Annexure A: MSPGCL's Comment on CERC Approach paper on Terms and Conditions of Tariff Regulations for Tariff Control Period 2024-29

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
3.1	***Tariff Determination - General Approach*** ……………. *The upcoming Tariff Regulations shall regulate the tariff of existing capacities as well as new projects under the RTM route under Section 62 which would continue to be the major source of power supply and cater to the growing demand of the country.* *In view of the above, 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.* *1. 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.* *2. 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 capitalisation may be allowed on certain counts on a normative basis.*	Given the current and expected changes in the power sector, it is important to acknowledge that relying solely on a normative approach for tariff determination would not be suitable under the circumstances. Pure normative approach would not be able to address the requirement of the expenses based on the dynamics of the power sector. Therefore, MSPGCL recommends against adopting an indiscriminate normative tariff approach for determining the tariffs of generation assets. MSPGCL acknowledges the importance of implementing a performance-based hybrid approach. However, it is crucial to ensure that generating companies can recover their costs to the fullest extent possible, when substantiated by supporting rational, and the determination methodology or approach should not unjustifiably restrict the entitled amount on account of simplification of tariff approach. Thus, it is necessary to conduct a prudence check on the expenses when allowing them under the performance-based hybrid approach. Even the guiding principles set under Section 61 (d) of the Electricity Act, 2003 specify for *safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;* **Therefore, simply applying norms to determine the expense amount would not fulfil the intended objective of recovery of reasonable cost of generation as given under Electricity Act, 2003.** The emphasis should be on addressing changes that pose implementation challenges. Introducing any drastic changes that give

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		the impression of reducing tariff revenues for generating companies would serve as deterrent. **Considering the aforementioned points, MSPGCL recommends against adopting a normative approach for tariff determination and suggests that the Hon'ble Commission may consider continuing with the current Hybrid approach of tariff determination.** Further, MSPGCL has provided its ARR component-wise detail submission against the respective provisions in this document.
3.2	***Approach 1: Normative Tariff*** ***3. Additional Capitalisation*** *It is further observed that apart from the year- on- year variation, which could be station specific, there could be inherent variation due to different costs of funds, funding patterns, depreciation rates, additional capitalisation and other plant specific peculiarities, and therefore a normative tariff for these stations appears to be feasible only when determined asset specific.* *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.* *In order to achieve the dual objectives as flagged above, for existing generating stations and transmission systems whose cut-off date shall be over by 31.03.2024, the gross fixed assets as approved as on 31.03.2024 may be considered for projecting base year AFC i.e., for the*	It is worth emphasizing that additional capitalization varies between stations due to site-specific factors. Therefore, a normative tariff mechanism would not be able to accommodate these dynamic requirements effectively. **Therefore, in the case of additional capitalization, it is advisable to allow it on an actual basis after conducting a prudence check. It is rightly pointed out that there would be inherent variation due to different cost of funds, funding patterns, depreciation rate, additional capitalisation and other plant specific peculiarities. Hence, it would be prudent to adopt the present hybrid approach of tariff determination in case of additional capitalisation as well.**

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	first year of the Control Period (FY 2024-25). Subsequently, fixed charges for future years may be approved on the basis of indexation that may be specified for each generating station/transmission system by the Commission from time to time. *In the case of new generating stations and transmission systems, as observed earlier, there is variation in the first 4-5 years causing aberrations, therefore, it is proposed that once the capital cost is approved on an actual basis as on cut-off date (5 years post CoD) after carrying out detailed scrutiny, all components of fixed charges may be determined on a normative basis from the sixth financial year (Base Year).* *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.*	
4.2.2	***Procurement of Equipment and Services*** *Section 63 of the Electricity Act, 2003, mandates that tariff be determined based on competitive bidding, Section 62 is about the determination of tariffs under the cost plus mechanism. It is, however, imperative that even under Section 62, the procurement of equipment and services be carried out through competitive bidding. In such a framework, in the interest of consumers, Work Contracts are required to be awarded on the basis of transparent competitive bidding, which shall form the basis of approval of such costs. Further, Tariff Policy, 2016 lays emphasis on the utility and benefits of competitive bidding, and therefore, even for projects being developed under Section 62 of the Act, the works need to be executed following the transparent process of competitive bidding. The Commission, through various Orders, have also*	The equipment and services for any utility/generating companies needs to be qualitative but at reasonable prices. The regulated tariff mechanism fulfils the requirement through competitive bidding and brings the transparency in the process. Hence, the process adopted for the award of work and service contracts can come prudence checks / scrutiny required under regulated tariff mechanism. Accordingly, the Appropriate Commission may issue directions for following specific policy / guidelines issued by the Government of India.

