Shri Harpreet Singh Pruthi
Secretary
Central Electricity Regulatory Commission
3rd & 4th Floor, Chanderlok Building
36, Janpath, New Delhi- 110001

July 31st, 2023

Subject: Comments on CERC Approach paper on Terms and Conditions of Tariff Regulations for the tariff period of 2024-29

Dear Shri Pruthi,

This is with reference to the Public Notice dated 26th May, 2023 for the Comments on the document, **Approach paper for Terms and Conditions of Tariff Regulations for the tariff period from 2024-29.**
I have gone through it and recorded some of my comments on the same. Additional suggestions are also provided for consideration of the Commission. We would be pleased to make a presentation before the commission as well.

I would be pleased to address any clarification, if required.

Thanking you,
Yours sincerely,

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Comments on

Approach paper for Terms and Conditions of Tariff Regulations for the tariff period from 01.04.2024 to 31.03.2029

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1. **Regulatory Impact Analysis (RIA) – Key to a Balanced Approach to Tariff Determination from the perspectives of Investors as well as the Consumers:** The approach paper outlines various options for a variety pf aspects related to tariff determination for generation and transmission under Section 62 of the Electricity Act 2003. Response to the specific aspects are provided herein. Various options suggested in the context of various components of tariff can be evaluated **in terms of their impact on various components of tariff as well as overall tariff to be paid by the consumers and returns to be obtained by the investors.** This would help bring a more balanced perspective from the point of view of the consumers as well as the investors. **The CERC should thus spearhead an approach to <u>Regulatory Impact Assessment (RIA)</u> while approving regulations for the sector.**

2. **Regulatory Framework to Emphasise Efficiency linked Normative Cost Recovery:** The regulatory approach for tariff determination under the CERC framework can generally be classified as normative cost of service approach. In the spirit of the Electricity Act 2003, and Tariff Policy, the regulatory approach, while approving normative costs, should emphasise on efficiency improvement by the regulated entities both in terms of technical as well as financial costs**. While the adopted approach allows for cost recovery based on norms, the norms themselves are based on actuals, in most cases** (as per CERC's Terms and Conditions for Tariff 2019). The norms, for example, for O & M cost in per MW term for the first year of the control period are based on actuals of the past few years, and are then escalated as per escalation factor. The regulatory framework should also provide for improvement in efficiency through better norms. Operational efficiency norms must provide incentive for improvement for the generation companies as well as transmission licensees.

   The co-authored study on Tariff Increase submitted by Centre for Energy Regulation (CER), IIT Kanpur to FoR (as referred in the approach paper) pointed out various factors summing up to the tariff increase particularly that in the context of transmission tariff. This can partly be attributed to general adherence to historical performance with limited targets for efficiency embedded in the norms for tariff. **The tariff approach to the control period 2024-29 should consider efficiency linked norms as discussed herein.**

3. **Normative Approach for Annual Fixed Cost (AFC):** As per the suggestions sought in section 3.1, following are the suggestions w.r.t. to the approach for determination of AFC:

a. **Combining the AFC components:** Based on analysis of the actual cost escalation, change in relevant price indices and commonality of basis, depreciation, interest on loan (IoL) and return on equity (RoE) can be combined in a single cost element and may be called capital cost recovery, as these can be linked to the same 'basis' for application of norms i.e. the capital cost of the project. Alternatively, RoE is suggested to be identified separately as it is a key parameter that needs separate visibility to the investors. Grouping of cost components should be undertaken if a common 'basis' for the same is used for fixing base year values. O&M and IoWC may be combined once a common 'basis' of application of the norms is identified and implemented for the base year.

An alternate approach is suggested wherein each fixed cost component can be linked to **opening capital cost (OCC)** and following equations may be used to derive the different AFC components in terms of opening capital cost of the project.

i. **Depreciation (Dep_t):**

$$\boldsymbol{Dep_t = (OCC_t * 5.28\% * D_t) + (OCC_t * 2.049\% * (1 - D_t))} \ldots\ldots\ldots\ldots \textit{(1)}$$

Where,

$OCC_t = Opening\ Capital\ Cost\ in\ t^{th}\ year$

$D_t = 1, if\ t \leq 12$

$D_t = 0, Otherwise$

The applied rate of depreciation by 5.28% for the first 12 years and 2.049% for rest of the life.

ii. **Interest on Loan(OL_t):** As per the current tariff framework, the loan is treated on normative basis of 70% of the capital cost and the weighted average rate of interest on actual loan portfolio is considered for calculation of AFC.

