such losses, the Commission is of the view that necessary initiative by way of regulations needs to be taken.

25.5.5 Hence, the Commission has proposed that third-party sampling shall be done at the billing end and receiving end through an agency approved by the Ministry of Coal to ensure recovery of compensation as per the FSA due to GCV loss and for passing on such benefits to the beneficiaries.

25.5.6 In case there is no third-party sampling by an agency approved by the Ministry of Coal, the actual loss in calorific value between "as billed" and "as received" basis shall be considered subject to a ceiling of 300 kCal/kg for pit-head generating stations and at 600 kCal/kg for non-pit head generating stations. The values are proposed so that the generating stations would invoke their rights on GCV slippage as per FSA. The Commission has also proposed that there shall be no GCV loss between the values "as billed" and "as received" in the case of integrated mines and imported coal.

25.6 Proposed Provisions

25.6.1 The Commission proposes Regulation 57 to 61 in the Draft Tariff Regulations which is as follows:

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

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

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

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

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

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

Thermal Generating Station	***Transit and Handling Loss(%)***
Pit head	*0.20%*
Non-pit head - Rail	*0.80%*
Non-pit head multi-modal transportation (using two or more than two mode of transport involving multiple trans-shipments)	*1.00%*

Provided that in the case of pit-head stations, if coal or lignite is procured from sources other than the pit-head mines which is transported to the station through rail, transit and handling losses applicable for non-pit head stations shall apply;

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

60. Gross Calorific Value of Primary Fuel: (*1) The gross calorific value for computation of energy charges as per Regulation 64 of these regulations shall be done in accordance with 'GCV as Received';*

Provided that the generating station shall have third party sampling done at the billing end and the receiving end through an agency certified by the Ministry of Coal and ensure recovery of compensation as per Fuel Supply Agreement(s) and pass on the benefits of the same to the beneficiaries of the generating station;

Provided further that in the absence of any third party sampling through an agency certified by the Ministry of Coal, the GCV shall be considered on the basis of 'as billed' by the Supplier less:

i. *Actual loss in calorific value of coal between as billed by the supplier and as received at the generating station, subject to maximum loss in calorific value of 300 kCal/kg for Pit-head based generating stations or generating stations with Integrated mine and 600 kCal/kg for Non-Pit Head based generating stations.*

No loss in calorific value between 'GCV as billed' and 'GCV as received' is admissible for generating stations procuring coal from Integrated mines or through the import of coal.

(2) The generating company shall provide to the beneficiaries of the generating station the details in respect of GCV and price of fuel i.e. domestic coal, imported coal, e-auction coal, lignite, natural gas, RLNG, liquid fuel etc., as per the Form 15 prescribed at Annexure-I (Part I) to these regulations:

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

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

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

(2) The normative consumption of specific reagents for the various technologies installed for meeting revised emission standards shall be as specified in Regulation 70 of these regulations."

26 Recovery of Capacity Charges for Thermal Stations

26.1 Background

26.1.1 Central Electricity Authority (CEA) in its 20th Electric Power Survey has projected the Peak Demand for a moderate scenario to grow to around 264.33 GW by FY 2026-27 and to 328.59 GW by FY 2031-32. This translates into an increase in peak demand of 60 GW by FY 2026-27 and by around 125 GW by FY 2031-32.

26.1.2 The Tariff Regulations, 2019, provide for recovery of the fixed cost of generation under two segments of the year, i.e., High Demand Season (period of three months, whether consecutive or otherwise) and Low Demand Season (period of remaining nine months, whether consecutive or otherwise) and for each day of the season in two parts i.e., Peak Period (4 hours) and Off-Peak Period (20 hours). Further, the capacity charge rate for Peak hours is 25% higher than that of Off-Peak Hours. To further promote generation during Peak Hours, an incentive @ Rs. 0.65/kWh for generation during Peak Hours and @ Rs. 0.50/kWh for generation during Off-Peak Hours was provided in the Tariff Regulations, 2019.

26.2 Existing Provisions of the Tariff Regulations, 2019

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

(1) The fixed cost of a thermal generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share / allocation in the capacity of the generating station. The capacity charge shall be recovered under two segments of the year, i.e. High Demand Season (period of three months) and Low Demand Season (period of remaining nine months), and within each season in two parts viz., Capacity Charge for Peak Hours of the month and Capacity Charge for Off Peak Hours of the month as follows:

Capacity Charge for the Year (CCy) = Sum of Capacity Charge for three months of High Demand Season + Sum of Capacity Charge for nine months of Low Demand Season

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

Capacity Charge for the Month (CCm) = Capacity Charge for Peak Hours of the Month (CCp) + Capacity Charge for Off-Peak Hours of the Month (CCop)

Where,

High Demand Season:

CCp_1= (0.20xAFC) x (1/12) x (PAFMp/NAPAF) subject to ceiling of (0.2xAFC) x (1/12)

CCp_2= {(0.20xAFC) x (1/6) x ($PAFM_{p2}$/NAPAF) subject to ceiling of (0.20xAFC) x (1/6)} – CC_{p1}

CC_{p3}= {(0.20xAFC) x (1/4) x ($PAFM_p$/NAPAF) subject to ceiling of (0.20xAFC) x (1/4)} – (CC_{p1}+CC_{p2})

CC_{op1}= {(0.80xAFC) x (1/12) x ($PAFM_{op1}$/NAPAF) subject to ceiling of (0.80xAFC) x (1/12)}

CC_{op2}= {(0.80xAFC) x (1/6) x ($PAFM_{op2}$/NAPAF) subject to ceiling of (0.80xAFC) x (1/6)} – CC_{op1}

CC_{op3}= {(0.80xAFC) x (1/4) x ($PAFM_{op3}$/NAPAF) subject to ceiling of (0.80xAFC) x (1/4)} – (CC_{op1}+CC_{op2})

Low Demand Season:

CC_{p1}= {(0.20xAFC) x (1/12) x ($PAFM_{p1}$/NAPAF) subject to ceiling of (0.2xAFC) x (1/12)}

CC_{p2}= {(0.20xAFC) x (1/6) x ($PAFM_{p2}$/NAPAF) subject to ceiling of (0.20xAFC) x (1/6)} – CC_{p1}

CC_{p3}= {(0.20xAFC) x (1/4) x ($PAFM_{p3}$/NAPAF) subject to ceiling of (0.20xAFC) x (1/4)} – (CC_{p1}+CC_{p2})

CC_{p4}= {(0.20xAFC) x (1/3) x ($PAFM_{p4}$/NAPAF) subject to ceiling of (0.20xAFC) x (1/3)} – (CC_{p1}+CC_{p2}+CC_{p3})

CC_{p5}= {(0.20xAFC) x (5/12) x ($PAFM_{p5}$/NAPAF) subject to ceiling of (0.20xAFC) x (5/12)} – (CC_{p1}+CC_{p2}+CC_{p3}+CC_{p4})

CC_{p6}= {(0.20xAFC) x (1/2) x ($PAFM_p$/NAPAF) subject to ceiling of (0.20xAFC) x (1/2)} – (CC_{p1}+CC_{p2}+CC_{p3}+CC_{p4}+CC_{p5})

CC_{p7}= {(0.20xAFC) x (7/12) x ($PAFM_{p7}$/NAPAF) subject to ceiling of (0.20xAFC) x (7/12)} – (CC_{p1}+CC_{p2}+CC_{p3}+CC_{p4}+CC_{p5}+CC_{p6})