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	laid emphasis on the need to follow a transparent process of competitive bidding for the procurement of equipment and services. *In view of the benefits that a transparent process of competitive bidding has and in order to protect consumer interests, it would be prudent to mandate the procurement of equipment and services duly following the policy/guidelines issued by the Government of India.*	
4.2.3	***Reference Cost for Approval of Capital Cost – Benchmark Cost V/s Investment Approval Cost*** *Another aspect with regard to the approval of capital costs that has been debated while framing earlier Tariff Regulations is the reference cost that needs to be considered while approving capital costs. The existing methodology of relying on the investment approval cost was also debated; however, in the absence of a better reference/benchmark cost due to the paucity of reliable data and the complexities and difficulties involved, the reliance on investment approval has continued. However, the hard costs of recently commissioned projects of similar specifications are referred to for prudence checks.* *For a thermal generating station, it is observed that there are several differences with regard to site conditions, water handling, coal handling systems, etc., and one benchmarked cost may not be a true representation of all such plants on the basis of which actual costs can be disallowed. These issues are even more profound in the case of hydro generating stations, as the costs significantly depend on several aspects such as choice of technology, design, reservoir based/Pondage/ROR, etc.*	1. The capital cost of Generating stations is dependent on site conditions, water handling, coal handling systems, etc. The cost also varies as per the market condition. Therefore, using benchmark cost as a reference for approving capital costs is not justified. 2. The investment approval cost also does not encapsulate the practical condition of the market. 3. Therefore, it is suggested to conduct a prudence check that takes into account the trend in previously approved costs and prevailing market conditions. This will allow for the determination of the most practical and reasonable cost.
	Capital Cost of Hydro Generating Stations	

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4.2.4	*As discussed in Section 3 of this Approach Paper, one of the primary reasons for a higher tariff in the case of hydro generating stations is the high capital cost incurred due to various reasons. The Commission has been carrying out prudence check on the capital cost of hydro generating stations on the basis of actual costs incurred. It has been observed that the major works of these projects are normally awarded through cost based competitive bidding with price escalation clauses. As these projects go on for years due to inordinate delays leading to cost overruns and time overruns, the price bids are rendered irrelevant. Suggestions are, therefore, invited for alternate ways to bid hydro projects as per the policy/guidelines that may be specified by the Government of India from time to time. In such biddings, the minimum implementation schedule quoted can be an important factor in the selection of contractors.* *It is also observed that the construction of hydro generating stations does impact local areas, especially those falling under the catchment area. As the people are affected, there is generally a growing dissatisfaction against the developer, which needs proper redress. The developers voluntarily carry out local area development initiatives such as building roads, schools, and clinics for the benefit of the people and to mitigate resistance to the project* ***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***	

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	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". ***Comments and suggestions are sought from stakeholders to incentivise the developer if it executes the project faster/ or ahead of schedule and vice-versa if it delays***	
4.3	*Capital Cost for Projects acquired post NCLT Proceedings* ***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.***	Major reasons for the power stations undergoing liquidations is unavailability of the power purchase agreements, absence of the fuel supply arrangements, land acquisition issues, delay due to the cost overrun because of the environmental/forest clearances, Local factors. **It is respectfully submitted that for the NCLT stations, if acquisition price is less than of the actual price for the project, Risk premium may be allowed to the new owners considering the risk involved with the project and therefore actual project cost allowable under normally adopted regulatory prudence and after factoring appropriate depreciations may be considered for the determination of the tariff.** **Similar approach may also be adopted in case of acquisition of such stranded assets in due-diligence process out of NCLT proceedings.**
4.4.1	***Computation of IDC – Post Scheduled COD*** *The above amendment read with Regulation 19(2)(b) of the CERC Tariff Regulations, 2019, provides for the computation of IDC on normative loans in cases of equity infusion in excess of 30% and may be continued.*	1. Delay in the project implementation due to the unforeseen conditions should be allowed in case of the uncontrollable factors which are beyond the control of the project developer/Generator. It is important to highlight that imposing penalties on developers by

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	It is further observed that there have been instances wherein the developer did not incur any IDC till SCOD as interest liability for the project started after SCOD and due to the above provision, in case the delay is not condoned, the entire IDC gets disallowed, which does not seem to be appropriate. ***In view of the above, it has been argued that the provision can be modified so as to allow proportionate IDC upto SCOD or upto the date of delay condoned on the basis of total IDC worked out till actual COD.*** ***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.***	disallowing IDC (Interest During Construction) for delays that are beyond their control would be unjustified. 2. Delay is being considered in the Original implementation period due to the unforeseen reasons, However the delay cannot be envisaged beforehand precisely. Hence, the existing mechanism wherein the pro-rate deduction may be done on IDC beyond SCOD. 3. IDC computed as per the Original investment approval is considering the ideal construction period with all the clearances/approvals in place or assumed to be obtained on time. It is also assumed that all the materials being supplied on time by the EPC contractor, power evacuation lines, water supply arrangement and other infrastructure to be in place on time. 4. There are certain non-controllable factors like Environmental clearances, Forest clearances which are not in the control of the developers. Also in case of unforeseen events like land acquisition issues, riots, fire, accident on site, pandemic situations like COVID, variation in the scheduled time for project completion is bound to happen which will impact the IDC. Accordingly, actual IDC may be allowed post prudence check.
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*	Relevant draft of 'Form' may be made available for offering comments from various stakeholders.

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	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.***	
4.8.1	***Delay towards obtaining forest clearance*** ***The Commission, while framing the CERC Tariff Regulations, 2019, in its Explanatory Memorandum, observed as follows…..*** *delays on account of getting forest clearances may also be many times beyond the control of utilities and therefore have been condoned in the rightful cases.* ***In view of the same, 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.*** *For the reasons mentioned above, the Commission included the delay on account of land acquisition in the list of uncontrollable factors along with Change in Law and Force Majeure. In this regard, it has been observed during the current period that, apart from land acquisition, delays on account of getting forest clearances may also be many times beyond the control of utilities and therefore have been condoned in the rightful cases. In view of the same, delays on account of forest clearances can also be considered for inclusion as uncontrollable factor provided that*	1. It is suggested to continue with inclusion of delay on account of land acquisition as an uncontrollable factor. 2. Delays on account of getting forest clearances is beyond the control of utilities and the Hon'ble Commission has treated delay in obtaining forest clearance as Force Majeure. Hence, it is imperative to include such delays as uncontrollable factors.

