5926/2018/CRU-CERC

(49)

RP-Sanjiv Goenka Group

Growing Legacies

DHARIWAL INFRASTRUCTURE LIMITED

Dhariwal Infrastructure Limited

CIN : U70109WB2006PLC111457
E-mail : dhariwalinfrastructure@rp-sg.in

Date:31-07-2018

To
The Secretary
Central Electricity Regulatory Commission
3 rd & 4 th Floor, Chanderlok Building,
36, Janpath, New Delhi- 110001

Sr Regr

Sub: Comments/suggestions on Consultation Paper - Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019

Dear Sir,

At the outset, we thank CERC for providing us an opportunity to give our comments/suggestions on the Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019 – "Consultation Paper" vide its notification No. L-1/236/2018/CERC dated 24.05.2018.

Accordingly, please find attached comments on the same on behalf of Dhariwal Infrastructure Limited, a Generating Company having its Registered Office at Kolkata and a 2 x 300 MW Coal-fired Power Generating Station at Tadali, near Chandrapur, Maharashtra.

The 3 hard copies along with soft copy as per the notification has been submitted for your kind consideration.

Thanking you

Yours faithfully,
For Dhariwal Infrastructure Limited

S. Gupta

Authorized Signatory

Encl:

RP - Sanjiv Goenka Group

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Comments on CERC Consultation Paper on Terms & Conditions of Tariff Regulations for the Tariff Period FY 2019-24

The Hon'ble Central Electricity Regulatory Commission ("***Hon'ble Commission***") has brought out the Consultation Paper on Terms & Conditions of Tariff Regulations for the period FY 2019-20 to FY 2023-24 and has sought comments from all the stakeholders. The comments and suggestions on the proposed tariff structure and its terms on behalf of Dhariwal Infrastructure Limited ("***DIL***") is provided in the following matrix for the kind perusal of the Hon'ble Commission.

Paragraph	**Particulars**	**Comments and Suggestions**
Tariff Design		
7.2.4 to 7.2.6	*The possible options for tariff structure could be to offer to the procurers having low demand a menu of options for ensuring dispatch by linking a portion of fixed charges with the actual dispatch and balance of AFC to availability. This will ensure optimum utilization of the infrastructure, as procurers will continue to procure power from the generating stations and the generator will get reasonable return without losing the demand.* *The tariff for supply of electricity from a thermal generating station could comprise of three parts, namely, fixed charge (for recovery of fixed cost consisting of the components of debt service obligations allowing depreciation for repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses), variable charge (incremental return above guaranteed return and balance operation and maintenance expenses) and energy charges (fuel cost, transportation cost and taxes, duties of fuel).*	**The existing generating stations and the transmission systems are expected to recover the allowable costs and the reasonable return based on their Availability and performance as is allowed under the existing framework. Hence, the proposed change may not be necessary.** **<u>Justification:</u>** 1. The generating stations and the transmission systems are meant to be available and ready to dispatch/transfer the available potential all the times. To make itself available, the generating stations are required to operate and maintain their assets which requires a cost of service which the consumers should pay for irrespective of the consumption of the available power. Such costs are reflected in the capacity/fixed charges of a generating station or a transmission system which are sunk costs for the consumers. Hence, there is a need for certainty of recovery of such investments may not be necessary. 2. It is submitted that Availability of a generating station is under the control of the developer. The actual dispatch is controlled by the beneficiaries depending on the load demand, the extent of spinning reserve and the availability of transmission system. With the current power supply position of the Country, the beneficiaries maintain adequate spinning reserves for meeting the peaking load. This would

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
	The recovery of fixed component could be linked to target availability, whereas variable component could be linked to the difference between availability and dispatch. Fuel charges could be linked with dispatch.	enable them to reduce the tariff from the generating station by limiting the actual dispatch only up to such level so as to bear only the fixed part of the fixed charges. For the existing generating stations also, where investments have already taken place, a significant part of fixed charges which is a sunk cost, will remain unrecovered. Therefore, linking the recovery of the variable part of the fixed charges with the difference between the Plant Availability and the actual dispatch would result into under recovery of fixed charges by the generating company due to lower dispatch by the beneficiaries. It is submitted that such uncertainty in recovery of part of fixed charges would be a deterrent for new investment in the power sector which is already stressed with idle assets. Even the investment in government bond markets will be more appealing to the investors compared to the power sector. Such proposal of splitting fixed charges is against the commercial principles as envisaged in Electricity Act 2003 and a violation of financial principles as well. 3. It will not be out of place to mention that the above proposal envisages a reduction in liability for payment of Fixed Charges by the beneficiaries in case they opt to schedule less from the generating station. However, the Hon'ble Commission may kindly take note of Table 6 of the instant Consultation Paper which is reproduced below.

<table>
<tr><th>PARAGRAPH</th><th>PARTICULARS</th><th>COMMENTS AND SUGGESTIONS</th></tr>
<tr><td></td><td></td><td>
Table 6 Comparative analysis between 2009-10 and 2016-17
(Figures are in Rs per KWh)
<table>
<tr><th>Year</th><th>2009-10</th><th>2016-17</th><th>%Change</th></tr>
<tr><td>Basic Price (ROM)</td><td>0.42</td><td>0.56</td><td>33.33%</td></tr>
<tr><td>Taxes and Duties</td><td>0.13</td><td>0.40</td><td>207.69%</td></tr>
<tr><td>Coal Transportation</td><td>0.33</td><td>0.51</td><td>54.54%</td></tr>
<tr><td>Taxes & Duties on Transportation</td><td>0.03</td><td>0.12</td><td></td></tr>
<tr><td></td><td>0.91</td><td>1.59</td><td>74.72%</td></tr>
<tr><td>Generation Plant(Fixed Cost)</td><td>2.01</td><td>1.66</td><td>-21.08%</td></tr>
<tr><td>Transmission Cost(Inter)</td><td>0.23</td><td>0.39</td><td>69.56%</td></tr>
<tr><td>Transmission Cost(Intra)</td><td>0.12</td><td>0.14</td><td>16.67%</td></tr>
<tr><td>Transmission losses</td><td>0.29</td><td>0.33</td><td></td></tr>
<tr><td></td><td>2.65</td><td>2.52</td><td>-5.16%</td></tr>
<tr><td>Distribution Cost</td><td>0.48</td><td>1.39</td><td>189.58%</td></tr>
<tr><td>Distribution Losses (AT&C)</td><td>1.03</td><td>1.17</td><td></td></tr>
<tr><td></td><td>1.51</td><td>2.56</td><td>69.54%</td></tr>
<tr><td>Cost of Supply</td><td>5.07</td><td>6.67</td><td>31.56%</td></tr>
</table>
[Note: (1) The above calculations (details at Annexure-1 (A) to 1(C)) are based on operational norms (as given in Table 7) of CERC Tariff Regulations.]

It is evident from the above table that the Fixed Charges for the generating station is the single component in the Cost of Supply which have reduced in the last 8 years. All other components of the cost of supply has increased albeit not in tandem. Such information suggests that the present regulatory framework is capable enough to contain the Fixed Charges of the generating station to a reasonable level.
</td></tr>
<tr><td>7.3.4</td><td>A clear policy/ regulatory decision are required in view of a number of thermal stations crossing the age of 25 years. Possible options could be (i) replacement of inefficient sub critical units by super critical units, (ii) phasing out of the old plants, (iii) renovation of old plants or (iv) extension of useful life etc. It is worth to note that performance of a unit does not necessarily deteriorate much with age, if proper O&M practices are followed.</td><td>The present regulatory framework allows the generating companies to execute Renovation and Modernization of the generating stations in order to extend the Useful Life of the project. In our humble opinion, the same provision may be continued in Tariff Regulations for FY 2019-24. We therefore humbly request the Hon'ble Commission to adhere to options (iii) and (iv), i.e., renovation of old plants or extension of useful life.</td></tr>
</table>

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		Justification: 1. Existing thermal power plants crossing their useful life of 25 years can continue the operation only if the benefit of the reduced fixed charges is higher than the impact of deterioration in efficiency w.r.t. newer units of similar size and specifications. The options as proposed by the Hon'ble Commission may be evaluated on the basis of net benefit available to the consumers considering the investment involved and the extension of life guaranteed in each option. 2. It is quite unlikely that the efficiency of the old units would be similar to the newer units even if the best O&M practices are followed. The deterioration of the efficiency does not only depend on the O&M practices, but on various factors like natural wear & tear and life of the equipment, incompatibility of old equipment with new spares, history of load pattern etc. Further sub-critical units of lower capacity offer better load control and management than super-critical units of higher capacity. All such factors should be considered while deciding upon the proposed options. 3. It is submitted that the first option proposed by the Hon'ble Commission, i.e., replacement of inefficient sub-critical units by super critical units involves huge requirement of capex fund and also, retrofitting work which do not seem realistic and financially viable. The second option of phasing out of the old plants may be executed only when the efficiency had undergone degradation beyond a recoverable limit.

