COMMENTS ON THE APPROACH PAPER FOR TERMS & CONDITONS OF TARIFF REGULATIONS FOR TARIFF PERIOD COMMENCING FROM 1.4.2024

Submitted by: GMR Energy Ltd.

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PART-A: Comments and Suggestions in response to the issues raised in the Approach paper

Clause No.	Approach paper	Comments
Clause 3.1 tariff Determination:	• Suggestions are sought as to how the present system of hybrid mechanisms of tariff setting under the cost plus approach can be made more efficient by moving closer to a normative or performance-based approach so that the same would positively impact the interests of consumers as well as utilities. Two possible options could be as follows: **Approach 1:** *Shift to a normative tariff, wherein, once capital costs are approved on an actual basis after prudence check, all other AFC components are determined on normative basis.* **Approach 2:** *Further simplification of the existing Performance Based Hybrid Approach, wherein on the basis of admitted capital cost, AFC components can be approved based on actuals or norms as may be specified for the control period. Further, additional capitalization may be allowed on certain counts on a normative basis.* • Further the paper seeks comments on the following points: *1*) **Whether clustering the components of AFC based on their nature to increase/ decrease will allow better projections? Any other possible method to cluster the AFC components?** **2) What other methodology can be adopted to determine the increasing/ decreasing factors?** **3) Whether the impact of additional capitalization can also be allowed through the same indexation mechanism or through a separate revenue stream?**	**Objections** • The proposed Indexation methodology would lead to complexity of the calculations, more discretion in the hands of regulator. • Shifting towards indexation methodology is not suggested as not much capacity is likely to be added under Sec-62 of the Act. • additional calculation of indexation factor will further-increase the complexity-of tariff determination **Comments & Suggestions** • However, If commission is inclined to adopt Approach- 1 then following medications must be incorporated: ○ Working Capital to be to be included in O&M expenses. ○ Normative regimes don't capture the Interest rate fluctuations therefore provisions to incorporate the fluctuations in the Interest rates should be included. ○ Working capital interest rates varies year on year therefore suitable provisions to adjust the fluctuations in the interest rates to be included. ○ Allowing the Additional capitalization through separate revenue streams may be implemented given that that the cost is allowed on actuals after prudence check. ○ However, Allowing the additional capitalization through indexation method (calculated on past period Ad-cap) is not advisable since the past Ad-cap trend cannot be use dot predict the future ad-cap trends. ○ Any Ad-cap allowed on normative basis/indexation basis should be subject to the annual adjustments based on actuals. **However, without prejudice to above submissions, it is suggested that the proposed changes should be considered for implementation after extensive stakeholder consultations from the control period starting from 2029-34 and the existing methodology of allowing costs at actual and subject to prudence checks and true-up must be continued to be followed in the forthcoming control period i.e 2024-29.**
Clause 4.2.1 Capital Cost and Provision for Interim tariff	Comments and suggestions are therefore invited from stakeholders on the following: • The provision for interim-tariff can, therefore, be continued in the next tariff period as well. However, comments and suggestions are sought from stakeholders on the continuation of the said provision.	**Comments & Suggestions.:** • It is suggested that Commission should provide a Normative tariff Instead of provisional tariff due to following factors: ○ *Exercise to determine the provisional tariff is time consuming in itself and takes time and resources not less than the determining the final tariff. In some cases in the past it has taken up to two years.* ○ *A normative tariff with provision for true-up instead of provisional tariff shall provide regulatory certainty, reduce regulatory burden and save a lot of time and resources.*
Clause 4.2.2 Procurement of	Comments and suggestions are therefore invited from stakeholders on the following:	**Comments** • It is suggested that it is practically very difficult to award the all the work and service contracts on the competitive bidding. Due to following reasons:

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Equipment and Services	• 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.	○ Limited no of vendors providing the service or having expertise. ○ Time constraint→ Competitive bidding is time consuming and urgent worksd cant be dependent on the competitive bidding. ○ There are instances when there are not sufficient number of Bids due to lack of participants. ○ There are numerous services like Liasoning with coal company, Railways, etc. Coal washing Services, Coal sampling services etc where in there are not enough parties to call for bids. **Suggestions:** CERC must categorize the works and services that must mandatorily follow competitive Bidding **OR** Provide a threshold value of the Contract beyond which all the works and services to be awarded through Competitive Bidding.
4.2.3 **Reference Cost for Approval of Capital Cost – Benchmark Cost V/s Investment Approval Cost**	**Comments and suggestions of stakeholders are invited on other efficient reference costs other than Investment Approval costs that can be considered for prudence checks.**	**Comments & Objections** • Benchmarking does not capture post-facto changes in costs arising out of uncontrollable factors / unanticipated constraints specific to a project. numerous factors. • Further, the Benchmark cost is not suitable for the hydro power plants because: ○ *The core of any benchmarking exercise lies in competitively discovered prices spanning across multiple market players which are determined rigorously for specificities of each asset and updated with high frequency.* ○ *Every hydro project is unique in nature and location specific and has different sort of features in combination such as underground powerhouse or surface powerhouse, scattered or compacted, storage or run off the river etc. which may significantly affect the cost and construction period of project even of same magnitude.* **Suggestions:** • Benchmarks should be specified based on the recently commissioned projects (say within 5 years). • Basis and Break-up of Benchmark costs should be disclosed. • Benchmark costs should be specified along with provisions to allow actual cost subject to actual conditions and Regulatory prudence check. • . • While prudence check due weightage must be given to project-specific conditions causing the price variation form the benchmarks cost.
4.2.4 Capital Cost of Hydro Generating Stations:	**Comments and suggestions are further sought from stakeholders on ways to expedite the development of hydro generating stations especially the construction phase, and increase their commercial acceptability.** Stakeholders are also required to consider the following aspects while making suggestions: 1. Ways to expedite the construction phase by adopting alternate ways of awarding construction contracts. 2. Contract to execute the project to be awarded only when all the required clearances and permits are available as on zero date.	**Comments & Suggestions:** • it is suggested that for expediting the development of Hydro stations and increasing their commercial viability, following additional aspects must be taken care of: • An appointed Nodal agency may help in fast-tracking the approvals to facilitate plug and play arrangement. • Basis CEA's identified river basins, Geological Survey reports/ data repository domiciled within a centrally-appointed agency to be considered to intercept site-specific geological surprises and made available to successful bidders against appropriate payment • While focusing on the quality and implementation schedule adverse events / uncontrollable factors and events must be taken into account.

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	3. Creation of Special Purpose Vehicle (SPV) for obtaining all mandatory approvals 4. Focus on quality and the implementation schedule. 5. Higher return on investments/equity for projects completed in a timely manner. 6. Higher return for dam/reservoir based projects and Pumped Storage Projects. 7. Levelized Tariff based one-time determination of tariff to remain uniform for useful life. 8. Escalable tariff adjusted for year-on-year inflation. 9. Possibility to further increase the useful life. 10. Consideration of expenses towards Local Development/infrastructure for public outreach for better project acceptability as pass through in capital cost or one time re-imbursement. **Comments and suggestions are sought from stakeholders to incentivize the developer if it executes the project faster/ or ahead of schedule and vice-versa if it delays.**	• Any decision to extend the life of the project should be based on the thorough study of independent experts and should be on case to case basis. • Increase in the Plant life should not hinder the recovery of Depreciation, ROE etc. • Useful life should be limited to and not exceeding technical design life Higher returns on investment to be given considering the capital intensive nature, large construction period and challenges faced during hydro project construction
4.4.1 Computation of IDC – Post Scheduled COD	Comments and suggestions are sought from stakeholders on the following options for allowing IDC: *1. Existing mechanism wherein the pro-rata deduction (based on delay not condoned) is done on IDC beyond SCOD.* *2. 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.* *3. IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay.* ***Illustration: Consider an asset that was supposed to be implemented in 36 months but suffers a delay of 12 months. Further, suppose IDC up to SCOD is Rs. X and IDC beyond SCOD till actual COD is Rs. Y, and the Commission has condoned a delay of 4 months then the IDC allowable under the above two scenarios (mentioned at Sr. No. 1 & 2) shall be as follows.*** *Under **Option 1** above the allowable IDC shall be Rs. X + [Y*(4/12)], i.e., only IDC pertaining to delay is pro-rated.* *Whereas,* *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.*	**Comments & Suggestions:** • IDC should be calculated specifically for each window/period of delay on case-to-case basis and should be allowed on actuals subject to prudence check ○ Mechanism can be placed wherein every party should submit a detailed delay analysis report prepared by independent expert analyzing the each event of delay along with the reason attributable to such delay. • The above mentioned report should be considered while finalizing the quantum of delay and corresponding IDC on case to case basis subject to prudence check.
Clause 4.4.2 : Treatment of Liquidated Damages	Suggestions are sought from stakeholders on necessary changes in tariff forms and regulation to provide further clarity on the adjustment of LD.	**Comments & Suggestions:** • There are instances where-in entire BG amount has been adjusted enbloc from the allowed capital cost without going into the breakup of the BG amount to ascertain the actual LD amount. • This has caused the incorrect adjustments of capital cost and loss of revenue to generators. • **Therefore it is suggested that:** ○ ***a separate Form for incorporating break up of LD/BG amount may be created OR***