$$\boldsymbol{OL_t = (OL_0 - (OCC_0 * 5.28 * (t - 1))) * IR} \quad \ldots\ldots\ldots\ldots \textit{(2)}$$

Where,

Opening Loan Value, $\boldsymbol{OL_0} = (\boldsymbol{1 - E}) * \boldsymbol{OCC}, if E \leq 30\% * OCC;$

$$OL_0 = 0.70 * OCC_0, Otherwise$$

$OCC_t = Opening\ Capital\ Cost\ in\ t^{th}\ year$

$E = Equity$ (Normative or actual equity whichever is lower)

$OL_t = Opening\ Loan\ in\ t^{th}\ year$

$IR = Interest\ Rate\ on\ Loan$

The rate of interest on the loan, which is linked to market parameter such as SBI MCLR (or any rate as the Commission may deem appropriate).

iii. **Return on Equity:**

$$\boldsymbol{RoE_t} = \boldsymbol{E}\% * \boldsymbol{OCC_0} * \boldsymbol{RoE}\% \quad \ldots\ldots (3)$$

Where,

E = Actual Equity (%)

OCC_0 = Opening Capital Cost

RoE% = Rate of Return on Equity

RoE_t = Return on Equity in t^{th} year

b. **Reduction of Equity Base[1] post repayment of loan:** It is suggested that accumulated depreciation over and above the accumulated debt repayment (including repayment towards normative loan) should be used to reduce the equity base for allowable RoE as a portion of the risk capital of the investor is available as free cash flow and is no longer deployed in normal business operations. In its absence the consumer is charged RoE for a capital that has already been recouped through depreciation (beyond debt repayment).

In case, such 'excess depreciation' is reinvested in the business, for example to finance working capital, this should attract the appropriate cost of funds as approved for such respective ARR element. The Figure 1 below illustrates the comparison between the prevailing modified GFA approach where only loan is reduced over time while, equity component, hence RoE remains constant throughout the life of the project vs the net fixed asset (NFA) approach where the depreciation beyond the repayment of loan reduces the equity base. The proposed regulatory approach for reduction of equity base should be integral part of the regulatory framework in the power sector, thus mitigating additional burden of tariff paid by the consumers.

The paper justifies continuation of the current framework, *"Increasing the Investors confidence by ensuring assured returns is important, and further considering the recent spikes in power tariffs in power exchanges indicating shortage of power availability, investment in Power sector needs a boost, and therefore the existing GFA approach, being a balanced approach, may be continued"*. It is important to highlight that most of the new investment in the sector is being undertaken through RE capacity addition through competitive bidding. There is limited capacity addition in thermal generation regulated by CERC. The suggested approach is not likely to impact new investment, which is already been serviced through compensatory tariff with such additional allowances. In any case, historical over recoveries to this account also remain irreversible.

[1] CER's opinion on "Developing MYT Framework: Insights and Discussion on the Draft Regulations of Gujarat and Chhattisgarh" at 1st Regulatory Manthan. https://cer.iitk.ac.in/RM/rm1