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	such delays are not attributable to the generating company or the transmission licensee.	
4.9	***Differential Norms - Servicing Impact of Delay*** *While dealing with various generation as well as transmission petitions in the past, it has been observed that in several cases the delays are attributable to lack of timely clearances, forest approvals, etc. which require constant and rigorous follow up. In most of these cases, it has been observed that these delays could have been restricted if the approvals were sought more assertively instead of merely through written correspondence. It is observed that it is always not possible for the Commission to ascertain if adequate efforts have been made at the senior level to get the clearances. Therefore, though impact of delay on account of uncontrollable factors may be allowed,* ***in order 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***	It is humbly submitted that when the delays are attributable to uncontrollable factors such as lack of timely clearances, forest approvals, etc. which require constant and rigorous follow up. Given that the delay has already been excused and the resulting impact has been accounted for, there is no justification for deducting even the slightest portion of the cost impact. There are certain operating processes which have to be followed for getting the relevant clearances. By stating that if the approvals were pursued with more assertiveness rather than solely relying on written correspondence, it is noted that the Commission may not always be able to determine whether sufficient efforts were made at the senior level to obtain the necessary clearances. If the Generator/licensees has made timely submissions and the authorities have not taken note of them despite multiple reminders, such circumstances should not arise. Therefore, it would be counterproductive to discourage the sincere efforts of Generator/licensees in cases where project delays occur due to the lack of timely clearances, forest approvals, and other factors beyond their control. Moreover, if the delay has already been excused in such instances, it would be inappropriate to disallow a portion (e.g., 20%) of the cost impact that corresponds to the condoned delay.

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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	O&M Expenses of generation company constitute of 1. Employee expenses (around 50% to 60% of total O & M) 2. Administrative and General expenses (around 5% to 10% of O & M) 3. Repair and Maintenance expenses (remaining part i.e. around 40% to 50% of O & M) Employee Expenses: Major heads of employee expenses are a. Basic salary b. Dearness allowances c. Allowances Bonus, other miscellaneous claims d. Terminal benefits (i) PF contributions (ii) Provision of projected benefits obligation towards accumulating Compensated Absences. (iii) Provision of projected benefits obligation towards gratuity. Employee expenses are uncontrollable expenses, especially in the case of government entities/utilities, owing to various socio-economic constraints. Under the current approach, where approved O&M is restricted at the normative level, the funds available for R&M are limited after covering employee expenses and administrative expenses. This results in an observed trend where the increase in employee costs is not adequately factored into the approved O&M costs, leading to constraints for generating companies in carrying out essential R&M activities within the remaining budget. As a consequence, there may be disallowance of crucial R&M expenses, which are vital for maintaining the plant at the desired normative performance levels.

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	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 and suggestions are sought from stakeholders on above suggestions and alternatives, if any.**	**Therefore, the proposed approach of segregating the O&M norms into two categories, namely "Employee costs" and "Other O&M expenses towards R&M and A&G expenses," is a prudent suggestion. This approach would grant generators the necessary flexibility in prioritizing R&M activities and reduce the likelihood of cost disallowances.** **In light of this, MSPGCL respectfully requests the Hon'ble Commission to allow O&M costs in the segregated manner as suggested, with employee costs approved at actuals, subject to prudence check, and the (A&G + R&M) component allowed at the normative level.** **Regarding the challenge of non-availability of historical approved norms in such a segregated manner, it can be resolved by apportioning the approved norms based on actuals during the relevant period. This adjustment would enable a fair and practical implementation of the proposed approach.**
4.12.4	*Inclusion of Capital Spares* *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.*	MSPGCL asserts that relying on correlation and predictability analysis over an extended duration, such as 15-20 years, would be inaccurate due to significant technological advancements during that time. **Therefore, it would be inappropriate to utilize such lengthy trends to make changes in the current mechanism of capital spares allowance. Therefore, MSPGCL suggest for maintaining the present approach of allowing capital spares.**

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	*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 lakhs 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.***	
4.12.5	*Impact on account of Change in Law and Taxes* *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.***	In cases where additional expenses which are one time in nature on account of change in law, the corresponding impact should be permitted as a one-time amount. However, if the change in law results in recurring expenses, it is necessary to include them in the actual expenses and allow for their consideration. A suitable mechanism may be devised to effectively capture and address such recurring impacts.
4.13	*Depreciation* ***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(ies).***	**As mentioned in the Approach Paper, considering the availability of long-term loans for 15 years instead of the current practice of 12 years, it may be suggested to allow depreciation to charge over period to 15 years instead of the existing mechanism of 12 years. This adjustment would aid generating stations in lowering the fixed component of the tariff, ultimately benefiting end consumers.**

