TANGEDCO

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To
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Lr. No CFC/RC/SE/CERC/EE/ F. Staff Paper /D.161/2023, dt: 31.07.2023.

Sir,

Sub: CERC - Terms and Conditions of Tariff for the period commencing from 1st April, 2024 – Approach Paper thereof – Comments and suggestions of TANGEDCO – Submitted for consideration.

Ref: File No. L-1/268/2022/CERC Dated 26.05.2023

With reference to the above, the comments and suggestions of TANGEDCO on the issues discussed in the staff paper are enclosed herewith for kind consideration please.

B. Rajeswari 31/07/2023
Chief Financial Controller/
Regulatory cell

Encl: comments and suggestions

TANGEDCO's VIEWS

Staff paper's core idea: Simplification of the tariff determination process is the core idea that shall drive the terms and conditions of tariff determination for the period FY 2024-25 to FY 2028-29. Further, the methodology for simplification has been (i) Exploring the option of determination of tariff on a normative basis. (ii) Modifying the existing approach to allow more parameters on a normative basis. In this regard, it is to be stated that the Electricity Act 2003 was formulated for promoting competition, protecting interest of consumers and rationalisation of electricity tariff among others. Further, Section 79 of the Electricity Act 2003, the Central Commission shall discharge the following functions, namely, (a) to regulate the tariff of generating companies owned or controlled by the Central Government (b) to regulate the tariff of the generating companies other than those owned or controlled by the Central Government specified in clause (a). Hence the main objective of Regulatory body is to ensure that the tariff fixed shall be reasonable, equitable and protecting the interest of consumers at the same time contributing to the development of electricity industry. Hence the core idea of the staff paper **to determine tariff on normative basis** shall be detrimental to the already struggling discoms, as the same will undermine the prudence check to be carried out by the Commission, thereby enabling the generators to take advantage.

Parawar comments on the staff paper is given below for consideration please:

Heading/ Regulation	Description as per Draft Regulation	Views and Comments
3. Possible Approaches to Tariff Determination 3.1. Tariff Determination – General Approach	➢ 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	Shifting to normative basis will be detrimental to tariff determining process. Already the following components are under normative approach in determining the annual fixed charges: i) Debt : Equity ratio ii) Quantum of debt for interest calculation iii) Return on equity iv) Quantum of working capital for interest calculation v) O&M expenses It is now proposed to include the Additional capital expenses under normative basis under the proposed

	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. The above two approaches have been discussed in detail in subsequent sections of this Approach Paper.	Approach 1. This will have a catastrophic impact on the tariff as detailed in the subsequent paras and hence TANGEDCO is not agreeable to Approach 1. Further the power sector shall strive towards efficiency and bringing in more normative parameters in tariff determination will undermine the efforts to supply power to consumers at best competitive rates. The debt-equity ratio of 70:30 allows the investor to invest a maximum of 30% equity. The IoL is charged based on weighted average interest on loans availed by the investor for various projects. But it is not normative but based on actual. ROE is at flat rate not linked to any rates offered by RBI for investments made by public. The O&M charges are normative but reviewed based on actual for the previous tariff blocks. The approach 1 will definitely incentivise inefficiencies and favour undue enrichment of the generation and transmission companies instead of achieving the objective of providing electricity at reasonable rate to the end consumers and regulating the tariff nearer to the realistic actual expenditure including reasonable profit margins. The first approach is deviating from the objectives of the Tariff policy and Electricity Act as well as diluting the responsibility of the Regulator in terms of prudence check of the tariff components and claims made by Generators/ Transmission licensees. Hence, the first approach to moving towards total normative basis is unacceptable. The Approach 2 is also making an alternate attempt to introduce more of normative components into tariff setting which is totally unwarranted. In the name of simplification, the Commission cannot pave way for inefficiencies, undue

		profiteering. When there is every opportunity to check the prudency of the expenditures, the regulator should adopt the actuals subject to bench mark norms / caps / ceiling.
3.2.Approach1: Normative Tariff	It is observed that once the capital cost, including additional capitalisation up to cut-off date, is approved for a certain project, the fixed charges for such projects follow a certain trajectory, except in the case of sporadic impacts of additional capitalisation. In order to give effect to such recurrent additional capitalisation in fixed charges, the generating companies and transmission licensees under the current mechanism, first file a petition seeking tariff on the basis of projected additional capitalisation and again file a true up petition seeking tariff based on actual additional capitalisation incurred during the tariff period. it has been observed that, in most of the cases, the only variation in the approved vis-à-vis trued-up fixed charges is on account of variation in additional capitalisation which is also insignificant in many of the cases. This requirement of approving additional capital expenditure on an actual basis has resulted in considerable and recurring efforts being put in by the generating companies and transmission licensees as well as the Commission, resulting in regulatory overburden, and therefore, simplification of tariffs by shifting to normative tariff has almost become a necessity.	The staff paper contends that the requirement for claiming additional capital expenditure on actual basis has resulted in considerable and recurring efforts being put in by the generating companies and transmission licensees. In this regard, it is to be pointed out that in any case, the generating and transmission companies have to do actual accounting as a part of their mandatory duty under many acts such as Companies Act/ Income Tax Act etc. Hence the reason that such filing of additional capital expenditure on actual basis increases the work of the companies is not acceptable. The approach paper has split the AFC into O&M expenses and AFC excluding O&M expenses. Further it has been analysed and stated that when the O&M expenses keep on increasing, but the rest of AFC component decreases. The increase in O&M expenses is due to escalation provided in the regulations as well as due to the impact of wage revision. However, splitting of AFC component based on this criteria and imposing a normative value for the rest of the components is not a viable solution. Already the O&M expenses are allotted on a normative basis. Hence the rest of the AFC components including Additional capital expenses shall continue to be determined as per the existing practice. As per the existing Regulation, the additional capitalization may be claimed under the following major counts upto the Cutoff date: i) Undischarged liabilities ii) Works deferred for execution

