CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Coram:
Shri Jishnu Barua, Chairperson
Shri Arun Goyal, Member

No. L-1/268/2022/CERC **Dated: 11th July, 2024**

In the matter of

Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024, applicable from 1.4.2024 – Statement of Objects & Reasons (SOR) thereof.

STATEMENT OF OBJECTS AND REASONS

Introduction

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 (36 of 2003) (hereinafter referred to as 'the Act'), the CERC was deemed to be constituted under the Act.

2. Clauses (a), (b), and (d) of sub-section 1 of Section 79 read with clauses (a) and (b) of sub-section (1) of Section 62 of the Act vest the Commission to regulate and determine the tariff of the generating companies owned or controlled by the Central Government; regulating the tariff of generating companies having a composite scheme for generation and sale of electricity in more than one State; to regulate inter-state transmission of electricity and to determine the tariff for inter-State transmission in electricity, among others;

3. Section 61 of the Act empowers the Commission to specify, by regulations, the terms and conditions for the determination of tariffs in accordance with the provisions of the said section.

4. In terms of clause (s) of sub-section (2) of Section 178 of the Act, the Commission has been vested with the powers to notify regulations on the terms and conditions of tariff under Section 61 of the Act. Clause 3 of Section 178 of the Act requires the Commission to make previous regulations after previous publications.

5. Clause (i) of Section 61 of the Act provides that the Commission shall be guided by the National Electricity Policy and Tariff Policy while making the regulations on terms and conditions of tariff; Rule 3 of Electricity (Procedure for Previous Publication) Rules 2005 notified by the Central Government provides the procedure of previous

publications which provides the Commission to decide the manner of publication.

6. The Commission initiated the process of notifying the CERC (Terms and Conditions of Tariff) Regulations, 2024 (hereinafter referred to as “the CERC Tariff Regulations 2024”) applicable for the period from 1.4.2024 to 31.3.2029, in the exercise of powers conferred under Section 178 read with Section 61 of Act and all other powers enabling it in this behalf and notified the same on 15.03.2024.

7. On March 29, 2023, the Commission sought details of the operational and performance data, including the operation and maintenance expenses from the various generating companies and Transmission Licensees. These details have been made available on the website of the Commission for all the stakeholders.

Consultation Process

8. On 25.05.2023, the Staff of the Commission issued an Approach Paper for framing the Terms and Conditions of Tariff Regulations for the tariff period from 01.04.2024 to 31.03.2029 and solicited comments from the stakeholders on various options for a regulatory framework to be considered while framing the new terms and conditions of Tariff Regulations for the tariff period 2024-29. The Approach Paper was issued to initiate discussions on the changes required, if any, on the existing tariff norms, keeping in view the developments in the sector during the ongoing tariff period, current and perceived challenges in the power sector, and duly recognizing the need for sustainable market development based on the experiences of the last twenty-four years of tariff regulation by the Commission, starting from May 1999. In response, 91 comments were received by the Commission from 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, as well as individual experts. The responses received have been made available on the website of the Commission for all the stakeholders.

9. On 26.09.2023, the Commission consulted with the Central Advisory Committee, and the members of the said Committee submitted their suggestions.

10. On 4.1.2024, the Commission issued the Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024 (hereinafter referred to as the “Draft Tariff Regulations, 2024” or “Draft Tariff Regulations”) exercising the powers vested under Section 61 and clause (s) of sub-section (2) of Section 178 of the Act and all other enabling powers and in compliance of the requirement under sub-section (3) of Section 178 of the Act. The Draft Tariff Regulations were prepared by the Commission after considering the responses and suggestions received from the various stakeholders and the Central Advisory Committee. Accordingly, the Commission has considered the following:

    a) comments of the stakeholders on the issues raised in the Approach Paper and the additional suggestions related to the Tariff Regulations;

b) suggestions of the Central Advisory Committee on the Approach paper;

c) recommendations of the Central Electricity Authority;

d) last five years' performance of the central sector generating stations, other inter-State generating stations, and inter-State transmission systems;

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

f) future need for the Sector based on the anticipated generation mix and associated grid support;

g) fostering energy security by promoting sustainable investments;

h) Need to support flexible operations for the integration of Renewable Energy and

i) balancing the interest of the stakeholders in accordance with the principles laid down under Section 61 of the Act.

The Commission had also issued an Explanatory Memorandum accompanying the Draft Tariff Regulations, wherein it explained the reasons and analysis relied upon while framing the Draft Tariff Regulations.

11. Public notice was issued by the Commission on 4.1.2024 soliciting the views/ suggestions/ objections of the stakeholders on the Draft Tariff Regulations by 10.02.2024, which was subsequently extended until 20.02.2024 vide notice dated 30.1.2024. In response, the Commission received 146 submissions from various stakeholders which were hosted on the Commission's website for access by interested persons.

12. Subsequently, on 15.02.2024, a Public Hearing on the Draft Tariff Regulations was held at SCOPE Complex, New Delhi, to solicit the views and objections of stakeholders and consumers. The list of participants in the public hearing held on 15.02.2024 and the presentations submitted during the hearing have been hosted on the website of the Commission.

13. The Central Electricity Authority revised some of the operational norms specified vide its earlier recommendation dated 19.12.2023 and submitted its revised recommendations on the operational norms on 15.03.2024. The CEA's recommendations have also been hosted on the Commission's website.

14. The Commission, complying with the provisions of the Act, the Electricity (Procedure for Previous Publication) Rules, 2005, after extensive consultations with all the stakeholders and giving due consideration to the recommendations of the Central Electricity Authority, proceeded to finalize the Terms and Conditions of Tariff Regulations, 2024.

15. The Commission has considered the comments of the stakeholders and interested persons on the approach paper and on the Draft Tariff Regulations, the recommendations of the Central Electricity Authority, the comments and views of the

participants in the public hearing, and their written submissions during and after the public hearing. The regulations have been finalized after detailed analysis and due consideration of the various issues raised.

Notification of the Tariff Regulations, 2024

16. On 15.03.2024, the Commission notified the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024 (hereinafter referred to as "Tariff Regulations, 2024") keeping in view the mandate of the Act, National Electricity Policy, and the Tariff Policy. Subsequently, the Commission vide corrigendum dated 09.04.2024 has rectified some minor inadvertent errors, which have also been considered while preparing this Statement of Objects and Reasons.

17. As stated, all the suggestions/views of the stakeholders have been considered and the Commission has attempted to elaborate on all the suggestions as well as its decision on each suggestion in the Statement of Objects and Reasons. Wherever possible, the comments and suggestions have been summarised clause-wise, along with the Commission's analysis on the same. However, in some cases, due to the overlapping of issues, ~~two~~ clauses have been combined to minimise repetition.

STATEMENT OF REASONS

18. The Explanatory Memorandum accompanying the Draft Tariff Regulations explained, in detail, the rationale behind the proposed Draft Tariff Regulations. This Statement of Objects and Reasons (SOR) has been issued with the intent of explaining the main objects and reasons behind the provisions of the Tariff Regulations, 2024, the changes carried out by the Commission from the Draft Tariff Regulations to the Tariff Regulations, 2024 notified after considering the suggestions of the stakeholders, wherever required.

Definition and Interpretation

1. Long Term Customer [Regulation 3(49)]

As proposed in Draft Tariff Regulations

1.1 In the Draft Regulations, the definition of Long-Term Customer was proposed as below:

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

Comments Received

1.2 GRIDCO has suggested to amend the definition to include a proviso specifying that the Long-Term Customer in relation to an Interstate Generating Station shall also include the person who has allocation in Interstate Generating Stations.

1.3 SRPC suggested replacing the term 'long term customer' with 'long term customer/GNA grantee.'

1.4 OPGC suggested to replace the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009 with the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022.

Analysis and Decision

1.5 The Commission has considered the suggestion(s) and has made suitable changes in the definition of "Long Term Customer" in Regulation 3(49) of the Tariff Regulations, 2024 to include the Designated ISTS Customers (DICs) and GNA grantees (excluding those granted T-GNA) as defined under the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022, as under:

> *"(49) 'Long-Term Customer' shall have the same meaning as 'Long Term Customer' as defined in the Central Electricity Regulatory Commission (Grant of Connectivity, Long-¬term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009 or Designated ISTS Customers (DICs) or "General Network Access Grantee" or "GNA Grantee" as defined in the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022 (excluding those granted "T-GNA");"*

2. Operation and Maintenance Expenses [Regulation 3 (56)]

As proposed in Draft Tariff Regulations

2.1 In the Draft Regulations, the definition of O&M expenses was proposed as under:

> *"(56) 'Operation and Maintenance Expenses' or 'O&M expenses' means the expenditure incurred for operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, maintenance, repairs and maintenance spares, other spares of capital nature valuing less than Rs. 20 lakhs, additional capital expenditure of an individual asset costing up to Rs. 20 lakhs, consumables, insurance and overheads and fuel other than used for generation of electricity:*
>
> *Provided that for integrated mine(s), the Operation & Maintenance Expenses shall not include the mining charge paid to the Mine Developer and Operator, if any, engaged by the generating company and the mine closure expenses."*

Comments Received

2.2 PPCL has suggested including the capital spares costing less than Rs. 5 Lakh and additional capitalisation of an individual asset costing up to Rs. 5 Lakh under O&M expenses for the generating company and transmission licensee.

2.3 PGCIL suggested including capital spares in the range of Rs. 5 Lakh to 20 Lakh while fixing O&M norms for transmission.

2.4 DVC suggested escalating the O&M norms by 1.40% in case capital spares less than 20 Lakh are included as part of the O&M expenses as the total actual cost of capital spares claimed during FY 2014-19 period is around 1.4% of the normative O&M cost. DIL suggested to allow capital spares as on actual basis.

2.5 MPPMCL suggested allowing capital spares as part of O&M expenses. However, if the same is not allowed under normative O&M expenses, then it was suggested that capital spares of the value of Rs. 50 Lakh and above may only be allowed separately as capital spares.

2.6 Several other stakeholders have also suggested various thresholds and ceiling limits for capital spares, as well as the additional capital expenditures to be included in the O&M expenses.

Analysis and Decision

2.7 Some of the stakeholders have suggested an increase in the limit of capital spares and additional capitalisation, while others have sought to reduce the said limit. Some stakeholders have especially sought a reduction of the limit proposed for capital spares. The Commission, after duly considering the suggestions of the stakeholders and after analysing the data received from generating companies and transmission licenses, observes that generally, the individual cost of capital spares is less than Rs. 10 lakhs. The Commission has therefore considered the capital spares of up to Rs. 10 lakhs to be part of the O&M expense norms. As regards additional capitalisation, the Commission, after analysis of the data submitted, finds no reason to change the limit proposed in the draft Tariff Regulations and has, therefore, retained the limit of Rs. 20 lakhs as specified in the draft regulations. The O&M norms specified for generation as well as transmission assets include capital spares of up to Rs. 10 lakhs and additional capitalisation of up to Rs. 20 lakhs. Accordingly, suitable changes in the definition of "Operation and Maintenance Expenses" have been made under Regulation 3(55) of the Tariff Regulations, 2024, as under:

"(55) 'Operation and Maintenance Expenses' or 'O&M expenses' means the expenditure incurred for operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, maintenance, repairs and maintenance spares, other spares of capital nature valuing up to Rs. 10 lakhs, additional capital expenditure of an individual asset costing less than Rs. 20 lakhs, consumables, insurance and overheads and fuel other than used for generation of electricity:"

However, the proviso to this regulation has been retained as proposed.

3. Scheduled Generation [Regulation 3(72)]

As proposed in Draft Tariff Regulations

3.1 In the Draft Regulations, the definition of Scheduled Generation was proposed as under:

(72) 'Scheduled Generation' or 'Scheduled injection' for a time block or any period means the schedule of generation or injection in MW or MWh ex-bus, including the schedule for Ancillary Services given by the concerned Load Despatch Centre in accordance with the Grid Code;

Comments Received

3.2 PCKL suggested that the Schedule for ancillary services should not be included in the 'Scheduled Generation' or 'Scheduled Injection' as "Schedule for Ancillary Services" is not the operative injection into the Grid.

Analysis and Decision

3.3 The Commission has considered the suggestions/views of the stakeholders and the justification provided therein. The Commission observes that the Scheduled Generation definition includes energy generated to support ancillary service. The Commission would like to clarify that Ancillary Service was included with a view to supporting the Grid stability, wherein the primary objectives were to maintain the grid frequency close to 50 Hz, restoration of the grid frequency within the allowable band as specified in the IEGC, and for relieving congestion in the transmission network, to ensure smooth operation of the power system and safety and security of the grid. However, the Commission would like to clarify that for the purpose of Incentive, the actual generation towards Ancillary Services will not be taken into account. The Commission would also like to clarify that in case any generator is selling power on exchange and the PLF of the station is higher than NAPLF, in such cases, for the purpose of incentives to be recovered from the long-term beneficiaries, such generation, i.e., scheduled on exchange, shall also not be accounted for while claiming incentives for higher generation over and above NAPLF. In view of the above, the Commission has retained the definition in the Tariff Regulations 2024, as proposed.

4. **Useful Life [Regulation 3(88)]**

As proposed in Draft Tariff Regulations

4.1 In the Draft Regulations, the definition of 'Useful Life' was proposed as under:

"(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) & 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 the case of coal/lignite based thermal generating stations and hydro generating stations, the Operational Life may be 35 years and 50 years, respectively."

Comments Received

4.2 MSPGCL has welcomed the decision to extend the useful life of Thermal and Hydro generating stations and stated that it will ensure availability for base load generating capacity, at times of high demand, to consumers.

4.3 BYPL has suggested that the Commission may only retain the provision of "Useful Life" and omit the term "Operational Life" to remove any ambiguity and /or enlarge the scope of the term "Useful life" as well as other provisions of the Draft Tariff Regulations. It has also suggested increasing the "Useful life" for Transmission assets, providing connectivity for generating stations to the pooling stations beyond the period of its useful life or operational life.

4.4 PPCL suggested increasing the Useful life of Gas based generating stations to 35 years with an extension allowable on a case-to-case basis.

4.5 PGCIL has suggested keeping the useful life of the OPGW unchanged, i.e., 15 years as the life of OPGW usually lasts between 15 to 20 years since in the previous years, it was observed that the performance of fibres of OPGW deteriorated significantly in 15 years. It has also stated that a large number of OPGW links installed during the period from 2002 to 2006 under the various projects implemented by PGCIL are not serviceable as these links are rusted and are also showing high signal and data losses in data transmission. PGCIL has therefore requested to keep the useful life of the OPGW unchanged, i.e., 15 years, as the fibres degrade early and cannot be matched with the life of the transmission line. PGCIL has further submitted that retaining the life to 15 years will offer flexibility for replacement on a need basis, and therefore, the depreciation rates for OPGW, provided under Appendix -I & Appendix-II, may be retained as 6.33% as provided under the Tariff Regulations, 2019 applicable for the period 2019-24.

4.6 MPPMCL has suggested that the useful life of the communication system should be retained as 15 years and to define the terms 'Operational Life.'

Analysis and Decision

4.7 The Commission has considered the suggestions of the stakeholders and the justification provided therein. The Commission observes that the Operational life is stipulated for coal and lignite-based stations as well as hydro generating stations, on the basis of the majority of plants operating efficiently well beyond the useful life, and, therefore, requires no change. As regards the definition of the term 'Operational Life,' the Commission would like to clarify that the same has already been defined in the proviso to the said regulations, wherein the operational life in the context of coal and lignite-based stations as well as hydro generating stations have been specified. For all other assets, no such exception has been made, and therefore, no generalised definition is required.

4.8 As regards the useful life of OPGW, the Commission has agreed to the suggestions of PGCIL and has retained the current norm of 15 years of useful life, as OPGW may not efficiently operate for a longer duration. Further, for reasons already detailed in the explanatory memorandum that the communication system (except for OPGW) and SCADA are similar to that of the IT system, the Commission has retained the life specified as 7 years. Accordingly, the useful life of OPGW has been separately considered as 15 years under Regulation 3(87) as under:

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

(a)	*Coal/Lignite based thermal generating station*	*25 years*
(b)	*Gas/Liquid fuel based thermal generating station*	*25 years*
(c)	*AC and DC sub-station*	*25 years*
(d)	*Gas Insulated Substation (GIS)*	*25 years*
(e)	*Hydro generating station including pumped storage hydro generating stations*	*40 years*
(f)	*Transmission line (including HVAC & HVDC)*	*35 years*
(g)	*Optical Ground Wire (OPGW)*	*15 years*
(h)	*IT system, SCADA and Communication system excluding OPGW*	*7 years*
(i)	*Integrated mine(s)*	*As per the Mining Plan*

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

5. **Date of Commercial Operation [Regulation 5 (1)]**

As proposed in Draft Tariff Regulations

5.1 In the Draft Tariff Regulations, Regulation 5 (1) was proposed as under:

"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."

Comments Received

5.2 MSPGCL suggested retaining Regulation 6 (1)(b) of the 2019 Tariff Regulations, wherein it has been specified that in case an associated transmission system is not available, but a generating station has achieved COD, the transmission licensees shall make alternate arrangement for evacuation of power at its own cost, failing which it shall pay the transmission charges, so that the generator may not face penalties for the delays in achieving commercial operation of the transmission system, especially when such delays are beyond its control and not due to any default on its part.

Analysis and Decision

5.3 The Commission has considered the suggestions and observes that the modalities governing the mismatch of the date of commercial operation between the Associated

Transmission and Generating stations are covered under the CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020. In this background, the Commission is of the view that there is no need to add the same under the Tariff Regulations. However, the Commission, in order to provide clarity, has decided to make suitable changes to Regulation 5(1) of the draft Tariff Regulations by mentioning that such modalities governing the mismatch shall be governed by the relevant provisions of the CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020. Accordingly, Regulation 5(1) has been modified as under:

> *"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. In the event of mismatch of COD between associated transmission and/or generating stations, the liability for the transmission charges shall be in accordance with the provisions of the Sharing Regulations, 2020 as amended from time to time."*

<u>Procedure for Tariff Determination</u>

6. **<u>Application for determination of Tariff [Regulation 9]</u>**

As proposed in Draft Tariff Regulations

6.1 In the Draft Tariff Regulations, Regulation 9 was proposed as under:

"(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."

<u>Comments Received</u>

6.2 PSPCL and DVC have submitted that the existing provision of filing tariff petitions based on the anticipated COD may be allowed to be continued.

6.3 With regard to the supplementary tariff of the Emission Control System (ECS), MB Power has submitted that the generating company may be allowed to file an application up to 90 days prior to the anticipated /scheduled COD of the ECS for the determination of provisional and/or interim supplementary tariff. It has further submitted that such a proviso will provide for the timely determination of tariff, which will allow debt servicing, maintain uniformity of cash flow and also reduce the carrying cost.

6.4 MSPGCL has suggested that the extended period of 90 days allowed in the draft Regulation to file a petition, as compared to the existing 60 days, is practical and suitable given the need for about 2-3 months for finalizing the accounts. In addition, it has been submitted that determining the amount of liquidated damages and un-discharge liabilities takes about 1 to 2 years.

6.5 AEML has suggested that the application for tariff determination may be delayed due to factors not under the control of the generating company. Accordingly, even in case of delay in filing the application for tariff determination, the carrying cost should be allowed from the COD. It has also been submitted that in case the Utility delays in filing the Petition, the carrying cost for the delay over and above the period of 90 days may only be disallowed for the utility and not for the entire period from COD of the project to the date of filing of the Petition.

6.6 MSEDCL has suggested that it is necessary for the Commission to have an assessment of the actual cost incurred by the generating station or unit thereof and the transmission system through an Auditor certificate for the determination of interim tariff. It has therefore suggested retaining the existing clause to submit the Auditor certificate certifying the cost no later than 60 days from the date of granting of the interim tariff, wherever the interim tariff has been determined based on the Management Certificate.

6.7 MPPMCL suggested that an Auditor certificate should be submitted compulsorily, the Commission should lay down certain norms and conditions to authorise qualified auditors to carry out necessary audits, and certain checks and penalties should be specified in case of any kind of data manipulation.

Analysis and Decision

6.8 The Commission has considered the suggestions of the stakeholders above and is of the view that the period of 90 days from COD is adequate as an enabling provision to allow interim tariff after the first hearing and hence no change is required.

6.9 The Commission in the Draft Tariff Regulations, 2024 had proposed the first proviso to Regulation 9(1) so that the Transmission Licensees can 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. The Commission has re-looked the applicability of the condition for smaller schemes, which require the scheme to be fully completed before a suitable petition is filed seeking tariff, and is of the view that the condition to incur 100% of the cost envisaged in the Investment approval may lead to delays in filing of a petition and therefore, the earlier proviso of 70% has been retained.

6.10 As regards the suggestion of the stakeholders for retaining the existing proviso for mandatory submission of an auditor certificate, the Commission is of the view that the utilities should be more accountable towards the data submitted while seeking tariff and therefore, the condition that wherever interim tariff is allowed on the basis of management certificate, the generating station or transmission licensee shall submit the auditor certificate certifying the cost within 90 days from the COD of the asset has been added.

6.11 The Commission also observes that the date of filing of petitions by the existing generating stations and the transmission licensees was specified as 31.10.2024 in the Draft Regulations. However, the date has been revised as 30.11.2024 in line with the 2019 Tariff Regulations.

6.12 Also, to provide clarity on the allowable carrying cost, the Commission has modified Regulation 9(5) and specified the rate of the carrying cost as one-year SBI MCLR + 100 basis points. The Commission has also specified that the carrying cost shall be computed as simple interest and at the rates specified above.

6.13 As regards the carrying cost to be allowed in case of a delay in filing the tariff petition as per sub-regulations 1 to 4 of Regulation 9, the Commission would like to clarify that in case of the existing generating station or unit thereof or the transmission system or element thereof, as the case may be, or any existing emission control system or any existing integrated mine, filing a tariff petition beyond the date of 30.11.2024, and in case, after deciding the petition, it is observed that the Utility is required to recover the differential tariff, in such cases, the carrying cost shall not be allowed to such Utility(ies) for the period for which the filing of the said petition is delayed beyond the stipulated timeline of 30.11.2024. In other words, the carrying cost for the period from 30.11.2024 up to the date of filing of the petition shall not be allowed. However, it is clarified that except for this period, the carrying cost for the period prior to 30.11.2024 (if applicable) and from the date of filing till the date of order shall be allowed. But in case, the Utility is required to refund the differential amount to the beneficiaries, the carrying cost shall be applicable for the delayed period also till the date of order.

[For e.g., A tariff Petition is filed by the Utility on 30.12.2024 instead of 30.11.2024, and the Commission issues a tariff order on 30.04.2025. As per the said order, if the Utility is required to recover Rs. X as a differential tariff, then the carrying cost for the period from 30.11.2024 to 30.12.2024 on Rs. X shall not be allowed. However, the carrying cost if any applicable, prior to 30.11.2024 on such Rs. X and that from 30.12.2024 till the date of order, i.e., 30.04.2025, shall be allowed. On the other hand, in case the Utility has to refund the amount, then the carrying cost shall also be made applicable for the entire period till the date of order.]