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4.14.1	***Weighted Average Rate of Interest and FERV*** ***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.***	In the case of generating companies, it is common to arrange project specific loans and not comprehensive financing for company as a whole. Also depending on the different timelines for different projects the loan tenures as well as loan drawals vary. Hence, the present practice of project specific consideration is more appropriate . **Therefore, MSPGCL recommends continuing the current methodology of calculating interest on loans based on the weighted average rate of interest derived from the actual loan portfolio.**
4.15	***Return on Equity (RoE) V/s Return on Capital Employed (RoCE)*** ***As in the past, much has been deliberated and discussed on the two approaches, and in view of the long-standing position of this Commission, the present system, or RoE approach, may be continued. Comments and suggestions are, however, sought from stakeholders on the continuation of the RoE approach.***	**The Hon'ble Commission made a sound decision when formulating the Tariff Regulations for the 2019-24 Tariff Period by choosing to maintain the Return on Equity (RoE) approach. This decision was justified considering the volatility of interest rates and the limited depth of the debt markets.** **It is recommended to continue the RoE approach for the Tariff Period 2024-29, as it offers investors clarity regarding the returns on their assets.**
4.16	*Rate of Return on Equity* *4.16.4 Methodology* *The formula for computing the return on equity based on CAPM is as under:* ***Re = Rf + β × (Rm − Rf)*** *Where:* *Rf = risk-free rate* *β = equity beta* *Rm-Rf = equity market risk premium*	1. The power sector has experienced an elevated risk perception due to the recent rise in NCLT proceedings. To attract investors in the power sector, it is imperative to design an appealing rate of return on equity that considers the market risk premium. Therefore, it is recommended to incorporate the market risk premium in the formula for calculating the return on equity using the Capital Asset Pricing Model (CAPM) method as proposed in Approach Paper. **2.** SERCs) typically follow the guidelines set by CERC Tariff Regulations. **The segregation of new and existing assets poses a challenge, making it unadvisable to revise the Return on Equity (RoE)**

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	There are different ways of estimating the above parameters. However, the following approaches are proposed for the estimation of the above parameters: ***Risk-free Rate:*** *The risk-free rate is the return that can be earned by investing in a risk-free security, e.g., a Government of India (GOI) bond. Most of the electricity/energy regulators, including FERC, USA, have been using an average 10-year bond yield over a six month to one-year horizon.* ***Keeping in view the international approaches to regulated rates of return, the average 10-year GOI securities rate over a one-year horizon may be considered a risk free rate.*** ***b. Equity Beta:*** *Most electricity/energy regulators calculate beta using a group of companies comparable to the target utility. This is mainly for the reason that the portfolio approach to estimating beta tends to provide more stable results as compared to company specific estimation methods. As for the beta estimates, a period long enough should be considered to create stability and statistically meaningful estimates. The period should reasonably reflect the current systemic risk of utilities as well as market conditions. The most common estimation window among regulators is 3-5 years using daily or weekly data. ACM, Netherlands, has been considering 3 years as a period of estimation, whereas FERC, USA, and Ofgem, UK, have been considering 5 years as* ***Risk-free Rate:*** *The risk-free rate is the return that can be earned by investing in a risk-free security, e.g., a Government of India (GOI) bond. Most of the electricity/energy regulators, including FERC, USA, have*	**specifically for new assets. Therefore, it is recommended to avoid implementing different RoEs for existing and new assets.** 3. Having differential rates of Return on Equity (RoE) for existing and new assets/projects may convey a signal that one is more susceptible to risk compared to the other. However, it is important to note that project risk varies depending on the specific phase of the project.

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	been using an average 10-year bond yield over a six month to one-year horizon. ***Keeping in view the international approaches to regulated rates of return, the average 10-year GOI securities rate over a one-year horizon may be considered a risk free rate.*** ***b. Equity Beta:*** *Most electricity/energy regulators calculate beta using a group of companies comparable to the target utility. This is mainly for the reason that the portfolio approach to estimating beta tends to provide more stable results as compared to company specific estimation methods. As for the beta estimates, a period long enough should be considered to create stability and statistically meaningful estimates. The period should reasonably reflect the current systemic risk of utilities as well as market conditions. The most common estimation window among regulators is 3-5 years using daily or weekly data. ACM, Netherlands, has been considering 3 years as a period of estimation, whereas FERC, USA, and Ofgem, UK, have been considering 5 years……….* ***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?***	

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	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.***	
4.16.5	***Rate of Return – Old Thermal Generating Station*** ***Possible options to encourage higher availability and generation from old generating stations can be as follows.*** ***1) Allowing additional incentive in the form of paise/kWh apart from those currently allowed may be allowed to such generating stations against generation beyond the target PLF.***	It is correctly stated that in order to encourage higher availability from old generating station to address the expecting demand, additional incentive in form of paise/kWh may be introduced. **Furthermore, MSPGCL asserts that if no Return on Equity (RoE) or a lower RoE is permitted for old units, there will be no motivation to operate such aging units.**
4.17	*Tax Rate* ***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.***	**1. Presently tax rate allowed for grossing up RoE is at effective rate which is worked out as MAT or Corporate tax divided by profit before tax. Further, while allowing in True Up, the same has been approved based on documentary evidence.** 2. **Therefore, the proposed or present mechanism of tax rate to be considered for computing effective tax rate may be continued.**