CC_{p8}= {(0.20xAFC) x (2/3) x ($PAFM_{p8}$/NAPAF) subject to ceiling of (0.20xAFC) x (2/3)} – (CC_{p1}+CC_{p2}+CC_{p3}+CC_{p4}+CC_{p5}+CC_{p6}+CC_{p7})

CC_{p9}= {(0.20xAFC) x (3/4) x ($PAFM_p$/NAPAF) subject to ceiling of (0.20xAFC) x

$(3/4)\} – (CC_{p1}+CC_{p2}+CC_{p3}+CC_{p4}+CC_{p5}+CC_{p6}+CC_{p7}+CC_{p8})$

$CC_{op1}= \{(0.80xAFC) \times (1/12) \times (PAFM_{op1}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (1/12)\}$

$CC_{op2}= \{(0.80xAFC) \times (1/6) \times (PAFM_{op2}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (1/6)\} – CC_{op1}$

$CC_{op3}= \{(0.80xAFC) \times (1/4) \times (PAFM_{op3}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (1/4)\} – (CC_{op1}+CC_{op2})$

$CC_{op4}=\{(0.80xAFC) \times (1/3) \times (PAFM_{op4}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (1/3)\} – (CC_{op1}+CC_{op2}+CC_{op3})$

$CC_{op5}=\{(0.80xAFC) \times (5/12) \times (PAFM_{op5}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (5/12)\} – (CC_{op1}+CC_{op2}+CC_{op3}+CC_{op4})$

$CC_{op6}=\{(0.80xAFC) \times (1/2) \times (PAFM_{op6}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (1/2)\} – (CC_{op1}+CC_{op2}+CC_{op3}+CC_{op4}+CC_{op5})$

$CC_{op7}=\{(0.80xAFC) \times (7/12) \times (PAFM_{op7}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (7/12)\} – (CC_{op1}+CC_{op2}+CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6})$

$CC_{op7}=\{(0.80xAFC) \times (7/12) \times (PAFM_{op7}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (7/12)\} – (CC_{op1}+CC_{op2}+CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6})$

$CC_{op8}=\{(0.80xAFC) \times (2/3) \times (PAFM_{o}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (2/3)\} – (CC_{op1}+CC_{op2}+CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6}+CC_{op7})$

$CC_{op9}=\{(0.80xAFC) \times (3/4) \times (PAFM_{op9}/NAPAF)$ *subject to ceiling of* $(0.80xAFC) \times (3/4)\} – (CC_{op1}+CC_{op2}+CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6}+CC_{op7}+CC_{op8})$

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

Where,

CCm= Capacity Charge for the Month;

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

CCop= Capacity Charge for the Off-Peak Hours of the Month;

CCpn= Capacity Charge for the Peak Hours of nth Month in a specific Season;

CCopn= Capacity Charge for the Off-Peak of nth Month in a specific Season;

AFC = Annual Fixed Cost;

PAFMpn = Plant Availability Factor achieved during Peak Hours upto the end of nth Month in a Season;

PAFMopn = Plant Availability Factor achieved during Off-Peak Hours upto the end of nth Month in a Season;

NAPAF= Normative Annual Plant Availability Factor

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

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

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

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

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

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

(5) The PAFM upto the end of a particular month and PAFY shall be computed in accordance with the following formula:

N

PAFM = $1000 \times \Sigma_{i=1-n} DC_i / \{N \times IC \times (100 – AUX_n - AUX_{en})\}$ %

Where,

AUXn =Normative auxiliary energy consumption as a percentage of gross energy generation;

AUXen = Normative auxiliary energy consumption for emission control system as a percentage of gross energy generation, wherever applicable;

DCi = Average declared capacity (in ex-bus MW), for the i^{th} day of the period i.e. the month or the year as the case may be, as certified by the concerned load dispatch centre after the day is over.

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

N = Number of days during the period.

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

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

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

26.3 Issues discussed in the Approach Paper

26.3.1 The following issues were brought out in the Approach Paper for consultation:

i) The actual period of high demand did not coincide with the forecast, and the Generating Companies had to postpone overhauling considering the sudden increase in demand. In some cases, such deferment has led to forced outages, thereby impacting the recovery of the AFC.

ii) The period of high demand and low demand is not the same for all the States in the Region, so declaring the common high and low demand period for all the States has its own challenges. For example, in Northern Region, the high demand season for hilly States such as Uttarakhand and Himachal Pradesh is winter months, whereas for adjacent Punjab the same lies in the months of August-September and for Delhi it is the summer months.

iii) Some of the generating stations have beneficiaries in different regions, which again increases the diversity of demand. Therefore, declaring a common high and low demand period is practically not possible. For example, Kahalgaon STPS and Farakka STPS have allocations to beneficiaries that belong to all five regions; therefore, in such cases, the objective of devising the above mechanism is rendered ineffective and may require tweaking of existing practice by RLDCs.

iv) While States have been demanding availability from the Generating Companies coinciding with State Peak, the Generating Companies have difficulty meeting this requirement due to the wide diversity of peak in different States.

26.3.2 As recovery of reasonable costs is of prime importance for any infrastructure sectoral growth, possible interventions/modifications may be required to address the peak and off-peak issues. Specific suggestions are also sought on the following:

i) Whether it would be advisable to limit the recovery based on daily Peak and Off-Peak Periods

ii) National versus Regional Peak as a reference point for recovery of fixed charges.

26.4 Stakeholders' Response

26.4.1 Stakeholders have submitted the following suggestions on above-mentioned issues.

a) NTPC submitted that currently, NAPAF needs to be achieved separately for Peak and Off-Peak Period, in accordance with CERC Tariff Regulations, 2019. Further submitted that NAPAF achieved in Peak and Off-Peak Hours may be considered on a cumulative basis which will avoid any under-recovery.

b) ASCI submitted that it is advisable to limit the recovery based on daily peak and off-peak periods so that the system is more responsive to changes in demand and ensures that generating stations are available when needed most. The reference point for recovery of fixed charges should be the national peak, which will ensure that generating stations are incentivized to be available during times when the grid is under stress.

c) PGCIL submitted that the Peak period should be based on net load and not overall load.

d) CEA submitted that the existing mechanism may be reviewed with the objective of giving more weightage for peak-hours. The peak hours corresponding to the national level for each FY should be specified upfront by NLDC on 31st January of the previous FY,

e) MB Power Limited submitted that National level peak and off-peak periods may be defined.

f) CESC Ltd. submitted that an earlier mechanism of Capacity Charge recovery linked to the overall average availability of the Generating Companies, based on the normative PAF, may be considered.

g) GMR Energy Ltd submitted that Regional Peak and Off-Peak need to be followed.

h) HMEL, DIL submitted that computation of monthly capacity charge based on daily Peak and Off-Peak periods may be retained.

i) OTPC submitted that the old simple approach to tariff determination and billing by Generating Companies may be considered. The approach of National or Regional Peak seems impractical, as State Peak and Off-Peak loads differ too much.

j) JSW proposed excluding Lignite & CFBC Technology plants from the proposed Tariff Regulation's Peak and Off-Peak Availability recovery method.