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
COMPONENTS OF TARIFF		
9.3	*The question is whether the annual fixed charges and energy charges are to be determined to the extent of the capacity tied up under Section 62 of the Act or for the entire capacity. One approach could be to determine the tariff of the generating station for entire capacity and restrict the tariff for recovery to the extent of power purchase agreement on pro-rata basis and balance capacity will be merchant capacity or tied up under Section 63, as the case may be.*	The following two scenarios need to be covered for recovery of fixed charges for a generating station whose entire capacity is not tied up through PPA either u/s 62 or 63. a) Some units of the generating station have a PPA while others have not. Change in law or emergence of new technologies requires that additional capital expenses have to be incurred for the running of the units having PPA. In this case the entire expenses incurred (if justified as per prudence check) shall be considered unit wise for tariff determination and not for the generating station as a whole. b) Where the long term PPA is for the partial capacity of the unit and a capex has to be incurred for meeting the requirements of law (FGD for example) the entire cost of such capex as required shall be considered for tariff recovery as a partial capacity FGD is not feasible. Such tariff shall be reviewed after any new PPA is entered into, for the balance untied capacity in future.
OPTIMUM UTILIZATION OF CAPACITY		
10.3	*(a) Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the anticipated reduction of utilization. Annual Contracted Capacity (ACC) may be treated as guaranteed contracted capacity during the year for the generating company and the distribution licensee and*	**We request the Hon'ble Commission to continue with the present regulatory framework wherein allow the Generating Companies to recover the Annual Capacity/Fixed Charges on the basis of total Contracted Capacity (CC) as specified in the PPA in order to recover the sunk cost in its entirety.**

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
	the capacity beyond the ACC may be treated as Unutilized Capacity (UC). The distribution licensee will have a right to recall Unutilized Capacity during next year and for securing such rights, some part of fixed cost, say 10-20% or to the extent of debt service obligations, may be paid; *(b) Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be re- allocated to the distribution licensee at market discovered price.*	
CAPITAL COST		
11.8	*One of the options is to move away from investment approval as reference cost and shift to benchmark/reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost.*	**The existing practice of determination of provisional tariff based on projected capital expenditure needs to be continued as it helps to minimize the impact of retrospective revision of tariff after the determination of final tariff.** **Justification:** 1. The capital cost claimed by the utilities during the determination of provisional tariff is based on projected capital expenditure which is generally made in line with the original investment approval unless there is expected cost overrun/time overrun on account of delay in the commissioning of the project. Hence the tariff claimed based on projected capital expenditure is close to actual capital expenditure which is determined at the time of truing-up of Capital Cost which minimizes the burden of carrying cost on the utilities/beneficiaries. 2. It is submitted that few packages although included in the original investment approval/benchmark cost may need to be shifted for capitalization beyond the

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		Cut-off Date due to many reasons not under control of the project developer. The Hon'ble Commission may kindly allow such expenditure beyond the Cut-off Date as long as the utilities are able to manage the capitalization within the projected cost. 3. Additional Capitalization by thermal generators for meeting the efficiency improvement targets under the PAT scheme, revised environmental norms, new requirements under direction of any statutory authority or 'Change in Law' etc. cannot be standardized and would vary on case to case basis. It would be very difficult to set benchmarking norms for such new technology as enough data/information may not be available. In our humble opinion, since the authority for according approval to such Additional Capitalization lies with the Hon'ble Commission, the same may be based on prudence/scrutiny of actual cost on case to case basis.
11.9	*Higher capital cost allows the developer return on higher base of equity deployed. In the cost plus pricing regime, the developer envisages return on equity as per the original project cost estimation. The regulations allow compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred. Therefore, in new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. The return on additional equity may be restricted to the extent of weighted average of interest rate of loan portfolio or rate of risk*	**In a cost-plus regime, the shareholder's minimum expected return on the invested amount is the Return on Equity as specified in the Tariff Regulations. The reduction of Capital Cost on account of time overrun/cost overrun by way of disallowance of IDC takes into account the reasonable penalty for inefficiency in Project Management. Such framework may therefore be continued.** **Justification:** 1. In case where the equity is deployed to fund the cost overrun/increase in project cost on account of uncontrollable factors, it would be unfair to restrict the recovery of expected rate of return on equity. The shareholders' return anyway suffers from the effect of prolonged gestation period on account of delay in commissioning of the Project.

<table>
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<tr><td></td><td>free return. Further, incentive for early completion and disincentive for slippage from scheduled commissioning can also be introduced.</td><td>2. In any case, the cost overrun is allowed by the Hon’ble Commission only after due prudence check of the delay and after satisfactory demonstration of no fault from developer’s side. In case the same is found attributable to the developer, the same is disallowed by the Hon’ble Commission. The developers do not earn any return on equity deployed for such disallowed investment. Hence, further reduction in reasonable return to shareholders for the cost overrun allowed by the Hon’ble Commission would imply imposition of penalty for no fault of the developer and is therefore not desirable. This would in turn reduce the cash flow to reserves for funding future growth.

3. The incentive for early completion of the project from scheduled commissioning may be linked with an additional post-tax Return on Equity of 0.5% in line with the prevailing Tariff Regulations.</td></tr>
<tr><td colspan="3">RENOVATION & MODERNIZATION</td></tr>
<tr><td>12</td><td>Renovation & Modernisation</td><td>Renovation & Modernization (“R&M”) should be allowed to be undertaken after specified years of service. Further, depreciation and debt servicing cost of the Additional Capitalization should be allowed to be recovered within the balance useful life of the plant after considering the life extension, if any. As an alternative, the Hon’ble Commission may allow special allowance on cumulative basis for the eligible plants and allow the balance capital cost for addition to the GFA.

<u>Justification:</u>
1. Approval of R&M expenditure for generating companies or transmission licensee should be provided through a separate exercise by the Hon’ble Commission after specified years of operation (to be fixed by Commission). Plants completing specified number of years of operation (say 15-20 years) may opt to take up R&M evaluation based on OEM recommendation & certification before submitting the</td></tr>
</table>

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		proposal before the Hon'ble Commission. Based on the evaluation, R&M schemes for the plant should be approved by the Hon'ble Commission based on a cost benefit analysis and expected life extension. 2. Taking up R&M on completion of 25 years could deteriorate the unit to such a condition that the R&M will not bring intended results. Taking up projects for R&M before completing 25 years of operation will give sufficient time for recovery of R&M expenses through tariff without significant increase in tariff. The utilities taking up R&M Projects, with expected life extension, should be allowed to recover the depreciation and debt servicing costs within the extended useful life of the project. In our humble opinion, the Hon'ble Commission may consider it essential to specify in Tariff Regulations the time period after which the generating companies/transmission licensees may opt for such R&M activities, based on industry trends and recommendations of key OEMs in the power sector. 3. Special Allowance as allowed by the Hon'ble Commission, in various Projects, could not meet the entire investment required for R&M purpose. Further, R&M projects cannot be undertaken on piecemeal basis. Therefore, if special allowances are envisaged for meeting the R&M requirements, the Hon'ble Commission should allow the utilities to utilize the accumulated special allowances, starting after say 15 years, at the time of undertaking the R&M Project. The balance, if any required for meeting the cost requirement of R&M Project may be additionally approved by the Hon'ble Commission. However, the utility may be allowed to recover the additional fixed charges only on the balance approved by the Hon'ble Commission. This is further explained through the following example:

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		Let us assume the Special Allowance for a Generation Project of 500 MW = Rs 10 Lakhs/MW escalated @9% p.a. The Generating Station shall be eligible for such Special Allowance after 15 years of operation. The Generating Station upon reaching 22 years of operation proposes to undertake R&M Project with an investment of about Rs 500 Crores. Total Accumulation of Special Allowance = 500*10/100*(1-(1+9%)^7)/(1-(1+9%)) = Rs 460 Crores Let the life extension proposed be of 7 years beyond 25 years. Balance fund required for meeting the R&M Project = (500-460) = Rs 40 Crores. Therefore, Rs 460 Crores of the proposed R&M Project shall be met through accumulated Special Allowance and the balance Rs 40 Crores may be allowed to be added in the Gross Fixed Asset. Depreciation, Interest on Loan and Return on Equity shall be available only on such Rs 40 Crores.
FINANCIAL PARAMETERS		
13.1	*The performance-based cost of service approach, a combination of actual cost and normative parameters has been evolved for the Tariff regulations. Components like return on equity, operation & maintenance expenses and interest on working capital have been specified on normative basis whereas cost of debt has been allowed based on actual rate of interest on normative debt. The normative parameters are expected to induce operational and financial efficiency. While continuing with the hybrid approach, more weightage may be*	**In view of the anticipated growth in electricity demand and the existing challenges in the power sector, a balanced hybrid approach is required to be adopted for tariff determination in the larger interest of the sector. Further, the Hon'ble Commission should ensure reasonable return for the developers, incentives for adopting the schemes customer benefitting the customers and recovery of reasonable costs on capital expenditure schemes implemented near fag end of the Project life.** **<u>Justification:</u>** 1. In our humble opinion, we request the Hon'ble Commission to kindly look into the following matter:

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	provided for normative parameters to induce greater efficiency during operation as well as in development phase.	a) The rate of return for equity needs to be fixed in a manner that will not only attract investment but generate sufficient resources for further growth in the power sector. b) The current incentives for restructuring or refinancing of debt structure may require review to encourage developers to go for reduction of cost of debt. The consumers get benefitted post restructuring of long-term loan in the form of reduced rate of interest leading to lower Interest of Loan component in Tariff. Therefore, in our humble opinion, the generating company should be allowed to retain at least 2/3rd gain out of such refinancing activities. The Tariff Regulations of CERC and various SERCs are required to be amended to this extent. c) For the Capex Schemes which would be required to be capitalized, in order to comply with the new provisions/amendments under the Environment Law/Rules and any other statutes, at the midway or at the fag end of the useful life of the Project, **the depreciation of such capitalized assets is required to be recovered within the useful life of the project**. The Tariff Regulations should clearly bring out - the recovery of depreciation under a separate category of Capex Schemes which are to be incurred under Environment law/Rules/any other statute and these depreciation rates should be clearly demarcated from the existing Depreciation Rates specified in the Tariff Regulations.
DEPRECIATION		
14.6 (a)	*Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff;*	**Increasing the useful life of plants based on quality of maintenance practices is not a feasible option and as such may not be adopted.**

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		Justification: 1. It would be very difficult to assess the maintenance quality of various plants as there are various parameters which affect the performance of the equipment. In a particular plant, the maintenance quality of different asset categories would be different. It would not be appropriate to assess the maintenance quality of the entire station on the basis of limited critical assets like BTG package. 2. Further, it is required to gather data/information on equipment failures, routine activities, process improvements etc. over a substantial period of time in order to assess the maintenance quality of the entire plant. In order to assess the quality of maintenance, the Hon'ble Commission is required to define relevant metrices, e.g., Forced Outage Rate, MTBF, MTTR and link actual Repair & Maintenance expenses with various major maintenance works executed over the years. Hence, such assessment can only be possible at mid-way or fag end of the useful life of the plant. It would be meaningless to incorporate the changes in the useful life of the assets and adjust the depreciation rates accordingly at a stage when there is only minor - amount that remains to be recovered.
14.6 (b)	*Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units;*	**The treatment of weighted average Useful Life in case of gradual commissioning of units should continue. It is simple, scientific and feasible approach instead of unit-wise computation of Useful Life.**
14.6 (c)	*Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/ equipment;*	**R&M projects should be admitted based on the technical reports and should not be restricted to limited items/equipment. Further, there may be requirement of additional capital expenditure on account of premature failure of equipment or to comply with the stricter statutory norms which may not necessarily ensure a life extension of the entire Project. Such schemes may be allowed based on their merit.**

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		Justification: 1. It is submitted that all the assets capitalized at the time of COD or thereafter, do not have same useful life. Some of the critical assets/part of the asset-packages like BTG, BoP etc. may have shorter useful life or become obsolete before the completion of its useful life due to non-availability of spares, services from OEM etc. Replacement of such critical assets therefore becomes critical for reliability and sustainable operation of the unit. Further, there may be instances during the lifetime of the Project wherein the utility has to incur capital expenditure in order to comply with stricter Environment Norms or such other norms under the statute. Such additional Capital Expenditure incurred during midway or at fag-end of useful life of the project therefore may include replacement assets or mandatory assets which are necessary but cannot ensure extension of the life of the entire project. Therefore, such additional capital expenditure does not require any reassessment of useful life. Further, the depreciation of such capitalized assets should be allowed under a separate category which is to be recovered within the useful life of the project irrespective of the Depreciation Rates specified in the Tariff Regulations. 2. R&M projects are undertaken by the utilities in order to operate the unit beyond its useful life at the same level of efficiency and reliability. Such R&M projects are envisaged and developed based on the conditions of the various equipment. Further, since the R&M projects are generally conceived after at least 15-18 years of operation, the compatibility of the available technology with the phased-out/existing technology always remains as an area of concern. Various modifications may be required to optimize the scope of R&M projects. Hence such R&M projects should be admitted based on the technical reports vetted by OEM/Expert Committees and should not be restricted to limited items/equipment.

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
14.6 (d)	*Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Ind AS and corresponding treatment of depreciation thereof;*	**There is no requirement for reassessment of useful life at the start of every tariff period and may be done only at the time of undertaking R&M projects.** **Justification:** 1. Depreciation allowed under the regulatory mechanism is a major component of tariff and assures the cash flow for the project which is utilized for meeting the debt service obligations. Frequent revision in depreciation will result in uncertain cash flows and this will create problem in arranging finances for the project. 2. Further, the re-assessment of life of critical equipment of the BTG package would require expert technical examination, i.e., Residual Life Assessment ("***RLA***") study and cannot be done based on any accounting estimate. Accordingly, the utilities would have to incur additional costs for such technical assessment at the beginning of every tariff period which needs to be factored in the O&M Expenses. Therefore, it is not required to reassess life and recompute depreciation rates at start of every tariff period. In our humble opinion, re-assessment of useful life should form part of the R&M scheme proposed by the utilities.
14.6 (e)	*Extend useful life of the transmission assets and hydro station to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation.*	**Useful Life of the thermal assets should not be increased without OEM consultation and recommendations based on RLA study.** **Justification:** 1. In our humble opinion, the useful life of the assets depends on various factors like equipment design, materials, O&M practices, etc. The equipment specification, design and materials used cannot be altered for existing utilities. It is therefore reiterated that extension of useful life of the project should be linked to RLA study and the corresponding R&M project wherein the Hon'ble Commission in consultation with the OEM may determine the extended useful life of the project

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		at the midway or fag end of the useful life of the project. The depreciation of such capitalized assets should be allowed under a separate category which is to be recovered within the extended useful life of the project irrespective of the Depreciation Rates specified in the Tariff Regulations.
14.6 (f) & (g)	*f) Reduce rates which will act as a ceiling.* *g) Continue with the existing policy of charging depreciation. However, the Tariff Policy allows developer to opt for lower depreciation rate subject to ceiling limit as set by notified Regulation which causes difficulty in setting floor rate, including zero rate as depreciation in some of the year(s).*	**Existing policy for charging Depreciation may be continued. Further, uniform rate of Depreciation for the entire project, linked to repayment of debt, should be adopted as a ceiling rate in line with the National Tariff Policy 2016.** **Justification:** 1. In our humble opinion, reducing the rates of depreciation will not fulfil the purpose of meeting the debt service obligation of the utilities and there would always be mismatch between the cash flow available through recovery of depreciation and the actual service obligation during the first 12 years of operation. The Weighted Average Rate of Depreciation for a full year (without any Additional Capitalization) for a generating station lies between 5.20% to 5.50%. The total depreciation reserve for 12 years therefore falls short by 4% - 8% so as to fully meet the debt service obligation even under the present methodology. 2. Further, the cost of debt/interest rates and the repayment period depends on the credit ratings and the past performance of the utilities. Therefore, there is no standardized rate and repayment period available at which the utilities can borrow from banks and financial institutions. Reducing the rates of depreciation would therefore impact the new players in the sector and create an entry barrier for fresh investments. 3. Further, the Weighted Average Rate of Depreciation, computed on the basis of individual depreciation rates of different class of assets capitalized with the

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		capitalized amount in each class of asset as the weights, is different for different utilities since the actual mix of capitalized assets for each utility varies from the other on various factors like technology, availability of resources, phasing of capitalization etc. It is therefore submitted that a uniform rate of depreciation for the entire project, linked to repayment of debt, should be adopted as a ceiling rate in line with the National Tariff Policy 2016. Accordingly, such rate of depreciation may be kept at 5.83% = (70% of debt/12 years of normative loan repayment period) for the initial period of 12 years. The balance value of the asset could be allowed to be depreciated over the residual life, duly considering the salvage value as per the existing practice.
GROSS FIXED ASSET (GFA) APPROACH		
15.2	*An option could be to base the returns on the modified gross fixed assets arrived at by reducing the balance depreciation after repayment of loan in respect of original project cost.*	**The Hon'ble Commission may continue with the Gross Fixed Asset (GFA) approach in the interest of desired growth of the power sector.** **Justification:** 1. It is to be noted that under Net Fixed Asset (NFA) approach, the equity base of the project will effectively reduce which in turn will reduce the return on equity significantly. Adoption of NFA approach may severally affect the internal resource generation of power generating companies and further investment in the power sector will be impacted adversely alongwith debt service obligation. The investors have made investments based on GFA approach and changing the methodology will have detrimental effect on the returns on the investments. In our humble opinion, therefore, NFA approach will be unfair on the developers as this will deny reasonable returns to the developer as well as it will not be able to provide adequate cash to developer to meet its debt service obligation.