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	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.	
4.18.1	*Working Capital Requirement* ***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.*** ***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.***	Gas generating stations produce relatively expensive power, which is primarily utilized to meet peak demand requirements. The current formula for allowing working capital is not advantageous for gas generating stations, considering their actual Plant Load Factor (PLF). Due to the higher cost of power from gas stations, beneficiaries are not scheduling them frequently. As a result, gas generating stations are entitled to a lower working capital requirement based on the existing formula. Therefore, MSPGCL requests a review of the methodology for determining the working capital requirement specifically for gas generating stations.
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.***	MCLR is a benchmark rate used by banks to determine lending rates for various loans, including floating rate loans. It is influenced by factors such as the repo rate, which is set by the central bank and represents the policy rate. **Hence, given that MCLR rates generally align with policy rate changes, it is recommended to continue linking the rate of interest on working capital to the MCLR rate.**
4.18.3	***Normative Working Capital and interest thereon***	In case of thermal power plants , fuel cost constitutes a significant component of the working capital requirement for generating companies. It is contingent upon the units to be generated, which in turn

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	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.***	relies on plant scheduling based on beneficiary demand. Therefore, the need for a true-up of the working capital requirement is primarily influenced by the variation between estimated and actual generation units. **Considering the dynamic nature of policy changes in the power sector, it would be suitable to maintain the current methodology or mechanism of entitlement of working capital.**
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 thermal***	**It is submitted that, the useful life of generating stations, which may still generate power at a lower rate as compared to a new plant can be extended provided that there should be a clear-cut mechanism of extension of existing PPA and the beneficiaries opting for PPA extension shall remain bound by the same till its extended expiry.** Most of the old power plants may not be complying with the revised environmental norms for emission and water consumption and modifications may have to be carried out involving capital expenditure to ensure compliance. So plants which are aging or nearly at the end of useful life should be allowed to recover the additional capital

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	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***	expenditure by way of special allowance within the balance useful / extended life. However, Commission may specify the improved operational norms for SHR/APC which would be allowed after renovation of the old plant for tariff determination. The extended life of the power plant may also be specified for computation of depreciation for the capital cost incurred in the renovation. If it is not feasible to achieve the specified operational norms after renovation, then the generating company may opt to retire the power plant. Further, near end of the useful life, the developers refrain themselves from additional capitalization because they may not be able to recover the balance depreciation after useful life. **In reference to the present provision for "special O & M allowance" option in lieu of major Renovation & Modernisation in case of units having completed life of 25 years, it is to submit that such provision is very essential , as it gives a flexibility to the generating company in decision making for execution of the major R & M or routine additional O & M considering the increasing needs for repairs. Execution of major R & M is a time consuming process. Thus, depending on the plant condition , the generator can take decision on whether to go for major R & M or to carry out normal plant operations with additional O & M.** **If it is found that major R & M is a better option, the generator should be allowed to approach the Hon'ble Commission with its proposal for additional capitalization for life extension with cost benefit analysis and post final approval of the proposal, the beneficiary and the generator may decide to extend the PPA period till extended life with the approved capitalization and tariff.**

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
		The Hon'ble CERC may specify financial and operational norms for determination of tariff of such plants to enable the generating company to select an appropriate option.
4.20	*Input Price of coal – **Integrated** Mine* *The Government of India, on 21.10.2014 notified "The Coal Mines (Special Provisions) Ordinance, 2014, [now "The Coal Mines (Special Provisions) Act, 2015 (11 of 2015) or "The Coal Mine Act"] which provides for the coal allocation through public auction or through an allotment order. As per Section 5 of the Coal Mine Act, the allocation of mine through allotment order is allowed to a Government Company and Case-2 generation projects.* *Unlike allocation by auction, allocation by Allotment Order on the basis of Government dispensation, is made without specifying the cost of coal mining or the price of coal. The allotment documents and standard Coal Mine Development and Production Agreement (CMDPA) issued by the Ministry of Coal, GoI does not provide any coal price for using coal in specified end use plants, except for specifying the end use as power generation.* *The Commission, vide the second amendment to CERC Tariff Regulations, 2019 has incorporated provisions with regard to the determination of the input price of coal and lignite, wherein such mines have been allocated to the generating stations. The Commission, before specifying the norms, had constituted a Working Group to suggest a regulatory framework for the determination of input price of the coal and lignite. The Commission, on the basis of the report submitted and after considering the suggestions received from various stakeholders, notified the second amendment to CERC Tariff Regulations, 2019 on 19.02.2021*	Currently, the power sector operates under regulation, where the tariff for power generation by generating companies is determined based on specified norms in Tariff Regulations. The major component of fuel cost for these power generating companies is coal. However, the coal sector operates without regulation, and coal prices are determined by coal companies themselves. In light of this, it is crucial to establish a framework for determining input prices of coal to bring it under regulation. This measure would aid in reducing and controlling the fuel cost for power generating companies, ultimately benefiting end consumers. MSPGCL humbly appeals to the Hon'ble Commission to establish a regulatory framework for determining the input prices of coal and lignite.

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	which specified the terms of the determination of the input price of coal to be considered for the determination of energy charges for power stations with integrated mine. *It is observed that so far the Commission has received a couple of petitions for the determination of the input price of coal and therefore not much actual data is available to review the current operational norms and other provisions. In view of no compelling reasons to revisit the current terms and conditions for the determination of the input price of coal, it is proposed that the current provisions be continued.*	
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%.*	It is recommended to consider a slight increase in the sharing ratio of gains for the utility, such as 60:40 (Utility: Consumers). This adjustment would serve as an incentive for the utility to exert more efforts in generating non-core revenues. Additionally, the Government may introduce schemes or provide directions, such as assets monetization, to promote the optimal utilization of generating and transmission assets.