		iii) Liabilities to meet award of arbitration. iv) Change in law, force majeure v) Procurement of initial capital spares The additional capitalization after cutoff date but within original scope of work includes: i) Arbitration ii) Change in law iii) Deferred work of ash pond, raising of ash dyke iv) Undischarged liabilities As seen from the above, the major component of additional capitalization is undischarged liabilities The additional capitalization beyond the original scope includes i)liabilities to meet arbitration ii) change in law iii) Force majeure events iv) Need for higher security and safety of plant v) Deferred ash pond work vi) Usage of water from sewage treatment plant TANGEDCO submits that the above Regulations cover all requirements of the generators post COD that may arise during the life time of the plant. Hence the existing regulations for specifying additional capital expenditure may be continued. Since additional capital expenditure is a continuance of original capital expenditure incurred, it cannot be normative at any point. Hence TANGEDCO would advocate the Approach 2, ie., Performance based hybrid approach, but without adding any other parameters on normative basis, to the already existing methodology.

3.3.Approach2: Performance Based Hybrid Approach	The second alternative to further simplifying the tariff determination process is to continue with the current practice of tariff determination with more AFC components being allowed on a normative basis. As more and more AFC components are approved on normative basis, it would ease the transition to a complete normative regime.	The second alternative to continue with the current practice of tariff determination with more AFC components being allowed on a normative basis, as stated by the Staff paper. Here it has been suggested that the possibility of specifying working capital requirements on a normative basis which can factor in variations due to actual fuel prices and interest rates to be considered for computing interest on working capital on a normative basis, needs to be explored. In this regard, TANGEDCO would like to submit that the working capital requirements shall be determined by the existing methodology itself as the method is a balanced approach and has been beneficial for both the generators and the consumers. Here it is pointed out that wherever normative method is not available in the existing Regulatory framework, the Staff paper is advocating normative methodology. And here when the working capital requirements are being approved on time tested normative basis, the staff paper attempts to change it to consider variations. Hence this attempt to dilute the methodology of arriving at working capital requirements shall be given up and TANGEDCO strongly advocates for the existing methodology to continue.
4.2 Capital Cost 4.2.1 Background	The approval of capital costs is one of the most important aspects of the tariff determination process, as almost the entire fixed charge throughout the life cycle of the project depends upon it. In the process of tariff determination, the Commission has been approving the capital cost of the projects on a case- to- case basis, which is dependent on the actual expenses incurred, duly certified by the auditors, and	Suggestions have been requested on continuation of the provision for interim tariff. In this regard, it is suggested that, the time period for filing interim tariff petition can be reduced to one month before the anticipated date of commissioning. Further, if the project is not commissioned even after a period of six months from the date of interim tariff, the utility may be directed to file a fresh petition

	after carrying out due prudence on the reasonability of the expenses incurred. The CERC Tariff Regulations, 2009, introduced an enabling provision that allows utilities to seek approval of the capital cost of new projects on an anticipated basis, which helps utilities minimise the time gap between the commissioning of the project and the generation of cash flows by means of tariff. 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.	seeking interim tariff. While granting interim or provisional tariff, the Commission does not look into the prudence of the claims made by the petitioner. While approving the final tariff, in many cases there are lot of variations /deviations from the claims to the approved tariff. Hence, the percentage of interim tariff may be reduced to 70% and the final tariff may be approved within the time line given in the Conduct of Business Regulations. The MoP's Electricity Amendment Rules 2022 provides 120 days for disposal of any dispute resolution petition by CERC. If not, the petitioner may approach APTEL. Under such circumstances, the Commission may find alternate ways and means to dispose the petitions within the timeline so that is will facilitate all the stakeholders to ease the business process.
4.2.2 Procurement of Equipment and Services	Work Contracts are required to be awarded on the basis of transparent competitive bidding, which shall form the basis of approval of such costs.	The generating companies / transmission licensees may be further instructed to go in for QCBS – Quality and cost based selection and also based on the historical performance of the bidders, **instead of merely selecting the Lowest bidder, based on price quoted.**
4.2.3 Reference Cost for Approval of Capital Cost – Benchmark Cost V/s Investment Approval Cost	Adopting benchmark norms 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. With regards to transmission systems, the cost is affected by tower design, terrain, soil type, and wind zones, and therefore it is generally argued that benchmarking will serve a limited purpose and may not be a better alternative to current project specific Investment Approvals. Comments and	The policy of adopting benchmark norms is a must for establishing reliable and sustainable power sector. Further bench marking is essential for improving efficiency and productivity, enhancing competitiveness and profitability and aligning cost with strategy. The Hon'ble CERC may strive to bring in bench mark norms periodically. In order to avoid over estimation, it is suggested that ➢ Clause (1) of Reg. 10 may be amended as "in case of the thermal stations and transmission system,