6.14 Accordingly, the Commission has modified Regulation 9 as under:

"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 70% 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 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 estimated 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 may consider granting interim tariff from the date of commercial operation after the first hearing of the application and where such 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 90 days from the date of Commercial Operation;

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 30.11.2024 , 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 of coal or lignite 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 at the simple interest rate of 1-year SBI MCLR plus 100 basis points 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(6) and 10(7) of these regulations."

7. <u>Determination of Tariff [Regulation 10(3) and 10(7)]</u>

As proposed in Draft Regulations

7.1 In the Draft Tariff Regulations, Regulation 10 (3), Regulation 10(6) and Regulation 10(7) was proposed as under:

"*10 **Determination of tariff***

(1) xxx

(2) 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 28 as on 1st April of the financial year in which such excess recovery was made

(3) xx

(4) xx

(5) 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.

(6) 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."

<u>Comments Received</u>

7.2 MSPGCL has suggested allowing the interim tariff at 100% of the cost submitted by new generating stations or units thereof, as the Petition will be filed after the date of the actual COD. It has also been submitted that in case the excess amount is paid by the beneficiaries to the generating station or its unit, the excess amount in accordance with the final tariff is to be refunded to the beneficiaries or vice versa, along with the carrying cost.

7.3 BYPL has suggested that the Commission, in the proposed Regulation 10(7), may explicitly clarify that the interest allowed to be charged on the differential amounts billed by the generating and transmission utilities would be limited until the issuance of the order and no further/additional interest will be allowed during the recovery from the beneficiaries in six equal monthly instalments, so as to avoid any imposition of additional interest on the monthly instalments beyond the issuance of the order.

7.4 APPCC has suggested that no interest shall be allowed or levied during the period of six-monthly instalments. APPCC and PPCL also submitted that if the amount is to be refunded, and there is a delay in the raising of bills by the generating company or transmission licensee beyond the period of 30 days from the date of issuance of the order, the same may be with the late payment surcharge.

7.5 DIL has suggested that interest should be allowed to accumulate even after the date of the order and until the date of the actual payment through equated monthly instalments. This according to it, will allow for a fair representation of the actual recovery period, rather than restricting it only up to the date of order.

Analysis and Decision

7.6 The Commission has considered the suggestions of the aforesaid stakeholders. As regards the approval of interim tariff, the Commission is of the view that in order to factor in certain disallowances that generally are the case, the provision for allowing interim tariff of up to 90% of the claimed tariff is reasonable and appropriate and, therefore, requires no modification.

7.7 As regards the proposal not to allow any carrying cost during the liquidation period of six-monthly instalments, the Commission is of the view that the said provision is just and proper and to avoid unnecessary complications which may lead to litigation. It is observed that most of the time, the differential amount that needs to be recovered or refunded is minor, and therefore, allowing the carrying cost during liquidation of the amounts in six monthly instalments, will only unnecessarily delay the recovery or refund of the amounts. Hence, the Commission has modified the proviso to allow the recovery or refund of the amounts in a maximum of six equal monthly instalments. The change is required so that in case of smaller amounts, the same can be refunded or recovered in a shorter span.

7.8 The Commission also observes that in certain cases, computing the differential amount to be recovered or refunded may be time-consuming and may require validation/ certification at several levels. Therefore, the Commission has increased the duration provided to raise the bills from 30 days to 45 days.

7.9 As regards the applicability of the late payment surcharge after the stipulated timeline, the provision has been retained. However, in view of the above changes, it shall be applicable after 45 days from the date of order.

Accordingly, Regulation 10 has been modified as under:

"10. Determination of tariff

(1) xx

(2) xx

(3) If the information furnished in the petition is in accordance with these regulations, the Commission may consider granting an interim tariff of up to ninety per cent (90%) of the tariff claimed in the case of a new generating station or unit thereof or transmission system, or element thereof during the first hearing of the application for billing purposes till the final tariff is determined by the Commission:

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) xxx

(5) xx

(6) Subject to Sub-Clause (7) 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 a maximum of six equal monthly instalments;

Provided that the bills to recover or refund shall be raised by the generating company or the transmission licensees within 45 days from the issuance of the Order;

Provided further that such interest, including that determined as per sub-clause (7) 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 45 days from the issuance of the Order, it shall attract a late payment surcharge as applicable in accordance with these regulations.

(7) 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."

8. Truing up of tariff for the period 2024-29 [Regulation 13 (4)]

As proposed in Draft Regulations

8.1 In the Draft Tariff Regulations, Regulation 13(1) and Regulation 13(4) were proposed as under:

***"13.** Truing up of tariff for the period 2024-29: (1) The Commission shall carry out the truing up exercise for the period 2024-29, along with the tariff petition filed for the next tariff period, for the following:*

a) the capital expenditure, including additional capital expenditure incurred up to 31.03.2029 as admitted by the Commission after prudence checks at the time of truing up:

b) the capital expenditure, including additional capital expenditure incurred up to 31.03.2029 on account of Force Majeure and Change in Law as admitted by the Commission.

(2)xx.

(3)xx

(4) The generating company for a specific generating station or for an integrated mine, or the transmission licensee, as the case may be, may make an application for interim truing up of tariff in the year 2026-27 if the annual fixed cost increases by more than 20% over the annual fixed cost as determined by the Commission for the respective years of the tariff period:

Provided that if the actual additional capital expenditure falls short of the projected additional capital expenditure allowed under provisions of Chapter 7 of these regulations, the generating company or the transmission licensee, as the case may be, shall not be required to file any interim true up petition for this purpose and shall refund to the beneficiaries or the long term customers, as the case may be, the excess tariff recovered corresponding to the projected additional capital expenditure not incurred, in accordance with Regulation 10(7) and 10(8) of these regulations, as the case may be under intimation to the Commission:

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

(5)xx"

Comments Received

8.2 PGCIL has suggested that the regulation may provide that the Transmission licensee can refund the excess tariff on account of other reasons also, viz funding, interest rate, MAT rate, etc., without filing any interim truing-up petition and submit the details of the same to Commission at the time of truing-up of tariff, so that unnecessary carrying cost may be avoided.

Analysis and Decision

8.3 The Commission agrees with the above suggestions of PGCIL and has, accordingly, incorporated changes in Regulation 13(4) to facilitate the refund of the excess tariff collected due to variations in parameters like interest rates or income tax rates to the beneficiaries or long-term consumers, without the necessity of filing any interim truing-up petition. Also, the Commission has provided clarity with respect to the truing-up of the additional capital expenditure incurred towards the Emission Control System by incorporation of a sub-clause under Regulation 13(1). Accordingly, Regulations 13(1) and 13(4) has been modified as under:

"13. Truing up of tariff for the period 2024-29: (1) The Commission shall carry out the truing up exercise for the period 2024-29, along with the tariff petition filed for the next tariff period, for the following:

a) the capital expenditure, including additional capital expenditure incurred up to 31.03.2029 as admitted by the Commission after prudence checks at the time of truing up;

b) the capital expenditure, including additional capital expenditure incurred up to 31.03.2029 on account of Force Majeure and Change in Law as admitted by the Commission;

c) the additional capital expenditure incurred up to 31.03.2029 on account of the Emission Control System as admitted by the Commission.

(2) xxx

(3) xx

(4) The generating company for a specific generating station or for an integrated mine, or the transmission licensee, as the case may be, may make an application for interim truing up of tariff in the year 2026-27 if the annual fixed cost increases by more than 20% over the annual fixed cost as determined by the Commission for the respective years of the tariff period:

Provided that if the actual additional capital expenditure falls short of the projected additional capital expenditure allowed under provisions of Chapter 7 of these regulations or reduction of tariff on account of change in the rate of interest on loan or income tax rate, the generating company or the transmission licensee, as the case may be, shall not be required to file any interim true up petition for this purpose and shall refund to the beneficiaries or the long term customers, as the case may be, the excess tariff recovered corresponding to the projected additional capital expenditure not incurred or on account of change in the rate of interest on loan or income tax rate, in the same manner as specified in Regulation 10(6) and 10(7) of these regulations, as the case may be under intimation to the Commission:

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

(5) xxx"

9. Tariff Structure [Regulation 17]

As proposed in Draft Regulations

9.1 In the Draft Tariff Regulations, Regulation 17 was proposed as under:

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

Comments Received

9.2 SRPC has suggested including the following proviso in case there is no common agreement between the generating station and the beneficiaries:

"In case of disagreement between the beneficiary and the generating station, the same will be decided by Commission on case-to-case basis."

9.3 NTPC has suggested removing Regulation 17, as it could lead to confusion due to different interpretations by the Utilities. NBPDCL has suggested that the beneficiary who has paid for the capex portion should be given preference for availing power as the tariff would be lower, considering that such plants are fully depreciated. It has also suggested that the arrangement which prevailed as per the 2019 Tariff Regulations, may be continued. BRPL has suggested that the proposal to omit existing Regulation 17(2) is against the promotion of the generation of electricity from renewable sources and is counter-productive to consumer interest as well as the steps taken by the Hon'ble Supreme Court and the Central Government to curb the deterioration of air quality in the NCT of Delhi. PSPCL has suggested continuing with the existing Regulation 17 (2) of the 2019 Tariff Regulations for the control period.

Analysis and Decision

9.4 The Commission has considered the suggestions of the stakeholders. With regard to Regulation 17(2), the need for deletion of the same has been clarified in the Explanatory Memorandum to the Draft Tariff Regulations, 2024. Hence, the suggestion of BRPL is not entertained. However, in order to clarify that the said regulation shall be effective only in case the PPA for the supply of electricity from such generating station has not been extended, a minor modification has been made to this effect in the said regulation. Accordingly, Regulation 17 has been modified as under:

"17. Special Provisions for Tariff for Thermal Generating Station which have Completed 25 Years of Operation from Date of Commercial Operation: In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation and the power purchase agreement for supply of electricity to beneficiaries from such generating station is not extended, the generating company and the beneficiary may agree on an arrangement, including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation."

Computation of the Capital Cost

10. Debt-Equity Ratio [Regulation 18(3)]

10.1 In the Draft Regulations, Regulation 18(3) was proposed as below:

"18. Debt-Equity Ratio:

(1)xxxx
(2)xxxx
(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.

Comments Received

10.2 MSEDCL has suggested that the words "*or whenever the asset is completing its useful life during 2024-29*" may be added after '*as on 01.04.2024*' and before '*is more than 30% of the capital cost*' so as to rationalise and balance the aforesaid clause.

Analysis and Decision

10.3 The Commission observes that in order to have uniformity in the treatment of equity over and above 30%, not only in cases where equity is higher than 30% as on 01.04.2024 but also in cases where the equity during the tariff period is higher than 30%, the same shall not be considered for the purpose of ROE. Therefore, necessary changes have been made in the first proviso to Regulation 18(3). Accordingly, Regulation 18(3) has been notified as under:

"18. Debt-Equity Ratio:
(1) xxx
(2)xx
(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 is completing its useful life during the 2024-29 tariff period, if the equity actually deployed 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. ..."

11. Capital Cost Hydro Generating Stations [Regulation 19(4)]

11.1 In the Draft Regulations, Regulation 19 (4) was proposed as under:

"19. Capital Cost:
(1)xxx

(2)xxx
(3)xx.
(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 the 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;
xx"

Comments Received

11.2 PSPCL suggested that the expenditure on account of Local Area Development should not be passed on to the beneficiaries. JBVNL has suggested that the 10% contribution towards the RGGVY and DDUGJY should not be recovered from the consumers and instead should be recovered from the concerned distribution utilities. It has also suggested that developing local infrastructure in any case should be recovered from the local government authorities like Municipalities or Gram Panchayats or from the State Government's budget. CEA has suggested that if any expenditure is proposed to be incurred towards developing local infrastructure before the commissioning of the project (other than that admissible under Budgetary support for enabling infrastructure), the same may be adjusted in a phased manner against 1% LADF already provisioned after the commissioning of the project.

Analysis and Decision

11.3 The Commission has considered the suggestions of the stakeholders. The Commission, in order to ease the resistance being faced by hydro power developers, had proposed an enabling provision to allow the expenses that the hydro power developers may have to incur towards Local Area Development. The Commission had allowed these expenses as these expenses may result in reducing the delay in the construction of the Project and thereby result in cost savings. The Commission, however, would like to clarify that in case the expenses incurred towards developing local infrastructure in the vicinity of the power plant not exceeding Rs.10 lakh/MW are covered under the budgetary support provided by the Government, the same should be adjusted subsequently, as and when such fund is received. Accordingly, minor modification has been effected in sub-clause (c) of Regulation 19(4) to enable the subsequent adjustment on receipt of such support from the Government. The Commission is also of the view that these expenses, if incurred prudently, will result in reducing the time overrun, thereby resulting in a lower capital cost of the project, which will ultimately benefit the consumers.

11.4 Accordingly, Regulation 19(4) stipulates as follows:

"19. Capital Cost:
(l) xx
(2)xx

(3)xx

(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) For uninterrupted and timely development of Hydro projects, expenditure incurred towards developing local infrastructure in the vicinity of the power plant not exceeding Rs. 10 lakh/MW shall be considered as part of the Capital cost, and in case the same work is covered under budgetary support provided by the Government of India, the funding of such works shall be adjusted on receipt of such funds:

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

12. NCLT Proceedings [Regulation 19 (5)]

As proposed in Draft Tariff Regulations

12.1 In the Draft Tariff Regulations, Regulation 19 (5) was proposed as under:

"19(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;"

Comments Received

12.2 Most of the Distribution utilities have supported the regulation stating that the lower historical cost or acquisition value may be considered for the determination of tariff. They have also suggested that for any additional capital expenditure for the Plant acquired through NCLT proceedings, whether existing or a new plant, the prior approval of the Commission should be obtained. AEML has suggested that the tariff of the Projects acquired through NCLT should continue to be computed based on the historical GFA only. Association of Power Producers (APP) has referred to the judgment dated 27.9.2019 of the Appellate Tribunal for Electricity (APTEL) in Appeal No. 183/2019 (Renascent Power Ventures Pvt Ltd. vs UPERC and UPPCL) and opposed the provision for reduction in the PPA tariff, post-acquisition. Jhabua Power Limited (JPL) has submitted that the Projects acquired through NCLT are already under financial stress. It has been submitted that during the bidding process, the intent of the lenders is to select a bid that will maximise the value for stakeholders (which is mainly bankers in Insolvency NCLT cases), and the Bidder's bid for these projects is based on the revenue which they will be able to generate or the capital cost that the Commission may approve. JPL has further submitted that if the capital cost is restricted to the acquisition value, the same will further reduce the value of the asset, and the bids will be quoted at a significantly lower value, which would result in a lesser recovery for the bankers. According to JPL, this will have an impact in two ways: (a) many bidders will not find it remunerative to bid for the project as the revenue they generate might not justify the risk they will take in acquiring such projects. (b) also, if the bids are quoted at a very low value due to a decrease in the capital cost base, then the bankers may also not select any bidder, and such asset will remain unresolved, and the Commission will continue to provide a higher rate of interest/IoWC, etc., till such time these assets are resolved. Some of the Consumer Representatives have submitted that the capital cost to be considered for approval of the existing projects under NCLT shall be the lower of the Net GFA and the acquisition cost, which should be considered as GFA (reinstated) for the purposes of tariff determination. They have also submitted that the modalities for the consideration of the debt-equity ratio and depreciation rate to be considered for the reinstated GFA have not been provided. They have further submitted that since the acquired project cost, in most cases, would not have lived its useful life, the approach for the consideration of accumulated depreciation is not provided. NTPC has suggested considering the historical price for tariff purposes, as the consideration of the acquisition price would reduce the revenues and thereby result in continued financial stress and this would also add further difficulties in the process of revival of the stranded project. MSPGCL has submitted that in the case of the operational power stations undergoing NCLT proceedings, if the acquisition price is lower than the actual project cost, a risk premium may be granted to the new owners to account for the inherent project risks. This, according to MSPGCL, would involve considering the actual project cost, adhering to the commonly adopted regulatory prudence, and factoring in appropriate depreciation when determining the tariff. NHPC has submitted that the inclusion of the provisions related to the computation of capital cost for the projects acquired post-NCLT proceedings is a welcome step and requested the Commission to include the same in the final regulations. It has also been submitted that these regulations will streamline the process of acquiring stressed projects and will attract more interest in such projects.

Analysis and Decision

12.3 It is observed that in the approach paper on the Terms and Conditions of Tariff Regulations for the period 2024-29, the Staff of the Commission had sought suggestions from the stakeholders on the following aspects of this issue:

(a) Historical Cost or Acquisition Value, whichever is lower, should be considered for the determination of tariff post-approval of the Resolution Plan.

(b) Tariff provisions to be included to address the cost of debt servicing, including repayment, that were allowed as part of the tariff during the CIRP process.

12.4 It is pertinent to mention that the Commission, after considering the various suggestion(s) received from the stakeholders, had proposed separate provisions for allowing the capital cost related to projects acquired through NCLT under the Insolvency and Bankruptcy Code, 2016 in the draft Tariff Regulations. Further, the Commission had also considered the proposal of the stakeholders for considering the expenses incurred towards making the acquired project operational, which shall be considered as additional capitalisation, subject to prudence check of the Commission, as per the provisions of additional capitalisation as proposed in the Draft Tariff Regulations.

12.5 The Commission has considered the suggestion(s) of the various stakeholders as above. While the distribution utilities and consumer groups have supported the provisions included in the Draft Tariff Regulations, some of the developers and generating companies have suggested considering the historical value of such assets for the determination of tariff. It is observed that some of the generation and transmission utilities have supported the consideration of the lower of the two reference values, provided that the generator/transmission utilities are allowed to incur additional capitalisation, if the acquired project requires the same for efficient and safe operation. The Commission is of the view that the provisions proposed in the Draft Tariff Regulations were after considering that these regulations are applicable to projects whose tariff is required to be determined under Section 62 of the Electricity Act, 2003, i.e., based on cost plus mechanism, and therefore capital cost for the purpose of computation of tariff should be based on the cost actually incurred by the generating company or the transmission licensee, as the case may be, seeking tariff. Thus, considering any expenditure which has not been incurred by them, would go against the cost-plus principle. Therefore, no change is warranted on this count. As regards the suggestion that the lower capital cost will result in prospective bidders losing interest in such projects, the Commission is of the view that the regulations provide for a specific return and is performance-based. Also, several projects are performing well under the same principle. Therefore, no change is warranted on this count also.

12.6 As regards the suggestion of the distribution utilities that prior approval of the Commission should be obtained for additional capitalization in respect of the plants (existing or new) acquired through NCLT proceedings under the Insolvency and Bankruptcy Code, 2016, the Commission would like to clarify that any additional capitalization required for the effective operation of the plant necessitates the submission of proper justification, which also includes the technical justification explaining the necessity of the said expenditure along with the anticipated/projected benefits towards the functionality or efficiency of the project, duly accompanied by a comprehensive cost-benefit analysis for consideration and prudence check of the Commission, on a case to case basis. Accordingly, Regulation 19(5) has been modified as under:

"19. Capital Cost: *(l)…*
(5) For Projects acquired through NCLT proceedings under the Insolvency and Bankruptcy Code, 2016, the following shall be considered while approving Capital Costs for the determination of tariff:

(a) For projects already under operation, historical GFA of the project acquired or the acquisition cost 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 capital 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 that has yet to achieve commercial operation, the acquisition cost 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, additional capital expenditure shall be allowed under the provisions of Chapter 7 of these Regulations."

13. Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC) [Regulation 21 (5)]

As proposed in Draft Tariff Regulations

13.1 In the Draft Tariff Regulations, Regulation 21(5) was proposed as under:

"21. (1) xxx

xxx

(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 60month 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."

Comments Received

13.2 Some of the distribution utilities have submitted that the Government of India (GOI) has introduced the PM Gati Shakti National Master Plan for economic transformation, seamless multimodal connectivity, and logistics efficiency. They have submitted that the comprehensive database of the ongoing & future projects of the various Ministries has been integrated, thereby facilitating the Planning, Designing, and Execution of the infrastructure projects with a common vision, and due to the same, the Central Government has eased the procedures for getting necessary approvals for the infrastructure projects. Henceforth, getting logistic approvals for infrastructure projects would be a swift and hassle-free process for all the stakeholders. Accordingly, they have submitted that there is no basis for allowing the condonation of delay of up to 90% on account of obtaining such approvals or clearances. They have also pointed out that in case the delay on account of such factors is condoned up to 90%, then no efforts would be taken by the generators/licensees to get such approvals in time and complete the project in a timely manner. Considering all the above factors, they have suggested that the said regulation may be deleted.

13.3 Some of the other Distribution utilities have submitted that the inclusion of delay on account of Land Acquisition / Forest Clearances as an uncontrollable factor may lead to a further delay in the commissioning of the Projects, as these might create a perceived image in the mind of the person who is responsible for taking timely clearances, approvals that at the end any delay will get condoned being uncontrollable and hence, his/her pro-activeness and rigorous follow-up for getting clearance may diminish. They have further submitted that as the developers have already obtained several forest clearances in the past and are very well aware of how long it usually takes to get these clearances, they should plan their project timelines accordingly and not use the Forest clearance as an excuse for the delay. They have also pointed out that the Government is developing an e-governance site and a single window clearance system for various activities, including forest clearance, and these initiatives aim to speed up the approval process for Land acquisition/forest clearance. Accordingly, these distribution utilities have suggested that the delay due to Land Acquisition and Forest Clearances should not be considered as an uncontrollable factor.

13.4 Some of the generators have submitted that the limit of maximum condonation of 90% in case of delay on account of forest clearances or the delay in the acquisition of Government land on account of the delay in approvals by the Government authorities may be removed. They have stated that the delay in such cases, which is not attributable to the Project developer, may be fully condoned and the IDC and IEDC for such period may be allowed in entirety. NTPC has suggested that any delay due to concerned authority towards Forest clearance, NHAI clearance, approval of Railways, or Government land acquisition, if condoned by the Commission, then 100% delay needs to be allowed. It has therefore suggested that the provision for condonation of 90% of the delay may be dropped**.** PGCIL has submitted that once the delay has been condoned, the Project should not be subjected to any further deduction/penalty. It has been submitted that considering the fact that the utilities are automatically disincentivized, if the Project gets delayed, if any such additional penalty is imposed, the same will lead to further loss to the developer without any fault, and such an approach may unnecessarily result in increased uncertainty and risk in the sector and will affect the investor's sentiment. PGCIL has therefore suggested that when the delay is on account of statutory clearances, maximum condonation shall be allowed up to 100% of the delay associated with obtaining such approvals or clearances, and no penalty may be imposed on the utilities.

Analysis and Decision

13.5 The Commission has considered the suggestions of the stakeholders; in the draft Tariff Regulations, the provision for condonation of delay of up to 90% was considered, keeping in view that the beneficiaries should not be burdened on account of the inherent delays associated with the statutory clearances/approvals. Since the acquisition of land has been categorised as an uncontrollable factor except where the delay is attributable to the generating company or the transmission licensee, the same has been excluded from the proviso to Regulation 21(5).