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	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 enabling infrastructure and human resources that can be utilised to increase non-core revenues through lease, data centres, 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 utilisation 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:***	
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***.	Following the commercial principle, it is recommended that the interest on the outstanding amount for the party entitled to receive payment should be calculated based on the remaining balance of receivables. In light of this, it is suggested to permit simple interest until the final instalment is received, otherwise, it would be unjust for the party entitled to receive the amount.

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
5.1	*Normative Annual Plant **Availability** Factor (NAPAF)* *Review of Existing Norms* ***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.***	As proposed in Approach Paper, methodology for computing PAF of Run-of River (ROR) Plants may be framed as specified in CERC Tariff Regulations 2004. So declared capacity of RoR plants means 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;"

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
5.1.2	*Recovery of Energy Charge for Hydro Generating Stations* *The Commission, while framing the CERC Tariff Regulations for the period 2009-14, modified the tariff structure for hydro generating stations, wherein a two-part tariff was structured in such a manner that 50% of the recovery of AFC was linked to achieving NAPAF, and the balance 50% was termed as Energy Charge and its recovery was linked to actual generation.* *It is observed that in the current mechanism, recovery of 50% of AFC is linked to actual generation, and in the event of any shortfall in actual generation below the saleable design energy, the same is allowed to be recovered as per Regulation 44(7). As the hydrological risk is eventually passed on to consumers, the usefulness of a two-part tariff may need to be reviewed. The existing provisions of the shortfall in recovery of AFC are leading to complications in the recovery process, wherein the affected generating company has to file petitions seeking such recovery.* ***Comments and suggestions are sought from stakeholders on ways to simplify the tariff recovery process for hydro generating stations.***	It is submitted that the Annual Revenue Requirement (ARR) for Hydro generating stations consists solely of fixed costs, without any variable costs involved. However, according to the regulations, 50% of the ARR can be recovered through fixed charges or capacity charges, while the remaining 50% can be recovered through variable charges or energy charge rates. **The payment of fixed or capacity charges for Hydro generating stations is tied to the Net Available Plant Availability Factor (NAPAF). However, there are situations where the availability of a Hydro generating station is affected by uncontrollable factors like non-availability of water storage due to less rainfall/ drought situation or restrictions on water release imposed by Govt. authorities etc. , leading to a decrease in the recovery of fixed costs. Therefore, it is necessary to provide clear guidelines specifying that the availability will not be reduced if the station is unavailable due to uncontrollable factors that are beyond the control of the hydro generating station.**
5.2	***Peak and Off-Peak Tariff*** ***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.*** ***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 issues***	The Approach Paper accurately addresses the issue concerning peak and off-peak tariffs. It is observed that the peak/off-peak periods defined by the Regional Load Dispatch Centers (RLDCs) differ among states within a particular region. Additionally, the declaration of peak and off-peak periods and the actual occurrence of these periods do not align. As a result, generating companies face challenges in efficiently planning overhauls, leading to forced outages. This, in turn, impacts the recovery of Annual Fixed Charges (AFC) for generating companies.

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	highlighted above. Specific suggestions are also sought on the following.	MSPGCL strongly objects to restricting the recovery based on daily peak and off-peak periods, as it would not be feasible for generating companies to align with such a model. Instead, recovery should be assessed on a cumulative basis for the peak/off-peak period, corresponding to the high and low demand seasons. Hence, it is suggested to conduct a thorough analysis of peak and off-peak periods on a regional basis by RLDCs and introduce an alternative approach that ensures maximum recovery of Annual Fixed Charges (AFC) for generating companies.
5.3	***Operational*** *Norms* *As these generating stations are operating at a much lower PLF, the actual performance data will also have a degradation impact.* ***Further, as the generating stations are separately allowed degradation impact due to low load operations, it is felt that the norms may be fixed considering the ideal loading of generating units.*** ***Comments and suggestions are sought from stakeholders on the above proposal and other key determinants to be considered while approving the norms.***	The challenges arise from technological changes or advancements in the power sector, as evident from the Approach Paper's Figure 11, which depicts a reduction in Plant Load Factor (PLF) of generating stations over the past 5 years. Taking into account anticipated changes such as the increased usage of Electric Vehicles (EV), Hydrogen, and Renewable Energy (RE) with battery storage systems, the power sector landscape is expected to undergo significant transformation. Consequently, setting operational norms based solely on historical performance for the next control period of 5 years would present challenges in terms of cost recovery for generating companies. **Hence, it is necessary to conduct periodic reviews of these norms and make appropriate changes to ensure their relevance and effectiveness.**
5.4	***Operational Norms - Inefficient Generating Stations*** *For those generating stations that have not been operating efficiently in the past and for which the Commission has been considering actual achievements to fix relaxed norms, in the interest of limited resources,*	**It should be acknowledged that certain generating plants were designed based on anticipated coal quality. However, the actual supply of lower-quality coal for such generating stations can lead to their deterioration and inefficiency. In such instances, relaxed norms become necessary to facilitate the recovery of Annual Fixed Charges**