	suggestions of stakeholders are invited on other efficient reference costs other than Investment Approval costs that can be considered for prudence checks.	prudence check of capital cost may be carried out taking into consideration the bench mark norms specified / to be specified and published by the commission from time to time ➢ In the cases of bench mark norms are not specified, the price variation clause/procedure in the contracts are to be scrutinized. The first and foremost important function of CERC is to regulate the tariff. Also, it has the mandate to ensure promotion of competition, efficiency and economy in activities of the electricity industry while specifying and enforcing standards with respect to quality. Cost benchmarking identifies competitiveness of pricing in industry terms, highlighting best in class pricing and subsequently showing areas for competitive pricing improvement. The Central Commission is duty bound to notify the bench marking norms for various generation and transmission projects so as to fulfil the above mandatory responsibilities. The specific provisions for bench mark norms that were available in the earlier Regulations shall be brought back.
4.2.4 Capital Cost of Hydro Generating Stations	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. 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	TANGEDCO submits that the expenses towards bringing in a hydro project shall be shared as follows: 1. Construction of dam and all related infrastructure related works such as roads, culverts etc shall be taken up by the State govt/ Central Govt PWD. For this purpose, a comprehensive proposal shall be evolved taking into account the probable requirements such as power production, irrigation, mitigation of flood etc so the expenses can be shared by all concerned departments. 2. All expenses related to bringing the power house including equipment and related civil structures

	all the required clearances and permits are available as on zero date. 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 incentivise the developer if it executes the project faster/ or ahead of schedule and vice-versa if it delays.	including power evacuation system shall be to the account of the project developer. This will reduce the tariff burden to be passed on to the consumer in a great way. Further since the dam serves multipurpose such as irrigation and flood prevention etc, this proposal shall be equitable. Ways to expedite development: 1. Works may be divided into smaller packages instead of awarding one single contract. 2. Creation of SPV for getting clearances especially State/ Central govt SPVs will be of advantage. 3. In respect of pumped storage system, it is beneficial to construct the power house closer to tail race instead of being practiced now inside the cavern. This will reduce the cost and time of construction, compromising a slight loss of head on account of this.
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.	The historical cost or acquisition value whichever is lower should be considered for the determination of tariff and no further addition shall be made to acquisition cost at a later stage.

4.4 Computation of Interest During Construction 4.4.1 Computation of IDC – Post Scheduled COD	It is observed that Regulations 21(1) and (2) of the CERC Tariff Regulations, 2019 specify as follows. "21. Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC) (1) Interest during construction (IDC) shall be computed corresponding to the loan from the date of infusion of debt fund, and after taking into account the prudent phasing of funds upto SCOD. (2) Incidental expenditure during construction (IEDC) shall be computed from the zero date, taking into account pre-operative expenses upto SCOD: . .....It is further observed that in the original Investment Approval of any project, the cost of the project is approved, which also includes IDC expenses under the no delay scenario. ....It is observed that at times, even though the project is delayed, due to prudent phasing of funds, the actual IDC, considering the delay impact, is well within the amount approved in the Investment Approval. Even in such scenarios, wherein the actual IDC is below that approved in original Investment Approval, due to existing provisions disallowing IDC corresponding to delay, the utilities are denied IDC. ...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 ... 3. IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay.	The timely completion of the project is totally in the purview of the generating company or a transmission licensee. It is their responsibility to engage suitable contractors having vast experience in the field for timely completion of the job. The timely completion of the project is further hugely dependant on continuous follow up of the generator or the transmission licensee. Since it is the responsibility of the generator/ transmission licensee to complete the project on time, any spillage of IDC beyond SCOD is not permissible, unless under unavoidable circumstances. *Further the following suggestions are made in this regard:* *i) The generators/ transmission licensee shall enter into an indemnifying agreement with their contractors for any financial implications arising out of the delay.* *ii) Further, provision may also be made for indemnifying the generator and transmission licensee for any delay so that the IDC and IEDC shall be recovered accordingly.* It has been proposed that in case the actual IDC is below that approved in original investment approval, the same may be allowed, as a lower IDC even is a delayed project is due to prudent phasing of funds adopted by the utilities. In this regard, the following are to be stated: The IDC portion approved in the Investment approval is exaggerated in many cases of the generator and transmission projects. Further the same is revised many times during the course of delay in execution. Hence the projected reduction in IDC at the end of the project is only fictional when compared to the original IDC as per the investment approval. Hence TANGEDCO is not agreeable for the same.

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 disallowed 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.	The Price variation clause between a generator and his sub vendor cannot be passed on to beneficiaries and TANGEDCO is not agreeable for the same.
4.6 Renovation and Modernisation (R&M)	Regulation 27 of the CERC Tariff Regulations, 2019 allows generating stations or transmission licensees to opt for R&M for the old generating stations and transmission systems that have outlived their useful life with the consent of the beneficiaries. The provisions also specify the manner in which such costs shall be considered for tariff purposes once cost reasonability is ascertained based on the residual life assessment and cost benefit analysis submitted along with the petition. Further, CEA, with an objective to maximise generation with efficiency enhancement, has already issued guidelines for R&M of Hydro and Thermal generating stations that need to be followed. As R&M allows the deferral of huge capital investments on the construction of new capacities and avoids seeking fresh approvals and clearances, it is a cost effective alternative and hence has been allowed in the past. In addition to the above, Regulation 28 of the CERC Tariff Regulations, 2019 provides for Special Allowance in lieu of R&M. Presently, the utilities have the option to choose	The provision of special allowance in the existing regulations shall be withdrawn. The gencos may go in for R&M periodically after conducting necessary RLA studies and other required assessments. The provision of a blanket special allowance is not subject to prudence check, as the same is made on normative basis. Further the generating companies are not mandated to furnish the details of expenses made under special allowance as per the existing Tariff Regulations. Hence the payment made by the exchequer is without any prudence check and therefore TANGEDCO suggests that the Regulation may be withdrawn as it is against the public interest.