13.6 The Commission observed that there is a need to ensure proper coordination and regular follow-ups on the part of the Generating Companies / Transmission Licensees to secure the clearances/permissions. Generally, the broad timelines for obtaining various clearances/permissions range from 3 to 10 months from various agencies. Accordingly, in light of the submissions of the parties and in order to encourage the utilities to secure such clearances/permissions at the earliest through proper coordination and regular follow-ups, the Commission is of the view that in case there is a delay in achieving COD is beyond six months from SCOD on account of delay in obtaining approval of any of the following activities namely, i) forest clearance, ii) NHAI clearance or iii) Railways permission, a time overrun of a maximum of up to 95% may be allowed, after prudence check. Accordingly, the proviso to Regulation 21(5) is modifies as under:

"21. Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC)
(1) xx
xxx
(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 a prudence check, either in entirety or on a 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 cases where the delay in achieving COD is beyond six months from SCOD on account of delay in obtaining approval of any of the following activities, namely, i) forest clearance, ii) NHAI clearance, or iii) Railways permission, a time overrun of maximum up to 95% shall be allowed after prudence check.

(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."

14. Initial Spares [Regulation 23]

14.1 In the Draft Regulations, Regulation 23 was proposed as under:

***"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 stations*	*-*	*4.0%*
(b)	*Gas Turbine/ Combined Cycle thermal generating Stations*	*-*	*4.0%*
(c)	*Hydro generating stations including pumped storage*	*-*	*4.0%*

hydro generating station

(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 Station*	-	*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."

Comments Received

14.2 PGCIL has suggested that initial spares for High-Voltage underground cables may be allowed based on actuals after a prudence check on a case-to-case basis.

Analysis and Decision

14.3 The Commission has considered the suggestion of PGCIL. It is observed that high-voltage underground cables are critical components of the transmission system, often imported by licensees from foreign manufacturers, leading to extended procurement timelines. In the absence of any historical data for computation of any ceiling norm for the high voltage underground cable, the Commission, has accepted the suggestion and has accordingly incorporated proviso (iv) to the effect that the initial spares of high voltage underground cables shall be allowed on actuals, after due prudence check, on a case-to-case basis. Based on the above, Regulation 23 is modified as under:

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

Stations

(c)	*Hydro generating stations, including pumped storage hydro generating station*	*-*	*4.0%*
(d)	*Transmission system*		
(i)	*Transmission line*	*-*	*1.00%*
(ii)	*Transmission Sub-station*		
	-Green Field	*-*	*4.00%*
	-Brown Field	*-*	*6.00%*
(iii)	*Series Compensation devices and HVDC Station*	*-*	*4.00%*
(iv)	*Gas Insulated Sub-station (GIS)*	*-*	
	-Green Field	*-*	*5.00%*
	-Brown Field	*-*	*7.00%*
(v)	*Communication system*	*-*	*3.50%*
(vi)	*Static Synchronous Compensator*	*-*	*6.00%*

Provided that:

i. Plant and Machinery cost shall be considered as the original project cost excluding IDC, IEDC, Land Cost, and Cost of Civil Works. The generating company and the transmission licensee, for the purpose of estimating Plant and Machinery 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.

iv. Initial spares of high-voltage underground cables used for the transmission system shall be allowed based on actuals on a case-to-case basis after carrying out due prudence check."

15. Computation of Additional Capital Expenditure

15.1 Additional Capitalisation within the original scope and after the cut-off date [Regulation 25)]

As proposed in Draft Tariff Regulations

15.2 In the Draft Tariff Regulations, Regulation 25 was proposed as under:

"(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 or raising of ash dyke 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."

Comments Received

15.3 PGCIL has submitted that leases of the leasehold lands for sub-stations are expiring, and the original owners are proposing to renew the lease or purchase lands at the prevailing market price. It has also been submitted that the quoted land/lease costs for such sub-station are exorbitantly high and even higher than the original project cost and such expenditure is capital in nature with a significant cost implication. PGCIL has also stated that lands being part of the original project cost, such expenditure qualifies as additional capitalisation within the original scope and after the cut-off date. Accordingly, PGCIL has suggested allowing such costs as an additional capital expenditure, and in cases where, apart from the one-time payment, an annual lease payment is also to be made, the same shall also be allowed to be billed as per actuals. APP has submitted that Coastal power plants, unlike river-water-based power plants, get adversely impacted due to issues related to excessive corrosion, silt, turbidity, salinity, sea erosion in tidal zones, cyclones & storms, and associated ecosystem challenges, which at times lead to generation loss, due to station shutdown and the equipments are getting damaged frequently. Accordingly, APP has suggested that in order to enable the Power producers of such Coastal power plants to approach the Commission for approval of new expenses not covered under the Regulations or alternatively, a separate additional capitalization norm should be specified for the Coastal power plants.

Analysis and Decision

15.4 The Commission has considered the suggestions of the stakeholders. It is observed that there are two types of cost associated with leasehold land, i.e., annual lease cost, which is recurring in nature, and one-time lease cost which is paid at the time of taking or renewing the lease. The latter represents a significant expenditure, which can't be serviced in one go through the O&M expenses and, therefore, shall form a part of the additional capital expenditure. Accordingly, clause (2) of Regulation 25 has been modified to include a separate provision for consideration of the additional capitalisation towards the renewal of the lease of leasehold land on a case-to-case basis. Necessary changes have been made to the regulations as under:

> ***"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 or raising of ash dyke 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.*
> *(e) The additional expenditure, excluding recurring expenses covered in O&M expenses, involved in relation to the renewal of lease of lease hold land on case to case basis.*
>
> *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 through normative O&M expenses."*

As regards the problems related to excessive corrosion, silt/turbidity issues etc., being faced by the Coastal power plants, affecting the power plant equipment and operation for reasons which are not within their control and could not have been avoided despite the generating company taking reasonable care or having complied with prudent utility practices, the generating company may approach the Commission on a case to case basis with proper justification and supporting documents justifying the need for additional capitalization within the original scope and after the cut-off date under Regulation 25 and beyond the original scope of work under sub-clause (i) to clause (1) of Regulation 26.

<u>Computation of the Annual Fixed Cost</u>

16. <u>Ramp Rate [Regulation 30 (3) (iii) (b)]</u>

As proposed in Draft Tariff Regulations

16.1 In the Draft Tariff Regulations, Regulation 30 (3) (iii)(b) was proposed as under:

"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%"

Comments Received

16.2 SRPC has suggested that the regulation of higher ramp was brought out to get more flexibility from the generating stations, but the said objective was not achieved, as none of the generators (in the Southern Region) have availed this additional ROE because the jump is very high from 1% to 2% and to 3% to 4%, and this needs to be broken down to smaller steps of 0.1%. It has further been submitted that the procedure finalized by NLDC, Grid-India, needs review, and a more practical procedure needs to be finalized to achieve the objective of higher ramps. Accordingly, SRPC has suggested to include the following:

"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 0.025% shall be allowed for every incremental ramp rate of 0.1% 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%:
c) NLDC will come out with Revised Procedure with the objective to achieving higher ramp rates."

Analysis and Decision

16.3 The Commission has considered the suggestion of SRPC and finds merit in reducing the incremental ramp rate for incentive purposes, which will encourage generating stations to make efforts to provide higher ramping capabilities. However, the Commission is of the view that the incremental ramp rates suggested are too granular and need to be distinct yet achievable. Therefore, the Commission has modified Regulation 30 (3) (iii) to allow an additional rate of ROE of 0.125% for every incremental ramp rate of 0.50% per minute achieved over and above the ramp rate specified by the Central Electricity Authority, subject to the ceiling of additional rate of return on equity of 1.00%. Accordingly, Regulation 30 (3) (iii) (b) has been modified as under;

"b) an additional rate of return on equity of 0.125% shall be allowed for every incremental ramp rate of 0.50% per minute achieved over and above the ramp rate specified by Central Electricity Authority, subject to the ceiling of additional rate of return on equity of 1.00%:"

17. Rate of Interest [Regulation 32(5)]

As proposed in Draft Tariff Regulations

17.1 In the Draft Tariff Regulations, Regulation 32(5) was proposed as under:

32. (1) xxx
xxx
"(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%."

<u>Comments Received</u>

17.2 Odisha Power has suggested changing the order of the proviso so that the ambiguity surrounding the interest rate, in cases where the actual loan for the emission control system exists, is eliminated. NTPC has suggested retaining the existing provisions with respect to Interest on loans on a project-specific basis, as the differential interest rate will impact the debt servicing, and the allocation of FERV among the beneficiaries of both old and new stations will pose a challenge. NHPC has submitted that the approach proposed in the draft regulations to calculate the interest on loans based on a weighted average interest rate of the company shall result in passing on the benefit of the Project specific reliefs provided by the Government to the beneficiaries of other projects and may turn those projects unviable. It has therefore suggested the continuation of the weighted average interest rate of a particular project if the project-specific loans are available. NHPC has further submitted that the normative loan proposed for the new projects, if the actual loan is not available, is too low, as the hydropower projects have long gestation periods, and therefore, loan creditors tend to add premiums over and above the base MCLR rate. It has therefore suggested the modification of Regulation 32(6) as under:

"(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 project or the transmission asset, 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 plus 100 basis points, of the relevant financial year."

17.3 DBPL has suggested considering the rate of interest as a 1-year MCLR, as applicable on the 1st of April of the relevant financial year, plus 150 basis points. DIL has suggested that the rate of interest (when the actual loan is not available) may not be linked to the SBI MCLR rate, as it is significantly lower than the market-reflective rate of financing. Further, suggested reconsidering the imposition of a fixed ceiling rate of interest, particularly at 14%, which may potentially hinder the financing of the emission control projects during the periods of elevated interest rates, as interest rates are subject to fluctuations influenced by various economic factors and therefore, imposing a fixed ceiling may not account for changes in market conditions. MSEDCL has suggested that the ceiling rate of loan shall not be equivalent to the base rate of return on equity that is allowed under these Regulations. It has stated that since the benchmark for ROE to be allowed on emission control system is considered at the SBI MCLR plus 350 basis points, the ceiling on interest can be linked to a maximum of SBI MCLR rate notified on 1st April of the respective year.

Analysis and Decision

17.4 The Commission has considered the submissions of the stakeholders. The Commission observes that few projects undertaken receive specific financial assistance, which is primarily meant to benefit the targeted consumers, and therefore, allowing the interest on the loan for such projects on the company as a whole may not benefit the beneficiaries from such assistance. It is further observed that sharing of FERV also may impose challenges as a specific project which has not utilised any external commercial borrowing may also have to bear the impact of FERV. The Commission has, therefore, retained the existing methodology of computing interest on loans on the basis of project-specific loans. The Commission has accordingly modified and merged Regulation 32(5) and Regulation 32(6) to include the above change. As regards the suggestion of specifying the rate of interest at the rate of 1-year MCLR+150 bps, the Commission is of the view that the intent of the proviso is to allow a notional recovery towards the funds deployed. The Commission is of the view that the rate corresponding to 1-year MCLR is enough to compensate for such an infusion of funds. Further, as this proviso will be applicable for all the entities, the rate of interest has been kept unchanged. As regards the ceiling rate of 14%, the Commission, in the explanatory memorandum, has detailed the reasons that for ECS, the rate of interest cannot be allowed to go beyond the rate of ROE allowed, and therefore, the draft provisions have been retained with respect to the ceiling of 14% provided for ECS, achieving COD post commissioning of the generating station.

17.5 The Commission would also like to clarify that when ECS is included in the original scope of the project and is commissioned along with the project, the risk associated with the construction of a generating station and ECS is similar, and therefore, the ROE is allowed at the normal rate. The ECS systems that have been commissioned after the commissioning of the generating station are allowed under a change in law event and do not share the same risk profile as in the case of new projects, and hence, the existing rate of ROE has been retained. Accordingly, the provisions of Regulation 32(5), Regulation 32(6) and Regulation 32(7) are as under:

"32. Interest on loan capital: (1) ...
(5) 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 commissioned subsequent to date of commercial operation of the generating station or unit thereof, 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%;*

Provided further that if the generating company or the transmission licensee, 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.

(6) The interest on the 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."

18. Depreciation [Regulation 33 (8) and Regulation 33(11)]

As proposed in Draft Tariff Regulations

18.1 In the Draft Tariff Regulations, Regulation 33(8) and 33(11) were proposed as under:

"xxx

(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.

xx

(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."

Comments Received

18.2 MSPGCL has submitted that after incurring the capital expenditure for extending the life of assets, the useful life of the assets would be prolonged. Therefore, MSPGCL has submitted that it would be more appropriate to link the remaining depreciation to the extended useful life of the assets rather than the operational life. MSEDCL has submitted that the balance depreciation to be recovered shall be spread over the balance operational life of the asset (being generating station or unit or transmission asset). Hence, MSEDCL has submitted that the regulation may be amended as under:

"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 and in case of the transmission system shall equally spread the depreciable value over the balance Operational Life of the Asset."

18.3 DIL has suggested adopting the depreciation schedule that is allowed for the existing projects as per Appendix I, (i.e., for P&M at 5.28%, over a 12-year period, prior to spreading the same over the balance useful life of the assets), even for new projects. MB Power has submitted that depreciation of ECS is still spread across a period of 25 years post-commercial operation of ECS, irrespective of the balance life of the existing Project/ balance tenure of the long term PPA(s). It has therefore requested that this anomaly be suitably addressed by spreading the depreciable value of the ECS of the existing Projects (SLM method) over the balance useful life of the coal/lignite-based thermal generating stations, remaining as on the COD of the ECS. MSEDCL has suggested modifying the regulation with regard to the depreciation of ECS as under:

"Provided that the remaining depreciable value as on 31st March of the year closing after a period of 15 years from the date of operation of such emission control system shall be spread over the balance operational life of generating station."

18.4 AEML has suggested allowing the recovery of ECS depreciation during the balance term of the PPA to ensure adequate funds for meeting the debt obligations.

Analysis and Decision

18.5 The Commission has considered the suggestions of the stakeholders. With regard to the depreciation to be allowed on additional capitalisation during the fag end of useful life, the Commission had proposed that in the case of generating station, the same shall be allowed to be recovered in the balance operational life or 15 years, whichever is lower. It is observed that as per this provision, at least 10 years will be available to recover the depreciable value of any additional capital expenditure that is incurred during the last five years of the useful life. The Commission also observes that in the case of the transmission system, the draft regulation proposed that the depreciable value for any additional capital expenditure shall be recovered with the balance useful life, which can range between 1 to 5 years. The Commission is of the view that the same should be allowed to be recovered uniformly, as done in the case of generating stations. The Commission has, therefore, revised the proviso so that the depreciable value shall be equally spread over the balance useful life of the asset or 10 years, whichever is higher.

18.6 As regards the recovery of the depreciable value of ECS, the Commission observes that as per the formulation provided in the draft Regulations, if the ECS was commissioned post-22nd year of the COD of the generating station, the generating station would only be able to recover less than 70% of the asset value by the end of the operational life. The Commission has, therefore, added a proviso so that, in case the date of operation of the emission control system is after the 20th year of commercial operation of the generating station or unit thereof but before the completion of the useful life of the generating station, depreciation on ECS shall be computed annually from the date of operation of such ECS, based on the straight line method, with a salvage value of 10% and the depreciable value shall be recovered till the operational life of the generating station. This will ensure that in case the COD of the ECS is prior to the completion of the useful life, the recovery of the depreciable value shall be ensured by the end of the operational life. Accordingly, the relevant provisions of Regulation 33(8) and 33(11) are modified as under:

"33. Depreciation: *(1) ...*

(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 completion 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 or 10 years whichever is higher.

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(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;

Provided also that in case the date of operation of the emission control system is after the 20th year of commercial operation of the generating station or unit thereof, but before the completion of the useful life of the generating station, the depreciation on emission control system (ECS) shall be computed annually from the date of operation of such ECS based on the straight line method, with a salvage value of 10% and the depreciable value shall be recovered till the operational life of the generating station.

(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.”

19. <u>Interest on Working Capital (IoWC)</u>

As proposed in Draft Tariff Regulations

19.1 In the Draft Regulations, Regulation 34 was proposed as under:

“(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."

Comments Received

19.2 SJVNL has suggested including water cess/water usage charges levied by various States in the IOWC calculations, as there is an interest loss when the payment is realised from Discoms 45 days after the payment is made to the home State. THDCIL has suggested that all the statutory taxes/ duties/ cess/ charges should also be part of working capital. Bihar Industrial Association has suggested to include the following in the regulations:

- Cost of Coal for ten days or actual whichever is less instead of 20 days.
- Advance payment of 1 week instead of 30 days;
- Maintenance spares @ 5% instead of 20%;
- Receivable of 1 week instead of 45 days;
- O&M Expenses of 1 week instead of one month.

19.3 NTPC has suggested to include the following:

- Maintenance spares – for coal-based generating stations @50% of O&M expenses.
- Maintenance spares for gas based generating stations@ 100% of O&M expenses.
- For calculation of IOWC, Fuel cost for 15 days may be increased to 30 days.

Analysis and Decision

19.4 The Commission has considered the suggestions of the stakeholders. We clarify that in the case of thermal generating stations, similar to the Security expenses and Water charges, capital spares are allowed at actuals and form part of the O&M expenses. These expenses are incurred regularly throughout the year and therefore, are required to be considered as part of the working capital either in the form of Maintenance spares or the O&M expenses. The Commission observes that the definition of the O&M Expenses provides for the inclusion of insurance charges. Therefore, in the case of hydro generating stations and for transmission systems, the O&M expenses for interest on working capital will also include insurance expenses. As regards the changes suggested in the norms of the working capital, the Commission is of the view that the norms proposed in the draft Tariff Regulations have been specified after a detailed analysis of several parameters, and therefore, the Commission is not inclined to modify the same. Accordingly, Regulation 34 is as under:

"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."

20. <u>De-Commissioning [Regulation 35 (1)]</u>

As proposed in Draft Tariff Regulations

20.1 In the Draft Tariff Regulations, Regulation 35 (1) was proposed as under:

"(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."

<u>Comments Received</u>

20.2 Some of the distribution utilities have submitted that it is not justifiable for the beneficiaries to bear the entire decommissioning and dismantling cost of the plant as the generating companies would earn certain revenue on account of the disposal of the assets. They have submitted that in addition to such revenue, the generating station will also have the benefit of having the existing land, which they can utilise. The distribution utilities have further submitted that the unrecovered depreciable value after the decommissioning (after duly adjusting the actual salvage value post disposal) may not be allowed to be recovered from the beneficiaries, and a fixed share of up to 50% may only be allowed to be recovered and the rest may be borne by the generator, similar to the sharing of gains between the beneficiaries and generators. Alternatively, they have submitted that instead of a generalized decommissioning clause which will burden the beneficiaries, it may be decided on a case-to-case basis, on the merits of the petition. They have added that in the interest of consumers and to avoid tariff shock, recovery may be allowed in twelve equal monthly instalments without any interest. GRIDCO has suggested to include the following proviso:

"Provided that, the beneficiary(ies) would not bear any Decommissioning and Dismantling Cost. Provided that, no depreciation would be allowed for spares purchased in excess of the percentage allowed in Regulation 23 of this Regulations.

Provided that, no depreciation would be allowed for capital spares which are not allowed by this Commission at the time of truing up under 3rd proviso to Regulation 36(1)(6) of this Regulations and/or equivalent Regulation of the previous Tariff Regulations and kept in inventory/not consumed by the generator."

Analysis and Decision

20.3 The Commission has considered the suggestion(s) of the stakeholders. The Commission is of the view that the value of assets may undergo changes owing to market conditions, regulatory frameworks, or technological advancements over their operational lifespan, thereby influencing their residual value post-disposal. It is pertinent to differentiate between the terms 'realization value' and 'salvage value.' The realisation value refers to the actual proceeds received from the sale or disposition of an asset in the market, net of any transaction costs or expenses incurred, whereas the salvage value refers to those allowed under the Tariff Regulations. Therefore, by adjusting the higher salvage or realization value, the provision ensures that the recovery mechanism aligns with the actual value derived from the assets. This will promote transparency and fairness in the regulatory process, as it considers the tangible market value of the assets post-disposal, thereby safeguarding the interests of the beneficiaries. The Commission has, therefore, made minor modifications to the proviso proposed to adjust the higher of the two revenues while allowing de-commissioning. The Commission also clarifies that in case of decommissioning, no depreciation shall be provided for initial spares claimed in excess of the allowable limit, as per Regulation 23 of the Tariff Regulations. Further, the Commission also clarifies that no depreciation shall be provided for capital spares in excess of those allowed during the truing-up of the tariff. Accordingly, Regulation 35 (1) is as under:

"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 salvage value or realisation value, whichever is higher, 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."

21. Operation and Maintenance Expenses [Regulation (36)]

As proposed in Draft Tariff Regulations

21.1 In the Draft Tariff Regulations, Regulation 36 was proposed as under:

"36 (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 0, (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 the 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 a unit size of less than 200 MW not covered above shall be determined on a 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 Stations:

a) The 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*
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*

Particulars	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
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.

***(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 Region, States 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 substation 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."

Comments Received

21.2 NTPC, with regards to the coal generating stations, has made the following suggestions:

a) Additional O&M expenses on account of consumption of capital spares individually costing less than Rs. 20 lakhs work out to be Rs 1 Lakh/MW/Year;

b) The additional O&M expenses required to include minor additional capitalization less than Rs. 20 lakhs is Rs. 0.7 Lakh/MW/Year;

c) The impact of the disallowed capital expenditure that has been met out of the O&M expenses amounts to Rs 1.4 Lakh/MW/Year;

d) The increase in O&M expenses due to the increased flexibility (100% to 55% loading) is Rs 2 Lakh/MW/Year, and

e) The additional O&M expenses for future additions of manpower are about Rs 0.5 Lakh/MW/Year.

21.3 As regards the gas stations, NTPC has suggested the following:

a) The number of start-ups in gas stations has increased from 881 in 2019-20 to 2063 in 2023-24 (up to Q3). Further, average Equivalent Operating Hours (EOH) consumption/unit/year has increased by 2.5 times. In view of this, the additional O&M expenses norm of Rs 2 lakhs/MW/Year may be provided due to the increased wear and tear, and additional O&M expense of Rs. 3.24 Lakh/MW/Year may be provided for compensation of start-up expense of gas station.

b) To include the consumption of capital spares individually costing less than Rs. 20 Lakhs, the additional O&M is Rs 1 Lakh/MW/Year;

c) To include the additional capitalization of minor assets less than Rs. 20 lakhs, the O&M expenses is required to be increased by Rs. 1 Lakh/MW/Year;

d) The impact of the disallowed capital expenditure that has been met out of the O&M expenses is Rs 1.35 Lakh/MW/Year.

In addition, NTPC has suggested including a suitable provision in the Tariff Regulations for reimbursement of the Ash Transportation expenses on a monthly basis, to avoid any accumulation of the carrying cost.

21.4 NHPC has suggested that the O&M expenses of a plant having a capacity beyond 200 MW should have a minimum value, which shall be equal to a plant having a capacity of 200 MW with the same cost/MW capital expenditure. It has also been submitted that Regulation 36(2)(b) needs to be modified to include an escalation rate for O&M expenses for new hydro generating stations. Accordingly, NHPC has proposed modification to Regulation 36(2)(b) as under:

"36.2(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 or equal to 200 MW, respectively and shall be escalated thereafter @ 5.86% for subsequent year of tariff period.