k) SRPC submitted that recovery may be restricted to daily peak and off-peak periods. Further, If the Peak season (Either Regional/National) concept is to be kept, then NAPAF should be increased for Peak season (Period) while reducing proportionately during Off-Peak season. Reducing NAPAF during Off-Peak Season will facilitate planned maintenance activities.

l) JP submitted that Peak and Off-Peak tariff should be declared for each region as the demand /supply of each region is different. Further generating station supplying to many regions should be given some leverage as it is difficult to take care Peak/Off-Peak season of all regions. Further, daily peak and off-peak based recovery is not advisable.

m) NHDC submitted that incentives such as 10% of MCP at power exchanges in the respective time block may be provided to boost investments in the hydro-power sector.

n) MSEDCL proposed a penalty for not maintaining the desired availability in the peak period.

o) GRIDCO submitted that the existing method of forecasting high-demand and low-demand season may be continued in the interest of consumers.

p) BYPL & BRPL submitted that Peak and Off-Peak hours are to be determined by Regional Power Committees/RLDCs based on beneficiaries' feedback.

q) MESCOM submitted that recovery based on daily Peak and Off-Peak periods may be avoided. Further, a national peak is not advisable for the recovery of FC.

r) NLCIL submitted that recovery of AFC can be done based on the station's cumulative availability during the Peak and Off-Peak Hours of the year.

s) Bajaj Energy submitted that recovery of fixed cost may be considered on the basis of Peak period at the State level wherein the beneficiary is located.

t) TANGEDCO proposed continuation of existing norms.

u) MPPMCL submitted that recovery of cost based on daily peak and off-peak periods may be considered. National Peak may not be considered.

v) TATA POWER submitted that peak season may be increased to 6 months - single or two separate periods. Since the National level merit order dispatch is yet to be implemented, as of now Regional Peak may be considered.

26.5 Commission's View

26.5.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders.

26.5.2 It is observed that many of the generating companies are facing operational difficulties due to the declaration of high demand and low demand season by RLDCs. This is because the period of high demand and low demand is not the same for all the Beneficiary States in the region, so declaring a common high and low-demand period for all the States in the region has its own challenges. The operational implications of a standardized high and low demand period are significant, as power generators and grid operators tailor their strategies and shut-down planning based on these periods. Failing to account for the unique demand dynamics of individual States may lead to inefficiencies in resource utilization and grid management and delay in taking shutdown, adversely impacting the generating units and putting the grid to risk.

26.5.3 To address the above concern, the Commission proposes to limit the recovery of fixed cost of generation based on Peak, and Off-Peak periods only, thereby removing the requirement for the generating stations to maintain specified target availability during high/low demand seasons.

26.5.4 As per Tariff Regulations, 2019, the Peak and Off-Peak incentives are 50 paise/kWh and 65 paise/kWh respectively for energy supplied over the normative PLF. It is observed that there has been an increasing gap between the Peak and Off-Peak Tariff discovered in the open market with the ratio of average Peak and Off-Peak Tariff in the range of 1:1.3 to 1:1.6 In view of the above, it is proposed to increase the incentive for energy generated in excess of the NAPLF during Peak Hours to 75 paise/kWh.

26.5.5 The Commission has observed that an increase in large-scale grid integration of Renewable Energy (RE) sources such as Solar and Wind has led to frequency deviations and weak frequency support due to generation load imbalances, thus reducing the system's inherent Frequency Response. To maintain the grid frequency and reliable grid operations, the Commission observes that a suitable Incentive mechanism needs to be developed for base-load power plants to provide a primary response when there is an immediate need for power in the grid network to maintain the grid stability. Therefore, the Commission has proposed to provide an incentive of up to 1% of AFC in case of all thermal generating stations linked with the Average Annual Frequency Response Performance (denoted as ß) of the generating station, as certified by RPCs, which shall be computed by considering primary response as per the methodology prescribed by the NLDC and shall range between 0 to 1.

26.5.6 It is also observed that CERC in IEGC, 2023 imposed restrictions on thermal and hydro generating stations from declaring declared capacity over and above MCR (5% over MCR in case of Thermal Generating stations and 10% over MCR in case of hydro generating stations). The restriction was imposed in the interest of better grid management. However, it is observed that the restriction has resulted in commercially impacting these generating stations. The above incentive will also compensate the thermal generating stations from the commercial impact of the restrictions imposed by the Grid Code on declaring capacity of up to 5% over and above MCR.

26.6 Proposed Provisions

26.6.1 In view of the above, the Commission proposes Regulation 62 in the Draft Tariff Regulations, which is as follows:

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

(1) The fixed cost of a thermal generating station shall be computed on annual basis based on the norms specified under these regulations and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station. The capacity charge shall be recovered in two parts viz., Capacity Charge for Peak Hours of the month and Capacity Charge for Off- Peak Hours of the month as follows:

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

Capacity Charge for the Month (CC_n) = Capacity Charge for Peak Hours of the Month (CC_{pn}) + Capacity Charge for Off-Peak Hours of the Month (CC_{opn})

Where,

CC_{p1} = [(0.20 x AFC) x (1/12) x ($PAFM_{p1}$/NAPAF) subject to ceiling of {(0.20 x AFC) x (1/12)}]

CC_{p2} = [(0.20 x AFC) x (1/6) x ($PAFM_{p2}$/NAPAF) subject to ceiling of {(0.20 x AFC) x (1/6)}] – CC_{p1}

CC_{p3} = [(0.20 x AFC) x (1/4) x ($PAFM_{p3}$/NAPAF) subject to ceiling of {(0.20 x AFC) x (1/4)}] - (CC_{p1} + CC_{p2})

CC_{p4} = [(0.20 x AFC) x (1/3) x ($PAFM_{p4}$/NAPAF) subject to ceiling of {(0.20 x AFC) x (1/3)}] - (CC_{p1} + CC_{p2} + CC_{p3})

CC_{p5} = [(0.20 x AFC) x (5/12) x ($PAFM_{p5}$/NAPAF) subject to ceiling of {(0.20 x AFC) x (5/12)}] - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4})

CC_{p6} = [(0.20 x AFC) x (1/2) x ($PAFM_{p6}$/NAPAF) subject to ceiling of {(0.20 x AFC) x (1/2)}] - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5})

CC_{p7} = [(0.20 x AFC) x (7/12) x ($PAFM_{p7}$/NAPAF) subject to ceiling of {(0.20 x AFC) x (7/12)}] - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6})

CC_{p8} = [(0.20 x AFC) x (2/3) x ($PAFM_{p8}$/NAPAF) subject to ceiling of {(0.20 x AFC) x (2/3)}] - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7})

CC_{p9} = [(0.20 x AFC) x (3/4) x ($PAFM_{p9}$/NAPAF) subject to ceiling of {(0.20 x

$AFC) \times (3/4)\}] - (CC_{p1}+ CC_{p2}+ CC_{p3}+CC_{p4}+CC_{p5}+CC_{p6}+CC_{p7}+CC_{p8})$

$CC_{p10}= [(0.20 \times AFC) \times (5/6) \times (PAFM_{p10}/NAPAF)$ subject to ceiling of $\{(0.20 \times AFC) \times (5/6)\}] - (CC_{p1}+ CC_{p2}+ CC_{p3}+CC_{p4}+CC_{p5}+CC_{p6} +CC_{p7} +CC_{p8} +CC_{p9})$