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		2. It is further submitted that as per National Electricity Plan, issued by Central Electricity Authority (CEA) in the month of December 2016, no new coal-based capacity was projected to be required till 2027. **But Central Electricity Authority (CEA) in the month of January 2018 revised the National Electricity Plan and projected an additional coal-based capacity 6,440 MW & 46,420 MW by 2021-22 and 2026-27 to meet the future peak demand and energy demand considering the retirement of coal-based capacity of 22,716 MW.** 3. We are of the considered opinion that the alternative option suggested in the Consultation paper is against the spirit of National Tariff Policy 2016 as returns will become unattractive post debts are repaid. If the NFA approach is considered, the returns will reduce after debt repayment is done. To see that the developers will have sufficient incentive to run the project efficiently and keep it in good operational condition till end of its useful life, NFA approach may not be the suitable option because presently the power sector is facing various challenges such as non-availability of fuel, cancellation of coal blocks, setting up of projects without linkages, lack of adequate long-term PPAs by states, promoters' inability to infuse equity and working capital, contract/tariff-related disputes, issues related to banks/financial institutions, and delay in project implementation, leading to cost overruns etc.
DEBT-EQUITY RATIO		
16.4	*For future investments, modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved.*	**We request the Hon'ble Commission to continue with the present model of Debt/Equity Ratio of 70:30 for the Tariff Period FY 2019-24.** **Justification:** 1. Taking into consideration the prevailing volatile financial market in India, developers are finding it difficult to raise finance for thermal power projects. It is

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		to be noted that currently many private entities in power sector are facing severe financial stress on account of idling assets. Many are on the verge of being declared Non-performing Assets or NPAs and/or are being referred to NCLT for restructuring by the lenders. In our humble opinion, we suggest that there should not be any discrimination of Debt: Equity ratio on the basis of financial leverage for existing as well as new projects. There must be a level playing field between private sector utilities or Central/State owned utilities in terms of Return on Investment which will ensure a fair competition in the power sector. 2. It is submitted that there is huge instability in rating of generating companies in view of sectoral issues such as fuel availability, long-term PPA, evacuation and DISCOM's Financial health etc. In other words, this approach would pose an entry barrier on the new players since the credit ratings are generally lower for new utilities in terms of financial stature. 3. The structuring of the Indian debt market is still in process, i.e., the debt market in India is yet to get stabilized. Therefore, the existing Debt: Equity approach may be continued. In case a developer is able to put incremental equity above normative level, additional incentive should be provided to the developer.
RETURN ON INVESTMENT		
17.4	*Comment and suggestions are invited from the stakeholders on the continuation of fixed rate of return approach or alternatives, if any.*	**It is humbly submitted that the Hon'ble Commission may continue with the Return on Equity ("*RoE*") approach for the Tariff Regulations for FY 2019-24.** **Justification:** 1. Benchmarking of cost of debt for implementation of Return on Capital Employed ("***RoCE***") approach is difficult in current unstable Indian debt market. With the falling Rupee, the foreign loans and bonds would become expensive and the

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		interest rates are expected to fluctuate. Any variation in cost of debt would add to the risk profile of the developer. In addition, the borrowing capability of different companies varies and depends on the rating in terms of its financial status. The existing players shall be benefitted as loans shall be available to them at lower rates and this may limit the influx of new players in the power sector and reduce the competition. 2. With RoCE approach, the developers may have to bear the upside fluctuations in the cost of debt, if any, and the Equity IRR of the project would drop. In our humble submission, the shareholders of the existing projects would be denied of the assured return promised to them based on earlier RoE based approach. This would reduce the confidence of the investors on the regulatory framework. 3. Further, if the Hon'ble Commission determines RoCE under normative approach, i.e., through composite fixed RoCE considering Debt: Equity ratio of 70:30, prevailing interest rates and fixed RoE, the consumers would be insulated from the effect of increasing interest rates. In a similar way, benefits, if any, achieved on account of re-financing of long-term loan can also not be passed onto the beneficiaries. This would not derive significant benefits for the consumers in the long run. 4. In view of above, it is proposed that RoE based approach may be continued for the next Tariff period.

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RETURN ON EQUITY		
18.6	*According to CEA, the capacity addition is no more a major challenge and adequate installed capacity (along with currently under installation) exists to meet the demand for the next 8-10 years. Further, the rate of interest has also come down in recent times. Therefore, there is market dynamics which favors reduction of rate of return. However, any such reduction will have negative impact on the equity already invested in the existing and under construction projects, creating further financial stress on such projects. Different rate of return for new projects (where financial closure is yet to be achieved), may be thought of, with different rates for generation and transmission projects.*	**In our humble opinion, there is no further requirement to increase the financial stress factors on the developers by reducing the existing reasonable rate of return on equity already invested in the existing and under construction projects.** **Justification:** 1. It is apparent from the present power sector scenario that the future growth in demand for the next 8-10 years can be met through improvement in PLF of the existing capacity and the gradual commissioning of the pipeline capacity. It is submitted that reducing the gap between demand and supply itself would be natural entry barrier for the new players unless they have a cost leadership over the existing players. Further, with the gradual saturation of the long-term market, the effect of market dynamics over price of electricity would be visible in the medium and short-term markets. Further, the existing plants are also striving with various difficulties to recover their reasonable return on account of several factors like change in law, non-regulated Coal invoicing and inefficient quality monitoring, differential treatment of Coal companies, delay in payment by DISCOMs and various other uncontrollable factors. 2. Even if we examine the trend of 10-year G-Sec bonds in domestic market, it has definitely come down from 8.5% in June 2014 to 6.18% in November 2016, but has again picked up the increasing trend and is currently pegged at 7.94% (as on 14.06.2018). In our humble opinion, such cyclic movement for G-Sec bonds is completely market driven and depends on various factors like liquidity in primary market, inflation expectations, risk perceptions etc. Such factors are not expected to continuously rise or continuously fall in a stable/growing economy like India. Therefore, the movement of interest rates in the primary and secondary markets

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		for the past five years would not be a suitable basis for concluding on a reduction in the rate of return on equity. Further, linking expected rate of return to market (through CAPM method) is also not advisable as the volatility in the capital market for the power sector may not represent the true pricing of private equities.
18.7 (b)	*Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects;*	**In view of the reduction of the demand-supply gap, the different rates of return for existing and new generation would definitely deter fresh investments in the sector at least for the next tariff period. In our humble opinion therefore, rate of RoE should be uniform for both existing & new generation projects.**
18.7 (e)	*Continue with pre-tax return on equity or switch to post tax Return on equity;*	The Hon'ble Commission may continue with the existing pre-tax return principle. **Justification:** 1. Switching to post-tax RoE will only de-link the pre-tax RoE into two separate elements for recovery – post-tax RoE and Income Tax. The Hon'ble Commission had in the Tariff Regulations 2014 shifted to 'effective tax rate' concept from 'applicable tax rate' concept. Since the effective tax rate could actually be computed only at the end of the tariff period, for the purpose of grossing up of pre-tax RoE during determination of provisional tariff, applicable tax rate had been utilized subject to truing-up at the end of the tariff period. Such methodology helps to meet the cash flows for the utility and as such continue with the existing pre-tax return principle.

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18.7 (f)	*Have differential additional return on equity for different unit size for generating station, different line length in case of the transmission system and different size of substation;*	**It would not be fair to have different rates of return on equity for different unit sizes or different line length or size of substation.** **Justification:** 1. Ideally the unit size of the generating station is finalized based on various factors like demand, availability of unit size as per demand, environmental clearance etc. Similarly, in case of transmission system, such system specifications are decided based on the requirement (augmentation or system upgradation). In our humble opinion, the equity investment therefore may not always depend on the wish of the developer and is driven by the system requirements.
18.7 (g)	*Reduction of return on equity in case of delay of the project;*	**There should not be any reduction in Return on Equity in case of delay of the Project as the inefficiency in Project Management is generally penalized by way of reduction in IDC and IEDC.** **Justification:** 1. The Tariff Regulations 2014 provide, in case of timely completion of the Project, for additional return of 0.5% is given to incentivize the project developer. Further, the IDC and IEDC for such early commissioned projects are allowed at actuals. However, in case of any delay, the Hon'ble Commission allows the cost overrun, if any, after due scrutiny of the reasons for such delay. The developers have to suffer the loss of IDC and IEDC incurred during the period of delay for the entire life if the same is not approved by the Hon'ble Commission. Such prudence scrutiny therefore already incorporates the disincentive by way of zero return on 30% equity invested on the amount of cost overrun. Additional reduction of return on equity in case of delay of project would lead to double penalization which would not be fair and equitable.

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COST OF DEBT		
19.4 & 19.5	*While allowing the cost of debt as pass through, options available for regulatory framework are either to consider normative cost of debt based on market parameters or actual cost of debt based on loan portfolio. As the tariff is determined for multi-year period and cost of debt varies based on changing market conditions, linking cost of debt to market parameters such as MCLR & G-sec will bring a degree of unpredictability. The regulatory approach evolved so far has been to allow the cost of debt based on actual loan portfolio. This does not incentivize the developers to restructure the loan portfolio to reduce the cost of debt. The current incentive structure may need review to encourage developers to go for reduction of cost of debt.* *(a) Continue with existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan, or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects;* *(b) Review of the existing incentives for restructuring or refinancing of debt;* *(c)Link reasonableness of cost of debt with reference to certain benchmark viz. RBI policy repo rate or 10-year*	**In our humble opinion, the existing method of working out cost of debt by considering weighted average rate of interest, calculated on the basis of actual loan portfolio, actual interest rate and scheduled loan repayment is the right approach for computation of tariff.** **Justification:** 1. Switching over to the methodology of normative cost of debt based on the present debt market conditions, may not suit to the developers because of its uncertainty, interest rate fluctuations, higher degree of risk and may result in unpredictable gain/loss for the generators and may discourage the investors. 2. The current incentives for restructuring or refinancing of debt structure may require review to encourage developers to go for reduction of cost of debt. The consumers get benefitted post restructuring of long-term loan in the form of reduced rate of interest leading to lower Interest of Loan component in Tariff. Therefore, in our humble opinion, the generating company should be allowed to retain at least 2/3rd gain out of such refinancing activities. The prevailing Tariff Regulations of CERC and various SERCs are required to be amended to this extent. 3. Benchmarking cost of debt will be difficult since the debt market in India is still in developing stage. Further, variation of cost of debt amongst various projects and companies having different ratings cannot be accounted by fixing any benchmark yield. This will pose significant financial risk on the companies who have availed debt at much higher rate of interest as compared to the benchmark yields. In other words, this approach would pose an entry barrier on the new players since the cost of borrowings are generally higher for new utilities with lower rating in