	between Special Allowance or to undertake R&M.	
4.7 Initial Spares	The Commission, in its Explanatory Memorandum to the draft Tariff Regulations for 2019-24 observed as follows. "2.5.7 It is noticed that there is not much difference between the initial spares of green field and brown field substations. Further, the initial spares of all compensation devices including series and shunt compensation and HVDC are kept at the same. The Commission proposes to maintain same level of initial spares for green field and brown field substation." In view of the above, a single norm can be considered for each of the following classes of transmission assets: 1. Transmission Lines, including HVDC lines 2. Substations (including HVDC S/s) 3. Dynamic Reactive Compensation devices 4. Communication Systems 5. Underground cable Comments and suggestions are sought from stakeholders on the above proposed approach and alternative options to standardise and simplify the norms for initial spares.	It is essential to revisit the norms for initial spares based on the actual usage and check the prudence the claims. In view of the above, the following are suggested: i) Reduction in the norms for initial spares ii) Include the Form to be furnished with the tariff petition for furnishing the details of initial spares procured and used at project site iii) Form for furnishing the details of unused spares and iv) Provision in the Regulation for decapitalising the unused initial spares.
4.8 Controllable and Un-Controllable Factors 4.8.1 Delay towards obtaining Forest Clearance	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 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.	In the Staff paper, under provision 4.2.4, under the suggestions to expedite the development of hydro generating stations, it has been suggested that contract to execute the project to be awarded only when all the required clearances and permits are available as on zero date. Hence this suggestion, if accepted will mitigate the issue of delay in getting forest and all clearances required for the project. Further, obtaining clearances requires continuous/ dedicated follow up by Generating companies / SPVs. Hence getting Forest clearances could not be considered under uncontrollable factors for delay in commissioning.
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	The proposal to allow RoE corresponding to cost and time overrun allowed over and above the project cost as per investment approval at the weighted average rate of interest is a welcome suggestion

	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. In view of the above, 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. 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.	
4.10 Additional Capitalisation	As per CERC Tariff Regulations, 2019, additional capitalisation for generating stations and transmission licensees is allowed under the following main categories. 1. Additional Capitalisation within the original scope of work executed up to cut-off date (Regulation 24). 2. Additional Capitalisation within the original scope of work executed after the cut-off date, including replacement under certain conditions. (Regulation 25). 3. Additional Capitalisation 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 Capitalisation on account of Renovation & Modernisation. (Regulation 27). 5. Additional	Additional capitalisation expenses pertaining to Railway infrastructure shall be allowed on case to case basis, instead of giving a blanket enabling provision in the Regulations, in order to ensure that the generators take a prudent decision on the same.

	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 Further, with regard to additional capitalisation under Sr. Nos. 3, 4 & 5 above, which are non recurring and generally require substantial expenses to be incurred, the current practice of allowing the same on an actual basis may be continued as such non-recurring and heterogeneous expenses cannot be translated into norms. However, additional capitalisation under Sr. No. 2 are generally not substantial but recurring in nature, and it has been observed that the same, for one reason or another have been recurring time and again, which is one of the prime reasons for which the entire exercise of tariff determination of hundreds of assets is done twice in the same tariff period. As	In respect of Sl. No. 3, 4 and 5 also, the additional capital expenses **shall be allowed after prudence check** as in Sl. No. 1 In respect of additional capitalization under Sl.No. 2, the claim of the generators are varied and not as per the allowed items under the Regulations. The generators tend to claim

	the entire exercise does not have big impact on tariffs, possible options, if any, need to be explored to eliminate the need for such an elaborate exercise.	O&M related spares as well as spares normally covered under repairs and maintenance under additional capital expenses. Hence any admission shall be subject to prudence check to avoid spurious claims.
4.10.1 Normative Add-Cap - Generating Station	For the purpose of simplifying the approval of additional capitalisation, the generating stations can be broadly classified into two categories. 1. Existing Generating Stations – These generating stations can further be classified into the following two sub-categories. a) Existing generating stations with a cut-off date on or before 31.03.2024. b) Existing generating stations whose cut-off date shall fall in the upcoming tariff block 2024-29. 2. New Generating Stations – Generating stations that shall achieve COD in the next tariff block, i.e., 2024-29.	As has been already explained, normalization of additional capital expenditure is not a good thought process. Each station requires additional capital expenses based on the type of station, age and other specific issues. When the generating company and the transmission Licensee are bound to account for actual expenditures in terms of additional capitalisation, the process of classification of for the purpose of simplification of Add cap approval is unwarranted and will lead to inefficiencies and undue enrichment resulting in over burdening the end consumers. For the sake of relieving the burden of the Regulators such simplifications cannot be allowed. Hence the existing Regulations which cater to all requirements of additional capitalization shall continue.
4.10.2 Normative Add-Cap – Transmission System	Unlike generating stations, additional capitalisation post cut-off date is rarely required in the case of transmission systems unless due to completion of useful life, performance degradation, the need for induction of new and efficient technology, Obsolescence of assets, or the absence of support from Original Equipment Manufacturer (OEM). Therefore, for Transmission Systems, additional capitalisation post cut-off date may be allowed on technological obsolescence, change in law, force majeure, or due to replacement as presently allowed under Regulation 26 and 27 of the CERC Tariff Regulations, 2019. Comments and	For any kind of additional capitalisation post cut off date, it should be allowed on actual basis. Since the additional capitalisation for Transmission projects post cut off date are rarely required, there shall not be any issue in scrutinising and approving the add cap.