Provided that the O&M expenses calculated for plants having capacity beyond 200 MW shall not be less than the O&M Expenses of a plant of capacity of 200 MW with same cost per MW."

21.5 NHPC has also suggested including the following additional proviso to enable them to file a Miscellaneous petition for claiming the impact of change in law:

"Provided that generating company may make a miscellaneous application for claiming impact of change in law event in case the overall impact is more than Rs. 10 Crore for all the generating stations."

21.6 In addition to the above, NHPC, with regard to Insurance charges, has suggested to consider the following:

"NHPC follows a transparent open tender process to discover the insurance premium for the Mega Insurance Policy, however, due to increase in risk perception of the insurance companies, the insurance premium has seen a tremendous increase in last few years. This increased insurance premium cannot be met from the insurance expenses allowed as part of normative O&M Expenses as the insurance premium is based on the last 5 years O&M Expenses including insurance premium which is then escalated at the rate arrived based on AICPI and WPI indices. The increase in insurance premium does not correlate with the increase in CPI and WPI Indices as the Insurance premium is discovered through open tender based on market trends.

21.7 Accordingly, NHPC, while pointing out that there is a substantial loss to the hydro generating stations, has suggested addressing the issue by following either of the two methodologies:

i) Allow the insurance premium for the next tariff period by escalating insurance premium of last 5 years @ CAGR of past 5 years' insurance premium.

ii) Allow the reimbursement of the Insurance premium separately from the normative O&M expenses, as done in the case of Security Expenses and Consumption of capital spares under the existing Tariff Regulations.

21.8 **SJVNL** has suggested that the rate of yearly increase of the O&M expenses may be increased from 5.86% to 6.64% in line with the Tariff Regulations, 2014. It has been submitted that in case the capital spares above Rs. 20 lakh are allowable beyond the normative O&M expenses, then at least the escalation rate should be 1.5% higher than the market inflation rate of 5.89%. SJVNL has further stated that the escalation rate of the silt-affected plant may be considered at a higher rate. As regards Insurance premiums, SJVNL has submitted that a separate clause may be considered to allow the increase in Insurance premiums on a year-on-year basis, as permitted for Security expenses and Capital spares. SJVNL has also suggested allowing ex-gratia, incentives, productivity-linked incentives and performance-related pay expenses under the normative O&M expenses to those hydro power stations that have a lower Man/MW ratio in comparison to the best industry practices. **NBPDCL** has suggested that the escalation in the normative O&M expenses is at a higher rate, which would subsequently result in a higher tariff. Therefore, it has been stated that the proposed escalation in normative O&M expenses is not rationale and needs to be relooked. **APP** has suggested allowing the Insurance cost over and above the normative O&M expenses for thermal generating stations. **MSEDCL** has suggested that as the O&M expense norms approved under the existing Regulations are already on the higher side, there is no need to further increase these norms for the next tariff period, and the same escalation rate, as defined in the existing Regulations, may be continued. It has further submitted that separate norms may be defined based on the completion of the life cycle of the plants, and the Commission may undertake a study on the basis of actual O&M expenses incurred by various stations to arrive at the O&M expense norms for the next tariff period. **MB Power** has suggested that in the Tariff Regulations 2024, additional O&M expenses (over and above the normative O&M expenses) on account of the change in law events or force majeure events may be allowed on actuals, irrespective of any minimum threshold levels. It has further submitted that for the first year of operation of ECS, the O&M expenses may be allowed at-least at the rate of 4% of the gross fixed asset of ECS, with an annual escalation at the proposed rate of 5.89%. Some of the transmission licensees have submitted that the terrain in the State of Sikkim (entirely a hilly state) and Darjeeling (predominantly hilly terrains) in the State of West Bengal are equally treacherous, if not more, and are engulfed in between mountains and hills and is also extremely prone to landslides, rockslide, shooting stones, rock mass failure, etc. While pointing out that the draft tariff regulations use the word "solely" to identify the transmission licensees whose transmission assets are falling in these regions, has been submitted that the use of the word "solely" restricts the transmission utilities that have a major portion of their transmission assets (greater than 50%) in the hilly terrains and only a minor portion of their transmission assets in plain terrain, from benefitting from the regulations. Accordingly, they have submitted that the regulations should include all such transmission licensees whose majority of the transmission assets (greater than 50%) are located in the North Eastern Region, State of Sikkim, District of Darjeeling in the State of West Bengal, States of Uttarakhand, and Himachal Pradesh, the Union Territories of Jammu and Kashmir and Ladakh. The **Association of DVC HT Consumers of Jharkhand** has suggested that the O&M expenses should not be permitted beyond the normative O&M expenses as specified in the Tariff Regulations. **SRPC** has suggested including a suitable provision in the Tariff Regulations for a higher annual maintenance contract (AMC)/Technical Support to ensure that the Projects are not getting affected on account of the higher cost of AMC towards Communication, SCADA, Technical support, AMR, UNMS, applications, etc., **PCKL** has suggested considering an escalation rate of an average of the actual 3.22% and average based on CPI & WBI of 5.89%, i.e., 4.55% for the O&M expenses. **MSPGCL** has suggested allowing the O&M expenses in a segregated manner, with the employee costs approved at actuals, subject to prudence check, and the (A&G + R&M) component allowed at the normative level. It has further suggested that the normative O&M expenses for the 500 MW series for 2024-25 should be escalated at the rate of 3.93%, as all the other series, i.e., 200 MW, 600 MW series, etc., have been escalated by the rate of at least 3.93%. **Sterlite Power Transmission Limited** has suggested for removal of the self-insurance while calculating the O&M expenses norms. It has also suggested that the Commission may true-up the O&M expenses, so that excess recovery from the O&M expenses recovered from TBCB projects may be adjusted. Sterlite has further submitted that the 4% escalation rate may be considered for the computation of O&M expense norms, and STATCOM and SVC must be considered as separate elements, having separate O&M and availability norms. **MPPMCL** has suggested including the spares of capital nature valuing less than Rs. 20 lakhs and additional capital expenditure of an individual asset costing up to Rs. 20 lakhs as part of the O&M expenses. It has also suggested that capital spares must form part of the O&M expenses allowed on a normative basis, and should not be allowed separately. Only in case the Commission finds it utmost necessary, then the capital spares, individually costing above Rs. 50 Lakh may only be allowed as capital spares. In addition, MPPMCL has suggested that the previous wage revision was implemented during the year 2016/2017, and at that time, the Commission had adopted the policy that the actual impact of wage revision along with the actual O&M expenses will be compared with the normative O&M expenses, at the time of truing up of the tariff and in case of any shortfall, only the impact of wage revision will be allowed, which may be continued. **AEML** has suggested removing the minimum limit specified to allow the impact of change in law or force majeure events from 10% to 5% of the normative O&M expenses. **NTPL** has suggested allowing the actual expenses incurred on account of Fly ash transportation separately to Ash Dyke and NHAI after a prudence check. **PPCCL** has suggested reducing the capital spares limit to Rs. 5 Lakh, for including such costs as part of the O&M expenses. **PSPCL** has suggested reducing the multiplying factor for NER and hilly terrains from 1.5 to 1.2 times. **PGCIL** has suggested the following:

(i) **S**ince all India O&M expenses are being considered towards O&M expense norms, the head-wise normalization may also be done on all India O&M expenses only, and the normalization done for 2019-20 requires to be re-evaluated to derive a realistic number, and the same may be used for the years 2020-21 and 2021-22, otherwise, as per statistical practices, aberrations noticed in 2019-20, being an outlier, has to be excluded for calculation purposes and the normalized O&M expenses for 2018-19 may be escalated using same escalation factor, to derive the notional O&M expenses for 2019-20, 2020-21 and 2021-22, which should be used to derive the O&M expense norms for the transmission assets.

(ii) Consider an escalation rate of 6.67%, arrived at on the basis of indices, excluding the COVID-19 pandemic period, 2020-21. Also, considering the cost-effectiveness and need for reserves, it is essential that the allocation of the entire amount of self-insurance reserve, i.e., @ 0.12% of the original cost of assets, is included in the normalized O&M expenses to arrive at the norms for 2024-29.

(iii) The normalized O&M expenses for the period 2018-19 to 2022-23 may be arrived at by including the Performance Related Pay (PRP) as part of the employee cost to arrive at the normative O&M expense norms for the period 2024-29. The O&M expenses relating to the Capital spares, costing between Rs 5 Lakhs to Rs 20 Lakhs, need to be factored in while deriving the O&M expense norms for the transmission licensees.

(iv) The CTUIL expenses, which form part of the O&M expenses submitted by PGCIL, may be excluded while determining the O&M expense norms. The normalized O&M expenses may be apportioned between the Substations and AC transmission lines in the ratio of 70:30 to arrive at O&M expense norms for the period 2024-29.

(v) A full-year expenditure from the second year onwards, with some escalation, may be considered for all HVDC stations that were commissioned during the previous tariff period. In order to ensure all transmission licensees, including PGCIL, get sufficient O&M expenses for the assets being maintained in hilly areas, the factor of 1.5 times, as notified, may be made applicable. However, the O&M expense norms for the HVDC bi-pole line, considered a Double Circuit quad AC line, may be retained in the Tariff Regulations.

(vi) The upfront investment of approximately Rs. 450 crores towards the adoption of various digital tools in asset management may be considered by the Commission while deriving the O&M expense norms for the period 2024-29. In order to continue with the benefit of a reduced operating expenditure, besides compliance with Cyber security, a suitable provision for Rs. 285 crores may be made in the Tariff Regulations for National Transmission Asset Management Centre (NTAMC) Upgradation expenses. Also, the expenditure on manpower forms a considerable portion of the O&M expenses, and therefore, a markup in lieu of employee recruitment should be kept while deriving the O&M expense norms.

Analysis and Decision

21.9 The Commission has considered the suggestions of the stakeholders. In the draft Tariff Regulations, in the case of the Thermal generating stations, the O&M expense norms have been computed for the different unit sizes on Rs in Lakh/MW basis, while for the Hydro generating stations, the O&M expense norms considered for each generating station is in Rs in Lakh for the tariff period. The O&M expense norms for the transmission system are also computed separately for AC systems and HVDC stations. For the AC transmission systems, the O&M expense norms are segregated into Rs in Lakh/Bay, Rs in Lakh/MVA/MVAR capacity, and Rs in Lakh/KM of the transmission line (separate for each voltage levels), while for the HVDC stations, the O&M expense norms are allowed in Rs.in Lakh/MW for the tariff period for the back-to-back stations and bi-pole stations. The issues raised by the various stakeholders are discussed below:

Escalation Rate

21.10 The Commission, while specifying the O&M expense norms, has calculated the escalation rate that is used to escalate the O&M expenses for the period 2024-25 to 2028-29, based on the WPI/CPI data as available till March 2023. As the actual data till the third quarter of 2023-24 was available, the same has been considered for computing the escalation rate. The average increase in WPI for 2019-20 to 2023-24 (till December 2023) works out to 4.93%, while the CPI for the same period works out as 5.73%. Considering the 60:40 weightages for WPI and CPI, respectively, the escalation rate works out to 5.25%

(as against 5.89% in the draft Tariff Regulations), in the case of thermal generating stations and transmission systems. In the case of hydro generating stations, considering the CPI and WPI weightages of 75:25, the escalation rate works out to 5.47% (as against 5.86% specified in the Draft Tariff Regulations, 2024). It is also observed that in the draft O&M expense norms, the escalation rate for O&M expenses for thermal generating stations during 2018-19 to 2023-24 was considered based on the actual increase in the normalised actual O&M expenses for the period from 2018-19 to 2022-23, which worked out as 3.22% per annum. It is however, observed that in the draft O&M expense norms, while calculating the annual escalation rate, the actual data for Muzaffarpur TPS was not considered. The generating station's actual data has now been included, and the annual escalation rate has been reworked as 3.52% p.a., and accordingly, the O&M expense norms for the thermal generating station have been revised.

Inclusion of the capital spares upto Rs. 10 lakh and additional capitalisation less than Rs. 20 lakh

21.11 The Commission has considered the suggestions of the various stakeholders with regard to the inclusion of capital spares and additional capitalisation as part of the normative O&M expenses and is of the view that incorporating spares up to Rs.10 Lakh and additional capitalisation less than Rs.20 Lakh in the normative O&M expenses, will simplify the approval process and will also reduce regulatory overburden. Therefore, the capital spares individually costing up to Rs.10 Lakhs and additional capitalisation less than Rs.20 Lakh are being made part of the normative O&M expenses for the generating stations and transmission licensees. Accordingly, the O&M expense norms for thermal generating stations and transmission systems have been revised. However, the generating stations or units thereof, as well as the transmission licensees, are directed to seek the reimbursement of capital spares on a consumption basis during the truing-up process if the cost of the individual spare part exceeds Rs. 10 Lakh. Further, individual assets costing Rs. 20 Lakh and above shall only be allowed as additional capitalisation. This aligns with the allowance for individual spares costing up to Rs. 10 Lakh and additional capitalisation less than Rs. 20 Lakh under the normative O&M expenses.

Insurance Expenses

21.12 The hydro generating stations and transmission licensees, particularly those utilizing complex machinery and equipment, are exposed to various risks such as equipment breakdowns, natural disasters, and operational accidents, and therefore, Insurance coverage is necessary to mitigate these risks and to ensure the continuity of its operations. Separately accounting for insurance expenses acknowledges the unique risk profile of hydro-generating stations and transmission licensees. Further, the insurance premiums can vary significantly based on various factors such as location, the technology used, and operational history. As per inputs from hydro geniting stations, it is observed that the Insurance premium has increased substantially during the last four to five years, owing to several incidences of flooding and inclement weather, causing widescale damages. Moreover, the increase in insurance premiums does not correlate with the increase in CPI and WPI Indices. The Commission is of the view that separating the Insurance expenses for hydro generating stations and transmission systems will avoid any major impact on utilities, thereby ensuring that tariffs are reflective of the specific risk exposure of individual facilities. Therefore, the Insurance expenses arrived at through competitive bidding for hydro generating stations and transmission licensees and associated communication systems are to be allowed separately after a prudence check. Accordingly, the O&M expense norms for hydro generating stations and transmission licensees on this count are being revised.

Competitive Procurement of Insurance Coverage

21.13 Since the Insurance expenses are to be permitted separately in the Tariff Regulations for hydro generating stations or transmission licensees and associated communication systems, as above, the Commission deems it necessary to specify the broad contours that the Utilities are to follow for better transparency in the Insurance procurement process:

- Prices are required to be discovered through a competitive bidding process.
- Invitation for bids to be opened to all Insurance Companies providing General Insurance Business in India, approved by the Insurance Regulatory and Development Authority of India (IRDAI);
- Technical and Financial criteria will be laid down in the tender to ensure that only technically & financially sound insurance companies may participate.
- The power to accord approval for renewals of Mega insurance Policies will be with the authorised person not below the level of Director of the Company.
- As insurance expenses are allowed at actuals, the tendency to over-insure may be avoided, and the specific coverage that utilities have been taking in the past may not differ significantly going forward.

Self-Insurance Reserve

21.14 In the draft Tariff Regulations, while computing the O&M expense norms, the Commission has considered the self-insurance reserve. While framing the Tariff Regulations, 2019, the Commission observed that the self-insurance reserve is an efficient mechanism for self-funding asset replacement in case of any damage to the transmission assets, and a sufficient check and balance mechanism was being followed. In view of this, the Commission has retained the provision for a self-insurance reserve. As the insurance expenses and SIS have also been allowed separately for the transmission licensees, necessary changes have been made in Regulation 36 (3)(d).

Ash Transportation expenses

21.15 In the draft Tariff Regulations, the Commission has not considered any Ash Transportation expenses while computing the O&M expenses due to the variable and irregular nature of ash disposal activities and was of the view that these expenses shall be allowed on actuals after prudence check. However, a new proviso is being introduced to permit the Ash transportation expenses separately, on a case-to-case basis, after a prudence check.

Other Issues

21.16 We notice that NEEPCO while submitting the O&M expenses data for its thermal generating stations, had not furnished the Corporate expenses in the format provided by the Commission, and therefore, the same could not be considered in the draft Tariff Regulations. NEEPCO has subsequently furnished the said details, and norms have been revised accordingly. As regards the O&M expense norms specified for the hydro generating stations of DVC, the revised O&M data furnished by DVC has been considered, and accordingly, the norms for hydro generating stations of DVC have been revised.

Transmission O&M expense norms

21.17 In the draft Tariff Regulations, the allocation of the normalized O&M expenses between the Sub-stations and the Transmission line was revised from 75:25 to a ratio of 65:35. The relevant extract of the Explanatory Memorandum to the draft Tariff Regulations is as under:

"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."

21.18 Some of the stakeholders have submitted that the allocation of the normalised O&M expenses may not be changed to 65:35 between the sub-stations and transmission lines, as the high voltage sub-stations consist of critical equipment such as Transformers, Reactors, Circuit Breakers, Current Transformers, Voltage Transformers etc. which require intensive O&M. They have also submitted that the addition of new substation equipment is higher as compared to the addition of new transmission lines. In view of this, the allocation ratio of the normalised O&M expenses between the sub-stations and transmission line has been reset to 75:25. Based on this, the O&M expense norms for the transmission systems have been revised.

21.19 The Commission also finds merit in the suggestion of PGCIL to exclude the CTUIL expenses from the O&M data submitted by them, to determine the O&M expense norms for the Transmission system. The Commission has, therefore, excluded the CTUIL expenses, as submitted by PGCIL, from the O&M expenses data and accordingly revised the O&M expense norms for the Transmission system. However, for the recovery of O&M expenses of CTUIL, the Commission has included a special provision under the Regulations.

O&M expenses for North East/Hilly Regions

21.20 The Commission has taken note of the suggestion(s) of the stakeholders and has made suitable changes in Regulation 36 (3) to include the State of Sikkim and the District of Darjeeling of the State of West Bengal within the proviso stipulated for O&M expenses applicable to the North East/Hilly Regions. This expansion is warranted due to the challenging terrain characteristics of these areas.

Communication System

21.21 In the Explanatory Memorandum to the draft Tariff Regulations, the Commission has proposed to consider the O&M expenses for the U-NMS scheme on actuals after due prudence check for the tariff period 2024-29. Accordingly, to provide an enabling provision, the Commission has modified Regulation 36 (3) (c) to allow the O&M expenses in case of U-NMS on actuals after a prudence check.

Impact of Change in Law

21.22 The Commission, in the draft Tariff Regulations, has proposed to allow the impact of the change in law events if the overall impact is more than 5% of the normative O&M expenses of the project for the year or Rs.10 crore, whichever is lower. Considering the suggestions of the various stakeholders, the Commission has modified the proviso by removing the limit of Rs. 10 crore and allowing the impact of the change in law event in case the overall impact is more than 5% of the normative O&M expenses of the project for the year.

Additional Expenses towards Digital Tools and NTAMC Upgradation

21.23 PGCIL has suggested that the upfront investment of Rs. 450 crores (approx.) towards the adoption of various digital tools in Asset management may be considered by the Commission while deriving the O&M expense norms for the period 2024-29. It has also suggested that to continue with the benefit of reduced operating expenditure besides compliances to Cyber security, a suitable provision for Rs. 285 crore may be made in the Tariff Regulations for National Transmission Asset Management Centre (NTAMC) Upgradation expenses. The Commission is of the view that these future expenses cannot be allowed as part of the normative O&M expenses, and in case these works are required for PGCIL, approval of the Commission may be sought by filing an appropriate petition after Investment Approval.

21.24 Based on the above, Regulation 36 has been modified as under:

"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	40.92	34.04	27.17	25.78	23.20
FY 2025-26	43.07	35.83	28.60	27.13	24.42
FY 2026-27	45.33	37.71	30.10	28.56	25.70
FY 2027-28	47.71	39.69	31.68	30.06	27.05
FY 2028-29	50.21	41.78	33.34	31.64	28.47

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

(2) Tanda TPS:

(in Rs Lakh/MW)

Year	*Tanda TPS (Unit 1)*
FY 2024-25 to FY 2028-29	42.52

(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*	*Agartala GPS*	*Small gas turbine power generating stations and Tripura Gas Station*	*Advance F Class Machines*
FY 2024-25	18.18	56.48	47.86	32.08
FY 2025-26	19.14	59.44	50.37	33.77
FY 2026-27	20.14	62.57	53.02	35.54
FY 2027-28	21.20	65.85	55.80	37.40
FY 2028-29	22.32	69.31	58.73	39.37

(4) Lignite-fired generating stations:

(in Rs Lakh/MW)

Year	*125 MW Sets*
FY 2024-25	38.81
FY 2025-26	40.85
FY 2026-27	42.99
FY 2027-28	45.25
FY 2028-29	47.62

(5) Generating Stations based on coal rejects:

(in Rs Lakh/MW)

Year	*O&M Expenses*
FY 2024-25	38.81
FY 2025-26	40.85
FY 2026-27	42.99
FY 2027-28	45.25
FY 2028-29	47.62

(6) The Water Charges, Security Expenses, Ash Transportation 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. 10 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 due to any change in law 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 of the project 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 @ 5.25% 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 Stations:

The 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
THPS	40,548.78	42,765.88	45,104.19	47,570.36	50,171.37
KHEP	20,749.20	21,883.71	23,080.25	24,342.21	25,673.18
Bairasul	7,856.31	8,285.87	8,738.92	9,216.74	9,720.68
Loktak	8,876.09	9,361.41	9,873.26	10,413.10	10,982.46
Salal	17,208.43	18,149.34	19,141.69	20,188.30	21,292.14
Tanakpur	11,696.62	12,336.16	13,010.67	13,722.05	14,472.34
Chamera-I	14,397.75	15,184.98	16,015.25	16,890.92	17,814.47
Uri-I	11,755.75	12,398.52	13,076.44	13,791.42	14,545.50
Rangit	6,351.54	6,698.82	7,065.09	7,451.39	7,858.82
Chamera-II	12,149.92	12,814.25	13,514.89	14,253.85	15,033.21
Dhauliganga	11,323.06	11,942.18	12,595.14	13,283.81	14,010.13
Dulhasti	17,754.67	18,725.45	19,749.30	20,829.14	21,968.02
Teesta-V	15,193.93	16,024.69	16,900.88	17,824.97	18,799.59
Sewa-II	8,053.42	8,493.76	8,958.17	9,447.98	9,964.57
TLDP III	9,281.92	9,789.43	10,324.68	10,889.21	11,484.60
Chamera III	9,598.50	10,123.32	10,676.83	11,260.61	11,876.31
Chutak	4,259.73	4,492.64	4,738.28	4,997.36	5,270.60
Nimmo Bazgo	4,346.80	4,584.47	4,835.13	5,099.50	5,378.33
Uri II	9,135.41	9,634.91	10,161.71	10,717.33	11,303.32
Parbati III	10,703.93	11,289.19	11,906.45	12,557.46	13,244.07
Kishanganga	13,952.53	14,715.42	15,520.01	16,368.60	17,263.59
TLDP IV	10,697.94	11,282.87	11,899.79	12,550.43	13,236.66
Indira Sagar	15,030.66	15,852.50	16,719.27	17,633.43	18,597.57
Omkareshwar	10,183.66	10,740.48	11,327.73	11,947.10	12,600.34

Particulars	*FY 2024-25*	*FY 2025-26*	*FY 2026-27*	*FY 2027-28*	*FY 2028-29*
Nathpa jhakari	*48,588.63*	*51,245.32*	*54,047.26*	*57,002.41*	*60,119.15*
Rampur	*18,287.58*	*19,287.49*	*20,342.08*	*21,454.32*	*22,627.39*
Koldam	*13,113.75*	*13,830.78*	*14,587.01*	*15,384.58*	*16,225.77*
Karcham Wangtoo	*12,612.68*	*13,302.30*	*14,029.64*	*14,796.74*	*15,605.78*
Kopili	*12,038.46*	*12,743.93*	*13,490.73*	*14,281.29*	*15,118.18*
Khandong I	*2,137.15*	*2,262.39*	*2,394.96*	*2,535.31*	*2,683.88*
Khandong II	*1,065.60*	*1,128.04*	*1,194.15*	*1,264.12*	*1,338.20*
Doyang	*7,540.48*	*7,982.36*	*8,450.13*	*8,945.31*	*9,469.52*
Panyor	*16,827.77*	*17,813.88*	*18,857.79*	*19,962.87*	*21,132.70*
Pare	*16,383.05*	*17,343.10*	*18,359.42*	*19,435.29*	*20,574.21*
Turial	*5,120.13*	*5,420.17*	*5,737.79*	*6,074.03*	*6,429.97*
Maithon	*3,261.23*	*3,439.55*	*3,627.61*	*3,825.96*	*4,035.15*
Panchet	*3,361.27*	*3,545.06*	*3,738.89*	*3,943.32*	*4,158.93*
Tilaiya	*1,027.67*	*1,083.86*	*1,143.12*	*1,205.62*	*1,271.54*
Teesta Urja Ltd.	*27,438.21*	*28,938.46*	*30,520.73*	*32,189.51*	*33,949.55*

a) 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 or equal to 200 MW, respectively and shall be subject to annual escalation of 5.47% per annum for the subsequent years.

b) 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 5.47% 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 5.47% per annum.

c) The Security Expenses, Capital Spares and Insurance expenses arrived through competitive bidding for hydro generating stations shall be allowed separately after prudence check:

Provided that the generating station shall submit the assessment of the security requirement, capital spares and insurance expenses along with its estimated expenses, which shall be trued up based on the details of year-wise actual capital spares consumed, actual insurance and security expenses incurred with appropriate justification;

Provided further that the value of capital spares exceeding Rs.10 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.

d) Any additional O&M expenses incurred by the generating company due to any change in law 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 of the project for the year.

e) 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;

f) The operation and maintenance expenses of the 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, 1966 and Narmada Water Scheme, 1980 under Section-6 A of the Inter-State Water Disputes Act, 1956 respectively.