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	such relaxation of norms may need re-consideration. This is necessary as the coal/lignite is limited resource that needs to be consumed efficiently and can be re-allocated to more efficient plants. ***Comments and suggestions are sought from stakeholders on the option to do away with relaxed norms currently allowed on the basis of actual performance for various efficiency norms of generating stations.***	**(AFC). Without such provisions, these generating stations would be unable to effectively contribute towards meeting the increasing demand of beneficiaries.**
5.5	*Operational Norms for* ***Washery*** *Rejects based Plants* *The Commission, while formulating the CERC Tariff Regulations, 2019, has specified the following operational norms for washery reject-based power plants:* *1. Station Heat Rate - To be approved on a case-to-case basis.* *2. Auxiliary Energy Consumption - 10%* *3. Secondary Fuel Oil Consumption - 2 ml/kWh* *4. NAPAF - 75% (First three years from COD) and 80% thereafter.* ***In view of no compelling reasons to amend the same, the existing norms for such plants may be continued in the next tariff period.*** ***Comments and suggestions are sought from stakeholders on the above proposal.***	It is suggested to analyze the available data for such plants and establish specific norms accordingly. In the absence of sufficient data, it would be appropriate to continue with the existing prevailing norms.
5.6	***Operational Norms - Emission Control System*** ***As only very few of such emission control systems have been commissioned, and in the absence of sufficient data on actual***	In approach paper it is stated that Implementation of an emission control system also requires the determination of supplementary energy charges, which impacts the power plant's standing on merit order, however most of these generating stations are still in the process of

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	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?***	implementing such systems, the current practice of excluding such expenses while preparing merit order may be continued. MSPGCL submits that the expenses incurred for implementing FGD and ECS should not be recovered through supplementary energy charges. These expenses are capital in nature and not related to fuel, so they should be recovered through AFC, fixed tariff, or supplementary fixed charges. Additionally, the recovery of these expenses should be linked to the availability of the plant, regardless of how much power is generated. Accordingly, suitable modification or new regulation may be introduced to address the above suggestion of MSPGCL.
5.7	***Compensation for Part-Load Operations*** …………	As per present mechanism of penalising generator by allowing the sharing of gains among Generator and beneficiaries

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	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. *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.*** ***Amendment to this clause:*** *Compensation for low load operation below 55% PLF. Impact to be allowed on actual or normative basis* *In case of old units (commissioned before 01.01.2004) which have not upgraded their plant control and instrumentation previously, capex requirement may around Rs. 30 Crore per unit* *It is estimated that the measures essential to operate at 40% load may require an estimated capital expenditure of around Rs. 10 Crore for each*	It is submitted that in the initial draft Approach Paper, the part load operation was proposed to be at 55% with some compensation to be given to generator for operating at part load. In the amendment issued thereafter, the part load operation is proposed at 40% in line with the CEA Regulations and accordingly compensation for the same is proposed to Rs. 30 Crore for Old plants and Rs. 10 Crore for new plants. Further, in the amendment it is proposed that the escalation in O&M to be up to 9%, 14% and 20% for loading of 50%, 45% and 40%. The Hon'ble CERC has referred the CEA's report on 'Flexibilisation of Coal Fired Power Plant' for computing compensation methodology for operating at thermal (Coal) Generating unit below 55% Minimum Power level. However, the capital cost (Rs.6 Crore, Rs.10 Crore and Rs.30 crore) considered for upgradation of control system has been assumed and there is no base for the assumption. **As a result, the actual capital cost needed to address the system upgrade requirement may vary from the estimated cost put forward in the Approach Paper. Further, based on this capital cost and assumptions considered for increase in O&M, increase in fixed tariff has been computed.** Considering this, it is submitted that the impact calculated in the approach paper relies on certain assumptions. **Hence, it is recommended that a normative amount for compensation be established, supported by appropriate rationale. Additionally, MSPGCL submits that compensation for capital costs associated with control system upgrades or retrofitting could be initially granted on a**

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	unit commissioned on or after 01.04.2004 except for units covered under para 3 (a) (iv) *Therefore, measures/retrofit are not required in these units for operation up to 40% load. However as per OEM few measures are required to be implemented for regular 40% load operation of subcritical units though the same 40% was demonstrated during PG test. Considering above it is proposed a maximum capital investment of Rs. 6 Crore may be allowed to the subcritical generating units where investment approval received on or after 01.01.2011*	**normative basis, with adjustments allowed on the basis of actual expenses during the true-up process with due prudence check.**
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*	It is rightly observed that the loss in Gross Calorific Value (GCV) of coal between "As Billed" and "As Received" is beyond the control of the Generator. Therefore, it would not be advisable to impose the risk of GCV loss on Generating companies. Generating companies operate within a regulated framework, but coal companies, which supply the fuel, are not subject to regulation. The cost of fuel is a significant portion of the generating companies' overall expenses. Currently, the generating companies pay for the coal supply based on its billed Gross Calorific Value (GCV). However, in practice, the coal used for power generation often utilised post a grade slippage of 2-4 grades of billing grade. In the current CERC Tariff Regulations 2019-24, the Gross Calorific Value (GCV) used for calculating the Energy Charge Rate (ECR) takes into account the GCV as received, reduced by 85 kcal/kg to account for stacking loss. This approach acknowledges that the generating company