	suggestions are sought from stakeholders on the above suggested approaches and other alternatives, if any.	
4.11 GFA/NFA/Modified GFA approach	Comments and / suggestions are invited for GFA/ NFA/ Modified GFA approach	GFA method and if required, modified GFA method is more suitable for Indian power sector, as NFA approach results in front loading of tariff.
4.12 O&M Expenses 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	The existing methodology of fixing normative O&M expenses involves collecting of data from all thermal stations regarding O&M expenses and fixing the norms for the next tariff period after considering an escalation factor. Whenever there is any huge liability for a generator such as wage revision, they are free to file a petition seeking additional O&M expenses after substantiating their claim that the wage revision expenses are over and above the O&M expenses allowed to them. Further Pay Commission are due once in 10 years only. Hence the present methodology may continue.

	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.	
4.12.2 Norms for HVDC Stations	The Commission, in its CERC Tariff Regulations, 2019, has approved normative O&M expenses for HVDC schemes wherein specific norms have been specified for some of the schemes and for the rest of the schemes, formulation of normative O&M expenses have been specified linking it with similar nature schemes for which specific O&M expenses are approved. It is observed that there is a need to simplify the same and therefore one norm for all HVDC schemes in terms of per MW considering the actual expenses incurred in the past may be specified. Comments and suggestions are sought from stakeholders on above suggestions and alternatives, if any.	There is absolutely no need to simplify the norms in terms of per MW basis as the O&M charges HVDC systems are specific to the type and capacity as well as life of the systems. Hence, the existing norms shall be expanded further more to have O&M charges specific to each case as the number of HVDC systems are very limited.
4.12.3 O&M Norms for Special Cases	It is observed that the O&M expenses towards the upkeep of transmission systems in the North Eastern and hilly regions of India entail additional costs due to logistical challenges as well as the inadequate infrastructure growth of the region. Several representations have been made by various entities seeking additional O&M expenses for transmission licensees that are operating in these regions. In this context, possible solutions need to be explored so that the development of electrical infrastructure in these regions is encouraged. In view of the above, comments and suggestions are sought from stakeholders on whether additional O&M expenses can be given for transmission assets being operated in the North Eastern and Hilly Regions and the manner in which such additional costs can be considered.	The historical data of O&M expenses incurred for North eastern and hilly region vis-a-vis other regions in the past five years shall be required to assess the actual additional cost required. Hence the same shall be provided.

4.12.4 Inclusion of Capital Spares	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.	**The definition of the term 'Capital spares' shall have to be incorporated in the upcoming Regulation,** as the Generators tend to book all spares under Capital spares, even though they may be of Repair and maintenance category or consumable (bearings, mill rollers etc) Further, it has been proposed to include spares value below Rs. 20 lakh under O&M and for spares above Rs. 20 lakh on case to case basis. In this regard, the following are suggested: i) The word 'each' shall be compulsorily included after Rs. 20 lakh in order to avoid ambiguity. ii) The provision for capital spares shall not be a blanket value and may be proposed conversant to age of the plant.
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	Impact of 'Change in law' in O&M expenses is not a recurrent claim. Only claim made by the generators under change in law in the tariff period 2014-19 is due to introduction of GST during 2017.

	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.	Since it is rarest of rare case, provisions need not be made in the O&M expenses under 'Change in law'.
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.	If the depreciation is proposed to be extended for 15 years instead of the present 12 years, based on loan tenure, then cost benefit analysis may be provided while issuing draft Regulations in order to weigh the pros and cons of the proposed extension.
4.14 Interest on Loans 4.14.1 Weighted Average Rate of Interest and FERV	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. Further, the cost of hedging related to foreign loans be allowed on an actual basis, without allowing any actual FERV.	TANGEDCO is not agreeable for weighted average rate of interest for a company as a whole, instead of project specific loan for the following reasons: a).The floating interest varies from bank to bank. If the WAROI is considered for company as a whole, in case of increase, the beneficiary who may be linked to one project may be made to bear the excess interest for a project where they may not be linked to. b) 70% of the Capital cost is under loan component. Hence the impact of this decision will have a huge financial impact on the beneficiaries. Regarding the cost of hedging related to foreign loans be allowed on an actual basis, without allowing any actual FERV, the same is agreeable for TANGEDCO.
4.15 Return on Equity (RoE) V/s Return on Capital Employed (RoCE	Commission, however, due to following limitations and de-merits, up till now has decided in favour of RoE: 1. Fluctuation of Interest Rates make benchmarking the cost of debt difficult. 2. Requirement of annual determination of WACC due to progressive change and reduction in capital	TANGEDCO advocates continuation of RoE instead of RoCE. However, the present rate of RoE @ 15.5% is very high when compared to prevailing market interest rates.