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		○ ***Provision for incorporation of LD amount should be created in the existing tariff forms in order to incorporate the breakup of the B/LD amount invoked.*** ○ ***Only the genuine LD amount must be deducted from the allowed capital cost not the entire BG amount.***
Clause 4.5 : Price variation	It is observed that time overrun due to delay in commissioning of projects not only increases IDC and IEDC, **it may also result in increase in the hard cost in case the contract provides for cost escalation beyond SCOD.** In such cases, if the impact corresponding to such delay is dis-allowed for the delay not condoned, it appears logical to extend the same treatment to price variation. Therefore, for allowing price variation, the utilities may be mandated to submit the statutory auditor certificate along with the petition duly certifying the price variation corresponding to delay and the same may be allowed on pro-rata basis corresponding to the delay condoned. Further, a separate form may also be specified to submit the relevant information pertaining to price variation. **Comments and suggestions are sought from stakeholders on the above proposal and suggest alternatives, if any.**	• If a project gets delayed then there may be variation in the process of the materials. • Therefore, It is suggested that Price variation of materials i.e Copper, Aluminum, Steel, Cement etc. should also be allowed. • The provision for submission of Auditor certificate for claiming the por9oce variation of material may be incorporate din the forthcoming regulations. • Appropriate tariff forms in this regard should be incorporated.
Clause 4.6: **Renovation and Modernisation (R&M) Allowance**	**Comments and suggestions are sought from stakeholders on continuation of the existing provisions and on the above suggestion <u>of continuing with Special Allowance,</u> if opted at the beginning of the tariff period for the rest of the tariff period.**	**<u>Comments:</u>** The provision re. the Special allowance under Regulation 27 of the CERC Tariff Regulations, 2019 must continue.
Clause 4.8: Controllable and Un-Controllable Factors	Delays on account of forest clearances can also be considered for inclusion as uncontrollable factor provided that such delays are not attributable to the generating company or the transmission licensee. Comments and suggestions are sought from stakeholders on continued inclusion of delay on account of land acquisition as an uncontrollable factor and on the further inclusion of delay on account of forest clearances as an uncontrollable factor.	**<u>Comments & Suggestions:</u>** • It is suggested that not only the Forest Clearance along with following items may be added in the list of Un-controllable factor: (Clause 22 (s) of 2019-24 regulations) I. Delay in Forest Clearance II. Delay in providing land to the implementing authority III. Delay in Providing the Evacuation facility or Delay in approval for synchronization of the Unit. IV. Court stay orders V. Restriction/Hindrances from buyers **Rationale behind the same is that all those factors are beyond the reasonable control of the generator hence must be included din the list of non-controllable parameters.**
Clause: 4.9 Differential Norms - Servicing Impact of Delay	***Comments and suggestions are sought on the following:*** *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.*	**<u>Comments & Suggestions:</u>** • The rigorous pursuit of approval from the authorities is hard to establish and subject to interpretations. • Once generator submits a request officially, the onus of giving the consent/approval lies with Govt and any delay there upon should not be linked with generator's performance • The Utilities generally resort to the official channels i.e. request letters and use unofficial channel's to follow-up against their request. However if the concerned agency causes

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	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.* ***Comments and suggestions are sought from stakeholders on the above so that developers may make more efforts to control the delays.***	delays due to any reason then the burden of the same cannot be transferred to the project developer in the form of 20% deduction in the allowed cost or any reduction in ROE. • Resorting to reduction in 20% the cost/Reduction in ROE would create an undue pressure on the project developer and it may indulge in unethical practices to get the approval within the time frame which may not be desirable. • Therefore the existing practice must continue, considering that utilities are automatically disincentivised if the project gets delayed.
Clause: 4.10 Additional Capitalization	As per CERC Tariff Regulations, 2019, additional capitalization for generating stations and transmission licensees is allowed under the following main categories. *1. Additional Capitalization within the original scope of work executed up to cut-off date (Regulation 24).* *2. Additional Capitalization within the original scope of work executed after the cut-off date, including replacement under certain conditions. (Regulation 25).* *3. Additional Capitalization beyond the original scope of work includes increased need for safety and security, Change in Law, Arbitration Award, Force Majeure, deferred works related to the ash handling system. (Regulation 26).* *4. Additional Capitalization on account of Renovation & Modernisation. (Regulation 27).* *5. Additional Capitalisation on account of revised emission standards. (Regulation 29).* It is however observed that the above provisions under which additional capitalisation is allowed is for specific works that are part of the original scope of work, are to carry out R&M, pertain to ash handling, are required due to uncontrollable factors such as a change in law or force majeure. It is further observed that Regulation 19(3)(e) of the CERC Tariff Regulations, 2019 specify that the capital cost of any existing generating station shall include the cost of railway infrastructure and its augmentation for the transportation of coal up to the receiving end. However, there are no enabling provisions under which a generating station can seek approval of costs pertaining to Railway Infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station (excluding any transportation cost and any other appurtenant cost paid to railways) that are not covered under the above provisions that may result in better fuel management, can lead to a reduction in operation costs, or shall have other tangible benefits **Therefore, in order to have an enabling provision under which such additional capitalization can be allowed with prior approval, a provision may be introduced to existing Regulation 26 to allow such expenses if they are found to be beneficial/essential for continued operations.**	**Comments & Suggestions:** The commission may modify the existing provisions by adding a **new clause @ 26 (g) i**n order to rectify highlighted the anomaly as under : ***26. Additional Capitalization beyond the original scope*** *(1) The capital expenditure, in respect of existing generating station or the transmission system including communication system, incurred or projected to be incurred on the following counts beyond the original scope, may be admitted by the Commission, subject to prudence check:* *(c) ....* *(d)....................* *(e)..........................* *(f) ....* ***(****g) Expenses incurred towards the development, maintenance and augmentation of railway Infrastructure utilized for Coal Handling in order to ensure better fuel management and reduced cost. (**Suggested Clause)***