$CC_{p11}= [(0.20 \times AFC) \times (11/12) \times (PAFM_{p12}/NAPAF)$ subject to ceiling of $\{(0.20 \times AFC) \times (11/12)\}] - (CC_{p1}+ CC_{p2}+ CC_{p3}+CC_{p4}+CC_{p5}+CC_{p6} +CC_{p7}+CC_{p8}+CC_{p9}+CC_{p10})$

$CC_{p12}= [(0.20 \times AFC) \times (PAFM_{p12}/NAPAF)$ subject to ceiling of $(0.20 \times AFC)] - (CC_{p1}+ CC_{p2}+ CC_{p3}+CC_{p4}+CC_{p5}+CC_{p6} +CC_{p7}+CC_{p8}+CC_{p9}+CC_{p10}+CC_{p11})$

$CC_{op1}= (0.80 \times AFC) \times (1/12) \times (PAFM_{op1}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (1/12)\}$

$CC_{op2}= [(0.80 \times AFC) \times (1/6) \times (PAFM_{op2}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (1/6)\}] – CC_{op1}$

$CC_{op3}= [(0.80 \times AFC) \times (1/4) \times (PAFM_{op3}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (1/4)\}] - (CC_{op1}+ CC_{op2})$

$CC_{op4}= [(0.80 \times AFC) \times (1/3) \times (PAFM_{op4}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (1/3)\}] - (CC_{op1}+ CC_{op2+}CC_{op3})$

$CC_{op5}= [(0.80 \times AFC) \times (5/12) \times (PAFM_{op5}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (5/12)\}] – (CC_{op1}+ CC_{op2+}CC_{op3}+CC_{op4})$

$CC_{op6}= [(0.80 \times AFC) \times (1/2) \times (PAFM_{op6}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (1/2)\}] – (CC_{op1}+ CC_{op2+}CC_{op3}+CC_{op4}+CC_{op5})$

$CC_{op7}= [(0.80 \times AFC) \times (7/12) \times (PAFM_{op7}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (7/12)\}] - ((CC_{op1}+ CC_{op2+}CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6})$

$CC_{op8}= [(0.80 \times AFC) \times (2/3) \times (PAFM_{op8}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (2/3)\}] - (CC_{op1}+ CC_{op2+}CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6}+CC_{op7})$

$CC_{op9}= [(0.80 \times AFC) \times (3/4) \times (PAFM_{op9}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (3/4)\}] - (CC_{op1}+ CC_{op2+}CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6}+CC_{op7}+CC_{op8})$

$CC_{op10}= [(0.80 \times AFC) \times (5/6) \times (PAFM_{op10}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (5/6)\}] - (CC_{op1}+ CC_{op2+}CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6}+CC_{op7}+CC_{op8} +CC_{op9})$

$CC_{op11}= [(0.80 \times AFC) \times (11/12) \times (PAFM_{op12}/NAPAF)$ subject to ceiling of $\{(0.80 \times AFC) \times (11/12)\}] - (CC_{op1}+ CC_{op2+}CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6} +CC_{op7}+CC_{op8}+CC_{op9}+CC_{op10})$

$CC_{op12}= [(0.80 \times AFC) \times (PAFM_{op12}/NAPAF)$ subject to ceiling of $(0.80 \times AFC)] - (CC_{op1}+CC_{op2+}CC_{op3}+CC_{op4}+CC_{op5}+CC_{op6}+CC_{op7}+CC_{op8} +CC_{op9}+CC_{op10}+CC_{op11})$

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

Where,

CC_m = *Capacity Charge for the Month;*

CC_P = *Capacity Charge for the Peak Hours of the Month;*

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

CC_{pn} = *Capacity Charge for the Peak Hours of n^{th} Month;*

CC_{opn} = *Capacity Charge for the Off-Peak of n^{th} Month;*

AFC = Annual Fixed Cost;

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

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

NAPAF= Normative Annual Plant Availability Factor.

(3) Normative Plant Availability Factor for "Peak" and "Off-Peak" Hours in a month shall be equivalent to the NAPAF specified in Clause (A) of Regulation 70 of these regulations. The number of hours of "Peak" and "Off-Peak" periods during a day shall be four and twenty respectively. The hours of Peak and Off-Peak periods during a day shall be declared by the concerned RLDC at least a week in advance.

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

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

The shortfall in recovery of Capacity Charge for cumulative Off-Peak Hours derived based on NAPAF, shall be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Peak Hours.

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

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

$$PAFM = 10000\,x \sum_{i=1}^{n} \frac{DCi}{[N\ x\ IC\ x\ (100 - AUXn - AUXen)]}\%$$

Where,

AUXn = Normative auxiliary energy consumption as a percentage of gross energy generation;

AUXen= Normative auxiliary energy consumption for emission control system as a percentage of gross energy generation, wherever applicable;

DCi = Average declared capacity (in ex-bus MW), for the i^{th} day of the period i.e. the month or the year, as the case may be, as certified by the concerned load dispatch centre after the day is over;

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

n = Number of days during the period;

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

(5) In addition to the AFC entitlement as computed above, the thermal generating station shall be allowed incentive of upto 1.00% of AFC approved for a given year which shall be billed at the end of the financial year as per the following.

Incentive = (1.00% x ß x CC_y)

Where,

ß = Average Annual Frequency Response Performance for that generating station, as certified by RPCs, which shall be computed by considering primary response as per the methodology prescribed by the NLDC and shall range between 0 to 1.

CC_y= Capacity Charges for the Year.

(6) In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 75 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 50 paise/ kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to scheduled generation in excess of-ex bus energy corresponding to

Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis, as specified in Clause (B) of Regulation 70 of these regulations.

(7) The provisions under Clauses (1) to (6) of this Regulation shall come into force with effect from 1.4.2024. Till that date, the capacity charge for a thermal generating station determined under these regulations shall be recovered in accordance with the provisions contained in Regulation 42 of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019, subject to the condition that the NAPAF and NAPLF shall be taken as specified under these regulations"

27 Incentive for Hydro Stations

27.1 Background

27.1.1 Under the Tariff Regulations, 2019, the norms for Incentive were specified for scheduled generation in excess of ex-bus energy corresponding to the Normative Annual Plant Load Factor (NAPLF). Such incentives were applicable for energy supplied by thermal generating stations and no incentives were provided to hydro generating stations for supplying power during peak period. Instead, hydro generating stations were provided incentives based on their availability (if exceeded NAPAF) which was not available for thermal generating stations. Under this mechanism, if a hydro generating station's actual availability exceeds NAPAF, it is allowed to recover a higher capacity charge in the same proportion as actual availability is higher than the NAPAF.

27.2 Existing Provisions of the Tariff Regulations, 2019

27.2.1 The current regulations do not have any provision allowing incentives to hydro generating stations on the basis of actual generation.

27.3 Issues discussed in the Approach Paper

27.3.1 Following issues were brought out in the Approach Paper for consultation:

a) "5.10 Incentives linked to generation in excess of target PLF/NAPAF, especially during peak periods, in the case of hydro stations and old pit-head generating stations, may need a review in order to encourage higher generation from such plants. This will result in increased generation from such plants and will also benefit beneficiaries."