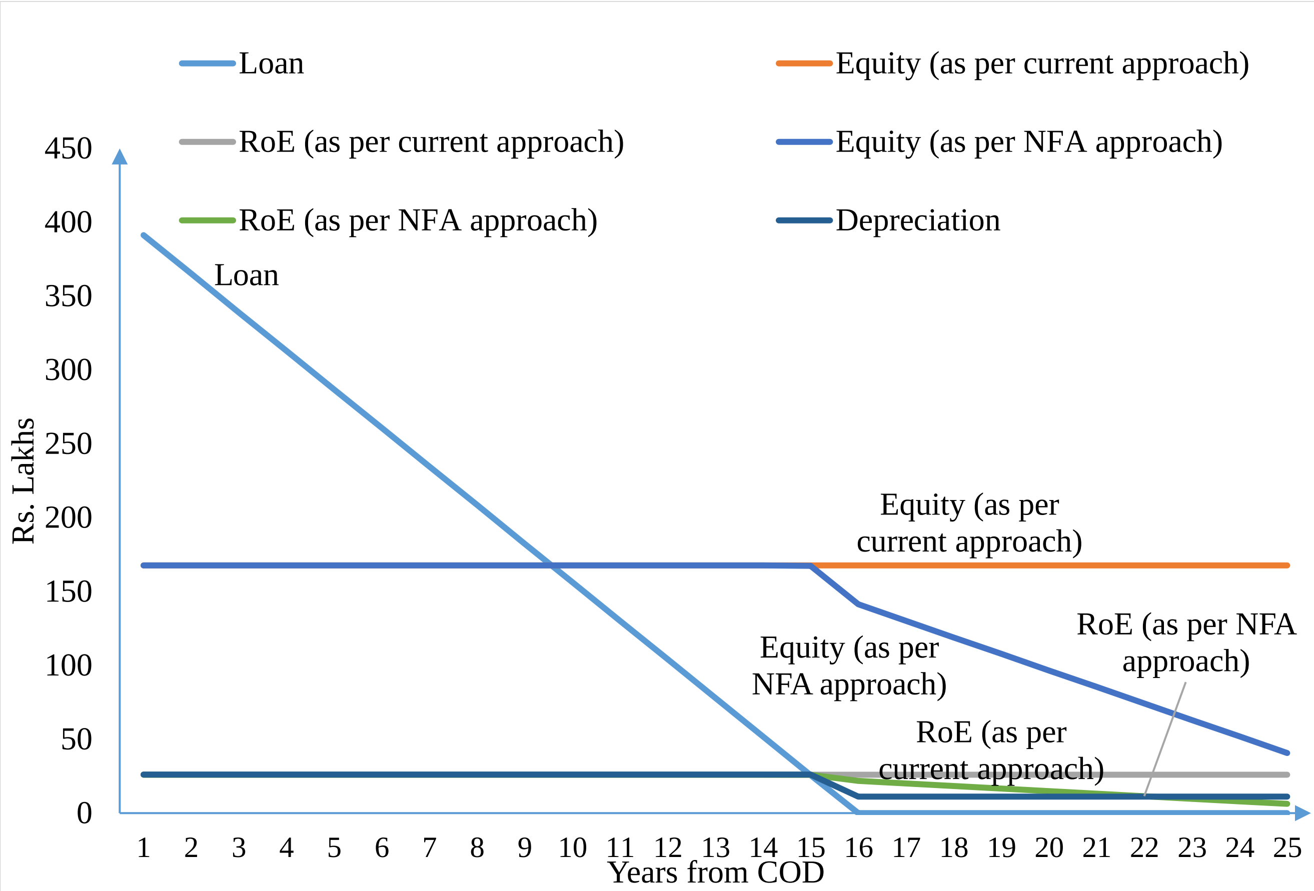

Figure 1: Modified GFA approach vs NFA approach

c. Introduction of efficiency factor for O&M expenses[2]: In the spirit of encouraging efficient operation, it is suggested that an efficiency factor may be incorporated for arriving at the normative O&M cost for the subsequent year. Efficiency factor may be introduced to encourage continual improvement across the cost components. For the above purpose, a framework similar to RPI-X regulation is suggested to be implemented for treatment of O&M expenses as illustrated in the following figure 1 to encourage efficient performance.

[2] CER's opinion on "Developing MYT Framework: Insights and Discussion on the Draft Regulations of Gujarat and Chhattisgarh" at 1st Regulatory Manthan. https://cer.iitk.ac.in/RM/rm1