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	Comments and suggestions are sought from stakeholders on the above and any other ways to address the issue flagged above.	
Clause: 4.10.1 Normative Add-Cap - Generating Station	For generating stations that have **already crossed the cut-off date as on 31.03.2024,** the additional capitalization for such generating stations can be considered as per the following. **1. Thermal Generating Stations** – Based on the analysis of actual additional capitalization 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 **<u>special compensation in the form of yearly allowance may be allowed based on unit sizes and vintage, which shall not be subject to any true up and shall not be required to be capitalized.</u>** **3.** While determining such special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under **Regulation 26 to Regulation** 29, wherever applicable, may not be included as these expenses may be allowed separately. 4. Further, any items that cost below Rs. 20 lakhs that may be in the nature of minor items such as tools and tackles, and those pertaining to Capital Spares may be allowed only as part of O&M expenses and may not be considered as part of additional capitalization in case of both thermal and hydro generating stations. 5. Further, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged. 1. By extending the cut-off date from the current 3 years to 5 years, which shall allow time to close contracts and discharge liabilities and eliminate the need to allow additional capitalisation post cut-off date unless in the case of Change in Law and Force Majeure. **Comments and suggestions are sought from stakeholders on the above suggested approaches and other alternatives, if any**.	**<u>Objections & Comments:</u>** • The Staff paper has termed the heading as Normative Add-Cap but the nature as suggested in the staff paper is completely different. • Deriving a unit/vintage specific compensation in place of Ad-cap is not appropriate w/o any provision for regulatory scrutiny or truing-up at the end of control period. • Allowing a uniform compensation in lieu of Ad-cap to all the generators w/o enquiring the need for compensation is a desirable practice. There may be an instances where a generator availing a special compensation has not actually incurred any cost and other the other hand there may be a generator that incurred more expenses than the allowed compensation. • There may be instances wherein there is an requirement of Ad-cap beyond the original scope and after the cut-off date in below mentioned scenarios: *1) An inherent deficiency (technical in nature for ex. Mechanical or metallurgical etc.) in machine causing performance degradation (not covered under warranty)* *2) Machine failures requiring immediate replacements (not covered under warranty or insurance).* *3) Expenses towards machine upgradation for enhanced safety and better performance not mandated by Govt. or regulations.* • In these situation the generator shall not be able to recover such costs as there are no other provisions in tariff regulations that allow such expenses **<u>Suggestions:</u>** Commission may go ahead in either of the following ways: • Continue the **exiting practice with no modifications** • Implement the special compensation scheme (as proposed by staff paper) with following modifications: *1) Compensation amount to be trued up at the end of control period based on technical audit* *2) Compensation availed should be allowed to be capitalized. So that generator is able to recover the depreciation and ROE on the amount invested.* *3) The 20 Lakh limit a proposed should be reduced to 5 lakhs/year. (25 Lakhs in control period)*
Clause: 4.11 GFA/NFA/Modified GFA approach	While the Net Fixed Approach is based on gradual reduction in the fixed assets to be considered for tariff purposes, wherein cumulative depreciation is deducted from the GFA and the resultant Net Fixed Assets are considered for the purpose of computation of tariff. The NFA approach is further suitable in context with the ROCE approach, wherein returns are allowed on the NFA based on the Weighted Average Cost of Capital (WACC). However, as interest rates keep varying, there is uncertainty with regard to returns to investors. As evident, the approach could result in reducing returns for investors as the project ages and may reduce the bankability of power sector projects, which could be detrimental, especially when	**<u>Comments & Suggestions:</u>** • We agree to the suggestion of the Staff that GFA based approach should continue in the next control period for the purpose of tariff determination.

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	the generating and transmission companies are expected to provide the much-needed infrastructure support that the economy will require in the next decade. **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.** **However, comments/ suggestions are invited on alternate approaches, i.e. GFA/ NFA/ Modified GFA approach.**	
Clause: 4.12.1 Segregation of Normative O&M Expenses	In the past, the Commission, has approved normative O&M expenses for Generating Stations and Transmission Licensees based on actuals incurred in the past, along with a certain escalation rate to cater to inflation and other changes. These O&M expenses primarily comprise three broad types of expenses, as mentioned below. 1. *Employee Expenses* 2. *Repair and Maintenance Expenses* 3. *Administrative and General Expenses* In the past, it has been observed that whenever there is a requirement to give effect to some issues affecting one or more of the above nature of expenses, e.g., Pay/Wage Revision impact, it becomes difficult to do so due to the absence of segregation of baseline expenses forming part of O&M expenses. As the Commission, while approving the norms, does not factor in such expenses, these expenses if deemed legitimate, may need to be allowed. The Commission observes that it is mostly in the case of employee expenses that such a one-time effect, mostly pay revision impact, is required to be given, and further, in the forthcoming tariff period, wage/salary revision is also anticipated, so **O&M norms may be specified under the following two categories.** **1. Employee Expenses** **2. Other O&M Expenses comprise Repair and Maintenance and Administrative and General Expenses.** However, considering that systems that are more automated will require less manpower and systems that are less automated will require more manpower, approving separate norms may result in inequity even though the total O&M expenses of such systems may be comparable. **Therefore, the above suggestion may also be seen from the perspective that these expenses have historically been allowed as one expense, and any change in the methodology as suggested above may result in unnecessary complications.** **Alternatively, to give effect to the impact of pay/wage revision, 50% of the actual wage revision can be allowed on a normative basis.**	**Comments & Objections:** • Proposal of bifurcating the O&M expenses for giving effect of one time pay revision for the public sector employees will be company-specific leading to industry compartmentalization • The O&M norms provided are also applicable for IPPs whose pay structure is different from the public sector employees. i.e. There are no Pay commissions as available for the Govt. Employees. • Therefore bifurcating the O&M expenses into Employee and Other O&M may not be desirable. **Suggestions** • Commission has already sought the breakup of the O&M Expenses (*via suo- motu order No. L-1/268/2022/CERC dt. 29.03.2023*) at corporate and local Levels, through this data repository commission can establish that what % of the O&M cost compromises the allowable salary and wage expenses • Accordingly the commission may decide the annual / periodic escalation on account of pay revision and incorporate this suitable while framing the O&M expenses. • Commission may allow the employee expenses for private sector based on 100% of actuals • The existing provisions of allowing separately the other expenses i.e Water Charges, Ash Transportation etc. must continue as per current practice.

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<tr><th>Clause No.</th><th>Approach paper</th><th>Comments</th></tr>
<tr><td></td><td>Comments and suggestions are sought from stakeholders on above suggestions and alternatives, if any.</td><td></td></tr>
<tr><td>Clause: 4.12.4 Inclusion of Capital Spares under O&M Expenses
'</td><td>The Commission has been allowing the following types of spares for a generating station as well as transmission licensee.
1. Initial Spares allowed on a normative basis.
2. Capital Spares that are not part of O&M expenses allowed on an actual basis.
3. Maintenance Spares that are allowed as part of normative O&M expenses

Due to the fact that some of the spares are being allowed on the basis of actuals and some are being allowed on a normative basis, considerable effort is required to map these expenses. It is observed that initial spares and maintenance spares (part of O&M expenses) are already allowed on a normative basis and it’s only the capital spares that are allowed on an actual basis. Further, the challenge with capital spares is that these expenses are non-recurring and sporadic, so benchmarking them can be difficult. However, it is anticipated that if Capital Spares are analysed for a longer duration, say 15-20 years, there can be some correlation and predictability to such expenses. Therefore, if the same can be projected with some degree of predictability, the same may be allowed on a normative basis along with O&M expenses.

Alternatively, instead of including all such capital spares as part of normative O&M expenses, recurring and low value spares below Rs. 20 lakh may be made part of normative O&M expenses, while for capital spares with a value in excess of Rs. 20 lakh, utilities may submit the same on a case to case basis for reimbursement with appropriate justification for the Commission’s consideration.

Comments and suggestion are sought from stakeholders on the above suggested approach and alternatives, if any, to streamline the approval process for spares.</td><td><u>Objections & Comments:</u>
• Benchmarking the Capital Spares for all the unit sizes is cumbersome as different unit sizes would have different patterns of capital spares requirements. Ex. For 350 MW unit sizes there is no separate norm in the existing tariff regime. Therefore the benchmarking of Capital spares expense for 350 MW unit would be difficult.
• The second approach advocated in the staff paper wherein spares upto 20 Lakhs value may be included in O&M expenses also do not seems appropriate as the value of 20 Lakhs is quiet high and generator shall be losing the depreciation, ROE etc on account of inclusion of the same in O&M.
<u>Suggestions:</u>
• Existing approach as per 2019-24 regulations for allowing the capital spares should continue</td></tr>
<tr><td>Clause: 4.12.5 Impact on account of change in Law to be incorporate in O&M Expenses</td><td>It is observed that there are no provisions with regard to allowing additional expenses on account of any change in law resulting in an increase in O&M expenses. However, including the same may lead to recurring impacts, and claims that may result in regulatory overburden.