"6.1 Separate Norms for ROR/Storage Based Hydro Projects

b) Currently, the terms and conditions for tariff components stipulated in the CERC Tariff Regulations, 2019 for all these types of hydro stations are the same except for the higher RoE allowed for storage based hydro stations and PSP. In addition to the cost components, in general, the NAPAF of storage based generating stations is higher than that of ROR based projects considering the ability of storage based generating stations to generate on demand. However, it is observed that there is a need for a more Enabling framework or incentive mechanism for dam/reservoir based generating stations to operate as peaking plants. Considering the anticipated increase in peaking loads, these stations may be incentivised to operate as peaking plants. One way to do so is by providing additional incentives for energy supplied during peak periods.

c) However, it is observed that there is a need for a more Enabling framework or incentive mechanism for dam/reservoir based generating stations to operate as peaking plants. Considering the anticipated increase in peaking loads, these stations may be incentivised to operate as peaking plants. One way to do so is by providing additional incentives for energy supplied during peak periods.

d) Enabling framework or incentive mechanism for dam/reservoir based generating stations to operate as peaking plants. Considering the anticipated increase in peaking loads, these stations may be incentivised to operate as peaking plants. One way to do so is by providing additional incentives for energy supplied during peak periods.

27.3.2 Stakeholders have submitted the following suggestions on this issue.

a) NHPC proposed to provide incentives at the rate of 10% of MCP during peak hours for energy generated during peak hours. Further submitted that the secondary energy rate should be linked with the market rate or rate may be increased from the existing Rs.1.2/kWh. In case ECR is below the secondary energy rate, the secondary energy rate may be restricted by ECR.

b) NEEPCO submitted that in the proposed methodology of DC for ROR, there is no incentive for ROR plants to support the grid with their maximum capacity during peak hours.

c) THDCIL submitted that additional incentives may be introduced to hydro plants.

d) NHDC submitted that the scheduling of power generation is carried out by concerned LDCs. Therefore, the operation of these power stations is not in the hands of the Generating Companies. Accordingly, suitable provisions/ guidelines may be made to allow the operation of ROR/ Storage based hydro projects in Peak Hours. Suitable incentives may be provided such as 10% of MCP at power exchanges in the respective time block, which may encourage the Generating Companies to minimize the downtime and to operate at their full capacity during peak hours.

e) SJVNL submitted that incentives linked to generation in excess of target PLF/NAPAF, especially during Peak Hours may be allowed for the hydro generating stations. Additional incentive @ 10% of MCP may be provided for energy produced during peak hours for ROR with pondage plants, as it will incentivize the Generating Companies to maximise their generation during peak hours.

f) NTPC, NHDC along with other Generating Companies proposed that the Storage/PSP projects are crucial for meeting peak demand, such project requires additional incentives.

27.4 Commission's View

27.4.1 As already discussed, an increase in large-scale grid integration of Renewable Energy (RE) sources such as Solar and Wind will require more and more primary response to maintain the grid stability. In section 26 under para 26.5.5, the thermal generating companies have been allowed an opportunity to earn up to 1% of AFC as incentive. With regard to hydro generating stations, it is observed that the capacity charges are already 50% of the total AFC. It is further observed that the restriction imposed by Grid Code prohibits hydro stations to declare up to 10% over and above the MCR vis-à-vis 5% impact in case of thermal stations. The Commission has therefore proposed to provide an incentive of up to 4% of Capacity Charge in case of hydro generating stations. The incentive shall be linked with the Average Annual Frequency Response Performance of the generating station, as certified by RPCs, which shall be computed by considering primary response as per the methodology prescribed by the NLDC and shall range between 0 and 1.

27.4.2 Further, in the Approach Paper, the need to incentivize the generation by hydro generating stations to meet peak load was discussed. In line with the same, the Commission has proposed to introduce a new incentive for Run of River (RoR) hydro stations where the incentive is proposed to be allowed on the scheduled saleable energy during the peak hours in excess of the average saleable scheduled energy during the day at the rate of Rs. 0.50/kWh. This is to promote ROR hydro stations to, as far as technically feasible, shift their generation to peak hours which shall reduce the requirement to purchase from a costlier marginal source. This provision is proposed as a win-win situation for both the Generating Stations and the Beneficiaries for optimal utilization of the existing resources.

27.4.3 The calculation of the incentive is clarified below with a brief illustration as follows:

Illustration:

A 100 MW Run of River hydro plant generates a total of 12 MU during the day, out of which 2.1 MU is generated during the peak hours.

Avg. saleable scheduled energy during the day	*= 12/24*
	= 0.5 MU/ hr

Total Peak Hours	*= 3 hours*
Avg. saleable scheduled energy during peak time	*= 2.1/3*
	= 0.7 MU/hr
Additional Energy eligible for incentive	*= (0.7-0.5) x 3hrs*
	= 0.6 MU
Incentive to be paid	*= 0.6x 0.5x10^6*
	= Rs. 3,00,000

27.5 Proposed Regulations

27.5.1 In view of the above, the Commission proposes to introduce Regulation 62 (5) and Regulation 65 (4) in the Draft Tariff Regulations which is as follows:

"62. ***Computation and Payment of Capacity Charge for Thermal Generating Stations***

(5) In addition to the AFC entitlement as computed above, the thermal generating station shall be allowed an incentive of upto 1.00% of AFC approved for a given year, which shall be billed monthly as per the following:

Incentive = (1.00% x ß x CCy)/12

where,

ß = Average Monthly Frequency Response Performance for that generating station, as certified by RPCs, which shall be computed by considering primary response as per the methodology prescribed by the NLDC and shall range between 0 to 1.

Ccy = Capacity Charges for the Year.

……."

"65. ***Computation and Payment of Capacity Charge and Energy Charge for Hydro Generating Stations***

(4) In addition to the AFC entitlement as computed above, the hydro generating station shall be allowed incentive of upto 4% of Capacity Charge approved for a given year which shall be billed monthly as per the following:

Incentive = (4% x ß x CCy)/12

Where,

ß = Average Monthly Frequency Response Performance for that generating station, as certified by RPCs, which shall be computed by considering primary response as per the methodology prescribed by the NLDC and shall range between 0 to 1.

CCy= Capacity Charges for the Year.

…

(10) In addition to the above, an incentive shall be payable to a ROR Hydro generating station @ 50 paise/kWh corresponding to the saleable scheduled energy during peak hours of the day in excess of average saleable scheduled energy during the day (24 Hours)"

28 Shortfall in Scheduled Energy for Hydro Generating Stations

28.1 Background

28.1.1 The Commission, while framing the Tariff Regulations for the period 2009-14, modified the tariff structure for hydro generating stations, wherein a two-part tariff was structured in such a manner that 50% of the recovery of AFC was linked to achieving NAPAF, and the balance 50% was termed as Energy Charge and its recovery was linked to actual generation. This approach aimed to facilitate scheduling, incentivize optimal plant availability and efficient energy production.

28.1.2 In Tariff Regulations, 2019, the Commission provided an enabling provision for recovery of energy charge in case the saleable scheduled energy (ex-bus) of a hydro generating station during a year is less than the saleable design energy (ex-bus) for reasons beyond the control of the generating station.

28.2 Existing Provisions of the Tariff Regulations, 2019

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

……

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

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

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

28.3 Issues discussed in the Approach Paper

28.3.1 In the current mechanism, recovery of 50% of AFC is linked to actual generation, and in the event of any shortfall in actual generation below the saleable design energy, the same is allowed to be recovered as per Regulation 44(7) of the Tariff Regulations, 2019. The existing provisions of the shortfall in recovery of AFC are leading to complications in the recovery process, wherein the affected generating company has to file Petitions seeking such recovery, which results in cash flow issues. Further carrying cost provided to the Generating Company increases the financial burdens on the consumers.