	employed. 3. Problems associated with benchmarking of the debt equity ratio 4. The evolving Indian Corporate Bond Market 5. The Majority of the stakeholders' views are in favour of the RoE approach. 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.	Hence the same shall be reduced based on the Average interest rate as prevailing in the market.
4.16 Rate of Return on Equity 4.16.1 Purpose	Section 61 (d) of the Electricity Act, 2003, and Paragraph 5.11 (a) of Tariff Policy 2016 have laid down broad guiding principles for the determination of the rate of return. These have been mandated to maintain a balance between the interests of consumers and the need for investments while laying down the rate of return. It is stipulated that the rate of return should be determined based on the assessment of overall risk and the prevalent cost of capital. Further, it should lead to the generation of a reasonable surplus and attract investment for the growth of the sector. The large-scale investments that the sector has witnessed in the past decade are a result of the appropriate fixed returns allowed. The year wise capacity addition in the last decade is shown in the following chart.	Since there has been a decade of high return on RoE prevailing, in order to bail out the ailing discoms, the rate of return on RoE may be reduced for the next five year period after analysing the present market scenario, subject to review after that. The RoE at present of 15.5% shall immediately be reduced and fixed at 12%, as many soft loans are available in the market for equity funding of the utilities.
4.16.2 Differential RoE	Further, 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	TANGEDCO welcomes the suggestion for lesser RoE in case of transmission assets, as there is no rick in the transmission sector.

	limited to the RoE component only." FOR has recommended differential RoE for Generation and Transmission Businesses with a reduction in RoE for Transmission Business.	
4.16.4 Methodology	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. Merit behind approving different Rate of RoE to thermal, hydro generation and transmission projects with further incentives for dam/reservoir based projects including PSP. 3. Merit in allowing RoE by linking the rate of return with market interest rates such as G-SEC rates/MCLR/RBI Base Rate.	Review on rate of RoE: As already stated the existing RoE of 15.5% is very high. The same shall be reduced to decrease the financial burden on discoms. Further, the RoE for Change in Law and Force majeure shall be at a much lesser rate, as there is no risk in such investment as the plants are already functioning and any additional expenses will be serviced by the existing beneficiaries. The present return on RoE of 14% in respect of FGD seems to be very high and shall be curtailed to the market lending rates in order to reduce the burden on exchequer. Already Return on equity for storage type hydro generating stations including pumped storage stations as well as RoR generating stations enjoy rate of equity @ 16.5%. Hence it is felt sufficient. Regarding the merit in allowing RoE linked to G-SEC etc., it is stated that the existing RoE of 15.5% is exorbitantly high and hence may be restricted, irrespective of the methodology adopted.
4.16.5 Rate of Return – Old Thermal Generating Station	Comments and suggestions are sought from stakeholders on various possible alternatives that incentivises generation from these efficient old generating stations.	Already the incentive for excess generation over NAPLF has been increased from 50 paise per unit during 2014-19 to 65 paise per unit during peak hours and 50 paise during off peak hours as per TR 2019-24. Hence the same provision is sufficient and may continue.
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	The notion that the maximum tax amount that shall be payable is limited by the tax rates notified for the relevant category is a very welcome move.

	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).	
4.18.1 Working Capital Requirement	Comments and suggestions are invited on any modification that may be required in the norms. It is further observed that CEA has revised coal stocking norms for coal based thermal generating stations with effect from 06.12.2021 and CEA has suggested disincentives for thermal power plants in the event the availability of any coal based power plant is lower than the normative availability (as per prevailing CERC Regulations/Norms, as applicable) due to a lower stock of coal maintained by the power plant as compared to the norm specified by the CEA. A Staff Paper titled "Methodology for Computing Deterrent Charges for maintaining lower coal stock by coal based thermal generating stations" was issued in May 2022 wherein the methodology for determining deterrent charges was proposed. In this regard, comments and suggestions were invited from generating stations and stakeholders.	In the statement of reasons to Tariff Regulations 2014-19, the Hon'ble CERC has explained as follows regarding the Interest on working capital: "28.20 Some of the stakeholders suggested that the truing up of working capital shall be carried out considering the actual fuel prices, interest rate, etc. In this regard, the Commission is of the view that the interest on working capital is allowed on normative basis, irrespective of whether the loan has been availed for working capital or not. In case truing up of interest on working capital or adjustment to interest on working capital is to be carried out based on actual fuel prices, fuel price escalation, movement in interest rates, liquid fuel stock, the objective of providing interest on working capital on normative basis will be defeated and the further the entire exercise of adjustments to interest on working capital will be complicated exercise resulting in frequent revision in tariff. **Further, there are several sources of obtaining working capital finance and the rate of interest on such working capital depends on the operational performance and profitability of operations, hence, the regulated entities shall be able to source funds at cheaper rate of interest, depending on their performance.**"