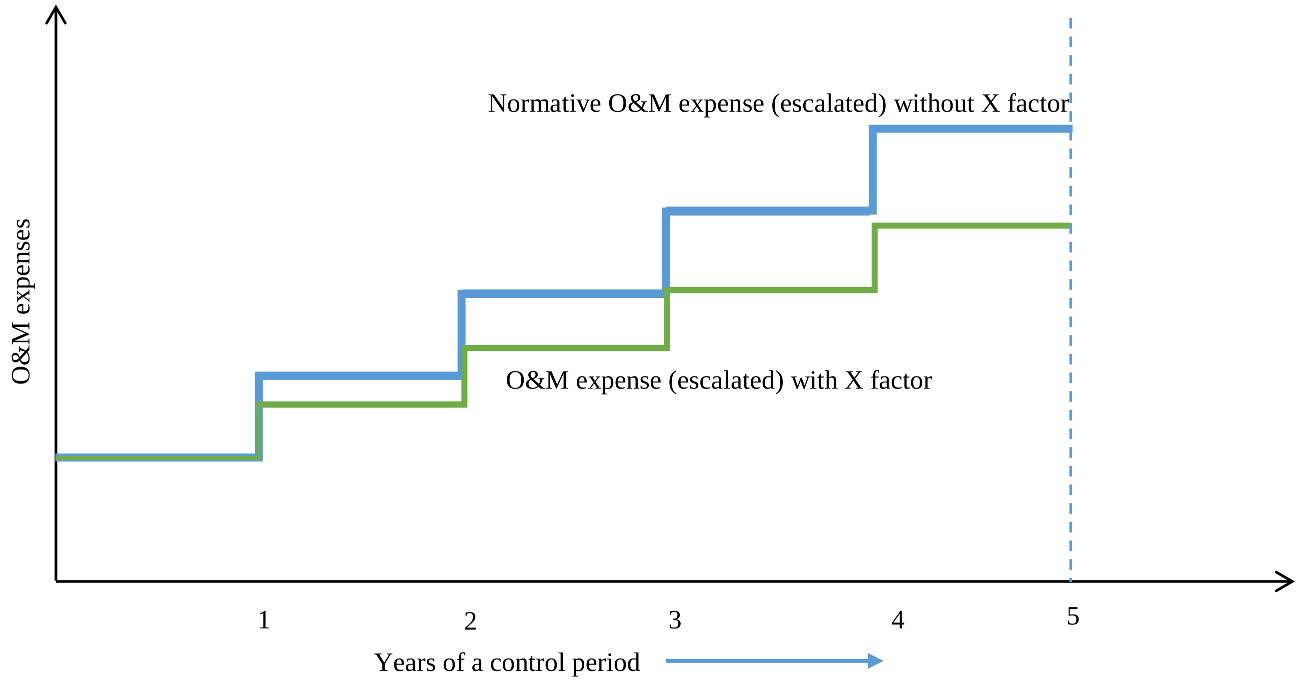

Figure 2: Representation of O&M expenses with efficiency factor (X)

Thus, the O&M expenses for a project can be expressed as per the following equation -

$$\boldsymbol{O\&M_t = O\&M_{t-1} * \left(1 + \frac{Price\ Index_t}{Price\ Index_{t-1}} - X_t^{O\&M}\right)} \quad \text{...} \ (4)$$

Where,

O&M: Normative Operation & Maintenance expenditure as approved by the Commission;

Price Index: Consumer Price Index for Industrial Workers;

$X_t^{O\&M}$: Factor representing an annual target for efficiency improvement in O&M.

The choice of the price index may be based on a single index or a weighted composite index calculated on the basis of proportion of different cost sub-components of the O&M cost i.e. wages & salary (W&S), repair & maintenance (R&M) and administrative & general (A&G) expenses. The W&S component may be linked to the CPI (industrial worker), R&M to the WPI of electrical equipment or weighted sum of electrical equipment and machinery & equipment and the A&G expenses to be linked to the CPI applicable to white collar workers ($CPI_{\text{urban \& clerical workers}}$). Such a sub-component based application of price index could be feasible if costs under the respective heads can be apportioned reliably.

Determining the Efficiency "X" factor:

Efficiency factor should be an integral part of the O&M cost approval process as the organisation is expected to optimise its cost of operation over time, while still providing for reasonable hedge from general price rise. Appropriate benchmarking studies such as Data Envelopment Analysis, etc. may be conducted to set benchmark for efficiency improvement across individual 'controllable' cost parameters across the MYT control period.

4. **Self-selection bias between project-based and normative tariff:** The approach, wherein the generating company or the transmission licensee have an option to select between the determination of tariff either on the project specific basis or normative basis for a particular control period, would lead to self-selection bias. The petitioners whose costs are less than the normative tariff will opt for the normative tariff, while the petitioners whose project costs are higher than the norms, will opt for the project specific tariff leading to the consumers paying higher tariff in totality. This approach would thus be counterproductive to consumers' interest.

5. **Normative tariff to reflect the actual costs?:** As per section 3.2.3, *"The asset specific normative tariff will allow the* ***tariff determined to be close to actuals****, thereby eliminating the chance of major gain or loss, and will also help achieve the other objective of eliminating the need for periodic tariff filings"* (emphasis added). Neither the Electricity Act, 2003 nor the Tariff Policy provide for tariff determination to follow the actuals, and emphasizes role of efficiency improvement. A framework that proposes to set normative tariff close to actuals essentially disregards room for efficiency improvement.

6. **Approval of energy charges on actual basis:** As per section 3.2.3, *"Further, with regard to Energy Charges, for both new and existing generating stations the same may be approved based on* ***actual fuel cost*** *and normative performance parameters as currently allowed."* Fuel costs should be allowed on the basis of 'actual costs' only to extent the cost of fuel is approved for purchase at a regulated price[3] or through competitive bidding.

7. **Fixing of Indexation:** The proposed approach for specifying the indexation in section 3.2.3.1.b states *"The indexation specified can be with regard to the previous year, i.e., AFC component as computed for the N^{th} year/AFC component as computed for the N-1^{th} year."* Thus, the proposed index is derived based on the **approval of the historical costs with a lag of 1 year** as also demonstrated in the appendix. The proposed indexation is a reflection of historical expenses and also disregards the need for improvement in normative parameters. This also seems to suggest that there would be separate index for each project as it refers to the respective AFC components.