Following issue was brought out in the Approach Paper for consultation:

Ways to simplify the tariff recovery process for hydro generating stations.

28.4 Stakeholders' Response

28.4.1 Stakeholders have submitted the following suggestions on the above issue.

t) NHDC submitted that recovery of reasonable costs is crucial for hydro-sector development, and energy charges up to 50% of AFC may be allowed to be recovered at the end of the financial year, in case shortfall is due to specific uncontrollable factor of hydrological failure/ lower monsoon, under intimation to CERC and the same may be subject to truing-up at the end of the tariff period.

u) THDCIL submitted that hydrological risks can lead to shortfalls in energy generation and NAPAF for plants. Therefore, both risk of under-recovery of capacity charge and energy charge may be allowed to the Generating Companies. Further suggested that the above risk should be allowed on the basis of certification of appropriate authority and need not submit a separate Petition for recovery of shortfall. This will help in the reduction of regulatory burden as well as the timely recovery of the due amount.

v) SRPC submitted that flexibility in regulations may be provided with regard to the recovery of energy charges for hydro generating stations.

w) MSPGCL submitted that payment of fixed or capacity charges for Hydro generating stations is tied to NAPAF. However, uncontrollable factors like water storage insufficient availability or government restrictions can affect the station's availability, reducing the recovery of fixed costs. Clear guidelines are needed to ensure availability is not reduced due to these uncontrollable factors.

28.5 Commission's View

28.5.1 Considering the issues discussed by the stakeholders as summarized above, the Commission has proposed to modify the existing recovery mechanism in case the saleable scheduled energy (ex-bus) during the year is less than the saleable design energy (ex-bus) for reasons beyond the control of hydro generating stations by allowing it to directly recover after adjustment of DSM energy which will be subject to truing up at the end of the tariff period. This will reduce the impact of delayed recoveries such as the cash flow impact on Generating Companies and will also avoid burdening beneficiaries with carrying cost. The Commission shall carry out the truing up of all such adjustments along with the truing up petition for 2024-29.

28.6 Proposed Provisions

28.6.1 In view of the above, the Commission proposes Regulation 65 in the Draft Tariff Regulations, which is as follows:

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

………..

(7) In case the saleable scheduled energy (ex-bus) of a hydro generating station during a year is less than the saleable design energy (ex-bus) for reasons beyond the control of the generating station, the generating station may directly recover the shortfall in energy charges in six equal interest-free monthly instalments after adjusting for DSM Energy in the immediately following year and shall be subject to truing up at the end of the tariff period.

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

(8) Any shortfall in energy charges on account of saleable scheduled energy (ex-bus) being less than the saleable design energy (ex-bus) during the tariff period 2019-24, which was beyond the control of the generating station and which could not be recovered during the said tariff period shall be recovered in accordance with Clause (7) of this Regulation:"

29 SCHEDULING, ACCOUNTING AND BILLING

29.1 Rebate and Late Payment Surcharge

29.1.1 It is observed that provisions with regard to rebates and late payment surcharge (LPSC) are already specified in the PPA, which at times conflicts with the values specified in the Tariff Regulations leading to litigations. Therefore, the Commission is of the view that in case an existing PPA has different provisions with regard to rebate and LPSC, the same shall take precedence over the provision specified in the Tariff Regulations. However, any future PPA should be guided by the provisions specified in the Tariff Regulations as is applicable from time to time. The Commission has therefore proposed the following Regulation.

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

Provided that in case different rebate mechanism is provided in the PPA, the same shall be governed by the provisions of the PPA.

80. Late payment surcharge: *In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary or long term customer as the case may be, beyond a period of 45 days from the date of presentation of bills, a late payment surcharge as specified in the Ministry of Power – Electricity (Late Payment Surcharge and Related Matters) Rules, 2022 as amended from time to time shall be levied by the generating company or the transmission licensee, as the case may be.*

Provided that in case a different LPS mechanism is provided in the PPA, the same shall be governed by the provisions of the PPA.

(2) Unless otherwise agreed by the parties, the charges payable by a beneficiary or long term customer shall be first adjusted towards a late payment surcharge on the outstanding charges and, thereafter, towards monthly charges billed by the generating company or the transmission licensee, as the case may be, starting from the longest overdue bill."

30 Miscellaneous Issues

30.1 Award of Arbitration

30.2 Background

30.2.1 The CERC Tariff Regulations, 2019 provide for allowing Additional Capitalisation including liabilities, to meet an award of arbitration or for compliance with the directions or order of any statutory authority, or order or decree of any court of law. Capital works involve significant investments and, if any disputes arise, especially in cases where an arbitration award is involved, it may result in a financial liability for the entity. Arbitration awards may include both a principal amount and an interest payment for compensating for the delay in payment. These expenses, though, need to be passed on to the end consumers, however it is to be ensured that such relief is compensating in nature and should not result in profit enrichment.

30.3 Approach Paper

30.3.1 Following issues were brought out in the Approach Paper for consultation:

a) Financial impact associated with these matters is considerable, and capitalizing the entire award amount may result in increased AFC, leading to an additional recurring burden on the beneficiaries over the remaining useful life of the asset. To avoid such situations, the principal amount may be capitalized and the interest amount may be allowed to be recovered in instalments from the beneficiaries.

b) Further, comments and suggestions are sought from stakeholders on the above approach and alternative ways, if any.

30.4 Stakeholders' Response:

30.4.1 Stakeholders have submitted the following suggestions on the above-mentioned issues:

a) PGCIL submitted that the principal amount may be capitalized as stated in the Approach Paper. However, the interest amount may be allowed to be one-time reimbursed along with carrying costs.

b) NTPC along with most of the Generating Companies and Transmission Licensees has proposed that they may not be denied capitalisation of the principal and interest amount in a cost-plus regulatory framework as the arbitration is not under their control.

c) NHPC submitted that a provision in the Tariff Regulations to allow the generating companies to claim tariff of the settlement amount under Vivad se Vishwas II may be introduced.

d) Most of the Beneficiaries and Consumer Representatives have supported the proposed approach and have mentioned that the interest may not be partially/ completely passed on to the consumers. Few stakeholders have suggested that the costs may be recovered as one-time charges and not get added to the capital cost of the project.

30.5 Commission's View

30.5.1 The Commission has examined and reviewed the comments/suggestions received from the stakeholders.

30.5.2 It is observed that the financial impact associated with arbitration award is considerable, and capitalizing the entire award amount together may result in a considerable increase in AFC, leading to an additional and more importantly a recurring burden on the beneficiaries over the remaining useful life of the asset. Therefore, in case there is a liability due to arbitration award, only the principal amount that has been paid is proposed to be capitalized and interest compensating for delay in payment shall be reimbursed at actuals. The proposed provision in the draft Tariff Regulations are reproduced below:

30.6 Proposed Regulations

30.6.1 In view of the above, the Commission proposes the following Regulation 91 to be included in the Draft Tariff Regulations, which is as follows:

"91. Award of Arbitration: *In cases where there is a liability with respect to capital works on account of award of arbitration having principal amount along with interest payment, the principal amount actually paid shall be capitalised.*

Provided that any interest amount associated with the arbitration award and actually paid shall be recovered in instalments along with carrying cost at the rate specified under Regulation 10(7) and 10(8) of these Regulations.