Comments and suggestions are therefore sought from stakeholders on whether to include any provisions with regard to allowing impact of a change in law on O&M expenses.</td><td><u>Objections & Comments:</u>
1. The essence eof the Change in Law compensation is to evaluate “adverse material change” impacting operations and restore the economic position of the affected party so as the Change in law has not occurred. This is also in accordance with Tariff Polcy resolution 2016 a sunder:
“After the award of bids, if there is any change in domestic duties, levies, cess and taxes imposed by Central Government, State Governments/Union Territories or by any Government instrumentality leading to corresponding changes in the cost, the same may be treated as “Change in Law” and may unless provided otherwise in the PPA, be allowed as pass through subject to approval of Appropriate Commission.”</td></tr>
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Clause No.	Approach paper	Comments
		2. Therefore in view of the above, denying the Change in Law compensation in any form whether Capital Expenses or in O&M Expenses for the sake of Regulatory overburden is not in accordance with law.
Clause: 4.13 Depreciation	It is observed that while specifying the depreciation rate, the tenure of the loan considered is 12 years, whereas the life of most of the assets is between 25 and 40 years. It is observed that shorter loan duration and higher depreciation in the initial years have resulted in front loading of tariffs. **Considering that nowadays loans are available for 15-18 years, the** possibility of increasing the loan tenure for the computation of depreciation rates needs to be explored. Excessive front loading of tariffs increases resistance to future investments. For example, external loans have much lower interest rates, therefore, spreading depreciation over longer periods in the case of external loans can be a viable option for reducing costs in the initial years, which shall, however, include FERV factor and other financing cost. Therefore, there is a need to create a balance and align the depreciation rate with the actual loan tenure and life of the assets. **In view of the above, a depreciation rate may be specified considering a loan tenure of 15 years instead of the current practice of 12 years. Further, additional provisions may also be specified that allow lower rate of depreciation to be charged by the generator in the initial years if mutually agreed upon with the beneficiary.** **Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**	**Objections & Comments:** 1. The Proposed methodology of calculating the depreciation is not aligned with the recent proposal of Ministry of Power to reduce the tenure of the long term PPAs from 25 years to Max 12-15 years, thereby precluding the availability of loans of more than 12 years. → We propose retention of the methodology of recovery of Depreciation along with other costs has within 12 Years. As a matter of fact CEA Regulations for Part Load operations would come under effect from the next control period which shall increase wear and tear and reduce the life of the Units→ therefore any question of increase in the life of the generation units do not arise unless retrofits and the associated expenditure are treated as pass-through under regulatory approval, corresponding to which PPAs can be entered into for extended periods and bank loans availed 2. The existing projects (commissioned as on or before 31.03.20204) should be allowed to recover the Depreciation based on the existing methodology of 2019-24 regulations considering 12 years period of Loan tenure. 3. In fact provisions must be incorporated to accelerate the Depreciation recovery due to reduction in life of the Generating units due to part load operations. 4. Slowing down the depreciation recovery for the sake of avoiding front loading is not advisable given the fact that Generators would need to make fresh investments in FGD and machine upgradation due to enable flexible operation and new Emission norms as mandated by CEA, MOEF & MOP. It would be better to leave the matter of recovery of Lower depreciation among the mutual understanding of Generator and Beneficiaries, **Suggestions:** Depreciation should be based on actual loan tenure and loan amount availed.. CERC may specify an index of Depreciation schedule for different loan tenures
Clause: 4.14.1: Weighted Average Rate of Interest and FERV	It has been observed while dealing with tariff petitions, especially in the case of transmission licensees that in most cases the loans are not availed for specific project, and in such cases, it becomes a cumbersome task to ascertain one to one co-relation between assets and loans, which also requires considerable time and effort. To address the same, the possibility of computing interest on loans on the basis of the actual weighted average rate of interest for a company as a whole can be explored. It is further observed that the current Regulations already have such a provision for those generating stations or transmission systems that do not have any actual loans. According to the provision, interest on loans is computed based on the WAROI of the generating company or transmission licensee. However, it is also observed that there are certain foreign loans that entail FERV/hedging costs in terms of repayment of the loan as well as interest. In this context, the Tariff Policy 2016 states that only for projects where the tariff has not been determined on the basis of competitive bids, the cost of hedging and swapping such loans to take care of FERV shall be allowed without allowing any actual FERV.	**Objections & Comments:** 1. Either Hedging Cost or FERV whichever is lower should be allowed on actual basis. 2. The Proposed new methodology computation of Loan (*where in loans are not availed for specific project*) should be applied on case to case basis. 3. For the sake of few cases methodology for the entire Sector should not be changed. 4. Staff paper itself says that this problem is prevailing in Transmission Assets. Therefore the commission may consider implementing the proposed methodology for Transmission Assets while leaving Generation Assets with current methodology of Interest Calculation being followed in 2019-24 period.

Clause No.	Approach paper	Comments
	To simplify the approval of interest on loans, the weighted average actual rate of interest of the generating company or transmission licensee may be considered instead of project specific interest on loans. Further, the cost of hedging related to foreign loans be allowed on an actual basis, without allowing any actual FERV. **Comments and suggestions are sought from stakeholders on the above suggestions and alternatives, including in respect of treatment of FERV/cost of hedging**	
Clause: 4.16 Rate of Return on Equity (RoE)	Forum of Regulators, in its Report on "Analysis of Factors Impacting Retail Tariff And Measures To Address Them" with regard to RoE, has recommended as follows: *"In the entire value chain, transmission business has the lowest risk. The RoE for transmission companies should therefore, be reviewed immediately. RoE for generation and transmission should be linked to the 10 year G Sec rate (average rate for last 5 years) plus risk premium subject to a cap as may be decided by Appropriate Commission. For a Discom, the RoE could be fixed based on the risk premium assessed by the State Commission. Income tax reimbursement should be limited to the RoE component only."* FOR has recommended differential RoE for Generation and Transmission Businesses with a reduction in RoE for Transmission Business. It is further observed that even though the present Tariff Regulations, specify RoE @ 15.50%, considering the gestation period involved, the effective IRR works around 12%. While IRR of 12% is considered reasonable, the effective return is adversely impacted with delay and even if the entire delay is condoned, the effective return keeps on reducing. **Comments and suggestions are sought from stakeholders on the following issues:** *1. Review of Rate of RoE to be allowed, including that to be allowed on additional capitalisation that is carried out on account of Change in Law and Force Majeure.* *2. Whether the revised rate of RoE to be made applicable to only new projects or to both existing and new projects?* *3. Whether timely completion of hydro generating stations can be incentivised to attract investments?* *4. Merit behind approving different Rate of RoE to thermal, hydro generation and transmission projects with further incentives for dam/reservoir based projects including PSP.* *5. Merit in allowing RoE by linking the rate of return with market interest rates such as G-SEC rates/MCLR/RBI Base Rate.*	**Objections & Comments:** 1. Any reduction or uncertainty in the ROE to be allowed for the sake of consumer interest would hurt the sector. However, considering the current inflation trends its suggested to increase the ROE by 0.5%. 2. As already noted in the Staff paper that Power Generation projects are a risky affair and risk perception of financial institutions towards the power sector has increased due to the initiation of insolvency proceedings against these projects, forcing lending institutions to take massive haircuts. 3. Further @ Para 4.16.3 of the staff paper it has been noted that the sector would need to attract the fresh investments present installed capacity needs to be almost doubled by FY 2029-30 and the augmentation of the grid has been planned to accommodate 537 GW of RE capacity by the year 2030 which will require big investments, including those from the private sector. Therefore increasing the ROE for the next tariff period is justified. 4. Keeping in view the above facts any reduction or uncertainty towards ROE recovery shall hurt the sentiments of the investors and that may result in investors shying away from investing in the sector. 5. Therefore there should not be any reduction in the rate of the ROE to be allowed and it should be kept at the same level of 15.5 % as per current regulations. (*If commission is not inclined to increase this limit.)* 6. There should be a premium of 2% over and above the 15.5% ROE allowed for the high risk projects We propose computation under CAPM basis as under: • R_f from average of 10 year D-Secs • Equity β from Sensex & BSE Power Index for preceding 5 years • R_m from historical returns for preceding 10 year period, taking into cognizance recent macro-economic context of fiscal and monetary policy changes Also, • Higher returns of 0.1% for hydro projects for every 1 month of COD advancement • Higher 1% and 1.5% RoE for hydro & PSP projects respectively, considering their status as RE and contribution to AS operations • Equity returns cannot be reviewed for already commissioned projects. Further G-Sec & MCLR fluctuate frequently→ Dwindling returns on equity would hurt the investors sentiments to invest in already risky power generation projects. • The allowed ROE of 15.5% are comparable to other regulated Infrastructure projects as under:

<table>
<tr><th>Clause No.</th><th>Approach paper</th><th>Comments</th></tr>
<tr><td></td><td></td><td>AERA: Airport economic regulatory authority of India Sets Fair Rate of Return (FRoR). The allowed returns on equity in recent year are as under
<table>
<tr><th>Project</th><th>Allowed ROE</th><th>Source</th></tr>
<tr><td>Delhi International Airport</td><td>15.41%</td><td>AERA's order on determination of Aeronautical Tariff for IGI Airport; Delhi for second control period (2019-24); (Debt-Equity- 48%:52%)</td></tr>
<tr><td>Chhatrapati Shivaji International Airport, Mumbai</td><td>15.13%</td><td>AERA's order on determination of Aeronautical Tariffs in respect of Chhatrapati Shivaji International Airport, Mumbai for the first Regulatory Period (2019-24); {Debt~Equity- 48%:52%)</td></tr>
<tr><td>Rajiv Gandhi International Airport, Shamshabad, Hyderabad</td><td>15.17%</td><td>AERA's order on determination of Aeronautical Tariffs in respect of Rajiv Gandhi International Airport, Shamshabad, Hyderabad for the first control period {2021-26) ; {Debt-Equity- 48%:52%)</td></tr>
<tr><td>Kempegowda International Airport, Bengaluru</td><td>15.05%</td><td>AERA's order on determi.nation of Aeronautical Tariffs in respect of Kempegowda l11temational Airport, Bengaluru, for the third Control Period (2021-26); (Debt-Equity- 48%:52%)</td></tr>
</table>
Therefore the allowed ROE 15.5% for the much riskier electricity sector than Airports Business is justified.</td></tr>
<tr><td>Clause: 4.17