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	Government Bond yield and have frequency of resetting normative cost of debt;	terms of financial stature. Hence, it is advisable to continue with existing norm until the debt market is matured in India.
INTEREST ON WORKING CAPITAL		
20.3 (a)	*Assuming that internal resources will not be available for meeting working capital requirement and short-term funding has to be obtained from banking institutions for working capital, whose interest liability has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed or change can be made.*	**The present methodology clearly sets out the item-wise capital allotment for sustaining daily operations. In our humble opinion, the existing methodology of determination of normative working capital is best suited for the generating station as it provides a clear projection of working capital to be provided for the tariff period. Hence, the present methodology may be continued.**
20.3 (b)	*As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken.*	**Normative/fixed fuel stock corresponding to generation at Normative Plant Availability is logical and equitable.** **<u>Justification:</u>** 1. Normative fuel stock is allowed to the generators for maintaining adequate inventory so as to generate as per the required schedule of the beneficiaries. In case the Plant Availability suffers on account of shortage of fuel, the generators are penalized by way of reduction in Fixed Charges 2. Benchmarking of fuel stock may not be fruitful for the purpose of determining the requirement of optimum working capital since the fuel supply position for the developers across the country are not the same. Non-pit head stations can range from as low as 50 Km to as high as 1500 Km. The risk of maintaining low fuel stock for non-pit head stations in the near-distance range is much less than that for similar stations at higher-distance range. Fuel-stock in transit for latter category

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		of stations also play an important role in mitigation of such risk. It is difficult to gather such data/information for all higher-distance non-pit head stations. 3. Further, in case of shortfall of coal supply under FSA, the generators have to procure e-Auction coal which accounts for around 25-30% of total coal procurement. Apart from the payment of initial Security Deposit (in cash or through BG) the generators are required to place advance cash deposit for the coal value either upfront or as per scheduled delivery. However, the actual materialization of bid quantity happens after long gestation periods with high chances of sub optimal materialization in many cases. The above results in blockage of working capital for the bidders with consequential higher interest cost. Getting refunds of coal value against quantity not supplied for some auction(s) is also a prolonged time-consuming process leading to further blockage of working capital.
20.3 (c)	*While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say, 15% maintenance spares being made part of working capital or O&M expenses.*	**The maintenance spares as working capital cannot be accommodated through the O&M Expenses and hence should be considered separately @20% of O&M Expenses in line with present Tariff Regulations.** **Justification:** 1. The cost of maintenance spares included in the O&M Expenses reflects the cost incurred in consumption of such spares whereas the maintenance spares as working capital reflects the cost of carrying such spares in the inventory. It is pertinent to note here that the procurement of maintenance spares is done on the basis of consumption and the projected maintenance schedule. Such inventory is required to be replenished with the consumption of such spares. 2. Many small fast-moving items included in the maintenance spares which are procured from local/alternate vendors through cash expenses with very limited

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		credit. Therefore, it is essential to include such items as working capital since a portion of the capital is blocked for maintaining a stable inventory of such fast-moving items.
20.3 (e)	*In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with "target availability" can be reviewed.*	**Working Capital linked to Normative Plant Availability may be continued for the next Tariff Period FY 2019-24.** **Justification:** 1. The working capital requirement is based on the projected demand of the beneficiaries. In absence of any feasible projected demand, the generator has to arrange for fuel, water spares, services and other consumables so as to able to generate 85% of the contracted capacity. In our humble opinion, a generator cannot forecast the demand of its beneficiary. In cases where the PLF is close to about 100%, the generator is bound to dispatch the power as per the schedule subject to declaration of its Plant Availability. In cases of sudden coal shortage, the generator has to bear the loss of recovery of fixed charges if the annual availability reduces below 85%. Therefore, linking working capital to Normative Plant Availability would ensure the generators to arrange adequate fuel for required generation. Such methodology may therefore be continued for the next tariff period as well. 2. Further, it is pertinent to note here that it would not be possible to ascertain each and every item of the working capital on actual basis. In such case, the Hon'ble Commission should also consider the receivables based on actual days taken by the beneficiaries to make the payment irrespective of disputes. In current market scenario with deteriorated financial health of the Distribution Licensees, the payments are delayed which in some case is as much as 6 months. The Generators

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		cannot claim the interest on working capital due to blockage of receivables for such long period. 3. The Hon'ble Commission may like to review the components of the working capital and include the cost of water charges corresponding consumption up to Normative Plant Availability in the O&M Expenses and the actual cost of holding the capital spares allowed during truing-up.
OPERATION & MAINTENANCE (O&M) EXPENSES		
21.7	*(a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure;* *(b) Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost.* *(c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects;* *(d) Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naphtha and R-LNG based plants).* *(e)Rationalization of O&M expenses in case of the addition of components like the bays or transformer or transmission lines of transmission system and review of*	**The Hon'ble Commission may determine the base O&M Expenses and the applicable annual escalation factor based on the methodology adopted during fixation of norms for FY 2014-19. However, there are some other expenditures like Ash Disposal Expenses, Water Charges, additional expenses due to vintage, unexpected expenses on account of any event under 'Change in Law' which should be allowed separately.** **Justification:** 1. The generating stations, irrespective of their size, incurs expenditure under the three broad categories a) Repair & Maintenance Expenses b) Administrative & General Expenses and c) Employee Expenses. These expenses are directly related to the inflation rate and are also specific to the State where the Generating Station is located since it decides the availability of labour, spares and other administrative expenses. Hence the existing practice of determining the annual escalation rate on O&M Expenses for the entire tariff period may be continued. 2. In our humble opinion, in addition to the base O&M Expenditure determined through suitable annual escalation factors year-on-year, we further suggest to expand the scope of O&M Expenses by including the provision for Change in Law

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	the multiplying factor in case of addition of units in existing stations; *(f)Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system.* *(g)Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.*	to capture the unexpected expenditure such as wage revision, change in taxes & duties etc. 3. The existing norm of O&M Expenses needs to be reviewed as they are not adequate to meet the actual O&M Expenses of generating companies and transmission licensees. Normative O&M Expenses need to reconsidered keeping in view the vintage of the project and different norms should be set for different projects depending upon the vintage profile. There is a need for upward revision of the existing normative O&M Expenses to meet the efficiency improvement targets under the Perform, Achieve & Trade (PAT) scheme notified under the Energy Conservation Act, 2001, mandatory usage of water from Sewage Thermal Plant (STP) as per National Tariff Policy, 2016 and Pollution Control System to meet the revised standards of emission norms. 4. Further, the present norms do not provide for various O&M expenses such as ash disposal expenses, water charges, increase in wages of regular employees etc. Ash disposal expenses vary from project to project and depend on ash content of coal, ash utilisation options available and technology employed for ash disposal. Ash disposal expenses should be considered at actuals after due prudence check and provided for over and above the normative O&M expenses on case to case basis. Further, the insurance charges for Thermal Generating stations may be allowed over and above Normative O&M Expenses as is done in case of water charges. Further, for certain projects with extra ordinary factors (lengthy railway siding, transmission line or water pipeline etc.) resulting in higher O&M Expenses should also be considered subject to approval by the Hon'ble Commission. 5. It is humbly submitted that nature of O&M activities for a generating station or a transmission licensee varies with the vintage of the assets. For newer assets,

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		requirement of spares is much less. However, with the vintage of such assets both spares and service costs increase in order to restore the capability of the assets to maintain optimum performance of the units. Further, with the fast advancement of technology, the old units/systems face the challenge of availability of spares on account of obsolescence. Therefore, it becomes onerous on part of old generating stations and transmission assets to perform at par with the new units/systems by incurring additional costs towards services and repair of old assets. In view of the above, the Hon'ble Commission may consider a graded increment in O&M Expenditure in Lakhs/MW after 10, 15, 20 and 25 years of operation in the tune of 5, 7, 9 and 11 lakhs/MW respectively over and above the Normative O&M Expenses to cater the vintage-based expenses. 6. It is further submitted that a separate provision for maintenance cost of Flue Gas De-Sulphurization (***"FGD"***) Plant and other emission control equipment may please be incorporated in the final Tariff Regulations. 7. It is submitted that the Hon'ble Commission does not allow any cost towards other businesses of the utilities, if any. The operating costs incurred by the utility towards such businesses are meant to generate profit which can be utilized for future growth of the utility. Hence it would not be fair to consider the income from such other businesses while determining the O&M cost of the utility.
FUEL - GROSS CALORIFIC VALUE (GCV)		
22.8	*(a) Take actual GCV and quantity at the generating station end and add normative transportation losses for GCV and quantity for each mode of transport and distance between the mine and plant for payment purpose by the generating companies. In other words,*	**It is submitted that the Hon'ble Commission may allow 'As Received' GCV measured at site by any third party alongwith with the margin for normative GCV loss between As-Received and As-Fired coal, as proposed by CEA, for the purpose of recovery of energy charges. However, the generating companies have no control on the losses between As-Billed and As-Received coal.**