(4) 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	*41.34*	*43.51*	*45.79*	*48.20*	*50.73*
400 kV	*29.53*	*31.08*	*32.71*	*34.43*	*36.23*
220 kV	*20.67*	*21.75*	*22.90*	*24.10*	*25.36*
132 kV and below	*15.78*	*16.61*	*17.48*	*18.40*	*19.35*
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)	*0.262*	*0.276*	*0.290*	*0.305*	*0.322*
Norms for AC and HVDC lines (Rs Lakh per km)					
Single Circuit (Bundled Conductor with six or more sub-conductors)	*0.861*	*0.906*	*0.953*	*1.003*	*1.056*
Single Circuit (Bundled conductor with four or more sub-conductors)	*0.738*	*0.776*	*0.817*	*0.860*	*0.905*
Single Circuit (Twin & Triple Conductor)	*0.492*	*0.518*	*0.545*	*0.573*	*0.603*
Single Circuit (Single Conductor)	*0.246*	*0.259*	*0.272*	*0.287*	*0.302*
Double Circuit (Bundled Conductor with four or more sub-conductors)	*1.291*	*1.359*	*1.430*	*1.506*	*1.585*
Double Circuit (Twin & Triple Conductor)	*0.861*	*0.906*	*0.953*	*1.003*	*1.056*
Double Circuit (Single Conductor)	*0.369*	*0.388*	*0.409*	*0.430*	*0.453*
Multi Circuit (Bundled Conductor with four or more sub-conductor)	*2.266*	*2.385*	*2.510*	*2.642*	*2.781*
Multi Circuit (Twin & Triple Conductor)	*1.509*	*1.588*	*1.671*	*1.759*	*1.851*
Norms for HVDC stations					
HVDC Back-to-Back stations (Rs Lakh per MW)	*2.07*	*2.18*	*2.30*	*2.42*	*2.55*
Gazuwaka BTB (Rs Lakh/MW)	*1.83*	*1.92*	*2.03*	*2.13*	*2.24*
HVDC bipole scheme (Rs Lakh/MW)	*1.04*	*1.10*	*1.16*	*1.22*	*1.28*

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 expense norms of Double Circuit quad AC line shall be applicable to for HVDC bi-pole line;

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 Region (including Sikkim), States of Uttarakhand, Himachal Pradesh, the Union Territories of Jammu and Kashmir and Ladakh, district of Darjeeling of West Bengal 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 substation bays, transformer capacity of the transformer/reactor/Static Var Compensator/Static Synchronous Compensator (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 or such similar 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. The expenses in case of U-NMS shall be allowed on actual basis after due prudence check.

(d) The Security Expenses, Capital Spares individually costing more than Rs. 10 lakh and Insurance expenses arrived through competitive bidding for the transmission system and associated communication system shall be allowed separately after prudence check:

Provided that in case of self-insurance, the premium shall not exceed 0.09% of the GFA of the assets insured;

Provided that the transmission licensee shall submit the along with estimated security expenses based on assessment of the security requirement, capital spares and insurance expenses which shall be trued up based on details of the year-wise actuals along with appropriate justification for incurring the same and along with confirmation 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 of the project 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."

Computation of the Input Price of Coal and Lignite from Integrated Mines

22 Adjustment on account of Non-tariff income (NTI adjustment) [Regulation 53 (1)]

As proposed in Draft Tariff Regulations

22.1 In the Draft Regulations, Regulation 53 (1) was proposed as under:

"(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."

Comments Received

22.2 NLCIL has submitted that their mines are captive mines, and as per draft Tariff Regulations, 2/3rd of the profit on the sale of lignite/coal is required to be passed on to the beneficiaries, whereas the risk and expenditure for carrying out the mining operation is entirely borne by the Mining companies. It has also submitted that the Mines and Minerals (Development and Regulation) Amendment Act, 2021 allows the captive miner to sell up to fifty per cent (50%) of the total coal or lignite produced in a year after meeting the requirement of the end use plant, considering that the risk & expenditure for carrying out the Mining operations are completely borne by the Mining company. NLC has further submitted that the actual coal or lignite produced may be less than 85% of the capacity due to reasons not attributable to mines, such as shutdown/partial loading of the Plant, Weather issues, Force majeure events, etc., and mines may not recover the full fixed cost due to these issues being beyond the control of the Mining company. It has added that the risk & expenditure in mining operation and any under-recovery of cost are entirely borne by the mining companies, and hence any risk or reward on account of outside sales shall rest with the Mining company, as was allowed in the past. Accordingly, NLC has requested the Commission that the sale of coal or lignite be kept outside the purview of NTI in the Tariff Regulations.

Analysis and Decision

22.3 The Commission has considered the submissions and is of the view that in cases where the off-take of coal falls below the stipulated Annual Targeted Quantity (ATQ) due to any justifiable reasons, and subsequently, the generating station having integrated mine opts to trade the extracted coal/lignite in the open market to generate revenue, it is imperative to first allow the recovery of the fixed costs, before considering any revenue for sharing with the beneficiaries. This adjustment aims to ensure the financial viability and sustainability of the integrated mine operation of the generating stations amidst the fluctuating coal off-take scenarios. In view of this, necessary modifications have been made to the proviso. It is, however, clarified that as per sub-clause (2) of Regulation 53, the NTI sharing mechanism shall not be applicable in case the mines have been allotted through an auction route under the Coal Mines (Special Provisions) Act, 2015. Accordingly, Regulation 53(1) has been modified as under:

"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:

Provided that in case the actual extraction is less than ATQ, no NTI adjustment shall be made till the total cost of extraction is recovered."

Components of Energy Charge

23 Gross Calorific Value of Primary Fuel [Regulation 60]

As proposed in the Draft Tariff Regulations

23.1 In the Draft Regulations, Regulation 60 was proposed as under:

"(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.

ii. 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."

Comments Received

23.2 GRIDCO, while suggesting to strengthen the framework of GCV, has mainly submitted the following:

a) Loss of GCV is recognized on account of the addition/extraction of moisture to/from the coal as delivered at the colliery end (i.e., equilibrated moisture + surface moisture).

b) A wide range of GCV loss (GCV loss on total moisture basis at the generating station end) allows the generator to factor in externalities like ingress moisture, rain, dew, etc., during transit, in addition to the total moisture (equilibrated moisture + surface moisture) received by them at the colliery end, resulting in lower GCV and thereby higher tariff burden on consumers.

c) CEA in its letter dated 20.07.2021, has stipulated the normative coal requirement for different sizes of pithead thermal power plants and non-pithead thermal power plants. The difference in the adjusted GCV has been derived after accounting for a 5% GCV loss between the 'as-received basis' (ARB) and equilibrated (EQ) basis without any differentiation in the GCV loss between the pithead and non-pithead stations. The average GCV loss between the different grades of coal, ranging from G1 to G17, is approximately 226 kCal/kg, which falls within the range of 300 kCal/kg for different grades of coal for both pithead and non-pithead based generating stations.

d) Accordingly, in the absence of any third-party sampling, the actual loss in the calorific value of coal between 'as billed' by the supplier and 'as received' at the generating station may be allowed, subject to a maximum loss in the calorific value of 300 kCal/kg for both pithead and non-pithead generating stations. This would enable generating stations to invoke their rights on GCV slippage as per the Fuel Supply Agreement (FSA).

e) In the case of a third-party sampling, if the difference in GCV between the billed amount by the supplier and the received amount at the generating station exceeds 300 kCal/kg, the third party must provide sufficient technical justification for the difference. This is because the beneficiaries are paying for the sampling and testing charges to the third party.

f) The GCV of coal directly affects the Energy charges and therefore, guidelines for third-party sampling of coal for GCV measurement should be formulated by the Government of India (either by the Ministry of Coal or by the Ministry of Power). The Commission may request the Government of India accordingly.

g) Modify the definition of "as received" for coal to include the FSA and lignite.

23.3 **NTPC** has suggested replacing the term "agency certified by the Ministry of Coal" with the term "agency certified by the Ministry of Power." It has also suggested that a clarification may be provided that the loss in GCV between 'as billed' and 'as received' shall be on an Equilibrated Moisture (EM) basis. NTPC has further submitted that for the purpose of billing to the Discoms, the GCV received at the generating station shall be further adjusted with the moisture correction. It has stated that integrated mines are supplying coal to the various generating stations with a distance varying from below 100 km to more than 1500 km, and as there is a direct correlation between the distance and GCV loss, a loss of 300 kCal/kg between 'as billed' and 'as received' GCV may be provided to the integrated mines, in addition to the moisture correction. NTPC has suggested that the loss in the calorific value of 300 kcal / kg (in addition to the moisture correction) may be provided between Mine end GCV and generating station end GCV, as under:

Sr. No.	**Distance between Mine and Generating Station**	**Difference between Mine End GCV (EM Basis) and Station End GCV (EM Basis)**
	(km)	**kCal/kg**
(i)	Distance (0-100 km)	0
(ii)	Distance (101-500 km)	75
(iii)	Distance (501-1000 km)	150
(iv)	Distance (1001-1500 km)	225
(v)	Distance (> 1501 km)	300

23.4 **Some of the distribution utilities** have suggested that a third-party sampling through an agency certified by the Ministry of Coal at the billing end and the receiving end should be made mandatory. They have also submitted that the proposal contained in the second proviso to Regulations 60(1) is totally against the provisions of Section 61 of the Electricity Act, 2003, as it simply allows a grade slippage in the range of 300 to 600 kCal/Kg for pithead and non-pithead stations respectively, which amounts to accepting the leakages in the fuel management system, which is highly unjustified and grossly against the interest of the consumers. These utilities have stated that each percentage drop in GCV will result in passing on the losses of thousands of crores of Rupees to the consumers. Therefore, these utilities have prayed for the deletion of the proposed proviso in the interest of justice and to allow the consideration of GCV on an 'as billed' basis. They have further submitted that there is a difference in the 'GCV billed and the GCV as received' for which the generating companies do not transfer any credit note to the beneficiary in a timely manner, and the same should be compulsorily passed on a month-to-month basis, to the beneficiaries. **NTPL** has suggested that in the absence of any third-party sampling through an agency certified by the Ministry of Coal, the provision for considering GCV on the basis of 'as billed' by the supplier less the 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 the calorific value of 600 kCal/kg should be made applicable. **PSPCL** has suggested the following:

- The proposed loss for pit head and non-pit head stations is high and needs to be capped.
- GCV 'as billed' is to be considered for pit head stations.
- Any loss in GCV due to non-sampling by the third party should be borne by the generator.
- Penalty for non-sampling by third part to be introduced.
- Loss in GCV for the non-pit head without third-party sampling is to be capped at 300 kCal/kg.
- Generating companies to be provided a target to reduce the GCV loss.

23.5 **Some of the consumer representatives** have submitted that if the actual GCV loss is 400 kCal/ kg from billed to the receiving point (non-pit head), the generating company, knowing that it would be entitled to a GCV loss of 600 kCal/ kg, may choose not to conduct the third-party sampling, to be done by an agency certified by the Ministry of Coal. They have also stated that the introduction of the second proviso may lead to foul play, as the generating company would get a leeway in terms of relaxation in the GCV, and hence, the second proviso may be deleted. These representatives have submitted that in the case of the non-pit head stations, the GCV loss to be allowed can be a maximum of up to 300 kCal/kg, which is equivalent to one grade slippage. They have submitted that allowing the GCV loss to a level of 600 kCal/kg accounts for 2 grade slippages, which is unreasonable and may not be considered. **Some of the other consumer representatives** have submitted that some generators were not complying with Regulation 60 (2) despite the Tariff Regulations explicitly providing for the same. They have submitted that on account of the non-compliance during the period 2019-24, the transparency in the cost recovery process is lost, and hence, to deter the generating companies from non-compliance with the regulatory provision, these stakeholders have proposed that a penalty may be imposed on the generating company/ unit, in the form of reduction in the rate of ROE by 1%. **Some of the generators** have requested to include a suitable provision in the regulation for waiver of the second proviso regarding the treatment of the difference between the GCV 'as billed 'and GCV 'as received' for such periods when the analysis of coal samples may not be possible due to certain contractual exigencies. **One Discom** has suggested capping the maximum loss in the calorific value, even in the case of GCV, on an 'as received' basis, i.e., 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. **KSEB**L has submitted that the sampling frequency may be specified in the regulation, and the same should be published, and any non-compliance may be penalized. It has also been submitted that it may be made mandatory for the generators to publish the source of fuel, the mode of transport, the distance of transportation for each source, the GCV of fuel from each source, blending ratio, surface transportation distance, and charges separately, along with the invoices and publish the same in the website and non-compliance may be penalized. **MPPMCL** has submitted that the regulation provides for displaying 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, on the website of the generating company. However, it has been submitted that most of the generators do not upload this data on their website timely and regularly, and such important data is also not being stored for the previous years on the website. MPPMCL has stated that as a result of this, the beneficiary faces many issues while complying with the audit observations and reconciliation work. Accordingly, MPPMCL has suggested that a provision may be incorporated in the regulation for generators to update the above data/details on their website timely and compulsorily.

Analysis and Decision

23.6 The Commission has considered the suggestion(s) of the stakeholder(s) and agrees with the suggestion that third-party sampling should be made mandatory, and the generating company is required to appoint an agency for third-party sampling in accordance with central government guidelines, if any. In addition to appointing a third-party agency, the generating company (ies) should also ensure the recovery of compensation as per the FSA signed by them and pass on the benefits to the beneficiaries in a timely manner. The Commission is also of the view that in case any generating station fails to appoint any third-party agency, the GCV of fuel in such cases should be considered on an 'as billed' basis, and no relaxation is to be permitted in case of non-compliance by any generator. As regards the GCV loss to be considered in case the fuel is supplied from an integrated mine to a generating station located far away, the Commission is of the view that a nominal loss in GCV is to be allowed since, during transportation, the GCV may deteriorate. Since the disallowance of any loss may severely impact the generating stations, the Commission has allowed the generating stations to factor in a loss of 15 kCal/kg from the GCV measured at the mine end for every 100 km distance beyond 200 km, or actuals, whichever is lower, subject to the condition that such an adjustment in aggregate, shall not exceed 300 kCal/kg. The Commission is also of the view that in case the generating station is within a range of 200 km, no loss in GCV is to be allowed. However, a graded loss, as proposed above, has been allowed in case the distance of the generating station from the mine is beyond 200 km. This has been considered to account for the potential degradation in the quality of coal during transportation over longer distances from the integrated coal mines to end-use generating stations. By allowing for adjustments based on the distance travelled, the amendment aims to ensure fairness in the Energy charge computation and to mitigate any adverse impact on the generating stations procuring coal from distant integrated mines. This adjustment aligns with the principles of equitable pricing and also recognizes the logistical challenges associated with long-distance coal transportation. While allowing the loss factors, the Commission is of the view that a detailed study is required to arrive at the loss of GCV of domestic coal at the generating station by considering the various factors impacting the calorific value throughout the entire value chain, from the delivery of coal till receipt at the generating station.

23.7 As regards the submission of relevant data pertaining to coal, in order to have transparency, the generating stations have been mandated to furnish the data/details to the beneficiaries as per Form-15 prescribed in Annexure-I to the Tariff Regulations. The generators are, therefore, required to strictly comply with clause (5) of Regulation 60 of the Tariff Regulations, failing which appropriate proceedings may be initiated against the non-complying generators. Based on the above, Regulation 60 has been modified as under:

"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';

(2) The measurement of GCV of domestic coal shall be done based on third party sampling through an agency to be appointed by the generating company in accordance with the guidelines, if any, issued by the Central Government and the generating company shall 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 that in the absence of third-party sampling, computation of the energy charges as per Regulation 64 of these Regulations shall be done in accordance with 'GCV as Billed';
(3) In the case of an integrated coal mine, the GCV of coal received at the end use generating station shall be adjusted by 15 kCal/Kg from the GCV measured at the mine end for every 100 km distance beyond 200 Km, or actual whichever is lower, subject to the condition that such an adjustment in aggregate shall not exceed 300 kCal/kg:

Provided further that the Commission after carrying out a detailed study may rationalise the mechanism for arriving at the gross calorific value of domestic coal at the generating station by considering the various factors impacting the calorific value throughout the entire value chain from the delivery of coal to receiving at the generating station.

(4) No loss in calorific value between 'GCV as billed' and 'GCV as received' shall be admissible for generating stations procuring coal through import.

(5) 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 primary 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."

Computation of Energy Charges and Capacity Charges

24 **<u>Computation of Payment of Capacity Charge for Thermal Generating Stations [Regulation 62(5) and (6)]</u>**

As proposed in Draft Tariff Regulations

24.1 In the Draft Tariff Regulations, clauses (5) and (6) of Regulation 62 were proposed as under:

"(5) In addition to the AFC entitlement as computed above, the thermal generating station shall be allowed an incentive of up to 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.

(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."

<u>Comments Received</u>

24.2 **SRPC** has submitted that some generators give a negative response, and therefore, if the incentive is proposed to be allowed generating stations to provide necessary support, there should also be a mechanism to disincentivise such generating stations for non-performance or for a negative response. It has also been submitted that if the number of incidents is less than 2, it would be difficult to assess the performance. Accordingly, SRPC has suggested the following modification to clause (5):

"(5) In addition to the AFC entitlement as computed above, the thermal generating station shall be allowed an incentive of up to 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 -1 to 1.
CCy= Capacity Charges for the Year

Provided there should be at least 2 incidents in a month to compute Incentive Average Monthly Frequency Response Performance for that generating station"

24.3 In addition**, SRPC** has also suggested that the energy transacted by the generating station to any entity other than the original beneficiary cannot be accounted for supplying power to the original beneficiary for the purpose of incentive. It has stated that the computation has to be done beneficiary-wise only with respect to the schedule of and normative ex-bus entitlement of the beneficiary. SRPC has also stated that the incentive cannot be calculated on the total schedule of the generating station and the ex-bus energy corresponding to the NAPLF of the station. Accordingly, SRPC has suggested the following changes to clause (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 of the beneficiary during Peak Hours and

@ 50 paise/ kWh for ex-bus scheduled energy of the beneficiary during Off-Peak Hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) of the beneficiary achieved on a cumulative basis, as specified in Clause (B) of Regulation 70 of these regulations."

24.4 **CEA** has pointed out that the CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007 (as amended) provides as under:

"All generating machines irrespective of capacity shall have electronically controlled governing system with appropriate speed/load characteristics to regulate frequency. The governors of thermal generating units shall have a drop of 3 to 6% and those of hydro generating units 0 to 10%. The coal and lignite based thermal generating units shall be capable of generating up to 105% of Maximum Continuous Rating (subject to maximum load capability under Valve Wide Open Condition) for short duration to provide the frequency response.

The hydro generating units shall be capable of generating up to 110% of rated capacity (subject to rated head being available) on continuous basis."

24.5 Further, Regulation 30 (10) (i) of the Grid Code provides as under:

"all generating stations shall have the capability of instantaneously picking up to a minimum of 105% of their operating level and up to 105% or 110% of their MCR, as the case may be, when the frequency falls suddenly and thus providing primary response whenever conditions arise. Any generating station not complying with the above requirements shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of the concerned RLDC."