It is important to note that in the case of the regulatory framework for the distribution segment across most of the states, the normative parameters imbibe the need for continuous efficiency improvement. As suggested above the indexation (escalation) be based on normative indices along with efficiency 'X'. It is suggested that the determination of index could be on the basis of weightage average index using appropriate WPI and CPI indices.

8. **Approval of additional capitalisation post cut-off date:** As per section 3.2.3.1.f *"Further,* ***in case <u>any</u> additional capitalisation is incurred or is required, the petitioner may file a separate petition seeking approval of capital expenditure****, and once such capital expenditure*

[3] In case the tariff of captive mines of a thermal station are approved on normative basis, the fuel costs of such thermal stations should remain norm based and not be approved on actuals.

is allowed, the variation on account of additional capitalisation on the AFC can be serviced by first computing the impact on the AFC and then adjusting the same through the same indexation mechanism as specified above. Such an adjustment can be carried out from the date of capitalisation of such additional capitalization" (emphasis added).

Additional capitalization up to the proposed cut-off period should be the one which has been envisioned and approved as a part of the original capex approval by CERC. It is suggested that, the separate approval for additional capitalisation post cut-off date of the plant to be allowed only in case such requirements arise due to change in law events, force majeure or due to arbitration. Further, in case of implementation of the proposed 'compensation allowance', there should not be a need for additional capitalisation.

9. **Procurement of goods and services for additional capitalization through competitive bidding:** As per the suggestions sought for *"Need to mandatorily award work and services contracts for developing projects under the regulated tariff mechanism through a transparent process of competitive bidding, duly complying with the policy/guidelines issued by the Government of India as applicable from time to time."*, it is suggested that the additional capitalization allowed either within the cut-off date or outside the cut-off date (due to change in law or arbitration), should also be mandated to be procured through competitive bidding process.

10. **Investment costs to be considered for approval of capital cost of project:** As per the section 4.2.3 of the proposed approach, *".... However, the hard costs of recently commissioned projects of similar specifications are referred to for prudence checks...."* It is suggested that the hard costs of the recently commissioned projects whose **hard costs of various components of the project which have been approved by the Central Commission** should be referred for approval of the capital costs of the projects.

Benchmarking of capital cost would thus be of significant importance. The Commission may come up with a separate framework for arriving at the benchmark after due consultation with the stakeholders. In the interim, **minimum of the hard costs as approved by the Commission may be considered as the benchmark cost** and if the project cost is higher than the benchmark cost, a certain fraction of the difference in the cost (say 75%) may be allowed as pass through after prudence check. Similarly, if the actual costs come to be less than the benchmark cost, then the developer may be allowed to retain a certain fraction of the difference (say 25%) as an incentive for efficiency and the rest 75% goes to beneficiary.

11. **Capital cost of hydro generating stations:** As per the suggestions asked in section 4.2.4 of the proposed approach *"As these expenses towards the advancement of the Local Area are required for the development of the project and for alleviating public resistance and delays, such expenses may be allowed as part of the capital cost with certain limits. Alternatively, these expenses may be met through budgetary support for funding the enabling infrastructure, i.e., roads and bridges, on a case-to-case basis which could be (i) as per actuals, limited to Rs. 1.5 crore per MW for up to 200 MW projects and (ii) Rs. 1.0 crore per MW for above 200*

MW projects, as per the Ministry of Power guidelines dated 28.09.2021 for budgetary support for "Flood Moderation" and for budgetary support for "Enabling Infrastructure", it is suggested that, the tariff framework should mandate that any portion of the budgetary support provided by the Ministry of Power for enhancement of the local area is neither claimed nor approved through the tariff determination process by the hydro generating station.

12. **Differentiated RoE for hydro projects with and without dam/ reservoir:** Given the fact that the cost of equity for infrastructure sector has reduced[4], the return on equity for the projects should also be reduced. However, given higher risk for the hydro projects, the return on equity for the new hydro power projects under the current tariff framework may be retained for the next control period (2024-29). Further, it is suggested that in case of new hydro projects, which include a large dam/ reservoir or a pumped storage facility (with a cutoff date), higher return on equity (say by 50 basis points) as compared to the run of the river projects may be introduced.

13. **Higher return on investments for hydro projects for early completion:** For enabling higher return on investments for timely/ early completion of projects, if the project is completed 90 days prior to the scheduled date of commercial operation (SCOD), a higher RoE (say 50 basis points) may be allowed for a period of 5 years from the COD irrespective of the control period. Similarly, RoE may be reduced (say 50 basis points) for the projects whose commissioning is delayed for more than 120 days post SCOD, applicable for 5 years irrespective of control period.