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	specify normative GCV loss between "As Billed" and "As Received" at the generating station end and identify losses to be booked to Coal supplier or Railways. *(b) Similarly, specify normative GCV loss between "As Received" and "As Fired" in the generating stations.* *(c) Standardize GCV computation method on "As Received' and "Air-Dry basis'' for procurement of coal both from domestic and international suppliers.*	**Justification:** 1. In reference to Ministry of Power (MoP) letter no. 3/2/2017 -Th-I dated 10.11.2017 and CEA letter No. 228/MISC/TPP&D/CEA/2017/1432 dated 17.10.2017 with regard to measurement of GCV of Coal on "as received" basis following corrigendum in CERC Tariff Regulations 2014 was issued. It is acknowledged that there are minor unavoidable losses inside the power plant in handling the coal starting from unloading point to the point of bunkering. Loss in GCV may occur mainly due to dust suppression measures used around coal conveyors and transfer points, loss in volatile matter during crushing of the coal etc. The extract of the last para of the letter is reproduced below: *"CEA has also examined the views taken by various state regulators for considering such loss for the purpose of tariff allowed to generators. However, as the margin would vary from plant to plant, season to season and varying coal characteristics,* ***CEA is of the opinion that a margin of 85- 100 kCal/Kg for a pithead station and a margin of 105-120 kCal/kg for a non-pithead station may be considered as a loss of GCV measured at wagon top at unloading point till the point of firing of coal in boiler."*** 2. Hence, we request the Hon'ble Commission to introduce the above corrigendum for the tariff period FY 2019-24 on account of normative GCV loss between "As Received" and "As Fired" in the generating stations. Imported coals also exhibit predominant GCV loss during stocking due to high Volatile Matter content therefore, we request the Hon'ble Commission to allow similar margin or normative GCV loss for Imported coal also.

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FUEL - BLENDING OF IMPORTED COAL		
23.6	*Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.*	**We request the Hon'ble Commission not to specify any normative blending ratio as it is operationally impractical.** **Justification:** The amount of blending of imported coal in a power plant would depend on many factors such as GCV of the domestic coal, GCV of the imported coal (low GCV or high GCV), shortfall in supply of domestic coal from linked mines etc. Hence, considering all these factors, the blending of imported coal should be left to the generating company to decide depending on the situations as mentioned above along with the boiler design. However, while fixing any norm for blending of imported coal, the Hon'ble Commission needs to recognize that it is not practically possible to accurately control the blending with the existing plant designs/ infrastructure so as keep the same within any prescribed limit.
FUEL – LANDED COST		
24.5 (a)	*All cost components of the landed fuel cost may be allowed as part of tariff. Or alternatively, specify the list of standard cost components may be specified;*	**It is essential to identify the broad categories of other charges which are incurred in bringing the Coal from the mines to the plant, e.g., the cost components for domestic coal being transported through rail/road mode may include the following:** **a) Cost of Coal (including Base Price, Royalty, Crushing Charges, Taxes & Duties, Incentives etc.) as charged by the Coal Companies** **b) Transportation cost** **c) Washery Charges, in case of mandatory use of washed Coal** **d) Handling Charges (including handling agent charges, supervision charges, etc.)** **e) Other Charges (including weighbridge operation charges, lease rental for using railway sidings etc.)**

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		f) Normative Transit & Handling Loss. **<u>Justification:</u>** 1. The cost components in Form 15 includes mainly the cost of Coal charged by the Coal Companies (including Base Price, Royalty, Taxes etc.), cost of transportation as charges by Railways/Transport Companies (excluding Demurrage Charges), cost of Diesel in case of MGR system for pit-head plants and normative handling & transit losses. 2. In our humble opinion, different categories of thermal power plants (like inland, coastal, pit-head, non pit-head etc.) incurs different cost components for bringing the Coal from the mines to the plant. Such cost components may include various items like bank guarantee cost, handling agent charges, weighbridge maintenance costs, siding rents to railways etc. The Hon'ble Commission has in its Order dated 11.07.2018 in Petition No. 93/MP/2017 expressed that expenses incurred in connection with purchase and transportation of coal such as coal supervision charges, coal handling agent charges, siding lease rentals and other incidental expenditures related to bringing the coal from the mine to the site are legitimate expenses which are incurred by the generating companies for supply of power to the procurers.
24.5 (b)	*The source of coal, distance (rail and road transportation) and quality of coal may be fixed or specified for a minimum period, so that the distribution company will have reasonable predictability over variation of the energy charges.*	**In our humble opinion, the landed price of fuel should be continued to be considered as pass through for generating companies.** **<u>Justification:</u>** 1. The Hon'ble Commission will deviate from the basic premise for allowing the cost of fuel as pass-through if the same is fixed over a period of time. Although the generating companies are allowed to procure coal either through Coal India Ltd,

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		Open market, e-auction mode, captive mine etc., the price and quality of such coal is beyond the control of the generating companies. Further, the flexible utilization of coal under the existing fuel supply agreement is presently available only to the State/Central generating companies and not to the private utilities. As per the CEA Report (refer para 3.3 and 18.5) the addition in the thermal power capacity in the last decade has been substantially contributed by the private sector. Therefore, any significant change in the methodology of computation of landed price of fuel should be based on the sectoral reality including the position of private players. 2. Further, it is infeasible to standardize the distance and quality of coal for all thermal power plants. No two thermal power plant has the same source, distance and quality of coal. In case any inappropriate norm is set, the burden of loss on account of energy charges would become unbearable for the private players. This will create uncertainty for procurement of fuel and the generation potential may suffer.
FUEL – ALTERNATE SOURCE		
25.2	*(a) Stipulate procedure for sourcing fuel from alternate source including ceiling rate;* *(b) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014.*	**It is submitted that cost of imported coal should be allowed as long as the sourcing is made transparently through competitive bids. Similarly, the landed price of washed Coal, which are required to be procured under any statutory mandate, should also be pass through for the generating companies.** **Justification:** 1. It is submitted that the present CERC Tariff Regulations 2014 stipulate detailed provisions for procurement of coal from alternative sources such as e-auction and imported Coal to bridge the shortage of supply from Coal India Limited ***("CIL")***.

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		We request the Hon'ble Commission to continue the same for the tariff period FY 2019-24. 2. It is further submitted that the parameters such as coal quality should be at the discretion of the power plant. As long as the sourcing of coal is made through competitive bids, the Generator should be allowed to place contract, source coal and claim availability. 3. In the case of shortfall in supply of coal from CIL and permission not being granted by the beneficiaries to procure coal alternate fuel source, the generating station should be considered as deemed available for the purpose of recovery of capacity charges. 4. Washing of coal having ash content more than 34% is a mandatory requirement for generating stations located at a distance exceeding 500 km from coal mines as per MoEFCC norms. This being a Change in Law event, generating companies have to be appropriately compensated, i.e., the landed price of such washed coal should be pass through for the generating companies.
OPERATIONAL NORMS		
26.3.6	***Station Heat Rate:*** *Approach for determination of station heat rate may need review including the criteria for specifying heat rate of old plants, continuation of relaxed norms for specific stations and possible changes required in the existing norms given in Tariff Regulation 2014-19.*	**It is submitted that the Hon'ble Commission may review the norms of Station Heat Rate considering not only the actual operational performance of NTPC Units but also various other factors like fuel quality, vintage of machines, OEM recommendations etc. which affect the Heat Rate of the generating units and provide an operational margin of 6.5% over the design Heat Rate in view of the fact most of the plants shall operate much below the normative PLF of 85%.**

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		Justification: 1. It is submitted that the thermal generating stations are expected to operate at significant part load operation in the upcoming years on account of restrictive dispatch instructions because of inadequate evacuation capacity/lower demand or poor financial conditions of distribution licensees or beneficiaries, fuel scarcity and fuel quality related issues. Such part load operation of thermal units will have negative impact on station efficiency, particularly SHR, Secondary Fuel Oil Consumption and Auxiliary Power Consumption. In view of the above, we request the Hon'ble Commission that Operational margin over the design heat rate may be reviewed and increased from 4.5% to 6.5% in line with CERC Tariff regulations 2009. 2. In the prevailing CERC Tariff Regulations 2014, date of commissioning of the units was considered for the purpose of arriving at normative operating parameters. In case the EPC order is placed by the generating company based on the operating norms prevailing on that date and the unit is commissioned in the next tariff period under different Tariff Regulations, the generating company shall be constrained with operating the unit with revised norms. Hence, the date of placing order on BTG manufacturer may be considered for the purpose of arriving at normative operating parameters. 3. It is further submitted that the operating norms should be based on the average performance of units in the country and not confined to NTPC stations alone. Further, operating norms should be based on past performance of the units in the country including State Utilities/IPPs of relevant vintage of the units and should factor in operating constraints, like, partial loading due to erratic load pattern of the beneficiaries and lower operating load factor due to shortfall of quantity and