24.6 CEA has submitted that since the above provisions are for mandatory compliance, ideally, there should not be any need to give incentive for such compliance. It has stated that if the incentive is given for providing frequency response, then the provision for equitable penalty for not meeting it must also be provided. However, CEA has submitted that if it is considered necessary to give such an incentive, then in the case of hydro power stations, the incentive of up to 2% of the capacity charge and penalty (2% of the capacity charge) in case of failure, may be considered, to bring it on par with the thermal power generating stations. **NTPC** has submitted that the capacity charges for the year (CCy) can be finalised only at the end of the financial year after certification of the availability by the RPC. It has therefore, proposed that the above formulae may be modified considering the capacity charge for the month (CCm) so that billing can be done on a monthly basis, based on monthly ß as certified by the RPC. NTPC, while pointing out that incentives should be computed by taking "up to the month capacity charges," i.e., monthly performance evaluation with yearly reconciliation, has submitted that the method of apportionment of incentives among the customers may also be mentioned for better clarity. It has stated that the methodology for calculating the average monthly frequency response performance and capacity charges may be included in the Tariff Regulations so that a uniform procedure for computation of ß may be achieved. NTPC has also submitted that as the quantum of the Primary Frequency Response (PFR) delivery depends upon the enthalpy of entrapped steam in the system before the control valve of the turbine, the PFR performance above 70% delivery needs to be considered as a deemed full delivery of PFR, and Beta may be considered as 1. **Some of the Distribution utilities** have submitted that incentive, which is to be given for primary monthly response of the generating station, may be provided as per the CERC (Ancillary Services) Regulations, 2022, and in case the incentive is not provided under the said regulations, the same may be included through an amendment. They have also submitted that since the operation of the primary monthly response of the said generator is the requirement of the grid, the incentive to be provided to this generator shall be recovered from all the grid participants that are responsible for the instability of the grid at that point in time. They have further submitted that there is no basis for the recovery of the cost of incentive arising due to the operation of the generator at the primary monthly response from the beneficiaries, and therefore, the clause may be deleted from this regulation and included, if required, in the CERC (Ancillary Services) Regulations, 2022 as an amendment. The distribution utilities have further submitted that the purpose of the incentive to the generator is to encourage improvement in the performance of the generating station, and currently, all inter-state generating stations are already operating at an optimum capacity, with PLFs in the range of 90-95% during the year. They have added that a further increase in the incentive will not make any additional benefit to the beneficiaries and there is no technical improvement possible by increasing the incentive from 65 paise to 75 paise per unit, as they are already operating at an optimum level. Accordingly, these utilities have suggested that the incentive may be maintained at 65 paise per unit for peak hours as per the existing Regulations. **MPPMCL** has suggested reducing the proposed incentive rate of 75/50 paise per unit to 35 paise per unit, for achieving the scheduled generation above 95% of the installed capacity. **MSPGCL has** suggested fixing the incentive rate at Rs. 1.00/kWh for off-peak hours and Rs.12.5/kWh for peak hours for the 1st year of the control period and escalation for the subsequent years, and the same incentive may be enforced uniformly across all States to incentivize all generators across the country to take part in countering the peak demand load. **One consumer representative,** while pointing out that the incentive for the present control period for peak hours is 65 paise/unit, has requested not to further enhance the same to 75 paise/unit, as the purpose for markets is to create more competitive power procurement in real time. It has been submitted that while markets depend on the demand-supply forces, linking the incentives with the market prices is unjust and may need to be reviewed.

Analysis and Decision

24.7 The Commission has considered the suggestion(s) of the stakeholders and agrees with the suggestion of SRPC proposing the grant incentives to the generators for delivering the primary response, provided that the generating station has offered frequency response on at least two occasions within a month, to assess its performance. Accordingly, the Commission has included a proviso to Regulation (5), stipulating that the incentive to the generating station shall be payable only if the Beta value is higher than 0.30. Regulations 62(5) and 65(4) provide that in addition to the AFC, the generating station shall be allowed an incentive for providing frequency response as a percentage of AFC approved for a given year, and the same shall be billed on a monthly basis to the beneficiaries.

24.8 As regards the recovery of capacity charges by the generating stations, when the station is under shutdown due to R&M or due to the installation of ECS, it is observed that the proviso to Regulation 62(2) states that the generating company shall be allowed to recover the O&M expenses and Interest on loan only. However, it is clarified that the normative availability of each generating station has been specified in the Regulations, and if the generating station, even after taking shutdown for R&M or for the installation of ECS, is able to manage such shutdown within the permissible limits, and the generating station is able to achieve the normative availability, then in such cases, the entire annual fixed charges shall be allowed to be recovered. Also, there could be a case wherein, due to such shutdown, the actual availability (say 80%) of the generating station falls below the normative availability (85%), and in such cases, the generating company shall be allowed to recover the annual fixed charges corresponding to 80% availability and only the O&M expenses and Interest on loan corresponding to 5% of the reduced availability. In such cases, the generating station has to substantiate that such reduction in its availability, is on account of the shutdown taken due to R&M or the installation of ECS. With regard to the increase in incentive for extra generation, the Commission is of the view that the increase in incentive in the current shortage scenario will result in increased generation from the limited available resources. Based on the above, clauses (5) and (6) of Regulation 62 are modified as under:

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

(1) xxx
(2) xxx
xxx
(5) In addition to the AFC entitlement as computed above, the thermal generating station shall be allowed an incentive of up to 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 with approval of the Commission, and ß shall range between 0 to 1:

Provided that the incentive shall be payable only if the Beta value is higher than 0.30.

CCy= 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 @ 55 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."

25 Computation and payment of energy charge for thermal generating stations and supplementary energy charge for coal or lignite based thermal generating stations: [Regulation 64 (4)]

As proposed in Draft Tariff Regulations

25.1 In the Draft Tariff Regulations, Regulation 64 (4) was proposed as under:

"(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."

Comments Received

25.2 **Some of the distribution utilities** have suggested retaining the provisions of the 2019 Tariff Regulations with regard to the blending of coal for the period 2024-29 as well. They have also submitted that the power purchase cost has increased by 10% (Rs. 1227 crore) during 2023-24 on account of the blending of coal, and therefore, the earlier proviso may be retained. **Damodar Valley Power Consumer Association** has submitted that allowing 6% of blending without any explicit direction of the MOP, GOI will result in a huge financial burden for the consumers. **OPGCL** has submitted that in the absence of any provision for capping of ECR on account of alternative sources of fuel, the base ECR for the subsequent years shall have no relevance, and hence, an enabling provision may be included, considering its applicability. **MB Power** has submitted that no such limit of 6% blending by weight may be imposed in the Tariff Regulations for the period 2024-29, but in the event, the Commission deems it appropriate to restrict such a blending, then the applicable provisions under Regulation 43(3) of the existing 2019 Tariff Regulations may be retained. **PCKL** has submitted that the MOP, GOI, has allowed the coal blending up to March 2024, and therefore, the Commission may not allow the 6% blending in the Tariff Regulations. It has further been submitted that the use of imported coal without prior information of the beneficiaries will impact the scheduling of power and will result in higher charges paid by the consumers. **APP** has suggested including a proviso in the Tariff Regulations, wherein it may be clearly specified that no prior permission is required from the beneficiaries in case of use of the alternative source of fuel supply, in compliance with the directives of the Government. It has further stated that if the discoms fail to provide the approval, then the generating companies, may be reimbursed for the loss of the capacity charges.

Analysis and Decision

25.3 The Commission has considered the suggestion(s) of the stakeholder(s). It is observed that the MOP, GOI, vide its letter dated 25.10.2023, has issued an advisory concerning the blending of imported coal at a rate of 6% until March 2024, which has been extended till June 2024, vide letter dated 04.03.2024. It is observed that in light of insufficient coal stocks/supply from the domestic sources and the prevailing power demand scenario, the Commission, in the exercise of its power under Regulation 76 of the 2019 Tariff Regulations (power to relax), has also issued Suo moto orders, determining the permissible percentage of blending of the imported coal. Given that the Commission has been issuing separate orders regarding the blending of imported coal based on the domestic coal stock/supply scenarios and power demand, as above, the Commission is of the view that separate orders will be issued with regard to the utilization of alternative fuel under special circumstances. The Commission is also of the view that since the earlier provision under the 2019 Tariff Regulations provides for proper checks and balances, the said provision has been retained under the present regulations. Notwithstanding the same, a proviso has been added that in case the Commission deems it fit, after considering the shortage of fuel, may vary through separate order(s), the blending ratio, and the requirement of beneficiary consent thereof, towards the use of an alternative source of fuel. It is also clarified that under the second proviso of Regulation 64 (3) (d), clause (5) may be read as clause (3).

25.4 Accordingly, the provisos to clauses (3) and (4) of Regulation 64 have been modified as under:

"64(3)xxx.

Provided 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 and in such case, prior permission from beneficiaries shall not be a pre-condition, unless otherwise agreed specifically in the power purchase agreement:

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

(4) Notwithstanding anything contained in clause 3 of this Regulation, the Commission after considering the shortage of fuel, may vary through separate Order(s), the blending ratio and the requirement of beneficiary consent thereof, towards use of alternative source of fuel."

26 **Computation of the payment of capacity charge and energy charge for hydro generating stations [Regulation 65 (4)]**

As proposed in Draft Tariff Regulations

26.1 In the Draft Tariff Regulations, Regulation 65 (4) was proposed as under:

"(4) In addition to the AFC entitlement as computed above, the hydro generating station shall be allowed an incentive of up to 4% of the 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."

Comments Received

26.2 **CEA** has submitted that the CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007 (as amended) provides as under:

"All generating machines irrespective of capacity shall have electronically controlled governing system with appropriate speed/load characteristics to regulate frequency. The governors of thermal generating units shall have a drop of 3 to 6% and those of hydro generating units 0 to 10%. The coal and lignite based thermal generating units shall be capable of generating up to 105% of Maximum Continuous Rating (subject to maximum load capability under Valve Wide Open Condition) for short duration to provide the frequency response.
The hydro generating units shall be capable of generating up to 110% of rated capacity (subject to rated head being available) on continuous basis."

26.3 Further, Regulation 30 (10) (i) of the Grid Code provides as under:

"all generating stations shall have the capability of instantaneously picking up to a minimum of 105% of their operating level and up to 105% or 110% of their MCR, as the case may be, when the frequency falls suddenly and thus providing primary response whenever conditions arise. Any

generating station not complying with the above requirements shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of the concerned RLDC."

26.4 CEA has submitted that since the above provisions are for necessary compliance, ideally, there should not be any need to provide incentives for compliance. It has been submitted that if incentive is given for providing frequency response, then the provision for equitable penalty for not meeting it must also be provided. CEA has further submitted that if it is considered necessary to give such an incentive, then in the case of hydro power generating stations, the incentive of up to 2% of the capacity charge and penalty (2% of the capacity charge) in case of failure, may be considered to bring it on par with the thermal power generating stations. **SRPC** has submitted that an incentive of 4% seems to be high for hydro generating stations, which, by design, have higher primary response capacity. It has further submitted that initially, 2% may be considered and after some proposer feedback, the same may be reviewed. As submitted in the case of thermal generating stations, SRPC has suggested that as some of the generators are giving negative responses, there should be a penalty mechanism to deter such responses. It has further submitted that if the number of incidents is less than 2, it would be difficult to assess the performance. **SRPC** has therefore suggested the following changes:

"In addition to the AFC entitlement as computed above, the hydro generating station shall be allowed an incentive of up to 4% of the Capacity Charge approved for a given year which shall be billed monthly as per the following. Incentive = (2% 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 -1 to 1.
CCy= Capacity Charges for the Year.

Provided there should be at least 2 incidents in a month in a month for the to compute Incentive Average Monthly Frequency Response Performance for that generating station."

26.5 **PCKL** has submitted that the generators have to adhere to the guidelines/Grid code, and hence, allowing any additional incentive may not be appropriate and will only add additional burden to the consumers. **MPPMCL** has submitted that the incentive of 4% on the capacity charge will significantly impact the increase in the capacity charges. It has stated that the hydro generating plants are meant for peaking power and quick start, and therefore, any additional incentive, on the basis of the average monthly frequency response performance, is an undue enrichment of the generator and may not be allowed. **PSPCL** has submitted that no additional incentive should be provided based on the frequency response. **NHPC** has suggested continuing with the provision of incentives for frequency response increasing the factor of 4% to 10%, and increasing the same to pumped storage hydro generation also.

Analysis and Decision

26.6 The Commission has considered the suggestion(s) of the stakeholders. The Commission observes that in order to be eligible for an incentive, a generating station should achieve a minimum performance, and therefore, the incentive is allowed only in cases where the beta value is over 0.30. It is pertinent to note that CEA and SRPC have suggested reducing the incentive from 4%, as proposed in draft Tariff Regulations, to a maximum of 2% in the case of hydro generating stations. Further, some of the generators have suggested to increase the incentive percentage from 4% to 10%. It is observed that the capacity charges, in the case of the hydro generating stations, are half of the total annual fixed charges. It is further observed that the Grid Code had put restrictions on the availability scheduling to 100% of the installed capacity, which was allowed to the extent of 110% for hydro generating stations, prior to the notification of the IEGC, 2023 and the said limit was 105% in case of the thermal generating stations. In view of the hydro generating stations being largely impacted due to the implementation of the Grid code restrictions imposed on higher scheduling and also the capacity charges for hydro generating stations being half of the annual fixed charges, the incentive was proposed up to 4% of the annual fixed charges for hydro generating stations as against 1% of annual fixed charges for the thermal generating stations. However, considering the suggestions of the consumers, the Commission has reduced the incentive for hydro generating stations to provide primary frequency response to 3% from the earlier norm of 4%. Accordingly, clause (4) of Regulation 65 is modified as under:

"(4) In addition to the AFC entitlement as computed above, the hydro generating station shall be allowed an incentive of up to 3% of the Capacity Charge approved for a given year which shall be billed monthly as per the following.
Incentive = (3% 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 with approval of the Commission, and beta shall range between 0 to 1:
Provided that incentive shall be payable only if Beta value is higher than 0.30.
CCy= Capacity Charges for the Year."

27 **Rate of Secondary Energy Charge [Regulation 65 (9)]**

As proposed in Draft Tariff Regulations

27.1 In the Draft Regulations, Regulation 65 (9) was proposed as under:

"(9) In case the energy charge rate (ECR) for a hydro generating station, computed as per clause (5) of this Regulation exceeds one hundred and twenty paise per kWh, and the actual saleable energy in a year exceeds {DE x (100- AUX) x (100 - FEHS) /10000} MWh, the energy charge for the energy in excess of the above shall be billed at one hundred and twenty paise per kWh only."

Comments Received

27.2 **NHPC** has submitted that the historical rate energy of saleable schedule energy, beyond the saleable design energy, over the various tariff periods are as under:

- 2009-14: 80 paise/kWh
- 2014-19: 90 paise/kWh
- 2019-24: 120 paise/kWh

- 2024-29: 120 paise/kWh

27.3 It has been submitted that the average Market Clearing Price (MCP) in the power exchanges has increased from Rs 3/kWh to Rs 5.5-Rs 6 /kWh. However, it has been pointed out that the Commission has not considered increasing the rate of energy beyond saleable design energy which is being supplied to the beneficiary Discoms, already at a lower rate than their ECR. NHPC has submitted that the energy beyond the saleable design energy generated by its generating station replaces the expensive power in the Power exchange, and the importance of the energy generated beyond the saleable design energy becomes even more significant when the energy is generated during the peak hours. Accordingly, NHPC has suggested increasing the rate of energy beyond the saleable design energy to 150 paise/kWh.

Analysis and Decision

27.4 The Commission has considered the suggestions of NHPC and finds merit in increasing the rate of energy beyond the design energy for the reasons stated therein. Accordingly, the rate of energy has been increased from 120 paise/kWh to 130 paisa/kWh. In terms of this, Regulation 65(9) is modified as under:

"(9) In case the energy charge rate (ECR) for a hydro generating station, computed as per clause (5) of this Regulation exceeds one hundred and thirty paise per kWh, and the actual saleable energy in a year exceeds {DE x (100- AUX) x (100 - FEHS) /10000} MWh, the energy charge for the energy in excess of the above shall be billed at one hundred and thirty paise per kWh only."

28 Computation and payment of capacity charge and energy charge for Pumped storage hydro generating stations [Regulation 66 (4)]

As proposed in the Draft Tariff Regulations

28.1 In the Draft Tariff Regulations, Regulation 66 (4) was proposed as under:

"(4) Energy charge payable to the generating company for a month shall be:
= 0.20 x {Scheduled energy (ex-bus) for the month in kWh- (Design Energy for the month (DEm) + 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir of the month)} x (100 - FEHS)/ 100.

Where,
DEm = Design energy for the month specified for the hydro generating station, in MWh
FEHS = Free energy for home State, in per cent, as mentioned in EXPLANATION-III under Regulation 76 of these regulations, if any.

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

Comments Received

28.2 **NHPC** has submitted that the present regulations only consider a scenario where the energy has been arranged by the beneficiaries. This, according to NHPC, needs to be revised in view of the fact that the energy required for pumping can be arranged by the developer from RE sources, in view of waiver of inter-state transmission charges allowed when the pumping energy from RE sources is at least 51% of the total pumped energy.

Analysis and Decision

28.3 The Commission has considered the suggestion(s) of NHPC and finds merit in the suggestion of NHPC to include the sharing mechanism of the cost in case the pumped energy is arranged by the generator. The Commission has accordingly included one proviso, which stipulates that if the energy for the pumping of water from a lower reservoir to the upper reservoir is arranged by the generating company, the charges for the pumping energy till the ex-bus of the generating station shall be payable by the beneficiaries in proportion to their respective allocation, in the saleable capacity of the generating station. Accordingly, Regulation 66 (4) has been modified as under:

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

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

Where,

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

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

Provided that if the energy for the pumping of water from lower reservoir to upper reservoir is arranged by the generating company, the charges for the pumping energy till the ex-Bus of the generating station shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station."

Norms for Operation

29 **Normative Annual Plant Availability Factor (NAPAF) and Normative Annual Plant Load Factor (NAPLF) for Incentive [Regulation 70 (A) (b) and 70 (B) (b)]**

As proposed in Draft Tariff Regulations

29.1 In the Draft Regulations, Regulation 70 (A) (b) and 70 (B) (b) was proposed as below:

"*(70) xxx*
(A) ***Normative Annual Plant Availability Factor (NAPAF)***
(a) 85% for all thermal generating stations, except those covered under clauses ...
(b) 80% for coal and lignite based generating stations completing 30 years from COD as on 31.03.2024;"
xxx
(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;"

Comments Received

29.2 **CEA** has suggested reviewing the NAPAF of 80% stipulated for coal and lignite-based generating stations completing 30 years from COD as on 31.03.2024. It has also been submitted that the various units of 10 stations (coal-based) of NTPC would be completing 30 years or more from COD as on 31.03.2024, and the average PAF for the 5 years from 2018-19 to 2023-24 for all these 10 stations has been well above 86%. CEA has further submitted that for DVC coal-based generating stations, only Maithon Power Limited (MPL) has completed 30 years from COD as on 31.03.2024, and the average PAF for 5 years from 2018-2019 to 2022-23 for MPL is around 89%. It has added that for lignite-based stations, only TPS-II of NLC has completed 30 years, and it has already been provided with the relaxed norms as 80% PAF. **NTPC** has suggested that NAPAF and NAPLF of 80% may be made applicable for generating stations completing 25 years from COD on or after 01.04.2024 (instead of 30 years proposed in the Draft Tariff Regulations). **KSEBL** has suggested that for thermal generating stations that have undergone R&M or availing efficient working after useful life, the NAPLF norm may be retained as 85%. **GRIDCO and some of the other distribution utilities** have suggested that there is no need to reduce the target availability and NAPLF to 80% for older generating stations. GRIDCO has proposed for revision of the target availability for old generating stations at 85% and 90% for the existing generating stations which have not completed 25 years of useful life. The Association of Power Producers has suggested that a further relaxation beyond 80% NAPAF is required for coal and lignite-based generating stations completing 30 years from COD as of 31.03.2024. The **association of DVC HT Consumers of Jharkhand** has suggested that NAPAF should be approved at levels considering the ageing of the thermal generating unit, which would be commensurate with the operational degradation which the plant would be exposed to over its useful life. Accordingly, they have proposed that the NAPAF levels be approved as under:

<u>For plants older than</u>:
20 years: 85.00%
15 years: 86.00%
10 years: 87.5%
Less than 10 years: 90.00%

<u>Analysis and Decision</u>

29.3 The Commission has considered the suggestion(s) of the stakeholders. The Commission, while specifying the norms in the Draft Tariff Regulations, 2024 had lowered the NAPAF for generating stations, completing 30 years to de-risk the operations of such generating stations. The Commission had also lowered the NAPLF for incentive purposes so that the generating stations are incentivised to risk operating the older generating stations. This was required because the old generating stations do not earn much ROE in terms of Rs./kWh when compared to the new generating stations, and in any year, if, for some reason, there is under recovery, the ROE earned gets eroded. The Commission, however, based on the observations and recommendations of the CEA and several other stakeholders, has re-considered this issue and has fixed the NAPAF and NAPLF for these generating stations as 83%. It is also clarified that the CEA has specified a specific norm of 80% for NLC TPS-II (Stage I and Stage II), which are also over 30 years old, and therefore, NAPAF of 80% will be applicable for both Stage-I and Stage-II stations of NLC TPS-II. Accordingly, Regulation 70 (A) (b) and 70 (B) (b) have been modified as under:

"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 (b), (c), (d) and (e);

(b) 83% for coal and lignite based generating stations completing 30 years from COD as on 31.03.2024;
xx

(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) 83% for coal and lignite based generating stations completing 30 years from COD as on 31.03.2024"

30 <u>NAPAF [Regulation 70 (A) (e)]</u>

As proposed in Draft Tariff Regulations

30.1 In the Draft Tariff Regulations, Regulation 70 (A) (e) was proposed as under:

"*(70) (A) (e):For following lignite fired thermal generating stations of NLC India Ltd.*
1. TPS-II State-I and Stage-II: 80%
2. Barsingsar (CFBC): 75%
3. TPS-II Expansion (CFBC) : 50%
4. TPS-1 Expansion : 80%
5. New Neyveli TPS : 80%;"

<u>Comments Received</u>

30.2 **CEA** has suggested reviewing the regulation stipulating 80% PAF for TPS-I Expansion and New Neyveli TPS. It has been submitted that the 5-year average PAF from 2018-19 to 2022-23 for TPS-I Expansion is 87.14%, and for New Neyveli TPS is 67.95%, wherein during 2022-23, the New Neyveli TPS has achieved the PAF of 86.92%. Accordingly, CEA has suggested that the Commission may review the said Regulation. **KSEBL** has suggested that the NAPAF for the CBFC technology station has been reduced. It has also been submitted that the relaxed norms are permitted to generators instead of a better and more efficient norm. KSEBL while pointing out that a very low NAPAF has been fixed for TPS-II Stages–I and II and TPS-II Expansion, has suggested NAPAF to be fixed at 80%. **TANGEDCO** has suggested that a reduced PAF of TPS II Expansion is due to the inherent design fault of the generating station, and approving the relaxed norms will result in an increase in the annual financial commitment of TANGEDCO by Rs. 175 crores.