		As rightly observed by the Hon'ble CERC there are several sources for financing the working capital of the generators/ transmission utilities. Hence the previous methodology (TR 2014-19) of allowing working capital without escalation may be considered and the same will avoid repeated filing of petitions. Regarding deterrent charges for Central generating stations are concerned low stock of coal/ lignite, the same is fair and equitable, as the working capital is paid by the beneficiaries considering the prescribed coal stock. Hence any reduction of caol stock shall avoid deterrent charges and provision shall be made to levy the same.
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.	The proposed methodology of one year MCLR plus 350 bps is very much on the higher side. Hence the same shall be restricted to SBI MCLR + 200 bps.
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.	Since receivables are based only on actual which keep changing, stipulating a normative working capital is not practically possible. The truing up may be done at the end of the tariff period, in order to avoid yearly truing up.
4.19 Life of Generating Stations and Transmission System	The Commission, in its Explanatory Memorandum to the draft CERC Tariff Regulations, 2019, has carried out a detailed analysis of increasing the life of assets and its impact on tariff, as well as a sensitivity analysis of the various components of tariff vis-à-vis asset life and has re assessed the life. Based on the study carried out, the Commission increased the life of hydro generating stations from 35 years to 40 years, keeping the life of other asset classes same as specified in the CERC Tariff Regulations, 2014.	The life of the thermal generating stations / transmission assets may be considered as 35 years, if the repayment period is also similarly extended. Further, RLA studies are to be carried out and submitted to the Commission/ beneficiaries, and it is felt that life of the plant may be decided on case to case basis based on the outcome of the assessment studies.

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 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. Comments and suggestions are sought from the stakeholders on the following: 1. Ways to increase non-core revenues through optimal utilisation of available resources. 2. Any modification in the sharing mechanism that may be required.	➢ In this case, the difference in Energy Charge Rate between the normative and actual is taken as gain. Due to the change in ECR on reconciliation, the position of the generator in MOD changes. This impacts the distribution utilities as well as other competing generators. **Hence the reconciliation process needs to be reviewed (either monthly or fortnightly) so as to have a realistic MOD.**
4.22 Treatment of arbitration award – Servicing of Principal and Interest Payment	The CERC Tariff Regulations, 2019 provide for allowing Additional capitalisation including liabilities, to meet an award of arbitration or for compliance with the directions or an order of any statutory authority, or order or decree of any court of	It has been stated that the recovery of interest may involve a carrying cost, if paid in instalments. The liability for arbitration is only due to the issue between

	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.	the project developer and their sub contractor. Hence the beneficiaries are not to be loaded with arbitration servicing at a later stage with interest, not due to their fault. Already the interest for delayed judgment in arbitration will have a huge impact on beneficiaries. Hence the rate of interest, if at all to be levied, shall be at G-Sec rates.
4.23 Treatment of interest on differential tariff after truing up	Regulation 10(7) of the CERC Tariff Regulations, 2019, specifies as follows: "(7) The difference between the tariff determined in accordance with clauses (3) and (5) above and clauses (4) and (5) above, shall be recovered from or refunded to, the beneficiaries or the long term customers, as the case may be, with simple interest at the rate equal to the bank rate prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments." As per the above, the differential amount of tariff needs to be recovered or refunded with simple interest in six equal monthly instalments. However, stakeholders have raised concerns over the method of charging interest on the differential amount up to the liquidation of the last instalment. 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	Levy of interest due to payment in six equal instalments shall not be imposed on the beneficiaries, and hence a welcome move.

	suggestions are sought from stakeholders on the above approach and alternative ways, if any.	
5 Operational Parameters impacting Tariff 5.1 Normative Annual Plant Availability Factor (NAPAF) 5.1.1 Review of Existing Norms	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 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.	It has been stated that the NAPAF has improved due to technological improvement, better O&M practices and shorter shutdowns and outages. Hence the improvement in PAF as stated shall offset any reduction of NAPAF due to coal shortage . Hence there is no need for revision of NAPAF.

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 incentivise peak period availability and availability during peak demand season. Further, the Tariff Policy also specifies that differential rates for fixed charges should be introduced By introducing the mandatory requirement of achieving target availability during peak hours and during high demand season, the generating stations were incentivised to be available during the time beneficiaries needed them the most. The Regulations stipulate the requirement for the generating stations to maintain specified target availability against the regional peak hours/demand season as declared by RLDCs. It is observed that though the segregation of recovery through peak and off-peak periods has brought in more accountability, there have been some operational difficulties while declaring high demand and low demand season which need to be taken care of. The current provisions require the Regional Load Despatch Centres (RLDCs) to notify in advance the months of high demand season and low demand season so that overhauling can be planned by the generators accordingly. The following issues have been brought before the Commission in this context: 1) The actual period of high demand did not coincide with the forecast, and the generators had to postpone overhauling considering the sudden increase in demand. In some cases, such deferment has led to forced outages, thereby impacting the recovery of the AFC. 2) The period of high demand and low demand is not the same for all the States in the Region, so declaring the common high and low demand period for all the States has its own challenges. For example, in Northern Region, the high demand season for hilly States such as Uttarakhand and Himachal Pradesh is the winter months, whereas for adjacent Punjab the same lies in the months of August-September and for Delhi it is the summer months. 3) Some of the generating	The existing peak and off peak tariff may continue, as the same has been beneficial to the end consumers, as the generators strive to make their machines available during the Peak period and high demand season. Earlier the generators could claim 100% AFC as they had twelve months to make up for any loss of availability and hence the beneficiaries were at the mercy of the generators. Being cheaper power, the CGS power were not available during high demand/ peak hours. In the Statement of Reasons for Tariff Regulation 2019-24, CERC has recorded as below, while substantiating the switch over to Peak and Off peak based AFC. 13.1.3 It has been submitted by some distribution licensees that the current framework of recovery of fixed cost based on target availability achieved on an annual basis, does not necessarily guarantee availability of generating stations during hours and months of their needs and that the regulations should ensure such availability through appropriate mechanism. To address this concern and also to introduce "value" of electricity, the draft Tariff Regulations, 2019 proposed recovery of Fixed Cost at differential rates during Peak Periods (not less than 4 hours in a day) and Off-Peak Periods (remaining hours other than Peak Hours), while assigning higher weightage to Peak Periods... The capacity charge rate for Peak Period was proposed at 25% higher than that of Off-Peak Period. It was also proposed that under-recovery of Capacity Charge in "Peak" or "Off-Peak" Periods in a month could be carried forward for recovery of Capacity Charge in their respective "Peak" or "Off Peak" Periods till the end of the quarter. However, carry forward of under recovery of Capacity Charge was not to be allowed for recovery from one quarter to the subsequent quarter. Besides, differential incentive rates for peak and off-