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		quality of fuel which is expected to continue in future. We therefore request the Hon'ble Commission may consider the following important criteria while specifying norms for station heat rate: a. Quality of Fuel b. Operating pattern of machines (part load/full load etc.) c. Vintage of machines d. Unit size e. Climatic condition.
26.3.7	***<u>Specific Secondary Fuel Oil Consumption</u>:*** *The existing norm for the Secondary Fuel Oil Consumption is 1.00 ml/kWh for lignite based CFBC technology with some exception in case of TPS-I and 0.50 ml/kWh for Coal based project with the provision for sharing of savings with the beneficiaries. Further reduction in specific secondary fuel oil consumption norms may adversely affect the boiler operations under different operating conditions including partial loading of units due to fuel shortage conditions. With contribution from renewable generation increasing in the grid, thermal power plants are facing frequent regulations of supply and operations at lower PLF up to technical minimum. The consumption of secondary fuel oil would change on account of nature of operations.*	**We request the Hon'ble Commission to revise the norm for Normative Specific Secondary Fuel Oil Consumption for the Tariff Period FY 2019-24 and increase the same to 0.75 ml/kWh for coal-based generating stations on account of significant shut downs and part load operation in coming years which are beyond the control of the Generators.** **<u>Justification:</u>** 1. In the present scenario, most of the coal/lignite/gas based thermal power plants are operating at low PLF levels due to various reasons including shortage of coal/gas, lower demand by the DISCOMs etc which have adverse impact on the operational norms of the Units, and hence, the existing normative Specific Secondary Fuel Oil Consumption for the new and existing generating stations are required to be reviewed We therefore suggest that the normative Specific secondary fuel oil consumption may be increased to **0.75 ml/kWh** for coal-based generating stations on account of significant shut downs and part load operation in coming years which are beyond the control of the Generators.

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		2. The Hon'ble Commission has on 06.04.2016 notified the final IEGC (4th Amendment) Regulations 2016 to address the issue of Technical Minimum Schedule for the Thermal Generating Stations arising due to low demand/power offtake by beneficiaries. It was duly recognized by the Hon'ble Commission that operating units under such part load operation has to bear adverse financial impact due to increase in Station Heat Rate, Auxiliary Energy Consumption and Secondary Fuel Oil Consumption leading to increase in Energy Charges which is beyond the control of Thermal Generating Station/Units. Accordingly, the Hon'ble Commission has through the above Regulations introduced compensation on the above parameters over and above their respective norms. We request the Hon'ble Commission to kindly align the above Regulation for the tariff period FY 2019-24. 3. Excess consumption of Secondary Oil, beyond the control of the Generator, and in order to maintain grid security, start-ups after shut down taken due to special requests from the procurers should be compensated at actuals.
26.3.8 & 26.3.10	***<u>Auxiliary Energy Consumption</u>:*** *The existing norms of auxiliary consumption of coal based generating station varies from 5.25% for unit size of 500 MW and above to 8.5% for 200 MW series units with steam driven boiler feed pumps and electrically driven boiler feed pumps and relaxed norms for specific generating stations of smaller size. Auxiliary consumption for gas based generating station varies from 1.0- 2.5% depending on open or combined cycle operation. The existing norm of auxiliary consumption of lignite based generating station is 0.5% more than coal*	**We request the Hon'ble Commission to include a provision in the Tariff Regulations 2019-24 for considering the site-specific factors, additional requirement due to installation of various Pollution Control equipment like FGD under statutory mandate or requirement for disposal of fly ash to distant lands through pumping systems etc. over and above the Normative Auxiliary energy Consumption on case to case basis.** **<u>Justification:</u>** In the present scenario, the existing normative Auxiliary Energy Consumption (***"AEC"***) for the new and existing generating stations are required to be reviewed

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	based generating station with electrically driven feed pump and 1.5% more if the lignite fired station is using CFBC technology. The auxiliary consumption does not include colony power consumption and construction power consumption. *…….* *Generating stations which have less auxiliary consumption than the norms, are able to declare higher availability by making adjustment of difference between actual (lower) and normative auxiliary consumption. Further, colony consumption is not a part of auxiliary consumption w.e.f. 1.4.2014 and therefore, the same cannot be accounted for against auxiliary consumption while declaring availability. Methodology of declaring availability after reduction of normative auxiliary consumption and colony consumption need elaboration.*	In view of the following measures undertaken by the generating companies to comply with the environmental norms: • Additional Auxiliary Energy Consumption for FGD Plant: 2% may be considered. • Additional Auxiliary Energy Consumption for ESP Upgradation: increased AEC on account of upgrades/retrofit should also be taken into consideration while formulating the APC norms in Tariff. • Additional Auxiliary Energy Consumption for additional Pump for Ash Disposal/Utilization: 0.5% may be considered. Usage of sea water requires more blow down as compared to plant using normal water. Therefore, for the generating stations using sea water, additional AEC may be allowed.
26.3.15	***<u>Normative Annual Plant Availability:</u>*** *The existing norms of annual plant availability may need review by considering fuel availability, procurement of coal from alternative source, other than designated fuel supply agreement, shifting of fixed cost recovery from annual cumulative availability basis to a lower periodicity, such as monthly or quarterly or half yearly;*	**Shortfall in coal supply under designated FSA urge the generators to procure coal from alternate sources at higher prices in order to maintain the availability of generating units at the level of 85%. The Hon'ble Commission may therefore revise the Normative Plant Availability factor to 80% or allow the deemed availability benefits in case of coal shortage.** 1. As the availability of domestic coal is out of control of the generators, there is a case for lowering of target Plant Availability to avoid under recovery of Fixed Charges by the generators. To protect the interest of the developers, the Normative Annual Plant Availability should be suitably aligned. Therefore, we suggest the Normative Annual Plant Availability may be set at 80% for existing

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		power stations under no coal scarcity scenario. In view of shortage of coal and uncertainty of assured coal supply on sustained basis experienced by the generating stations, the Normative Annual Plant Availability for recovery of Fixed Charges may be relaxed to 70% for the generating stations, which are covered under new Fuel Supply Agreement ***("FSA").*** 2. Further, in view of the shortfall of coal supply from CIL and reluctance of DISCOMs to approve procurement of imported coal or in the event of power from the generating station not being scheduled by Load Dispatch Centre, the generating station should be considered as deemed available and should be allowed to recover full Fixed Charges. 3. It is submitted that the thermal generating stations are essentially base load stations designed to meet the base load requirement of the country. Hence, the concept of differential Normative Annual Plant Availability for off-peak and peak period should not be applied for thermal stations.
26.3.16	***<u>Transit & Handling losses:</u>*** *The Commission had specified norm of 0.2% for the pit head station and 0.8% for the non- pit head stations as loss in transit & handling. The same may have to be reviewed based on the actual data of the past period.*	**The Hon'ble Commission may allow Transit Losses for different generating stations considering the distance of travel of Coal from mine to site, usage of washed Coal and factors of loss during inland transportation in case of imported coal. Accordingly. The Hon'ble Commission may incorporate suitable provisions for determining the Transit Loss on case to case basis.** **<u>Justification:</u>** 1. It is submitted that pit-head and non pit-head generating stations have different levels of transit and handling losses. In the prevailing Tariff Regulations, the Hon'ble Commission has specified normative transit and handling losses of 0.8% for non pit-head stations and 0.2% for pit-head stations. In our humble opinion,

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		the Hon'ble Commission may revise the transit and handling losses and should link it to the distance between the fuel source and generating stations. 2. Further, transit and handling losses are not under the control of the generator. In case of high losses for the reasons beyond the control of the Generator, they may be allowed to approach the Commission for approval of project specific transit and handling losses. 3. It is submitted that the Transit Loss in Coal depends not only on the location of the generating stations and the mode of transportation of Coal, but also on the surface moisture content of coal. The surface moisture in the Coal varies depending on the source. It is further submitted that on account of stringent norms stipulated by MoEFCC on restriction of ash content in coal, the generating companies are required to procure low ash content coal such as Washed Coal. However, the coal sourced from the Washeries contains high surface moisture which gets evaporated in transit resulting in loss in weight. It is noteworthy that the Hon'ble Tribunal in a catena of Judgments held that the Transit Loss in Washed Coal and Un-washed Coal cannot be the same. The relevant excerpts from the Judgment of the Hon'ble Tribunal in Appeal No. 26 of 2008 dated 07.04.2011 are reproduced below: *"22. According to the Appellant, the State Commission has allowed a normative coal transit loss of 0.8% by holding that the same is nationally accepted loss level as prescribed in the Tariff Regulations of the Central Commission. It is noticed that the State Commission has rejected the claim of the Appellant merely on the ground that NPTC had not challenged the coat transit loss for the Dadri and Badarpur Stations which requires the same washing of coal. As pointed out by the Learned Counsel for the Appellant, the ground that the NTPC*