<u>Analysis and Decision</u>

30.3 The Commission has considered the suggestion(s) of the stakeholders. Based on the observations made by CEA and analysis of the actual PAF achieved by TPS-I Expansion, New Neyveli TPS, TPS II Expansion, and TPS II (Stage 1 & 2), the Commission has revised the PAF for TPS-I Expansion from 80% to 85%. As regards the PAF achieved by New Neyveli TPS from 2018-19 to 2022-23, the Commission has observed that New Neyveli TPS has been able to achieve PAF above 85% only during 2022-23. Therefore, keeping in view the fact that Unit-II for the generating station has achieved its commercial operations only on 10.02.2021 and that the said station will take some time to stabilize its operations, the Commission has retained the PAF of 80% for New Neyveli TPS as proposed in the draft tariff regulations. As regards the PAF achieved by TPS II Expansion, it is observed that though the 5-year average PAF of TPS II Expansion is 44.45% only, keeping in view the same and considering the recommendations of the CEA vide letter dated 19.12.2023, the norms were fixed at 50%. However, considering the concerns of distribution companies and in an endeavour to keep a balance between the interests of generators and beneficiaries, and on the basis of revised recommendations of the CEA vide its letter dated 15.3.2024, the Commission has revised the norms for TPS II Expansion from 50% to 70%. Accordingly, Regulation 70 (A) (e) has been modified as under:

"(e) For following lignite fired thermal generating stations of NLC India Ltd.
1. TPS-II State-I and Stage-II : 80%
2. Barsingsar (CFBC) : 75%
3. TPS-II Expansion (CFBC) : 70%
4. TPS-1 Expansion : 85%
5. New Neyveli TPS : 80%"

31 **Gross Station Heat Rate [Regulation 70 (C) (a) (i)]**

As proposed in Draft Tariff Regulations

31.1 In the Draft Tariff Regulations, Regulation 70 (C) (a) (i) was proposed as under:

"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*

Comments Received

31.2 **Tata Power** has suggested fixing the ceiling limit of 2388 kCal/kWh for the 500 MW generating units regardless of its COD instead of 2375 kCal/kWh as proposed in the draft tariff regulations. It has also been submitted that the SHR norms may be considered as lower than 2388 kCal/kWh and the actual Heat Rate during the year, subject to a minimum of the SHR norm arrived at by design parameters for units having COD on or after 01.04.2009. **MSPGCL** has submitted that the SHR should not be reduced for thermal generating units of 200/210/250 MW series, in view of deteriorating coal quality and thermal generating units of 200/210/250 MW series getting old. It has also been suggested to retain the SHR as specified in the existing Tariff Regulations for 200/210/250 MW sets. **MB Power** has submitted that the normative GSHR may be retained at their respective levels as stipulated under the 2019 Tariff Regulations if not relaxed any further. **DIL** has submitted that the norm of GSHR for thermal power projects shall be fixed after a review of the past performance at the start of each control period. **DVC** has submitted that the Commission has been gradually reducing the GSHR norms for the thermal generating plants by making them more stringent. It has also stated submitted that in the draft tariff regulations, the Commission has further reduced the norms for both old thermal generating stations (with COD before 01.04.2009) and new thermal generating plants with higher capacity units (>500MW), which would have a significant impact on the financial performance of DVC generating stations, which are already struggling to achieve the present norms laid down by the Commission. DVC has submitted that the Commission should continue with the existing SHR norms for all the DVC generating plants. **GMR Energy,** while pointing out that the draft tariff regulations do not provide any separate norms for heat rate for 300/350 MW unit sizes, has suggested that 300/350 MW unit sizes should be clubbed with the norms for 200 MW unit sizes since the 300/350 MW units are technically the extension of 200/250 MW unit sizes. **CEA** vide its letter dated 15.03.2024, has recommended that the SHR of 200 MW series commissioned prior to 01.04.2009 may be revised to 2415 kcal/kWh.

Analysis and Decision

31.3 The Commission has considered the suggestion(s) of the stakeholders. Considering the suggestions of the CEA and other stakeholders, the Commission has made suitable changes under Regulation 70 (C) (a) (i) along with the inclusion of Notes to the regulation. The Commission has also revised the Gross Station Heat Rate for the 200 MW series as 2415 kCal/kWh. Accordingly, Regulation 70 (C) (a) has been modified as under:

"(C) Gross Station Heat Rate:

(a) Existing Thermal Generating Stations achieving COD before 1.4.2009

(i) For Coal-based Thermal generating stations other than those covered under clause (ii) below:

200-300 MW Sets	***500 MW Sets (Sub-critical)***
2,415kCal/kWh	*2,375kCal/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 and above 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 as per the Grid Code. The generating company shall, based on the 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 with on a case-to-case basis."

32 **Gross Station Heat Rate [Regulation 70 (C) (b) (i)]**

As proposed in Draft Tariff Regulations

32.1 In the Draft Tariff Regulations, Regulation 70 (C) (b) (i) was proposed as under:

"70. Norms of Operation for thermal generating stations:
(C) Gross Station Heat Rate
(b) Thermal Generating Stations achieving COD on or after 1.4.2009:
(i) For Coal-based and lignite-fired Thermal Generating Stations:

For 200-300 MW Sets.: 1.05 X Design Heat Rate (kCal/kWh)
For 500 MW Sets and above: 1.04 X Design Heat Rate (kCal/kWh)"

Comments Received

32.2 **NTPC** has suggested the following:

(a) To review the maximum turbine cycle heat rate for steam parameters 270 kg/cm^2 (abs) / 600°C / 600°C: NTPC suggested reviewing the specified limiting value of Turbine Cycle Heat rate at 100% load for Ultra-Supercritical parameters; otherwise, utilities may have no option but to opt for lower parameters and lose in terms of efficiency for 25 years.

(b) Re-consult with turbine OEMs before finalizing the turbine cycle heat rate limits both at 100% load and at part load.

(c) Optimization of a plant at both 100% TMCR load and 55% TMCR load: In addition to specifying the Turbine Cycle Heat rate at 100% load, the same may be also specified at 55% load, considering that units are likely to run at part load in future most of the time due to increasing RE penetration and as per projections made by CEA.

(d) Inclusion of a maximum unit design heat rate: To include the maximum unit design heat rate in the table. This is required to enable the utility/vendor to guarantee the unit heat rate without giving separate guarantees for TG and SG. Norms should be based on unit heat rate.

(e) Boiler Efficiency based on coal quality: The boiler efficiency depends mainly upon coal quality and does not depend upon the type of technology employed, i.e., subcritical, and supercritical technology. Accordingly, it is requested that the Boiler efficiency specified in the table be fixed based on coal quality and not based on technology.

32.3 **JITPL** has submitted that in the previous tariff regulations, the Station Heat Rate was approved as 1.05 x Designed Heat Rate irrespective of the unit size, and the same may be retained as higher capacity units running at part load or under flexible operation have higher heat rate deterioration as compared to smaller unit sizes. **L&T Energy – Power has** submitted that if boiler efficiency works out to be lower than 86% for Sub-bituminous Indian coal and 89% for bituminous imported coal, based upon the design coal properties provided in tender specifications, the actual calculated Boiler efficiency should be allowed to be considered for finalization of Station heat rate. **Bajaj Energy and AEML** have submitted that the existing operating margin of 5% over and above the design heat rate for all thermal generating stations may be continued. **GMR Energy** has suggested that the proposed norms must be made applicable for the plants commissioned after 01.04.2019, and other plants should continue with the existing norms, i.e., 1.05 x Design Heat rate. It has also been submitted that the cut-off date for the application of SHR norms, i.e., 01.04.2009, should be revised to 01.04.2019 since a considerable time has elapsed and technology has also evolved. **NTPL** has submitted that the existing norms as per the 2019 Tariff Regulation may be retained for the period 2024-29 also. **MSPGCL** has suggested that the margin for SHR should be retained at 1.05 times the design energy for the 500 MW set.

Analysis and Decision

32.4 The Commission has considered the suggestions of the stakeholders. The Commission observed that the margin in the draft tariff regulations was specified based on the recommendations of the CEA. However, in view of submissions of several stakeholders, the Commission has examined the issue in detail and, in order to balance the interest of generators and the consumers, has increased the operating margin to 4.50% over and above the design heat rate for 500 MW series and above, as applicable for the tariff period 2014-19. Accordingly, Regulation 70 (C) (a) has been modified as under:

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

(i) For Coal-based and lignite-fired Thermal Generating Stations:
For 200-300 MW Sets. : 1.05 X Design Heat Rate (kCal/kWh)

For 500 MW Sets and above: 1.045 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 per cent make up, design coal and design cooling water temperature/back pressure."

33 **Norms of Operation for thermal generating stations [Regulation 70 (F) (1)]**

As proposed in Draft Tariff Regulations

33.1 In the Draft Tariff Regulations, the following was proposed under Regulation 70 (F) (1)

"70. Norms of Operation for thermal generating stations:
(F) Norms for Consumption of Reagent
(1) The normative consumption of specific reagents for various technologies for the reduction of emission of sulphur dioxide shall be as under:

The normative consumption of specific reagents for various technologies for the 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 the formula:

$$\frac{\text{K x Normative heat rate (kcal/kWh) x Sulphur content of coal (\%) kg/kWh}}{\text{GCV of Coal (kcal/kg)}}$$

(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)xxx
(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]"

Comments Received

33.2 **APP** has submitted that the norms for the consumption of reagents may be relaxed for the forthcoming tariff period. It has stated that based on practical experience on the ground, the norms may be notified for the period 2029-34. APP has also submitted that ECS is being installed as a result of the change in law event, and therefore, the entire cost of installation and reagent must be reimbursed to the generating company, on actuals, in order to restore the same economic position as the change in law had not occurred. It has been submitted that, as of now, there is not enough experience with the operation of ECS to arrive at an established norm. APP has stated that it may not always be feasible to arrange the limestone with a purity higher than 85%. **CEA** has submitted that the provisions under Regulation 70 F (1) (a), 70 F (1) (b), and 70 F (1) (d) may be revised as per the first amendment to the 2019 Tariff Regulations, notified on 25.8.2020. **NTPC** has submitted that the formula specified for working out the normative specific consumption of limestone involves maintaining of elaborate records and is a cumbersome process. It has also been submitted that the limestone cost difference works out to be very minor, and so the normative limestone consumption may be specified in line with the normative consumption mentioned for other technologies. NTPC has further submitted that for Part load operations, Reagent consumption will be more, and therefore, appropriate correction for the same may be provided. It has been submitted that for DSI Technology, the consumption varies when the imported coal is being fired, and therefore, the correction for imported coal may be provided.

Analysis and Decision

33.3 The Commission has considered the suggestion(s) of the stakeholders. CEA, vide its letter dated 15.03.2024, has recommended changes in the formula vis-à-vis its earlier recommendations dated 19.12.2023 for the computation of limestone consumption of wet limestone-based FGD system as under:

[K x Normative heat rate (kcal/kWh) x Sulphur content of coal (%)/CVPF in kCal/Kg] x [85/LP]g/kWh
Where,
CVPF = (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 the value of K shall be equivalent to (35.2 x Design SO2 Removal Efficiency/96%) to comply with the SO2 emission norm of 100/200 mg/Nm3 or (26.8 x Design SO2 Removal Efficiency/73%) for units to comply with the SO2 emission norm of 600 mg/Nm3;

Provided further that the limestone purity shall not be less than 85%.

33.4 Considering the suggestions of CEA and the other stakeholders, the Commission has made suitable changes in Regulation 70 (F) (1) (a). Also, based on the revised recommendations of the CEA dated 15.03.2024, the formula has been revised for the following:

(a) Formula for computation of Limestone consumption of lime spray dryer/semi-dry FGD system and (b) Formula for computation of Limestone consumption of CFBC power plants (Furnace Injection).

33.5 It is to clarify that for the computation of limestone, the GCV to be considered is in accordance with Regulation 60, which further refers to Regulation 64, which requires the stacking loss of 85 kCal/kg to be accounted for. Therefore, the weighted average GCV of coal/lignite for the purpose of computation of limestone consumption under Regulation 70 shall be worked out considering 'as received' GCV less 85 Kcal/Kg. Accordingly, Regulation 70(F) has been modified as under:

"(F) Norms for consumption of reagent:

(1) The normative consumption of specific reagents for various technologies for the 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 the formula:

[K x Normative heat rate (kcal/kWh) x Sulphur content of coal (%)/CVPF in kCal/Kg] x [85/LP]g/kWh

Where,

CVPF = (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 the value of K shall be equivalent to (35.2 x Design SO2 Removal Efficiency/96%) to comply with the SO2 emission norm of 100/200 mg/Nm3 or (26.8 x Design SO2 Removal Efficiency/73%) for units to comply with the 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 x90/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 lignite as received, in kCal per kg as applicable for lignite based thermal generating stations;

xxx"

34 **Norms of Operation for hydro generating stations [Regulation 71]**

As proposed in Draft Tariff Regulations

34.1 In the Draft Tariff Regulations, Regulation 71 was proposed as under:

"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:
xxx.

(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*

Station	Type of Plant	Plant Capacity No. of Units x MW	NAPAF (%)
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*
Tilaya	*Storage*	*2x2*	*80*
Maithon	*Storage*	*3x20*	*80*

Comments Received

34.2 **SJVNL** submitted that Nathpa Jhakri HPS (NJHPS) and Rampur HPS are located in Satluj Basin, which encounters abnormally high silt during high inflow season. It has been stated that during this period, the quantum of silt increases significantly, which is damaging the underwater components of unit(s) and therefore, extensive annual plant maintenance is being done every year for these plants. It has also been submitted that in addition, during high inflow season, plants are being shut down every year for a few days due to high silt, and silt flushing of the reservoir at Nathpa is being done every year. SJVNL has also submitted that there is a protocol signed among NJHPS, Rampur HPS, and Karcham Wangtoo HPS (upstream of NJHPS) for co-ordinated generation reduction during the high silt period. SJVNL has further stated that Rampur HPS is a unique generating station that does not have its own storage / pondage at all and is operating with the water coming out from the tail race tunnel of NJHPS and, thus, acting as a tail race extension of NJHPS. It has been pointed out that Rampur HPS is running in tandem with the upstream NJHPS on a 1:1 basis, and the water so flowing after being used for generation in NJHPS is diverted into the Rampur HPS intakes through the TRT pond. SJVNL has added that the discharge of water released from NJHPS is being fully utilized by Rampur HPS in a steady state condition, avoiding any spillage of water at TRT of Nathpa Jhakri Project. Accordingly, SJVNL has suggested that the following aspects may be considered by the Commission while finalising the NAPAF of SJVN's generating stations:

(a) The Commission in the draft tariff regulations, has fixed the NAPAF of Pondage type plants where the Plant availability is significantly affected by silt as 85%. However, the NAPAF of NJHPS and Rampur HPS is fixed as 90% and 85%, respectively. The Commission in the Regulations has fixed a maximum NAPAF of 90% for any Storage and Pondage type plants. NJHPS and Rampur HPS are highly affected by silt. However, the aforesaid provision of Regulation is not exercised by the Commission for proposing NAPAF for these stations, and a maximum of 90 % NAPAF is fixed for NJHPS. Similar treatment is given for Plants, whether it is affected by silt or not.

(b) NJHPS (6x250 MW) and Rampur HPS (6x68.67 MW) are encountering abnormally high silt during high inflow season, due to which these Plants are shut down every year, for a few days due to the increase in the quantum of silt, in compassion with the permissible design limit. Also, extensive annual plant maintenance is being done every year for around 60 days (10 days for each unit) by both Plants, due to which the PAF loss is for 60 days approx. corresponding to one unit or station.

(c) Further, the Commission in the IEGC Regulations, 2023, effective from 01.10.2023 onwards, has restricted the hydro power plants from declaring the declared capacity, limited to ex-bus installed capacity, except in case of spillage of water during high inflow season. This would result in the reduction of the actual Plant Availability Factor of the generating station by 6.67 % (8 months out of 12 months) from the previous year's achievements. During the previous years, the existing provision of the IEGC Regulations restricting the overload capacity of the declared capacity was not there. Therefore, the data of the actual Plant Availability Factor, on a yearly basis, may be derived based on the aforesaid provision of the IEGC Regulations, 2023.

(d) As Rampur HPS is running in tandem with the upstream NJHPS, Rampur HPS would be shut down in case of the non-availability of a unit of NJHPS. The Commission in its previous order, directed that the NAPAF of Rampur HPS must be lower than NJHPS, considering the tandem operation of the Projects. Considering 5 % of forced outage of upstream NJHPS, the NAPAF of Rampur HPS may be fixed as 5 % lower than the NAPAF of NJHPS.

(e) In view of the aforesaid reasons, the NAPAF of NJHPS and Rampur HPS may be considered as 85% and 80 % respectively.

34.3 **NHPC** has submitted the following:

(a) Based on the norms defined in the draft tariff regulations, the normative annual plant availability factor (NAPAF) of RoR power stations under the control of NHPC has been proposed as under:

Salal:	75%
Tanakpur:	70%
Uri-1:	80%
Uri-2:	80%

(b) As these hydro power stations are purely run-of-the-river power stations, the Minimum Draw Down Level (MDDL) and Full Reservoir Level (FRL) of these stations are practically the same. NHPC has also submitted that these power stations do not have the storage capacity to over-declare. In the IEGC Regulations 2023, the declaration has also been capped up to 100% during the lean season.

(c) Further, the payment of capacity charges for hydro generating stations totally depends on NAPAF. However, there are situations where the availability of a hydro generating station is affected by certain uncontrollable factors like the non-availability of water storage due to less rainfall/ drought situation or mandatory water release imposed by the Governmental authorities, etc., like e-flow implemented by the Hon'ble NGT, leading to a decrease in the recovery of fixed costs. Thus, it would be very difficult to achieve the NAPAF (as proposed in draft tariff regulations) considering the above factors. Therefore, it is imperative that the NAPAF of these hydro power stations be retained as per the provisions of the 2019 Tariff Regulations, as given below:

Salal:	64%
Tanakpur:	59%
Uri-I:	74%
Uri-II:	70%

34.4 As regards the proposed NAPAF of pondage RoR with pondage power stations, NHPC, while pointing out that the NAPAF of Bairasiul, Chamera-II, Sewa-II and Kishanganga Power Stations are on the higher side, has submitted the following:

- As per Tariff Regulations, the NAPAF of power stations for the next tariff period is being fixed based on the actual achievement in previous years. Bairasiul Power Station has been facing a high silt problem and less inflow, and due to this, the power station has not been able to achieve the NAPAF of 90%. Referring to Regulation 71(A)(1)(c), wherein the NAPAF for 'Pondage type plants where plant availability is significantly affected by silt is 85%, NHPC has submitted that in view of the constraints, the NAPAF of Bairasiul Power Station may be reviewed and be fixed at 80% (approx) so that Bairasiul can recover its capacity charges accordingly.

- Similarly, the average PAF for the last 5 years in respect of Chamera-II Power Station, as calculated, is 79.58%, whereas the NAPAF of this Power Station has been proposed to be 90%. Chamera-II Power Station also faces the problem of silt, which also impacts the availability of the power station. Therefore, the NAPAF of the Chamera-II power station may also be reviewed and fixed at 80%, as achieved during the last tariff period.

- The average PAF for the last 5 years in respect of the Sewa-II power station calculated is 73.45%, whereas, the NAPAF of this power station has been proposed to be 89%. Sewa-II power station is also facing the problem of less inflow and therefore, the NAPAF of Sewa-II power station may also be reviewed and fixed around 73% as achieved during the last tariff period.

- The NAPAF of Kishanganga HEP for the period 2024-29 has not been mentioned in the draft tariff regulations. The average PAF for the last 5 years works out to approx. 63.81%, and further, it has also been experienced fewer inflow issues. Therefore, the NAPAF of Kishanganga power station for the period 2024-29 may be reviewed accordingly, to avoid further stressing the plant.

- The PAF of the hydro generating power stations is also being impacted due to changing hydrology, and imposition of the mandatory release of water as e-flow implemented by Hon'ble NGT.

34.5 Accordingly, NHPC has suggested that the NAPAF of Baiarasiul, Chamera-II, Sewa-II, and Kishanganga hydro power stations may be reviewed and fixed close to 5-year averages so that the recovery of capacity charges of these power stations is not affected and the power stations are not stressed.

34.6 **THDCIL** has submitted that originally, the NAPAF of Tehri HPP and Koteshwar HEP was 77% and 67%, respectively, which got revised and increased up to 80% and 68% based on the higher plant availability achievements, which is attributed to the following:

a. Overload capacity declaration during the high head period, in the case of Tehri HPP high head period is from mid-August to mid-January normally.
b. Outages of units/plants were within acceptable limits.

c. However, after the implementation of the IEGC Regulations 2023 w.e.f. 1.10.2023, the DC of the plant has been restricted as per Regulation 45, i.e., Scheduling of power from hydro generating stations for overload capability up to 10% of the installed capacity allowed during high inflow and water spillage conditions. Owing to this, the PAF of the plants shall be adjusted considering the impact of IEGC Regulations 2023, over the restriction of DC during the non-high inflow period. Further, Tehri HPP is approaching its half useful life, and Koteshwar HEP has completed 15 years, and the outage trends of these plants are increasing due to ageing, which affects the availability of plants.

d. Hence, considering the significant impact of IEGC Regulations 2023 and the increase in outages, the NAPAF of Tehri HPP and Koteshwar HEP may be restored as per the 2009 Tariff Regulations, i.e. 77% for Tehri HPP and 67% for Koteshwar HEP or otherwise it may face under-recovery of the capacity charges.

34.7 **NEEPCO,** while pointing out that its Tuirial hydro power station has not been included/considered in the Tariff Regulations, has submitted that NAPAF of 75% as allowed in an order dated 10.12.2023 in Petition 125/MP/2021(NEEPCO v Govt of Mizoram & Ors) may be considered.

Analysis and Decision

34.8 The Commission has considered the suggestions of the stakeholders. It is observed that few of the plants are affected by high siltation and the provisions of Regulation 45 of the IEGC Regulations, 2023. In view this, the Commission has made suitable changes under

Regulations 71 (A) (4) and has marginally reduced the NAPAF of the following generating stations:

THDCIL:
THPS - NAPAF revised to **77%** from 80%;
KHEP – NAPAF revised to **66%** from 68%.

NHPC:
Baiarasul - NAPAF revised to **85%** from 90%;
Salal – NAPAF revised to **70%** from 75%;
Chamera-II – NAPAF revised to **87%** from 90%;
Sewa-II – NAPAF revised to **86%** from 89%.

NEEPCO:
Ranganadi - NAPAF revised to **85%** from 88%;

SJVNL:
Natpha Jahkri - NAPAF revised to **87%** from 90%;
Rampur – NAPAF revised to **83%** from 85%.

34.9 With regard to the Run of the River power stations, wherein NHPC has sought the relaxation of the NAPAF, the Commission observes as under:

(a) In respect of Tanakpur HPS, NHPC has requested to continue with the existing norm at 59%. However, it is observed that the said generating station has consistently been able to achieve the NAPAF above 70% from 2018-19 to 2022-23, and the 5-year average NAPAF achieved by this station during the period is 79.96%. In view of the consistent performance during the past 5 years, the Commission expects the generating station to be able to achieve a PAF of over 70% during the upcoming control period, even after factoring in the restrictions imposed by the IEGC Regulations, 2023. Accordingly, the Commission has retained the PAF of 70% for Tanakpur HPS.

(b) For Uri-I HPS, NHPC has requested to continue with the existing NAPAF norm of 74%. However, it is observed that the said power station has consistently been able to achieve an NAPAF above 90% from 2019-20 to 2022-23, and the 5-year average NAPAF achieved by this station during the period from 2018-19 to 2022-23 is 92.11%. In view of the consistent performance during the previous 4 years, the Commission expects the generating station to be able to achieve a PAF of over 80% during the upcoming control period, even after factoring in the restrictions imposed by the IEGC Regulations, 2023. Accordingly, the Commission has retained the PAF of 80% for Uri-I HPS.