14. **Acquisition value of the projects acquired post NCLT and its effect on the AFC of the project:** As per the suggestions sought for the cost to be considered while determination of tariff u/s 62 of the Act for the projects acquired post NCLT proceedings, the approach of considering the lower of the historical cost and acquisition value of the project seems appropriate. However, it need to be clarified whether the acquisition value consist only of the equity component of the project cost or complete cost of the project.

The following cases illustrate the possible scenarios that may occur post NCLT proceedings and the treatment of the cost:

[4] Kewal Singh, Anoop Singh, Puneet Prakash, 2022, "Estimating the cost of equity for the regulated energy and infrastructure sectors in India" *http://dx.doi.org/10.1016/j.jup.2021.101327*

Case 1: When the acquisition value post NCLT proceedings are <u>less than</u> the actual project capital cost – In such cases, both, debt and equity component of the cost of acquired project will be restructured (**reduced**). Hence, the **RoE and IoL component of the AFC will reduce** leading

> Case 1 scenario: For e.g. the cost of the project is Rs. 1000 Cr. Considering the debt to equity ratio as 70:30, the loan and equity will be Rs. 700 Cr. and Rs. 300 Cr. resp. When the project goes to NCLT, the entity buying the project may not be willing to pay Rs. 300 Cr. equity. At the same time the banks may restructure the loan and forego some principal amount component of project. Thus, after the NCLT proceedings, the actual loan and equity of the project will be reduced to, say 300 Cr. and 150 Cr. respectively. Thus, the interest rate on the loan component will be applicable on Rs. 300 Cr. instead of Rs. 700 Cr. and the return on equity will be applicable on Rs. 150 Cr. instead of Rs. 300 Cr. Also, the depreciation allowed should be lower of the restructured loan repayment amount or the applicable depreciation under the tariff framework.

to reduction in the tariff of the beneficiary. Further, the **depreciation should only be applicable on the restructured capital cost.**

Case 2: When the acquisition value post NCLT proceedings is <u>greater than</u> the actual project capital cost – In such cases, the historical value of the project, at the time of acquisition (after appropriate deduction of costs recovered and debt restructuring), should be considered for recovery.

15. **Revenue earned during construction period to offset IDC and IEDC:** It is suggested that in cases when the revenue earned during construction phase of the project is higher than IDC, such amount may be used to offset the IEDC incurred for the project.

16. **Pro-rated IDC to be allowed:** As per the suggestions sought between the two options in section 4.4.1 of the proposed approach, *" Pro-rata IDC may be allowed considering the total implementation period wherein the actual IDC till implementation of the project is pro-rated considering the period upto SCOD and period of delay condoned over total implementation period……Under Option 1 above the allowable IDC shall be Rs. X + [Y*(4/12)], i.e., only IDC pertaining to delay is pro-rated. Under Option 2 the allowable IDC shall be Rs. (X+Y)*[(36+4)/48] wherein the total IDC is pro-rated based on the SCOD and delay condoned vis-à-vis the actual implementation period of 48 months"*, <u>option 1 seems appropriate</u> because, while it provides solace for the generator/ transmission licensee, it also encourages the generating station/ transmission licensee to complete the project in timely manner.

An another option may be exercised, where the 50% IDC and IEDC applicable for the delay condoned beyond the SCOD may be allowed as pass through, **given the fact that the generating station/ transmission licensee has collected the LD, if any, and it has been deducted from the total IDC and IEDC incurred.**

17. **Deduction of LD amount collected from total IDC and IEDC incurred:** As per the proposed approach in section 4.4.2, *"It is observed that the current provisions specify that in the event that the delay is not attributable to the generating company or transmission licensee,*

the additional IDC and IEDC beyond SCOD ***shall be allowed and the total LD amount collected shall be deducted****” (emphasis added).* It is suggested that the clause may be rephrased as *“.....additional IDC and IEDC beyond SCOD shall be allowed* ***after deduction of collected LD amount from total IDC and IEDC****.”*

18. **Servicing the impact of delay on account of forest clearances and approvals:** The comments sought in section 4.9 of the proposed approach states, *“1. To encourage rigorous pursuit of such approvals from statutory authorities, even if delay beyond SCOD on account of clearances and approvals that are condoned, some part of the cost impact (****Say 20%****) corresponding to the delay condoned may be disallowed. 2. Alternatively,* ***RoE corresponding to cost and time overruns allowed over and above project cost as per investment approval may be allowed at the weighted average rate of interest on loans instead of a fixed RoE****. 3. The current mechanism of treating time overrun may be continued, considering that utilities are automatically disincentivised if the project gets delayed”* (emphasis added).