Tax rate</td><td>In view of the above discussion and recent amendments to the Income tax regime, a domestic company shall fall under one of the following brackets, and the maximum tax amount that shall be payable is limited by the tax rates notified for the relevant category. Therefore, Base Rate of RoE may be grossed up as follows:

1. At MAT rate (If not opted for Section 115 BAA)

2. At effective tax rate (if not opted for Section 115BAA) subject to ceiling of Corporate Tax Rate; or

3. At reduced tax rate under Section 115BAA of the Income Tax Act or any other relevant categories notified from time to time subject to ceiling of rate specified in the relevant Finance Act.

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

In view of the above discussion, comments and suggestions are sought on the above and any other alternative(s).</td><td><u>Comments & Suggestions:</u>

1. ROE should be grossed up with actual rate of tax paid.
2. Therefore if company falls in any of the conditions as mentioned in the Paper as under :
a. MAT rate OR
b. At effective tax rate (if not opted for Section 115BAA), OR
c. At reduced tax rate under Section 115BAA of the Income Tax Act OR
d. any other relevant categories notified from time to time subject to ceiling of rate specified in the relevant Finance Act.

Then ROE must be grossed with the actuals ROI whatever category it falls.</td></tr>
<tr><td>Clause 4.18.1

Working Capital For Thermal generation:</td><td>The Commission has been specifying different norms for approving working capital requirements for coal/lignite, gas, hydro generating stations and transmission business. The Commission, while formulating the CERC Tariff Regulations, 2019, has adjusted the norms considering the following key determinants.</td><td><u>Comments & Objections:</u>

A. Working capital consist of following components:
(i) Cost of coal or lignite and limestone towards stock,(for 10 days for pit-head generating stations and 20 days for non-pit-head generating)</td></tr>
</table>

Clause No.	Approach paper	Comments
	1. Actual fuel stock position maintained by plants – Pit Head (changed to 10 days from 15 days) and Non-Pit Head (changed to 20 Days from the earlier 30 days) 2. Average Credit Cycle – Changed to 45 days Receivables. The CERC Tariff Regulations, 2019 also allowed the fuel cost for the purpose of computation of working capital to be linked with the latest available prices, as against the previous mechanism of calculating the fuel cost at the commencement of the tariff period without any price escalation. The Commission has now allowed the reset of the fuel price during every financial year of the tariff period. In addition to the above, the Commission also specified the working capital norms for Emission Control System through the first amendment to CERC Tariff Regulations, 2019. **It is observed that the working capital norms are efficient, so the existing norms may be retained. However, comments and suggestions are invited on any modification that may be required in the norms.**	*(ii) Advance payment for 30 days towards cost of coal or lignite and limestone for generation corresponding to the normative annual plant availability factor* *(iii) Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil;* *(iv) Maintenance spares @ 20% of operation and maintenance expenses including water charges and security expenses;* *(v) Receivables equivalent to 45 days of capacity charge and energy charges* *(vi) Operation and maintenance expenses, including water charges and security expenses, for one month.* B. In the recent past there were instances where in the GOI issued direction sunder sec-11 of the Act to mandatory blend the imported coal by up to 10%. The directives further required to mandatorily place the orders of the imported coal (in advance) to avoid any loss of generation due to coal shortfall. C. Advance payments made to coal accompanies along with LC charges (in case of payment through LCs) should be incorporated in W/C norms. D. The Working capital norms do not accommodate such fluctuations and are based on the prices of domestic coal only under normal circumstances. E. The Imported coal costs is substantially high as compared to domestic coal and procurement of such imported coal needs increased amount of Working Capital requirements. F. Also the Change in Law events also cause increased working capital requirements, G. Secondly for computation of Energy Charges for calculation of working capital, the Coal cost is considered before the start of the control period. This number is considered as constant for calculating the cost of Coal/Energy Charges receivables for next five years period for purpose of Working Capital computations. → The Approach is erroneous since the energy charges fluctuate almost every month and in the scenario where imported coal needs to be blended the allowed working capital is low as compared to actuals. H. Therefore it can be seen that there is a need to review the existing norms in order to accommodate such instances of increased working capital requirement. **<u>Suggestions</u>** A. It is suggested to link the energy charges & Coal Cost for purpose of working capital with the CERC Escalation rates applicable for Domestic coal B. Alternatively the energy charge component of the working capital may be allowed separately to be computed on monthly basis based din actual fuel cost. C. Impact of Change in law on Working capital to be separately allowed on case to case basis.

Clause No.	Approach paper	Comments
Clause 4.18.1 **Working Capital For Gas generation:**	With regard to gas based generating stations, from the operational data in recent years, it is observed that the PLF of such generating stations is around 20%-25%. As power from these plants is costlier it is generally scheduled by beneficiaries only to meet peak requirements. It is anticipated that these generating stations will continue to operate at such low PLFs in the next tariff period, and therefore, the current practice of allowing working capital requirements considering generation at normative PLF may need review. Comments and suggestions are invited on any modification that may be required in the norms of old gas generating stations to factor in the actual generation while allowing for the working capital requirement for gas based generating stations.	**Comments & Suggestions:** 1. CERC should prepare a recovery plan for revival of Stranded Gas based Assets. 2. Peak and Off-Peak Tariff should be specified for gas based stations to enable participation in HP-DAM. 3. Road map should be provided for Gas Plants to participate in AS markets against provisions for price realization according to the nature and duration of services availed.
Clause 4.18.2 **Rate of Interest on Working Capital**	The Commission, while formulating the CERC Tariff Regulations, 2019, shifted from base rate to a more efficient MCLR based funding which is more responsive to policy rate changes. As per the existing Regulations, the Bank Rate for the purpose of computing the Interest on Working Capital (IoWC) is defined as one-year MCLR plus 350 bps. **Stakeholders may comment as to whether the same may be continued or may suggest any better alternative to the same.**	**Comments & Suggestions:** **The same methodology must continue.**
Clause 4.18.3 **Normative Working Capital and interest thereon**	As discussed in Section 3 of this Approach Paper, in order to simplify the process of tariff filing and its determination and reduce the regulatory burden on generating and transmission companies, the possibility of determining Annual Fixed Charges (AFC) on a normative basis is being evaluated. Most of the cost components, such as Depreciation, RoE, O&M Expenses, are already determined on a normative basis. It is further observed that the working capital norms are allowed and then trued up after factoring in the actual receivables, fuel prices (Thermal Generation), MCLR and normative O&M expenses. With regard to thermal and gas based generating stations, fuel costs form sizeable part of the working capital requirement, and as working capital requires truing up on the basis of actuals primarily because of changing fuel expenses, **it is to be explored how working capital can be approved such that yearly truing up is not required.** **Comments and suggestions are sought from stakeholders on the ways to determine IoWC along with any other alternatives, if any, so that the same may not require periodic truing up.**	**Comments & Suggestions:** On the start of the tariff period O&M may be provided based on the actuals thereon it can be linked to CERC escalation rates. Escalation rate to be employed should be suitable combination of Energy Charge and Capacity charge escalation rates specified by CERC.
Clause 4.19 **Life of Generating Stations and Transmission System**	It is observed that as more and more coal based thermal generating stations are operating efficiently even beyond 25 years, there may be a case to align the normative life of these stations, considering that with proper upkeep, these generating stations can operate even beyond 30 years. Similarly, in the case of transmission sub-stations it is observed that these assets can operate way beyond 25 years similar to transmission lines, and therefore, **the useful life of coal based**	**Objections & Comments:** • For transmission lines life of 40 years is reasonable however for coal based plants increase in the plant life shall hinder the recovery of Depreciation since the typical borrowing tenure is 12 years and any change in Plant life shall be detrimental to recovery of Depreciation.