Provided further that such number of instalments shall be decided by the Commission on a case-to-case basis depending upon the amount to be reimbursed."

30.7 Approval Process of Non-ISTS Lines carrying Inter-State Power

30.8 Background

30.8.1 Section 79(1) (c) and (d) of the Electricity Act, 2003, entrusts the Central Commission to determine the tariff for inter-State transmission systems. The Commission has been determining tariff for the inter-State transmission lines developed, owned, and operated by various transmission licensees.

30.8.2 The Commission, in Order dated 14.3.2012 in Petition No.15/SM/2012, taking into consideration the request of the State utilities, proposed to include the transmission lines connecting two States in the PoC charges and had accordingly directed the States owning these transmission lines, to file appropriate petitions for determination of tariff for the 2011-14 period in accordance with the provisions of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009). Further, for the 2014-19 tariff period, the Commission vide order dated 12.5.2017 in Petition No.7/SM/2017 directed the State utilities to file tariff petitions for these transmission lines along with the certificate of the concerned RPC in accordance with the provisions of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014. The Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010, which were in force until 31.10.2020, provides for consideration of an intra-State transmission system as an inter-State transmission system on the basis of power flow (>50%). Therefore, the certification of non-ISTS lines used for carrying inter-State power was done on the basis of load flow studies of a line if STU puts up a proposal to RPC and RPC based on the percentage of usage of these lines approved the said lines as being used as ISTS.

30.8.3 The Commission, while framing CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020, observed that various RPCs have adopted different methodologies for certifying non-ISTS lines as inter-ISTS lines. For example, in the case of WRPC once the intra-State line is declared deemed inter-State line, that line retains the status of ISTS for the rest of its life whereas in the case of other RPCs, the ISTS certification was valid for only 1 year. Therefore, the Commission vide CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020 abolished the certification process and instead decided to review such cases on a case-to-case basis.

30.9 Issues discussed in the Approach Paper

30.9.1 Following issues were bought out in the Approach Paper for consultation:

i) Approval process to be followed before undertaking the construction of new intra-state transmission lines carrying inter-state power.

ii) Capital cost to be considered for the computation of transmission charges in respect of intra-State lines (carrying inter-State power) of the State transmission utilities.

30.10 Stakeholders' Response:

30.10.1 Stakeholders have submitted the following suggestions on this issue:

(a) Most of the Generating Companies and Transmission Licensees proposed that existing norms may be continued.

(b) Some of the Transmission Licensees have proposed that there are disagreements and lack of consensus regarding the interpretation of what qualifies as an ISTS line.

(c) Some of the Generating Companies and Transmission Licensees have proposed that the capital cost/Tariff of such lines should completely be removed from the asset base of the STU for the purpose of estimation of State ARR.

30.11 Commission's View

30.11.1 The Commission has examined and reviewed the comments/suggestions received from the stakeholders.

30.11.2 It is observed that to discuss the issue of certification of inter-State lines, a meeting was held with RPCs, CTUIL, NLDC on 5.9.2023. In the meeting, it was decided that the following conditions need to be considered before qualifying any ISTS or any Natural ISTS transmission asset as an inter-State line:

i) The Transmission lines have not been developed for the sole purpose of beneficiaries of the single State.

ii) The Transmission lines should have been conceived as Inter-State lines at the planning stage.

iii) Transmission lines should be used for evacuation and transfer of interstate power on a regular basis as identified by CTU in consultation with the concerned RPC and RLDC.

iv) Proper mechanism is in place for the maintenance of such a transmission system.

v) Such a transmission system is under operation and the appropriate metering system is in place to record the flow of power.

30.11.3 The Commission, in view of Section 39 of the Electricity Act, 2003, observes that no new Inter-State lines shall be planned and developed by State Transmission Utility unless agreed by CTU in consultation with RPC and approved by the Ministry of Power.

30.11.4 The Commission has therefore proposed that the above conditions need to be met for any line to qualify as the Inter-State line.

30.12 Proposed Provisions

30.12.1 In view of the above, the Commission proposes to include Regulation 93 in the Draft Tariff Regulations, which is as follows:

"93. Approval Process of Non-ISTS Lines carrying Inter-State Power:

(1) Existing intra-state transmission lines other than Natural ISTS lines shall be considered as ISTS systems;

Provided that these transmission lines are being used for evacuation and transfer of inter-state power on a regular basis as identified by CTU in consultation with the concerned RPC and RLDC;

Provided further that such transmission system is under operation and appropriate metering system is in place to record flow of power;

Provided further that a proper mechanism is in place for the maintenance of such a transmission system.

(2) Existing Intra State lines which were planned as ISTS System shall also be considered as ISTS lines;

Provided that such lines have not been developed for the sole purpose of the beneficiary(ies) of a single State;

Provided further that such transmission system is under operation and appropriate metering system is in place to record flow of power;

Provided further that a proper mechanism is in place for the maintenance of such a transmission system.

(3) CTU, in consultation with RLDC shall identify all such natural ISTS lines and non-ISTS lines which are utilized for ISTS power transfer after ascertaining that such nature of flow of power has become permanent.

(4) No New ISTS lines shall henceforth be planned and developed by State Transmission Utility unless agreed by CTU in consultation with RPC and approved by the Ministry of Power.

(5) New transmission lines which have been conceived as ISTS lines at the planning stage shall be considered as part of the ISTS system;

Provided that such lines have not been developed for the sole purpose of the beneficiary(ies) of a single State;

Provided further that such transmission system is under operation and appropriate metering system is in place to record flow of power;

Provided further that a proper mechanism is in place for the maintenance of such a transmission system.

(6) Tariff of all such ISTS lines shall be approved based on provisions of these Regulations, and the fixed charges of such system shall be allowed based on the availability certified by respective RPCs and shall be allowed to be recovered as per the mechanism specified in CERC (Sharing of Inter-State Transmission Charges and Losses), 2020."

30.13 Public Procurement through Competitive Bidding

30.14 Background

30.14.1 Section 63 of the Electricity Act, 2003, mandates that the adoption of Tariffs be determined through transparent competitive bidding. Section 62 is about the determination of tariffs based on cost-plus mechanism. It is, however, imperative that even under Section 62, the procurement of equipment and services is carried out through competitive bidding. In such a framework, in the interest of consumers, Work Contracts are required to be awarded on the basis of transparent competitive bidding, which shall form the basis of approval of such costs. Further, Tariff Policy, 2016 lays emphasis on the utility and benefits of competitive bidding, and therefore, even for projects being developed under Section 62 of the Act, as far as practically possible, the works need to be executed following the transparent process of competitive bidding.

30.15 Issues discussed in the Approach Paper

30.15.1 Following issue were bought out in the Approach Paper for consultation:

(i) Need to mandatorily award work and services contracts for developing projects under regulated tariff mechanism through a transparent process of competitive bidding using public procurement platforms duly complying with the policy/guidelines issued by Government of India as applicable from time to time.

30.16 Stakeholders' Response:

30.16.1 In response, Stakeholders have submitted the following suggestions on this issue:

(a) NTPC, PGCIL, along with most of the Generating Companies and Transmission Licensees proposed that exemptions may be provided for adopting a transparent competitive bidding process for certain contracts except for BTG and other main contracts under certain circumstances.