The approach 1 to disallow 20% of the impact of delay seems a little too harsh and may be reduced to 15% to encourage the generating company or transmission licensee for rigorous pursuit of approvals given the fact that the generation company or transmission licensee may have limited control over clearances and approvals but need to pursue the approvals diligently. Option 2 is a better approach as it allows return on the cost and time overruns corresponding to delay in approvals and clearances, allowed over and above the project cost as per investment approval, **at the weighted average rate of interest on loans and not on fixed RoE**.

19. **Additional Capitalisation:**

A. **Normative add-cap for works related to original scope works within as well as beyond the cut-off date and corresponding liability discharge:** Add-Cap on account of the original scope works within the cut-off date and corresponding liability discharges may be represented as a percentage of the total investment approval or total capital cost admitted by the Commission and allowed only up to the cut-off date.
The capacity-wise analysis of capital expenditure as a **percentage of admitted capital cost**, for the plants with years of operation up to 7 years from COD as on March 31, 2023 is shown in the following Table 1.

Table 1: Admitted capital cost distribution across years

Capacity (MW)* No. of Units	Plant Name	Years from COD							
		0	1	2	3	4	5	6	7
250*2	Barauni II	78.45%	0.01%	1.94%	9.51%	3.94%	6.15%	-	-
500*1	Unchahar Stg-IV	80.04%	2.59%	4.76%	8.75%	3.44%	0.28%	0.14%	0.00%
660*2	Khargone	81.49%	4.29%	5.35%	6.28%	2.59%	0.00%	-	-
660*2	Tanda Stg-II	81.21%	4.17%	4.18%	2.32%	6.61%	1.51%	-	-

660*2	Solapur	86.72%	1.66%	1.79%	3.51%	3.51%	3.26%	0.00%	0.00%
660*3	Nabinagar	86.79%	0.73%	3.41%	0.70%	3.97%	4.39%	-	-
800*2	Gadarwara	96.39%	1.49%	0.44%	0.85%	0.41%	0.41%	-	-
800*2	Lara	71.61%	6.77%	2.38%	5.60%	10.10%	3.53%	-	-
	Weighted Average	83.66%	3.01%	2.24%	2.96%	4.57%	2.45%	0.00%	0.00%
	Median	81.35%	2.12%	2.90%	4.55%	3.72%	2.39%	0.00%	0.00%
	Suggested Norm	**84%**	**3%**	**3%**	**3%**	**5%**	**2%**		

- The majority of Add-Cap is distributed during the initial 4-5 years of operation of a plant from COD. Hence, it is suggested that the cut-off for add-cap may be extended from 3 years to 5 years from COD, and the definition of the cut-off date may be modified as "the last day of the ***sixtieth calendar month*** from the date of commercial operation of the project". Based on the admitted capital cost, proportion of capital cost up to SCOD and proportional distribution of add-cap across the first 5 years from COD may be fixed as a norm as suggested in Table 1 above.
- It is suggested that no add-cap on account of original scope works and corresponding liability discharge to be approved post cut-off date i.e. 5 years from SCOD.

  The expenditure due to add-cap for ash dyke/ ash transportation is observed to be minimal up to first 15 years from COD. Hence, the add-cap on account of ash dyke/ ash transportation should not be allowed up to 15 years from COD and may be allowed beyond 15 years on a case to case basis.

20. **Deemed approval of variation in add-cap to reduce regulatory burden:** Under the deemed approval framework (as proposed herein), a generating company or a transmission licensee could be allowed to recover the excess amount over the (approved) annual add-cap expenditure[5] (while still remaining within the overall approved capital cost) for the respective years (within the first 5 years) if the impact of such additional recovery on tariff is within a percentage range to be defined by the Commission. This would also mean that the generation company would consider lower add-cap amount for a subsequent year (within the five year period) so that the overall capital cost remains the same as originally approved. This would only affect the time value of money as total capex spend would remain the same. The adjustment/ true-up of such recovery can be done at the time of true-up at the end of the control period or at any interval within the control period as the Commission may deem appropriate. The suggested approach is similar to the mechanism for approval of fuel and power purchase adjustment cost (FPPAC) in the case of distribution licensees.

    Following scenario illustrates the possible approach for approval of add-cap -

    - In case add-cap proposed to be treated as change in existing tariff due to add-cap $\leq \boldsymbol{x}$ %, 80% cost recoverable of the additional tariff by the generating company or the transmission licensee may be levied without going through any regulatory proceedings.