Clause No.	Approach paper	Comments
	thermal generating stations and transmission sub-stations may be increased to 35 years from the current specified useful life of 25 years. It is, however, observed that one of the factors that has enabled these assets to operate beyond 25 years is the regular operations and maintenance carried out by the utilities. In the past, the Commission has allowed a special allowance for these assets in order to take care of the increasing need for repairs that are required to keep the equipment operating efficiently. As the need for higher repairs will still be required, the current dispensation of allowing a special allowance or provision of R&M may be continued after 25 years. **Comments and suggestions are sought from stakeholders in on the proposal.**	• For New Plants it would be difficult to get the loan of > 15 years tenure→ Depreciation under recovery • The useful life of the station cannot be increased without taking into account the design parameters. There are some units which are designed for specifically 25 years. For ex. GMR Warora as per design specification is designed for 25 years only • CEA part load operations regulations shall come in force during next control period→ shall reduce the useful life of the Thermal units due to part load operations. • The Units which are running efficiently beyond 25 Years are supplied by BHEL. However, most of the IPPS have installed the Units of Chinese origin which are ye tot to establish their actual age. • Before taking any action re. tweaking of the Normative Age of thermal units a comprehensive technical study must be carried out by independent experts. • Views of OEMs (Chinese & others) must also be sought. • The Increment of Age should be Unit specific and only those units should be allowed to operate beyond 25 years which are given clearance in the technical studies of the independent experts. • The Independent study should be made only after completion of 12-15 years from COD. • Policy initiatives of Govt indicate that Indian Electricity market is moving towards a shorter duration whereby PPA tenures would be capped for 12-15 years; in such a scenario any increase in normative plant life needs to be avoided **Therefore in such a scenario the useful life of the Generating station should not be tweaked in this control period. Regulations may be framed accordingly.**
Clause: 4.21 Sharing of Gains	Regulation 60 of the CERC Tariff Regulations 2019, allows sharing of gains on account of the following: *1. Due to efficiency gains related to operational parameters namely Station Heat Rate, Auxiliary Energy Consumption, SFOC which are to be shared in the ratio of 50:50.* *2. Due to the refinancing or restructuring of loans, net gains are to be shared in the ratio 50:50.* *3. Non-Tariff Income – The net income to be shared in the ratio of 50:50.* *4. Clean Development Mechanism (CDM) Benefits – 100% of gross proceeds towards CDM benefits in the first year are to be retained by the developer, and from the second year onwards, 10% is to be shared with beneficiaries, and thereafter, every year 10% incremental benefits are to be shared, subject to a maximum of 50%.* *5. Sharing of income from other businesses of transmission licensees – To be shared with the beneficiaries as per the Central Electricity Regulatory Commission (Sharing of revenue derived from utilization of transmission assets for other business) Regulations, 2007.* It is observed that both generating companies as well as transmission utilities have considerable resources in the form of assets such as land banks and other	**Objections & Comments:** ○ It is suggested that sharing mechanism should be such that if any fresh investment is required to be made by the generator then the sharing of net revenue should be in the ratio if 75(Generator) :25 (Discom)→ This shall encourage the generator to utilize the available resources to its fullest. ○ The generator is paying the rent amount of the land to the Govt./ This amount is not recoverable in tariff. Therefore the major portion of gains for the better utilization of the land should be available with generator only.

Clause No.	Approach paper	Comments
	enabling infrastructure and human resources that can be utilised to increase non-core revenues through lease, data centers, eco-tourism, etc., which should be explored, and in order to generate such lateral revenue opportunities, the utilities need to be incentivised. **1. Ways to increase non-core revenues through optimal utilization of available resources.** **2. Any modification in the sharing mechanism that may be required.** **Comments and suggestions are sought from the stakeholders on the following:**	
Clause 4.22 **Treatment of arbitration award – Servicing of Principal and Interest Payment**	The CERC Tariff Regulations, 2019 provide for allowing Additional capitalization including liabilities, to meet an award of arbitration or for compliance with the directions or an order of any statutory authority, or order or decree of any court of law. It is observed that in certain cases, these awards are issued after prolonged litigation. In general, these awards have two components the principal amount and the interest amount. At times, the financial impact associated with these matters is considerable, and capitalising the entire award amount may result in increased AFC, leading to an additional recurring burden on the beneficiaries over the remaining useful life of the asset. To avoid such situations, the principal amount may be capitalised and the interest amount may be allowed to be recovered in instalments from the beneficiaries. However, such a recovery of interest may also involve carrying cost. **Comments and suggestions are sought from stakeholders on the above approach and alternative ways, if any.**	**Comments & Suggestions:** To avoid tariff shock it is suggested to capitalize 30-50% of the award amount (Including estimated surcharge) before the actual award. Balance amount can be capitalized over a period of 4 years (25% each year) as and when the award gets Finalized
Clause 4.23 **Treatment of interest on differential tariff after truing up**	In order to streamline the rate of interest on the differential amount, the current practice of allowing a simple interest rate as per Regulation 10(7) in the 2024-29 tariff block may be continued. Further, interest may be allowed to be charged on the differential amount by the utility only until the issuance of the order, and no interest may be allowed during the recovery in six equal monthly instalments. Comments and suggestions are sought from stakeholders on the above approach and alternative ways, if any.	Time Value of Money needs to be considered while amending the existing provisions, particularly in a regime of uncertain economic outlook and financial volatility. The Carrying Cost must be payable till the Issuance of the order and Interest must be charged post due date after the Billing.
Clause 4.3 **Capital Cost for Projects acquired post NCLT Proceedings**	Comments and suggestions are sought from stakeholders on the following issues: 1. *Historical Cost or Acquisition Value whichever is lower should be considered for the determination of tariff post approval of Resolution Plan.* *2. Tariff provisions to be included to address the issue of the cost of debt servicing, including repayment, that were allowed as a part of the tariff during the CIRP process.*	**Comments & Suggestions:** Minimum of Cost of Acquisition or Historical cost should be used to determine the tariff. CERC should specify the treatment of cases and impact on tariff where the acquisition of a project results in unsustainable debt to be amortized and recoverable at the end of asset life.
Clause 5.1.1 **Normative Annual Plant Availability Factor (NAPAF):**	• Historically, the target availability has been determined based on the data available for the few past years. The recovery of fixed charges was linked to the Plant Availability Factor (PAF). The Normative Annual Plant Availability Factor (NAPAF) has been specified considering the past years' data and best industry practices. However, due to changing dynamics	**Comments & Suggestions:** **For Thermal Coal based Plants:** • Normative plant availability factor may be retained @ 85% level. • However there should be a **provision for deemed availability in** case of loss of Availability due to fuel shortage or forced shutdown due to part Load operations.

Clause No.	Approach paper	Comments
Review of Existing Norms	such as technological improvement, better O&M practices, and shorter shutdowns and outages, the PAF has improved. • However, a shortage of domestic fuel affects PAF, and it has been an area of concern in recent years. In the event of bridging the gap through e-auction, or imported coal (other than fuel arrangements agreed in PPA), the need for prior consent of beneficiaries, the maximum permissible limit of blending, etc. has also been deliberated under Section 5.9 of this Approach Paper. • Similarly, for Hydro generating stations, PAF is impacted due to changing hydrology, and restrictions imposed on the flow of water, and changes in the pattern of water usage in the case of multipurpose dam projects. **In view of the above, the existing norms of NAPAF may need review by considering past years' PAF, the procurement of coal from alternate sources, other than designated fuel supply agreements, changes in hydrology, etc.** • Further, it is observed that current Regulations, although specifies the mechanism for computing PAF of storage based hydro generating stations, do not specify a methodology for computing PAF of Run-of River (ROR) Plants. There is a need to specify a mechanism for the same, and based on such a specified mechanism, the current NAPAF value may need reconsideration. • **One option can be to re-introduce the methodology that was being adopted in the CERC Tariff Regulations, 2004. Based on Regulation XI (b) under Chapter 3 of the Tariff Regulations, 2004, the methodology can be specified as follows:** ***"In case of purely run-of-river power stations, declared capacity means the ex-bus capacity in MW expected to be available from the generating station during the day (all blocks), as declared by the generating station, taking into account the availability of water, optimum use of water and availability of machines;"*** • Comments and suggestions are sought from stakeholders on the above suggested option and any other methodology that can be considered for the computation of plant availability for ROR based hydro generating plants.	• Accordingly the regulations for the forthcoming control period may be framed.
Clause 5.2 **Peak and Off-Peak Tariff**	• In the tariff period FY 2019-24, the concept of peak and off-peak tariff was introduced for thermal generating stations to incentivize peak period availability and availability during peak demand season. Further, the Tariff Policy also specifies that differential rates for fixed charges should be introduced. • **As recovery of reasonable costs is of prime importance for any infrastructure sectoral growth, comments/suggestions are sought on the possible interventions/modifications required to address the**	**Comments & Suggestions:** Daily peak and off peak based recovery is not advisable. Regional Peak & Off-peak needs to be followed as per current practice. It is suggested if there is any loss in the recovery of capacity charges corresponding to Peak period of a particular year then the generator must be allowed to recover that loss during the balance period of the Control period.