(b) Some of the Generating Companies and Transmission Licensees have proposed that exemptions may be provided for projects acquired through NCLT and for works that are awarded to government agencies/departments such as Railways, PWDs, etc., on a deposit works basis for exclusive nature of work.

(c) Some of the Generating Companies and Transmission Licensees have proposed that enabling provisions may be introduced for equipment to be purchased under Force Majeure, Change in Law, etc.

(d) Some Generating Companies have suggested not to mandate competitive bidding for small value contracts.

(e) CESC Ltd has suggested procurement of equipment or services for developing projects through a transparent, competitive bidding process. However, in exigent situations that require procurement on an urgent basis competitive bidding can't be done (force majeure, unforeseen exigencies etc), and enabling provisions should be there in the next control period.

(f) GMR Energy Ltd has submitted that it is practically very difficult to award all the work and service contracts based on competitive bidding.

30.17 Commission's View

30.17.1 The Commission has examined and reviewed the comments/suggestions received from various stakeholders.

30.17.2 The Approach Paper has already discussed the need for procurement of equipment and services on the basis of transparent competitive bidding. The cost forms the basis of tariff and therefore, as far as practicably possible, competitive bidding should be adopted duly complying with the general financial rules issued by the Government of India as applicable from time to time. Hence, the Commission has introduced a separate regulation that shall govern Public Procurement through Competitive Bidding.

30.18 Proposed Provisions

30.18.1 In view of the above, the Commission proposes the following Regulation 100 in the Draft Tariff Regulations:

"100. Public Procurement through Competitive Bidding: *The generating company for a specific generating station or for an integrated mine or a transmission licensee shall procure equipment, work and services through a transparent process of competitive bidding.*

Provided that under certain exceptional circumstances, equipment, works and services may be procured through other methods, as provided under general financial rules issued by the Government of India and applicable from time to time."

31 Procedure for Transmission System Availability

31.1 Background

31.1.1 The Commission vide Central Electricity Regulatory Commission (Terms and Condition of Tariff) (third Amendment) Regulations, 2023 dated 15.12.2023 had amended the "Procedure for Calculation of Transmission System Availability Factor for a month".

31.2 Existing Provisions of the Tariff Regulations, 2019

"Procedure for Calculation of Transmission System Availability Factor for a Month

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

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

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

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

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

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

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

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

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

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

TAFMn (in %) for AC system:

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

Where,

o	=	*Total number of AC lines.*
AVo	=	*Availability of o number of AC lines*
p	=	*Total number of bus reactors/switchable line reactors*
AVq	=	*Total actual operated capacity of y^{th} HVDC back-to-back station block*
R	=	*Total rated capacity of y^{th} HVDC back-to-back station block*
AVr	=	*Availability of y^{th} HVDC back-to-back station block*
U	=	*Total no of HVDC poles*
AVu	=	*Total no of HVDC Back to Back blocks*

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

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

Where

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

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

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

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

i. *Shut down availed for maintenance of another transmission scheme or construction of new element or renovation/upgradation/additional capitalization in an existing system approved by the Commission. If the other transmission scheme belongs to the transmission licensee, the Member Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved. In case of a dispute regarding deemed availability, the matter may be referred to the Chairperson, CEA, within 30 days.*

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

iii. *Shut down of a transmission line due to shifting or modification of such transmission line or otherwise because of the Project(s) of NHAI, Railways, and Border Road Organisation. Member Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved;*

Provided that DICs are not affected by the shutdown of such a transmission Line;

iv. *Shut down of a transmission line due to the Project(s) of NHAI, Railways and Border Road Organization, including for shifting or modification of such transmission line. Member Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved;*

Provided that such deemed availability shall be considered only for the period for which DICs are not affected by the shutdown of such transmission line.

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

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

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

iii) *The outage period which can be excluded for the purpose of sub-clause (i) and (ii) of this clause shall be declared as under:*

a. Maximum up to one month by the Member Secretary, RPC;
b. Beyond one month and up to three months after the decision at RPC;
c. Beyond three months by the Commission for which the transmission license shall approach the Commission along with reasons and steps taken to mitigate the outage and restoration timeline.

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

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

31.3 Commission's View

31.3.1 As the "Procedure for Calculation of Transmission System Availability Factor for a month" has been recently amended by the Commission on 15.12.2023 vide the Central Electricity Regulatory Commission (Terms and Condition of Tariff) (third Amendment) Regulations, 2023, the Commission has proposed to adopt the same for tariff period 2024-29.

31.4 Proposed Provisions

31.4.1 In view of the above, the Commission proposes to revise the procedure provided in Appendix -IV in the Draft Tariff Regulations, which is as follows:

"Procedure for Calculation of Transmission System Availability Factor for a Month

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

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

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

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

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

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

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

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

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

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

TAFMn (in %) for AC system:

$$= \frac{o \times AVo)+(p \times AVp) + (q \times AVq) + (r \times AVr)+(u \times AVu)}{(o + p + q + r+u)} x100$$

Where,

o	=	*Total number of AC lines.*
AVo	=	*Availability of o number of AC lines*
p	=	*Total number of bus reactors/switchable line reactors*
AVq	=	*Total actual operated capacity of y^{th} HVDC back-to-back station block*
R	=	*Total rated capacity of y^{th} HVDC back-to-back station block*
AVr	=	*Availability of y^{th} HVDC back-to-back station block*
U	=	*Total no of HVDC poles*

AVu	=	*Total no of HVDC Back to Back blocks*

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

$$= \frac{\sum_{x=1}^{s} Cxbp\,(act)\,X\,AVxbp + \sum_{y=1}^{t} Cy\,(act)btb\,X\,AVybtb}{\sum_{x=1}^{s} Cxbp + \sum_{y=1}^{t} Cybtb} x100$$

Where

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

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

(a) *For each circuit of the AC line – The number of sub-conductors in the line multiplied by ckt-km;*

(b) *For each HVDC pole- The rated MW capacity x ckt-km;*

(c) *For each ICT bank – The rated MVA capacity;*

(d) *For SVC- The rated MVAR capacity (inductive and capacitive);*

(e) *For Bus Reactor/switchable line reactors – The rated MVAR capacity;*

(f) *For HVDC back-to-back stations connecting two Regional grids- Rated MW capacity of each block; and*

(g) *For STATCOM – Total rated MVAR Capacity.*

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

i. Shut down availed for maintenance of another transmission scheme or construction of new element or renovation/upgradation/additional capitalization in an existing system approved by the Commission. If the other transmission scheme belongs to the transmission licensee, the Member Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved. In case of a dispute regarding deemed availability, the matter may be referred to the Chairperson, CEA, within 30 days.

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

iii. Shut down of a transmission line due to the Project(s) of NHAI, Railways and Border Road Organization, including for shifting or modification of such transmission line. Member Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved;

Provided that such deemed availability shall be considered only for the period for which DICs are not affected by the shutdown of such transmission line.

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

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

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

iii) The outage period which can be excluded for the purpose of sub-clause (i) and (ii) of this clause shall be declared as under:

a. Maximum up to one month by the Member Secretary, RPC;
b. Beyond one month and up to three months after the decision at RPC;
c. Beyond three months by the Commission for which the transmission license shall approach the Commission along with reasons and steps taken to mitigate the outage and restoration timeline.

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

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