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	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 minimising the loss.* ***Comments and suggestions are sought from stakeholders on ways to reduce the gap between GCV "as billed" and "as received".***	has limited control over the actual GCV received compared to what was billed. Thus, a certain degree of variation between the billed GCV and the received GCV is allowed. It is worth noting that this methodology is widely accepted and followed, as it recognizes the practical challenges faced by generating companies in accurately receiving the exact GCV as billed. By considering the GCV as received, after accounting for stacking loss, for calculating the ECR, it accommodates the variations beyond the control of the generating company. In Maharashtra, according to the MERC MYT Regulations 2019, there is a permissible difference of up to 600 kcal in Gross Calorific Value (GCV) between the loading end and unloading end. As a result, there is a restriction on the complete allowance of GCV variation, which is not in line with regulations specified by CERC for the 2019-24 control period. Due to restrictive allowable GCV loss, MSPGCL has been incurring disallowance of fuel cost to the tune of Rs. 700-1000 Crore annually. In view of above, wider accepted methodology of consideration of GCV "As received" less additional margin towards storage losses, to arrive at the GCV "as fired" for calculation of energy charge rate as per prevailing CERC tariff Regulations is more appropriate and practical. **Hence, the MSPGCL strongly suggest that the present approach of considering "GCV as Received" with allowable margin for stacking loss to arrive at the GCV "As fired" for calculation of ECR must be continued. Furthermore, MSPGCL urges the Hon'ble CERC to enforce this approach uniformly across all State Commissions, ensuring that the**

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
		energy charge rates of all generating companies are comparable and aligned for Merit Order dispatch.
5.9	***Blending of Coal*** ***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.***	It is important to acknowledge that the blending of coal within the allowed range is contingent upon the quantity of domestically available coal. In the proposed approach paper, it is suggested to tie-up the consent of beneficiaries to the percentage of imported coal blending rather than consent to certain increase the Energy Charge Rate (ECR), could facilitate a swift response to an upsurge in demand by generating companies. MSPGCL acknowledges the potential benefits of this approach in enabling a quick response. However, MSPGCL asserts that DISCOMs would be unable to accurately assess the actual impact of coal blending when granting consent to generating companies based on the percentage of blending. Consequently, the primary objective of obtaining consent from beneficiaries for coal blending would be compromised. **Hence, it is suggested that either an alternative mechanism for obtaining consent from beneficiaries for coal blending should be devised, or the existing mechanism based on per unit impact (within 30%) should be maintained with some necessary modifications. These adjustments would help address the current challenges faced by both generating companies and beneficiaries.**
5.10	*It is observed that the incentives linked to NAPLF, NAPAF and NATAF have been specified in existing Tariff Regulations. In this regard, it is observed that the incentive linked to availability is already allowed as*	In the previous fiscal year, owing to an increase in demand and delays in commissioning additional capacity, the Ministry of Power advised against retiring older generating units. Instead, these units were

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
	per the prescribed formulation on a pro-rata basis and may be continued. ***However, incentives linked to generation in excess of target PLF/NAPAF especially during peak periods, in the case of hydro stations and old pit-head generating stations, may need a review in order to encourage higher generation from such plants. This will result in increased generation from such plants and will also benefit beneficiaries.*** ***Comments and suggestions are sought from beneficiaries on the above proposal and any other alternative options, if any.***	instructed to continue operating and meet the rising demand. The tariff for such aging power plants is relatively lower, given that they undergo necessary maintenance to remain operational. Therefore, in order to fulfil the demand, it becomes essential to incentivize and encourage hydro generating stations as well as older generation stations, as they prove valuable during peak requirements. **Therefore, to provide incentives for such plants, it is suggested to offer additional incentives for generation beyond the normative Plant Load Factor (PLF). Therefore, it is suggested to either increase or maintain the existing incentives as specified in the current regulations.**
6.1	*Separate Norms for ROR/Storage Based Hydro Projects* *However, it is observed that there is a need for a more enabling framework or incentive mechanism for dam/reservoir based generating stations to operate as peaking plants.* ***Considering the anticipated increase in peaking loads, these stations may be incentivised to operate as peaking plants. One way to do so is by providing additional incentives for energy supplied during peak periods.***	MSPGCL concurs that it is essential to establish norms specifically for Run-of-River (RoR) and storage-based hydro projects. The purpose of these norms is to provide incentives for these projects to operate as peaking plants, enabling them to effectively meet the demands during anticipated peak load periods.
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.***	It is submitted that the tariff structure for cost recovery related to Emission Control Systems (ECS) should primarily consist of supplementary fixed charges. Despite the auxiliary consumptions being altered following the installation of Flue Gas Desulfurization (FGD) or ECS, the recovery of the installation costs should be permitted irrespective of the generation, contingent upon the plant's availability. Hence, MSPGCL appeals to the Hon'ble Commission to appropriately amend the current provisions. As the supplementary tariff for FGD and

Clause No	Proposed Clause	MSPGCL Proposed Comments/Suggestions
		ECS installation will be recovered through supplementary fixed tariffs, there will be no need to exclude these tariffs in Merit Order dispatch considerations.
6.3	***Decommissioning of Generating Station and Transmission Assets*** ***In view of the above, comments and suggestions are sought from stakeholders on the possible approaches to recover or refund the impact of decommissioning costs in case the generating stations/transmission systems are decommissioned before the completion of their useful lives, if such decommissioning is done in compliance of a statutory order or due to technological obsolescence duly approved by RPC.***	It is crucial to take into account the existence of stranded or inefficient assets and the consequences that arise when such assets are decommissioned. **If a generating station is decommissioned before its expected lifespan due to compliance of particular statutory Orders, the entirety of the depreciation that hasn't been recovered should be allowed for retrieval. Additionally, the generating companies should receive a single compensation for the decommissioned assets. If this one-time compensation and the remaining depreciation are not approved, then the decommissioned assets should not be removed or deducted from the licensee's regulated Gross Fixed Assets (GFA). Consequently, the recovery of all cost elements associated with GFA should be permitted.**