Clause No.	Approach paper	Comments
	issues highlighted above. Specific suggestions are also sought on the following. **1. Whether it would be advisable to limit the recovery based on daily peak and off-peak periods.** **2. Suggestions on National versus Regional Peak as a reference point for recovery of fixed charges.**	Due to part load operations as mandated to be commenced during next tariff period there will be increased need for O&M and shutdowns therefore it may not always be possible for plant to be available during peak hours
Clause 5.6 **Operational Norms for emission control system**	• **As only very few of such emission control systems have been commissioned, and in the absence of sufficient data on actual operational performance and its impact on auxiliary consumption, the current tariff norms may be continued for the next control period. However, comments and suggestions are sought from stakeholders on the continuation of the existing norms, or is there a need to modify the same?** • **Further, as considerable expenses have been incurred to reduce the adverse impact on the environment, suggestions are also sought on ways to incentivizing proper operation of such emission control systems so that the very purpose of incurring such huge expenses can be achieved and accounted for.** • Implementation of an emission control system also requires the determination of supplementary energy charges, which impacts the power plant's standing on merit order. The Commission, considering that most of the generating stations are yet to install these systems, ruled that these supplementary energy charges shall not be considered while preparing merit order. In view of the earlier approach and considering that most of these generating stations are still in the process of implementing such systems, the current practice of excluding such expenses while preparing merit order may be continued. **Comments and suggestions are sought from stakeholders on whether the current mechanism to exclude these expenses may continue until these generating stations equip themselves with emission control systems as per the MoEF&CC notification dated 31.03.2021?**	**<u>Comments & Suggestions:</u>** • As indicated in the staff paper itself that only few emission control systems have been commissioned therefore at this juncture specifying the stringent norms without taking into account the ground realities and actual operational data is inappropriate. • The commission has standardized the reagent consumption, O&M, Aux power due to Emission control systems in the regulations. It is requested to reexamine the same and for the forthcoming tariff period there must be relaxation in the norms. Standardization approach must be taken from the 2029-34 tariff period when the actual data of emission control systems shall be available • Considering the variable charges of the emission control systems for preparation of the Merit Order is neither prudent nor just. This would amount to penalizing those generators who have implemented MOEF directives ahead of the deadline • The MOD must be prepared excluding the Variable charges of Emission control system still the deadline to install the FGD systems i.e. 31.12.2024 or any other date as and when decided by the Ministry.
Clause 5.7 **Compensation for Part-Load Operations:**	• It is observed that the current dispensation allows degradation in the following operational norms, for part load operations of the generating stations. *1. Station Heat Rate* *2. Auxiliary Energy Consumption* *3. Secondary Fuel Oil Consumption* • It is observed that currently the impact is being allowed considering the norms or actuals, whichever is lower. This mechanism results in operational gains being passed on to the beneficiaries, while any losses are borne by the generator. The mechanism may need a review wherein either normative norms are followed, or compensation is limited to actuals. • It is further observed that there have been instances where the actual PLF of plants has been even below 55%. The current provisions for compensation do not cover operating PLF below 55%, and therefore, devising a compensation mechanism to govern such cases may also be required.	**<u>Comments & Suggestions:</u>** • Ministry of power had already notified the Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023. • As per the said regulations a Thermal Plant must be able to operate at 40% PLF which is quite below the operational Norms. • Therefore the forthcoming regulation may specify the Norms of operation considering the below technical minimum operation. • Commission should come up with draft methodology to compensate the plants on account of part load operations. • If a Generator is operating below the technical minimum level then the following relaxations must be extended to it: 1. **Actual SHR & Aux power consumption during part load operation** 2. **LDO/ HFO consumption to part load operation.** 3. **Reduced Life of Machine→** Accelerate depreciation benefit in order to recover the entire depreciation within reduced lifecycle of machine

Clause No.	Approach paper	Comments
	With regard to the compensation norms, an Expert Committee has already been constituted; however, in view of the above discussion, comments and suggestions are sought from stakeholders on the earlier norms and any changes that may be required to compensate the generators to operate the plants in a flexible manner to support the Grid.	4. **Increased Coal consumption due to degradationation in SHR, AUX.** 5. **Increased O&M expenses to deal with technical challenges arising due to modification sof the existing units due to CEA regulations for flexible operation.** 6. **Increase working capital required owning to increase in operating costs.** 7. **Part load operation expenses must be covered under uncontrollable parameters (Regulations 22 of 2019-24 Control period) of the Regulations and must be entirely pass-through.** • Duration of part load operation must be noted/recorded at SLDC/RLDC level and at the end of tariff period truing up exercise the cost attributable to part load operations must be compensated based on the actual expenses incurred. A separate tariff form may be inserted in this regard.
Clause 5.8 **Gross Calorific Value (GCV) of Fuel**	Gross Calorific Value (GCV) of fuel is one of the most important factors on which energy charges depend. Based on the measurement points, the GCV of any specific fuel can be different, such as GCV "as Billed" (As billed by Coal Company), GCV "as Received" (GCV measured when the fuel is received) and GCV "as fired" (GCV of coal just before it is sent for firing). -------------- The GCV of fuel keeps on varying at different reference points due to various factors such as moisture content, and grade slippages at the mine end, or during transportation or during storage at the plant end. The current Regulations specify that the GCV of fuel for the purpose of allowing energy charges shall be considered on an as received basis as other factors due to which there is a loss in GCV are not under the control of the generating stations. The Commission, considering the same allowed computation of energy charges on the basis of GCV "as received" basis plus an additional margin of 85 kCal/kg towards storage losses without differentiating between pit head and non-pit head stations. The approach has found wider acceptance, however, it is observed that the variation in GCV "as billed" and "as received" is significant due to loss of GCV at mine end and during transportation, often leading to grade slippages. Though, the magnitude of such losses has reduced in the past, they are still significant and **may need to be accounted for in terms of risk sharing between the coal company, the railways and the generating station.** At present, the generator pays for the coal based on GCV "as billed" and quantum of coal at the loading point. It is observed that the loss in GCV from "as billed" to "as received" has been allowed on an actual basis. As mentioned earlier, even though the loss in GCV "as received" vis-à-vis "as billed" has reduced, one can argue that as the actual loss has been allowed in the past, there have not been considerable efforts made by generators in minimizing the loss. **Comments and suggestions are sought from stakeholders on ways to reduce the gap between GCV "as billed" and "as received".**	**Comments:** It may be noted that there are many reasons for deviation between as Billed as and As received GCV of coal as discussed below: 1. Different methods of measuring GCV are used for different purposes. Three methods were seen to be used: **A.** *For imported coal, GCV was reported on 'Air Dried basis' (ADB) while paying for coal imports.* **B.** *For payment to domestic coal companies for supplies, GCV was reported on 'Equilibrated basis' (EB)* **C.** *For energy billing, the stations reported GCV on 'Total Moisture basis'(TMB)/ARB* **The different methods used for assessing GCV lead to different GCV values→ For a given sample, ADB method gives the highest GCV value followed by EB method. The TMB method gives the lowest GCV value among the three methods.** 2. Mis-declaration of Grade by Coal companies: Sometimes there are instances where the coal company declares a higher grade of coal but actual receipt is of much lower grade. Such cases are dealt in accordance with established practices and benefit of Lower Grade GCV is captured in Form-15 and passed on to consumers at a later date. 3. During monsoons the ARB GCV variance from the billed value is higher. **4.** Railways plays no role in GCV loss minimization, its role its limited to transportation. The Railway being in Monopolistic situation shall not allow any compensation/sharing of Risk on account of Loss of GCV. 5. Insurance of Coal during transportation is also available for only Loss of Quantity not for the Loss of Quality. 6. Grade slippages are also dealt with coal companies in accordance with the provisions of the FSA and benefit if any is passed on to consumers a later date. The FSa is standard document and is specified by Ministry only. 7. generator has very limited role to play prior to coal is actually delivered at its premise and efficiency of generator in preventing GCV loss may be measured by comparing as Received and As fired GCV. **Suggestions:** **New pricing regime (as suggested below) is necessary to avoid this anomaly and align to Global Practices.**