(c) For Uri-II HPS, NHPC has requested the Commission to continue with the existing NAPAF norm of 70%. However, it is observed that the said station has consistently been able to achieve a NAPAF above 90% from 2018-19 to 2022-23, and the 5-year average NAPAF achieved by the said station during the period from 2018-19 to 2022-23 is 95.06%. In view of the consistent performance during the previous 5 years, the Commission expects the generating station to be able to achieve a PAF of over 80% during the upcoming control period, even after factoring in the restrictions imposed by the IEGC Regulations, 2023. Accordingly, the Commission has retained the PAF of 80% for Uri-II HPS.

34.10 Also, the Commission, based on the actuals of the past and the currently specified norms has specified the NAPAF for the following stations:

(i) NHPC Kishanganga – 83%
(ii) Sikkim Urja Teesta-III – 85%
(iii) NEEPCO Turial – 75%
(iv) JSW Energy Karcham Wangtoo – 90%

34.11 Based on the above, Regulation 71 has been modified as under:

"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:
xxx

(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			
THPS	*Storage*	*4x250*	*77*
KHEP	*Storage*	*4x100*	*66*
NHPC			
Station	***Type of Plant***	***Plant Capacity No. of Units x MW***	***NAPAF (%)***
Bairasul	*Pondage*	*3x60*	*85*
Loktak	*Pondage*	*3x35*	*88*
Salal	*ROR*	*6x115*	*70*
Tanakpur	*ROR*	*3x31.4*	*70*
Chamera-I	*Pondage*	*3x180*	*90*
Uri I	*ROR*	*4x120*	*80*
Rangit	*Pondage*	*3x20*	*90*
Chamera-II	*Pondage*	*3x100*	*87*
Dhauliganga	*Pondage*	*4x70*	*85*
Dulhasti	*Pondage*	*3x130*	*90*
Teesta-V	*Pondage*	*3x170*	*87*
Sewa-II	*Pondage*	*3x40*	*86*
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 with Pondage*	*4x40*	*90*
Kishanganga	*ROR with Pondage*	*3x110*	*83*
Teesta III	*Pondage*	*6x200*	*85*
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 .*	*85*

Station	Type of Plant	Plant Capacity No. of Units x MW	NAPAF (%)
Tuirial	*Storage*	*2x30*	*75*
NTPC			
Koldam	*ROR with Pondage*	*4x200*	*90*
SJVNL			
Nathpa Jhakri	*Pondage*	*6x250*	*87*
Rampur	*Pondage*	*6x68.67*	*83*
DVC			
Panchet	*Storage*	*2x40*	*80*
Tilaya	*Storage*	*2x2*	*80*
Maithon	*Storage*	*3x20*	*80*
Karcham Wangtoo	*ROR with Pondage*	*4x261.25*	*90*

35 **Auxiliary Energy Consumption- Regulation 71 (C)**

As proposed in the Draft Tariff Regulations

35.1 In the Draft Tariff Regulations, Regulation 71 (C) was proposed as under:

"(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%*

Comments Received

35.2 **NEEPCO** has submitted that the auxiliary consumption for NEEPCO's 60 MW Turial HPS is about 4% and the same has been given cognizance in the order dated 10.12.2023 in Petition 125/MP/2021 by allowing the auxiliary consumption of 4.304% for the period 2014-19, with a direction to get recommendation of CEA for the period 2019-24 Therefore, NEEPCO has suggested to consider the AEC of 4.304% for Turial HPS.

Analysis and Decision

35.3 The Commission has considered the suggestion(s) of NEEPCO. The Commission in its order dated 10.12.2023 in Petition No. 125/MP/2021, had observed that the actual AEC of the generating station (Turial) is between 3.03% (2017-18), 4.48% (2018-19) and 4.04% (2019-20). Accordingly, the Commission, considering the past actual AEC, has fixed the AEC of 4% for the tariff period 2024-29. Accordingly, Regulation 71(C) has been modified as under:

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

(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%*

** AEC for Tuirial HPS = 4%*

Miscellaneous Provisions

36 **Deviation from the ceiling Tariff [Regulation 88(2)]**

As proposed in Draft Tariff Regulations

36.1 In the Draft Tariff Regulations, Regulation 88(2) and (3) was proposed as under:

88(1) xxx

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

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

Comments Received

36.2 **NHPC has** suggested that the generating company or the transmission licensee, as the case may be, may opt to charge a lower tariff that is mutually agreed upon and can be collected over the entire lifespan or the agreed period for a power station, contrary to the current limit of five years. It has also been submitted that Tariff Regulations are required to be modified to allow the recovery of the agreed tariff between the generator and the discom(s) for the entire life / for the agreed period for a power station, in contrast to the present duration of five years only. Accordingly, NHPC has suggested that the agreed tariff must be isolated from any changes in future regulatory norms to avoid any dispute between the parties.

Analysis and Decision

36.3 The Commission has considered the submissions made by the Stakeholder and is of the view that no change is required in the existing proviso. The Commission would like to re-iterate the existing provision that in case a utility charges a lower tariff on account of lower depreciation as against that allowed under the tariff Regulations, the Petitioner shall be allowed to recover the unrecovered depreciation in the subsequent tariff periods. In view of this, Regulations 88(2) have been retained as proposed.

37 <u>Approval Process of non-ISTS lines carrying inter-state power [Regulation 93]</u>

As proposed in Draft Tariff Regulations

37.1 In the Draft Tariff Regulations, Regulation 93 was proposed as under:

"(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."

<u>Comments Received</u>

37.2 **CTUIL** has suggested to include the following**:**

"Provided that STU shall put up a proposal to respective RPCs, who shall in turn forward the same to CEA mentioning that these transmission lines are being used for transfer of inter-state power. CEA in consultation with RPCs, CTU, NLDC and the RLDCs would examine and certify the proposal."

37.3 While **CTUIL** has suggested deleting clause (3) of Regulation 93, it has proposed for modification of clause (5) of Regulation 93 as under:

> *"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 a proper mechanism is in place for the maintenance of such a transmission system upon its COD."*

37.4 As regards clause (6) of Regulation 93, CTUIL has suggested to include the following**:**

> *"In case of availability certificate for such intra-state lines is not obtained by transmission licensee from RPC within 9 months, only 50 % MTC shall be allowed for the particular month for which availability certificate has not been submitted and 50 % MTC already billed shall be recovered from intra-state Licensee and refunded to the beneficiaries".*

37.5 **HPPTCL** has submitted that the MOP, GOI vide its OM dated 08.03.2019, has declared the hydro power as Renewable Energy for all capacities of hydro power projects in addition to earlier HEPs up to 25 MW. It has further submitted that the CERC (Sharing of Inter-State Transmission Charges & Losses) Regulations, 2020 has defined National Component as the sum of National Component-Renewable Energy and National Component-HVDC, out of which National Component-Renewable Energy, for the purpose of sharing of transmission charges of the transmission systems developed for renewable energy projects, as identified by CTU. HPPTCL has stated that since hydro power is a renewable source, as notified vide the said OM dated 08.03.2019, the evacuation of hydro power should also be a part of the National Component and must be declared as deemed ISTS, whether developed by STU or CTUIL, irrespective of any criteria set in the draft tariff regulations. It has further submitted that considering the peculiarity of hydro rich States, if at all some criteria are to be made, only the generation period, i.e., from April to September, must be considered as a criterion for declaration of the transmission asset planned/ constructed for the evacuation of hydro power as ISTS, and if the system is majorly being used for evacuation of power to ISTS. **HPPTCL** has stated that any provisions with regard to the certification of a non-ISTS line carrying ISTS power should be applicable for projects whose investment approval is on or after 01.04.2024. Therefore, it has been submitted that the transmission system, whose investment approval was before 31.03.2024 and is being developed by the State Transmission Licensees (STUs), the same may be considered as part of the ISTS system, and in the absence of such an exemption, the hydropower generators shall be forced to pay dual transmission charges. **HPPTCL** has also pointed out that the MOP, GOI, vide its notification dated 01.12.2022, has waived off the payment of inter-state transmission charges for 18 years from the date of commissioning of the hydro projects in a bid to further realise the GOI's commitment to achieving its power requirement from renewable sources of energy. Consequently, a scenario has emerged wherein the GOI has exempted the new hydropower projects from payment of inter-state transmission charges, while concurrently, some hydropower plants will have to pay dual transmission charges. This, according to HPPTCL, will jeopardise the GOI's commitment to achieving its power requirement from renewable sources of energy.

Analysis and Decision

37.6 The Commission has considered the suggestions of the stakeholders. In our view, the suggestions made with regard to the inclusion of the evacuation infrastructure for hydro stations in the National component and the criteria to be adopted for taking the generation data for certification do not fall under the purview of the present regulations, and hence these have not been dealt herein. As regards the other suggestions, the Commission is of the view that the inclusion of the CEA, STU, and RPC in the certification process will help ensure transparency and technical verification, thereby promoting a safe and efficient transmission infrastructure. The Commission has, therefore, amended the draft tariff regulations, so that the CEA, in consultation with STU and RPC, will certify as to whether the transmission lines should be considered as part of the ISTS system.

37.7 It is further clarified that to arrive at the correct transmission charges, the timely filing of a non-ISTS petition is necessary. It has been observed that the existing utilities, after getting the tariff, do not file the petition on time, as they continue to receive the existing tariff. The Commission is of the view that if the petition is not filed in time, appropriate proceedings may be initiated against them, which may include the exclusion of the earlier transmission charges from YTC.

37.8 Based on the above, Regulation 93 is modified as under:

"93. Approval Process of Non-ISTS Lines carrying Inter-State Power:

Existing intra-state transmission lines other than Natural ISTS lines, as certified by CEA based on the recommendations of the STU and RPC, 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 after its COD;

Provided that such lines have not been developed for the sole purpose of the beneficiary(ies) of a single State.

(1) 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 after its COD.

(2) CTU, in consultation with RLDC shall identify all such non-ISTS lines which are utilized for ISTS power transfer after ascertaining that such nature of flow of power has become permanent.

(3) 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.

(4) 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 after its COD.

(5) 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."

38 **Special Provisions relating to Central Transmission Utility of India Ltd. (CTUIL)**

38.1 In the Draft Tariff Regulations, no specific provision was provided, as CTUIL expenses were included in the norms.

Comments Received

38.2 **PGCIL** has submitted that the Commission had directed it to continue with the existing arrangement beyond 01.04.2024, i.e., PGCIL to support the CTUIL expenses. PGCIL has also submitted that it may continue to do the same till the time suitable revenue stream of CTUIL is formulated. It has further submitted that a separate account for the same shall be maintained and once the revenue stream for CTUIL is finalized, the expenses incurred by PGCIL for CTUIL may be reimbursed with a carrying cost. Accordingly, PGCIL has sought an appropriate direction in this regard.

Analysis and Decision

38.3 The Commission has considered the suggestions of PGCIL. The Commission is of the view that the fees and charges of CTUIL must be explicitly approved by the Commission through a separate regulation. Until the Commission formulates and issues an appropriate regulation, the expenses incurred by CTUIL will need to be covered by PGCIL. However, it is made clear that PGCIL will recover these expenses as additional O&M expenses by way of a separate Petition. The special provision outlines the regulatory framework for fees and charges for CTUIL and sets forth an interim mechanism for managing its expenses until a formal regulation is notified. This will ensure that CTUIL's financial operations are subject to regulatory oversight and that any expenses incurred are accounted for and recovered in a transparent manner. Accordingly, Regulation 99 provides as under:

"99. Special Provisions relating to Central Transmission Utility of India Ltd. (CTUIL): *The fees and charges of CTUIL shall be allowed separately by the Commission through a separate regulation:*

Provided that until such regulation is issued by the Commission, the expenses of CTUIL shall be borne by Power Grid Corporation of India Ltd. (PGCIL) which shall be recovered by PGCIL as additional O&M expenses through a separate petition."

Other Issues

39 **Part Load Compensation**

Comments Received

39.1 **SRPC** has submitted that a new proviso may be added as Regulation 64 (8) under:

"Provided also that till the mechanism of part load compensation is notified by the Commission, the mechanism in this regard already in force under the Central Electricity Regulatory

Commission (Indian Electricity Grid Code) Regulations, 2010 shall continue to be in operation. However, this would include compensation under SCED and SCUC. Further compensation for SFC for USD cases would also continue till Procedure is notified by the Commission"

39.2 **PCKL has** submitted that as per the Grid Code, part load compensation is being paid for the plants operating at a technical minimum. It has been submitted that in case the expenditure incurred by the generating stations for flexible operation is included in the capital cost for which tariff is being paid, such generating station shall not be paid the part load compensation. **NTPC** has submitted the following:

1. *Degradation factors recommended by CEA to be included in the Tariff Regulations.*
2. *Part load compensation should be allowed on normative basis instead of "normative or actual whichever is lower.*
3. *Part load compensation factor due to heat rate deterioration may be increased*.

Analysis and Decision

39.3 The Commission has considered the suggestion(s) of the stakeholders. The Commission observes that in order to negate the financial implications on the generators due to part load operations, the Commission 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 Regulations, 2010. The Commission is also in the process of specifying a fresh compensation mechanism based on the CEA's recommendations to compensate for the degradation of norms due to increased part load operations.

40 **Procedure for calculation of transmission system availability factor for a month [Appendix IV]**

As proposed in Draft Tariff Regulations

40.1 In the Draft Tariff Regulations, Appendix-IV was proposed as under***:***

"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 nth 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:

$$= \frac{o \, X \, AVo)+(p \, X \, AVp) + (q \, X \, AVq) + (r \, X \, AVr)+(u \, X \, AVu)}{(o + p + q + r+u)} x100$$

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 yth HVDC back-to-back station block*
R	=	*Total rated capacity of yth HVDC back-to-back station block*
AVr	=	*Availability of yth HVDC back-to-back station block*
U	=	*Total no of HVDC poles*
AVu	=	*Total no of HVDC Back to Back blocks*

TAFMn (in %) for HVDC System:

$$= \frac{\sum_{x=1}^{s} \text{Cxbp (act) X AVxbp} + \sum_{y=1}^{t} \text{Cy (act)btb X AVybtb}}{\sum_{x=1}^{s} \text{Cxbp} + \sum_{y=1}^{t} \text{Cy btb}} x100$$

Where

Cxbp(act)	=	*Total actual operated capacity of xth HVDC pole*
Cxbp	=	*Total rated capacity of xth HVDC pole*
AVxbp	=	*Availability of xth HVDC pole*
Cybtb(act)	=	*Total actual operated capacity of yth HVDC back-to-back station block*
Cybtb	=	*Total rated capacity of yth HVDC back-to-back station block*
AVybtb	=	*Availability of yth 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."*

Comments Received

40.2 SRPC has suggested that the outage certification of the HVDC system by SRPC is being done and being furnished, but the final availability is not being communicated by CTUIL to RPCs in a timely manner, nor is the same being displayed in a transparent manner. Therefore, SRPC has suggested that one of the RPC may be entrusted with the availability certification of the HVDC system, and in case of the HVDC asset being shared on a Regional basis, the Member Secretary of the region may be entrusted with the availability certification. Accordingly, **SRPC** has suggested the following changes in the regulations:

"Transmission system availability factor for nth calendar month ("TAFMn") 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 which is 100% in National Component, transmission System Availability shall be calculated on a consolidated basis for all inter-state HVDC systems by Member Secretary of one of the RPCs. The certified outage data in respect of HVDC systems by respective RPC to Nodal RPC and the Availability Certificate would be furnished to all RPCs by Nodal RPC which would be put up on RPC website.
In the case of the HVDC system which is paid by Region, transmission System Availability shall be calculated on a consolidated basis for all such inter-state HVDC systems by Member Secretary of that Region."

"Switching off of a transmission line to restrict over-voltage, manual tripping of switched reactors, and elements on power and physical regulation as per the directions of the concerned RLDC."
"Shut down of a transmission line due to the Project(s) of Railways, NHAI/State Highways, Border Road Organization and all types of development infrastructure projects with broader public utilization/benefit 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."

40.3 **SRPC** has also submitted that on many occasions, the entities are not taking maintenance in a routine manner and carrying out maintenance during the opportunity shutdown, which affects the reliability. Therefore, in order to ensure timely maintenance, accountability, and responsibility, SRPC has suggested the following provision:

"Any opportunity shutdown and restoration needs to be taken with exchanging code with SLDC/RLDC/NLDC as applicable. Minimum of actual Outage period or 50% of the total outage period of opportunity shutdown of the entity availing the opportunity shutdown would be booked in its account."

40.4 In addition, SRPC has suggested the following changes:

"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 or refer to CERC SOP Regulations 2012 for estimation of reasonable restoration time. Circuits restored through ERS (Emergency Restoration System) and shall be considered as available;"

40.5 SRPC has also suggested that the availability certification of the HVDC system needs to be done by the nodal RPC, and if the availability certification of the HVDC system is to be done by the CTUIL, the timeline of outage certification by RPC and the availability certification by CTUIL may be added. **CEA** has suggested modification in Para 4(iii) of Annexure-IV to the Draft Tariff Regulations, as under:

"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 and any other infrastructure project(s) for which shifting or modification of such transmission line approved by Central Government in wider public interest. Member Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved;"

40.6 CEA has further submitted that the proviso under sub-clause 4(iii) mentioned in the Draft Tariff Regulation is not necessary. It has stated that while approving the shutdown, RPCs take care of the grid-related issues, but ensuring that the DICs are not affected, may not be possible. Accordingly, such provisions have the potential to give rise to disputes. **CEA** has also submitted that there may be conflicting interests between the transmission licensee and the Discoms, who are members of RPC, and therefore, the decision of the outage period should rest with a neutral entity. However, the outage period of beyond one month may be handled by the CEA. **PGCIL** has submitted that the elements of inter-regional systems may be merged with the respective regional systems for which the same RPC is certifying availability for inter-regional systems so that all the transmission assets shall be covered under five Regional-systems. It has also been pointed out that inadvertently, in the formula for AC system, HVDC blocks and Poles have been mentioned in place of the AC system elements, and the same may be rectified as under:

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

$$= \frac{o \text{ X } AVo)+(p \text{ X } AVp) + (q \text{ X } AVq) + (r \text{ X } AVr)+(u \text{ X } AVu)}{(o + p + q + r+u)} x100$$

Where, o = Total number of AC lines.
AVo = Availability of o number of AC lines.
p = Total number of bus reactors/switchable line reactors
AVp = Availability of p number of bus reactors/switchable line reactors
q = Total number of ICTs.
AVq = Availability of q number of ICTs.

r = Total number of SVCs.
AVr = Availability of r number of SVCs
u = Total number of STATCOM.
AVu = Availability of u number of STATCOMs"

40.7 PGCIL has suggested that instead of restricting the proposed provision regarding the deemed availability to specific organization, the same may be provided for all such important infrastructure projects as proposed below;

"(iii) Shut down of a transmission line due to the Project(s) of NHAI, Railways, Border Road Organization, any other project(s) executed by Central Govt./ State Govt. and their PSUs meant for broader public utilization 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;"

40.8 PGCIL has submitted that as per the provisions of the 2019 Tariff Regulations notified on 07.03.2019, in case of any disagreement regarding the cause of failure, the case is referred to CEA, and based on the technical/design parameters, the final report on the said failure is issued by the CEA, in consultation with all stakeholders/technical experts. It has been submitted that waiver of the outage period for availability calculation is considered only if it is technically established that there is no design deficiency and the element must have been designed to meet the CEA technical standards. It has further submitted that the restoration period of the transmission line mainly depends on the extent of damage, accessibility, and type of site like Plain, hilly, Riverbed, etc., including its accessibility and climatic condition, and due to these conditions, the restoration of transmission lines, sometimes takes more than three months, despite the best efforts by transmission licensee, especially in case of hilly terrain or riverbed. Also, the certification of the transmission availability for such cases is being done by the Member Secretary, RPC, as a routine process. Accordingly, PGCIL has proposed the following changes.

"Provided that in case of any disagreement with the transmission licensee regarding reason for outage, same may be referred to Chairperson, CEA within 30 days. The above need to be resolved within two months:

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

Analysis and Decision

40.9 The Commission has considered the suggestion(s) of the stakeholders. The Commission agrees with the proposal for deemed availability to be provided for all important infrastructure projects and is of the view that including any other infrastructure project approved by the MOP broadens the range of projects that may necessitate the shutdown or modification of transmission lines. However, to have checked, the Commission has modified the proviso to authorise the Member Secretary, RPC, to restrict the deemed availability period as considered reasonable by him for the work involved. The Commission is also of the view that apart from the deemed availability, any other costs involved in the process of such shutdown of transmission line shall not be borne by the DICs. Accordingly, the provisions have been modified in Appendix IV. The Commission has also considered the submission of PGCIL regarding the formula for the AC System, HVDC blocks, and Poles mentioned in place of AC system elements and has accordingly modified the same.

40.10 With regard to Para 7 of Appendix IV, i.e., time frame for certification of transmission system availability, the Commission is of the view that the licensee should submit the outage data along with the documentary proof (if any) and its TAFPn calculations. Accordingly, the Commission has made suitable modifications in Para 7 of Appendix IV. The Commission has also considered the suggestion of SRPC for availability certification of HVDC systems; the availability of all inter-State HVDC systems is to be calculated on a consolidated basis for each transmission licensee since the HVDC systems are located in various regions and are also inter-regional and the following methodology may be adopted for certification of availability and operated capacity by RPC:

i) For inter-regional HVDC systems, the drawee region shall act as Nodal RPC, and for inter-regional HVDC systems, the respective RPC, and for intra-regional HVDC system, the respective RPC shall be the Nodal RPC.
ii) The certified outage data by respective RPC would be furnished to Nodal RPC and Nodal RPC shall issue the availability certificate.

40.11 Further, the transmission licensee shall calculate the consolidated availability of their HVDC system as per Appendix-IV and furnish the same to all the RPCs along with calculation details.

40.12 Accordingly, Appendix IV has been modified as under:

Appendix-IV

Procedure for Calculation of Transmission System Availability Factor for a Month

Transmission system availability factor for n^{th} [3] 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.

22. *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.*

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

TAFPn (in %) for AC system:

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

Where,

o	=	*Total number of AC lines.*
AVo	=	*Availability of o number of AC lines*
p	=	*Total number of bus reactors/switchable line reactors*
AVp	=	*Availability of p number of bus reactors/switchable line reactors*
q1	=	*Total number of ICTs*
AVq	=	*Availability of q number of ICTs*
r	=	*Total number of SVCs*
AVr	=	*Availability of r number of SVCs*
u	=	*Total number of STATCOM*
AVu	=	*Availability of u number of STATCOM*

TAFMn (in %) for HVDC System:

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

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*

24. *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;*
    (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.*
25. *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 or any other infrastructure project approved by Ministry of Power. Member Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved;*
    Provided that apart from the deemed availability, any other costs involved in the process of such shutdown of transmission line shall not be borne by the DICs.
    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.
26. *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:*
    Outage of elements due to 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;

i) *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;*

ii) *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.*

27. *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 along with documentary proof (if any) and TAFPn calculation 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."*

Sd/-	Sd/-
(Arun Goyal)	**(Jishnu Barua)**
Member	**Chairperson**