[5] As suggested above in Table 1.

- If, ***x***% < change in existing tariff due to add-cap ≤***y***%, ***y***% cost recoverable of the additional tariff by the generating company or the transmission licensee may be levied onto the consumers, and the balance shall be recoverable up to 70% without going through any regulatory proceedings.
- If, change in existing tariff due to add-cap >***y***%, 10% cost recoverable of the additional tariff by the generating company or the transmission licensee may be levied onto the consumers without going through any regulatory proceedings, and the differential claim shall be recoverable on filling of an application for prior approval by the Commission at the time of true-up or any such interval within the control period as specified by the Commission. The values of ***'x'*** and ***'y'*** may be as specified by the Commission.
- **Adjustment of under-/over-recovery of revenue:** The revenue recovered by a generating company or a transmission licensee on account of change in existing tariff due to add-cap, without going through any regulatory proceedings, shall be trued up at the end of control period or any such interval as decided by the Commission within a control period.
  In the case of under-recovery, a carrying cost at the benchmark interest (i.e. interest on loan) be allowed. In case of excess revenue recovered for the year against cost incurred due to add-cap, the same would be recovered from the generating company/ transmission licensee at the time of truing up along with **its carrying cost to be charged at least 400 basis point above the benchmark interest rate** at the time of truing up of the costs accounting for the fact that interest also has been claimed from over recovery by the generating company/ transmission licensee. This will disincentivise undue over recovery from the beneficiary.

Capital expenditures due to arbitration, change in law, force majeure, etc. do not have a predictable pattern and cannot be envisaged as a norm. Hence, they may be dealt on case-to-case basis and separate approval should be taken from the Commission.

21. **No separate yearly allowance/ special compensation for add-cap:** As per clause 4.10.1, the approach for normative add-cap for generating stations states *"For generating stations that have already crossed the cut-off date as on 31.03.2024,…1. Thermal Generating Stations – Based on the* ***analysis of actual additional capitalisation incurred by such generating stations in the past (15-20 years)*** *and co-relating such expenses to different unit sizes such as 200/210 MW series, 500/660 MW Series and different vintages (5-10, 10-15, 15-20, 20-25 years post COD),* ***a special compensation in the form of yearly allowance may be allowed based on unit sizes and vintage****, which shall not be subject to any true up and shall not be required to be capitalised. 2. Hydro Generating Stations – As each hydro generating station is unique owing to various factors, additional capitalisation of such generating stations may not be benchmarked as can be done for thermal generating stations. However, in the case of a* ***specific hydro generating station, the additional capitalisation is recurring in nature, and hence station wise normative additional capitalisation may be approved in the form of special compensation*** *which shall not be subject to any true up and shall not be required to be capitalized"* (emphasis added).

As referred above in Table 1, in case of thermal generating stations, add-cap does not occur beyond 5 years of operation from COD. Hence it is suggested that the **add-cap may not be allowed beyond 5 years of operation from COD for thermal generating stations.** Further, the proposed approach takes into account the past expenditure incurred by the generating stations and defines a particular number to be approved either based on the capacity of the station for thermal stations or the project specific numbers in case of hydro generating stations. Dependence on past data (without efficiency factors) not only passes on the inefficiencies of the past but also allows the generating stations to overlook the efficient practices and measures for add-cap expenditure. **This may also lead to increase in the expenditure of the generating stations beyond the actual requirement of the add-cap.**

21. **Regulatory Sandbox - Deemed approval of add-cap in case of transmission system:** In case of transmission systems, the projects are often implemented in multiple stages and capital investment towards each of such components of project implementation is presented as separate petition.

An approach considering Deemed approval as discussed in the above section can be considered for approval of the add-cap wherein the transmission licensee is allowed to recover the add-cap expenditure incurred if the impact of such additional recovery on tariff is within the range as defined by the Commission. The adjustment/ true-up of such recovery can be done at the time of true-up at the end of the control period or at any interval within the control period as the Commission may deem appropriate including the deduction of over recovery done by the transmission licensee as already explained above. This would reduce the number of petitions before the Commission and thus reduce the overall regulatory burden. A mechanism similar to the one mentioned above could be implemented for under-/over-recoveries.

Such deemed approval should only be available for such transmission licensees who have already files at least five tariff petitions and have been issued an order against the same demonstrating that they have an established internal mechanism for the same. **A Regulatory Sandbox approach may be considered as a test case by the Commission.** Based on its outcome, such a process can then be implemented, say, one year after the beginning of the upcoming control period.