	stations have beneficiaries in different regions, which again increases the diversity of demand. Therefore, declaring common high and low demand period is practically not possible. For example, Kahalgaon STPS and Farakka STPS have allocations to beneficiaries that belong to all five regions; therefore, in such cases, the objective of devising the above mechanism is rendered ineffective and may require tweaking of existing practice by RLDCs. 4) While States have been demanding availability from the generators coinciding with State Peak, the generators have difficulty meeting this requirement due to the wide diversity of peak in different States. 5) On the other hand, suggestions have also been received for a 'National' level Peak Period in view of the fact that the grid is integrated and India has a National market in operations. 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 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.	peak periods were also proposed. 13.1.4 The Commission has considered the suggestions received from the stakeholders and has decided to retain the elements of peak and off-peak hours and seasonality in the tariff structure. ...... 13.1.8 To further promote availability and generation during the peak hours, it has been decided that in addition to the capacity charge, any "generation" beyond the generation corresponding to the specified NAPLF during a month will carry differential incentive rates, i.e. @ Rs. 0.65/kWh for generation during Peak Hours and @Rs. 0.50/kWh for generation during Off-Peak Hours. Hence the existing Regulations has addressed the issue of both the discoms and the generators and arrived at the Peak and Off peak tariff with corresponding incentives. Therefore the existing methodology may continue.
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 proposal to fix the operational norms of thermal stations on ideal loading of generating units is not practically possible, as the stations are backed down based on the MOD. Hence the norms and degradation all are station specific and it is not possible to fix them based on ideal loading.

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 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.	Instead of incentivising the generator for proper operation of emission control system commissioned at huge cost to public exchequer, there shall be a mechanism to penalise them if the emission control systems are not in proper operation. There shall be a mechanism for reduction of Annual fixed charges, based on the poor performance of the system and a regulation to the effect may be proposed.
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.	As per the CEA (Flexible operation of coal based thermal power generating units) Regulation 2022 notified on 25.01.23, the coal fired generating units shall achieve minimum power level of 40% according to the phasing plan specified by the authority from time to time. If the technical minimum is revised to 40%, then the compensation for degradation of performance also will be revised to take care of this degradation.
5.8 Gross Calorific Value (GCV) of Fuel	Comments and suggestions are sought from stakeholders on ways to reduce the gap between GCV "as billed" and "as received".	Stringent monitoring at the loading point and third party and joint sampling are some of the ways to reduce the gap between as billed and as received GCV.
5.9 Blending of Coal	Linking the consent of beneficiaries with the percentage	The present coal availability in the country and the ceiling

	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.	limit for blending have not been discussed in the staff paper. The details are required to arrive at an opinion regarding this issue. At any cost, higher blending will lead to higher cost to end consumers and hence a balanced approach is felt necessary.
5.10 Incentives	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 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.	It is felt that the prevailing incentive quantum is sufficient and no upwards / additional revision is felt necessary.
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.	While approving tariff for emission control system, the methodology of tendering, number of bidders, comparison with ECS for similar capacity plants shall all be taken into consideration.
6.3 Decommissioning of Generating Station and Transmission Assets	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.	Can be considered on case to case basis while filing the true up petition at the end of the tariff period.

6.8 Necessity to Review the need of Regulation 17 (2)	The Commission, in its Tariff Regulations, 2019 introduced the following Regulation. "17. Special Provisions for Tariff for Thermal Generating Station which have Completed 25 Years of Operation from Date of Commercial Operation: (1) In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation, the generating company and the beneficiary may agree on an arrangement, including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation. (2) The beneficiary shall have the first right of refusal and upon its refusal to enter into an arrangement as above, the generating company shall be free to sell the electricity generated from such station in a manner as it deems fit." As per Regulation 17 above, the generating stations and beneficiaries have the option after 25 years of operation to enter into a mutual agreement to recover capacity charges based on scheduled generation. However, the beneficiaries are allowed under 17(2) with the first right of refusal to such arrangement and can exit from the ongoing PPA. ...... In view of the above, the provision under Regulation 17(2) of Tariff Regulations, 2019 may result in further complication and being seen as inequitable for the generator, is required to be modified. Comments and suggestions are sought from stakeholders on the above.	TANGEDCO strongly objects modification/ deletion of this Regulation. The beneficiaries have serviced the entire cost of the plant in 25 years and it is in that spirit the Regulation 17(2) provides the first right of refusal to continue with the PPA or to exit out of the same if the cost is felt higher. Hence with this logical reasoning in mind, the Hon'ble CERC included the Regulation in TR 2019-24. Now any attempt to tamper / remove the same is unacceptable. Further, the Legal disputes pending at High Courts may be studied before deciding on this issue.

B. Rajeswari 31/07/2023
CFC/ Regulatory Cell