Clause No.	Approach paper	Comments
		International norms of coal pricing follow the practice of declaring GCV on 'As Received Basis (ARB)', being measured at loading end, and thereby, capturing Total Moisture content in coal. *it is suggested that GCV measurement of CIL coal under third party sampling be undertaken on-site at the loading end under prevailing atmospheric conditions and declared on 'As Received Basis (ARB)' to form the basis of initial invoicing and subsequent true-up at receiving end basis CERC regulations of GCV corrections.* *It is to be ensured that such exercise of determination of GCV is completed within a prescribed time limit so that the sample represents the actual Total Moisture Content in coal and is not affected by the atmospheric conditions in the laboratory that is likely to occur if it is kept for a prolonged time.* *GCV on 'As Received Basis'/'GAR', will correspond to coal delivered via Rail or Road Receipt Challans at the Point of Sale and prices are to be aligned according to the band such GCV will conform to.* *In other words, prices should be reset according to GAR and the corresponding GCV band to reflect the marketable heat content of coal sold to customers at the loading end.*
Clause 5.9 **Blending of Coal**	In order to address the issue of depleting coal stocks and building stocks before the monsoon, the Ministry of Power issued an advisory dated 07.12.2021 to all domestic coal based power plants to import coal to meet their requirements by blending with imported coal to an extent of 4% by State generating companies & Independent Power Producers (IPPs). MoP again vide its letter dated 28.04.2022 directed the concerned stake holders to import at least 10% of their coal requirements for blending. Due to the easing out of the shortage situation, MoP again, issued revised directions vide letter dated 09.01.2023 wherein the domestic coal based generating stations are required to plan for 6% blending until September 2023. The generating companies are reported to be facing problems complying with the above directions of the Ministry of Power on account of the absence of permission by the concerned beneficiaries, which is required under Regulation 43(3) of the CERC Tariff Regulations, 2019. Regulation 43(2)(b)(3) of the CERC Tariff Regulations, 2019 stipulates as follows: ***" Provided also that where the energy charge rate based on weighted average price of fuel upon use of alternative source of fuel supply exceeds 30% of base energy charge rate as approved by the Commission for that year or exceeds 20% of energy charge rate for the previous month, whichever is lower shall be considered and in that event, prior consultation with beneficiary shall be made at least three days in advance."*** Staff of the Commission, in June 2022, published a paper analyzing the impact of blending of coal on the energy charges and noted that even when blending of coal is less than 10%, the 30% ECR threshold limit gets breached. In view of the same and considering that the shortage situation may recur, following can be analysed.	**<u>Objections</u>** Procurement of Alternative coal on competitive bidding basis should not be made compulsory The Procurement of coal through Transparent competitive Bidding is not always feasible due to many operational difficulties. Some of them are listed below: 1. Coal Suppliers are limited and it's not necessary that competitive Bidding shall provide the lowest prices. 2. Urgent procurement do not leaves enough time to follow NITTY-GRITTY of competitive bidding. 3. The Govt. directives have not made any such requirement to procure Coal on Competitive Bidding basis. **<u>Comments & Suggestions:</u>** It is suggested that asking for the beneficiaries' approval for Blending once directives have been issued by ministry is vague process and serves no purpose as Directions of the govt. Under sec-11 or any other notification shall supersede the Tariff regulations and is binding on all the parties including the beneficiaries. Alternatively, commission may replace the words % increase in Base energy Charge" with the Blending Percentage. **<u>The Competitive bidding condition for Procurement of Alternate coal must not be impose din regulations.</u>**

Clause No.	Approach paper	Comments
	"Linking the consent of beneficiaries with the percentage blending of imported coal instead of an increase in ECR may enable a swift response to an increase in demand by the generating company. Procurement of such coal (other than linkage coal) has to be done through a transparent competitive bidding process." **Comments and suggestions are sought from stakeholders on the above proposal and any other alternative, if any.**	
Clause 6.2 **Tariff Structure for Cost Recovery for Emission Control System**	As not all generating stations have installed the emission control system, and most of these works are in the execution stage, therefore the existing tariff recovery mechanism may be continued. **However, comments and suggestions are sought from stakeholders on alternatives to the existing tariff mechanism for recovering the impact of the installation of emission control systems.**	**Comments & Suggestions:** The Regulation issued by CERC re. recovery of Tariff for installation of Emission control systems have following issues: 1. **Plant Life→** Ld. CERC has failed to consider Plant Specific Design factors and has come out with a blanket order with respect to the Plant Life. Ld. CERC failed to consider the fact that there are some Plants which are Specifically designed for 25 years. 2. **Depreciation→** Recovery is extended beyond PPA tenure & Plant life. 3. **Reagent Consumption→** has been standardized. Instead of actuals 4. **O&M Expenses→** Allowed value is lower than the estimated actuals 5. **No Provisional tariff Granted** 6. **ROE recovery:** has been reduced

PART-B: Comments & Suggestions of Additional aspects not covered in the Approach Paper

Aspect	Comments/issues & Suggestions
Cross Border trade	• The commission should provide guidelines for Tariff determination of Hydro Generation in case of cross border Import by an Indian entity. (*as per clause 7.1 1 of the Guidelines for Import/Export (Cross Border) of Electricity-2018 issued by Ministry of Power.)*
Norms of Operation for 350/ 300 MW units	**Issue:** • Prevalent Tariff regulations do not provide any separate norms (SHR, AUX, O&M etc.) for 300/350 MW unit sizes→ creates ambiguities as different unit sizes have different parameters • It is to be noted that the Norms of Operation (SHR, AUX etc), as specified by CERC in the Tariff regulations is also applied for Change in law Compensation for Sec-63 PPAs. Therefore the Norms of Operations have a wider implication not only on Sec-62 PPAs but also for Sec-63 PPAs. • Currently CERC is applying the norms of 500 MW units for 300/350 MW units. However 500 MW unit sizes have different technical specifications and abaility. Now there are sufficient number of 300/350 MW units operating in the country (close to 10 years). Therefore, CERC should take into account the actual data of those units and come out with parameter/Norms more close to reality rather than clubbing with 500 MW Unit size. **Suggestions:** • CERC must specify separate norms for 300/350 MW units.

Part-C: Comments on Addendum to Approach paper: Compensation methodology for operating a Plant below 55% min. Power Level

General Comments

- The Flexibilization of Thermal Units is a Change in Law event under tariff regulation 22 (2) (b) and should be treated under Uncontrollable Parameters and impact must be a complete Pass-through as per the regulations.
- Compensation should be plant specific, based on actuals Subject to prudence check.

Re. CAPEX

- The proposed estimated CAPEX numbers in the approach paper by are limited in their scope and are not applicable for all the plants. For ex. Paper has not specified the numbers for 300 or 350 MW units.
- The proposed CAPEX numbers should only be treated as Benchmark and not the ceiling limits.
- The CAPEX numbers may not be close to reality. For Ex. CEA had provide the Benchmark costs for the FGD installations however the actual costs for large no. of cases are in variance of the specified benchmarks costs by CEA.
- The Cost incurred on retrofitting of the units for enabling the part load operation must be allowed under Ad-Cap on actuals.

Re. Penalty

- There should not be any penal provision for not exhibiting part load level for at least 6 months from the retrofitting of the units. This would allow the system to be stabilized.
- Penal provisions in failure of part load operation may be incorporated in 2019-34 period based on the experiences of 2024-29 tariff period.

Re. O&M & other Costs

- If any shutdown is required for the retrofitting then it must be allowed under deemed availability→ Discussion paper is silent on this aspect.
- Incremental O&M Expense should be allowed separately on actuals based don the duration of the Part load operation and actual load level.
- Cost attributable to O&M i.e. heat rate degradation, Increased APC, Oil Cost etc. to allowed on actuals based on actuals.
- Due to increased O&M there will be increase in instances of shut down of the units causing revenue loss to the generators→ There should be a mechanism to identify & reimburse such losses to the Generators.

Additional Points for PSPs *(per MoP Guidelines dated 10-4-23)*

- Peak and Off-Peak Tariff to provide price signals for peak and base load operations
- Road map for monetisation of AS operations