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		had been allowed only 0.8% coal transit loss and the same had not been challenged by the NTPC cannot be the valid ground to deny the claim of the Appellant. ***The important aspect that the State Commission has failed to consider is that the transit loss cannot be the same both for unwashed and washed coal.****.”* It is further submitted that the PSERC had incorporated a Transit Loss in Coal at 1% in its Tariff Regulations 2014 notified on 01.07.2014 to partially ease the hardships faced by the generating companies pertaining to transit and handling loss of coal. Further, JSERC had through APR Order for Tata Power dated 31.05.2015 provisionally approved a separate Normative Transit Loss of 1% for Washed Coal. In our humble opinion, the Hon’ble Commission may therefore revise the Normative Transit & Handling Losses for the tariff period FY 2019-24 considering, a) a suitable factor to determine the Transit Loss for Washed Coal, or, b) provision for determining the Transit Loss in Washed Coal on case to case basis. It is further submitted that the Transit Loss in case of Imported Coal at 0.2% may not be adequate if we observe the mode of transportation of such coal to any generating station. Imported Coal involves multiple handling after reaching the port. The norm of Transit Loss in Imported Coal at 0.2% may be realistic for the coastal states where the Imported Coal received at the jetty stockyards are directly transferred to the coal stockyards either through mechanical system or through conventional road and railway transportation system to the generating station. However, it is pertinent to note here that for non- coastal state the

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		Imported Coal has to be transported from any of the sea-port through road and rail transport for a distance at par with the coal mines. Therefore, for non-coastal states, the basic premise for Transit Loss in Imported Coal is same as that of Transit Loss in Domestic Coal from non-pithead mines. We therefore request the Hon'ble Commission to consider the Transit Loss of **0.8%** for the tariff period FY 2019-24 in line with the Transit Loss in Domestic Coal from non-pithead mines.
26.4.2	***Thermal Generation (Coal washery rejects based):*** *The Tariff Regulations, 2014 provides operational norms for thermal power plant based on coal washery rejects. Coal rejects exhibit distinguished characteristics. Coal rejects cannot be stacked as it would require a substantial amount of land at the mine site and storing of rejects for prolonged period is hazardous as it may lead to combustion.*	**We request the Hon'ble Commission to consider introducing a preferential tariff for Coal washery reject based generating units to make such projects viable.** **<u>Justification:</u>** 1. In our humble opinion coal washeries rejects based projects essentially fall under the waste energy category. Capital Cost of such projects is very high. Given that GCV and the quality of rejects would be very low, Normative O&M Expenses, Specific Fuel Oil Consumption and Auxiliary Energy Consumption specified for coal rejects for the existing tariff period for FY 2014-19 are not sufficient. Due to inferior quality of rejects, there is a need to further revise the norms upwards on O&M Expense, Specific oil consumption and Auxiliary Power Consumption for the tariff period FY 2019-24.
INCENTIVE		
27.5 (a)	*Review linking incentive to fixed charges in view of variation of fixed charges over the useful life and on vintage of asset - Need for different incentives for new and old stations;*	**We propose the Hon'ble Commission may link the Incentive back to Plant Availability and Annual Fixed Charges over the Useful life of the Plant which would provide the opportunity to the generating stations to recover the lost Depreciation and interest costs in other years and restore the Project IRR.** **<u>Justification:</u>** 1. Since ensuring Availability of units is linked to Fixed Charges, it will be judicious to restore the methodology of linking the incentive also with the Fixed Charges.

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		Further, the incentive is being provided to a generating station and the same should depend on the performance parameters on which the generating station has its control. The PLF is controlled by the beneficiaries and therefore, the generating stations having a huge gap between Plant Availability and PLF, stand to lose despite maintaining a higher Declared Capacity. Further, the existing provision of Dis-Incentive below Normative Plant Availability impacts the recovery of Depreciation and Interest payment of the generating stations for. As per the National Tariff Policy 2016, the mechanism of Incentive and Dis-Incentive needs to be encouraged among the developers. Since the Dis-Incentive for the generators is already linked to Normative Annual Plant Availability factor (NAPAF), an equitable approach need to be adopted for Incentive. 2. PLF-based Incentive mechanism would allow the beneficiaries to maintain adequate spinning reserves for meeting the peaking load. This would not address the lack of efficiency in demand forecasting and effective utilization of resources by the DISCOMs.
27.5 (b)	*Different incentive may be provided for off peak and peak period for thermal and hydro generating stations. Differential incentive mechanism for storage and pondage type hydro generating stations may also be considered.*	**It is humbly submitted that Incentive may be linked back to Plant Availability achieved over the year instead of separate incentive mechanism based on peak and off-peak hours.** **<u>Justification:</u>** 1. It would be prudent to link the incentive for generators to parameters which are under the control of the generators like availability. The PLF is not a parameter which can be controlled by a generator. The beneficiaries maintaining a high spinning reserve, generally opt for lower scheduling during off-peak hours to avoid the incentive. Hence it would be equitable to provide incentive to

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		generating companies on the basis of the availability of their generating units during the year.
27.5 (c)	*Review the incentive and disincentive mechanism in view of the introduction of compensation for operating plant below norms.*	**As explained above, we propose the Hon'ble Commission may link the Incentive back to Plant Availability which would provide the opportunity to the generating stations to recover the lost Depreciation and Interest costs in other years and restore the Project IRR.**
IMPLEMENTATION OF OPERATIONAL NORMS		
28.1	*The new tariff regulations take effect from 1st April of the tariff period. The Tariff Regulations require the generating company or transmission licensee to file the petitions within 180 days from the date of notification of the regulations. Since the tariff determination is quasi-judicial function, there is a time lag between filing the petition and finalization/ issuance of tariff order. Till the issuance of final order, the generating company or the transmission licenses keep charging the tariff based on previous tariff order including operational norms. The operational norms notified by the Commission in new tariff regulations take effect much after the date of coming into force of new tariff regulations. Consequently, the benefits of the improved operational norms are passed to beneficiaries only after time lag of few months.*	**It is humbly submitted that the Hon'ble Commission may continue with the operational norms of the previous Tariff Period provisionally till the issuance of final Tariff Order of the present Tariff Period.** **Justification:** The Tariff Order includes approval of the specific operational norms, especially, SHR, in terms of Tariff Regulations or its interpretations, alongwith relaxation/margin, if any. Therefore, if the normative operational parameters are implemented before the Tariff Order is passed by the Hon'ble Commission, the same will undergo unnecessary reconciliation/adjustment. As far as the financial benefits accrued in terms of improved operational parameters, the same can be passed to the beneficiaries after issuance of the Tariff Order alongwith applicable Carrying Cost as per the prevailing practice. As such, the beneficiaries are benefitted due to improved operational parameters for the entire tariff period.

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SHARING OF GAINS IN CASE OF CONTROLLABLE PARAMETERS		
29.1 to 29.3	*The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement in controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil consumption, refinancing of loan and the true up of primary fuel cost. Subsequent to above, the compensation mechanism has been introduced for operation in CERC (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016. …… In view of the compensation mechanism, it needs to be considered as to whether the ratio of sharing of benefit may be reviewed.* *The compensation mechanism introduced through IEGC entails the hedging of the risk of operating at low PLF. The compensation coupled with normative controllable parameters creates a buffer for generating companies. In view of this, the merit order operation can be linked with the PLF in such a way that the plants under Section 62 may be encouraged to compete for maximum PLF.* *Further, different generators adopt different methodology for sharing of gain, say on monthly or annual basis. Thus, procedure for the monthly reconciliation or annual reconciliation mechanism may need to be prescribed.*	**It is submitted that the Hon'ble Commission may revise the ratio for sharing of gains between generating company and beneficiaries in 80:20 ratio on account of improvement in operational parameters and also allow the same ratio for sharing of loss between the generating company and beneficiaries.** **<u>Justification:</u>** 1. It is submitted that Station Heat Rate, Specific Secondary Fuel Oil Consumption, and Auxiliary Energy Consumption are the Controllable Parameters for a generating company. As per prevailing Tariff Regulations, any loss in revenue on account of not achieving the normative operational parameters are borne by the generating companies. Hence, it would be logical that any gain on account of efficient performance should be rewarded entirely to the generating companies, i.e., any efficiency gain or loss out of such operational parameters should be entirely on account of the generating companies. In case the Hon'ble Commission decides to share the gains out of such operational parameter with the beneficiaries, we propose that the generating companies should be allowed to share the same in the ratio of 80:20. We further request the Hon'ble Commission to introduce a provision for sharing of loss out of operational parameters in the same ratio 80:20 in case the non-achievement of such operational parameters upto normative level is on account of the generating company and not due to part load operation. 2. It is noteworthy that the compensation mechanism under IEGC is applicable for the generating companies only in case of part load operation upto Technical Minimum of the units when the demand of the DISCOMs are low. Hence, it will

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		be unfair to link the concept of sharing of gain of the Controllable Parameters with such compensation mechanism under IEGC. 3. There must be a level playing field in terms of generating stations under Section 62 and Section 63 as both the routes are available under the Electricity Act 2003. For merit order, variable cost is considered as per existing procedures for economical dispatch of power by respective load dispatch centres. Same principle may be extended in future to prioritize efficient generators. The same should not be linked to PLF as the same is not under the control of the generating company.
LATE PAYMENT SURCHARGE & REBATE		
30.1 & 30.2	…. *In view of the introduction of MCLR, the rate of late payment surcharge may need to be reviewed. One option is to add some premium over and above MCLR.* …. *Valid mode of presentation of bill, (email, physical copy etc.), authorised signatory, definition of two days (working days or including holidays) may need elaboration.*	**In our humble opinion, rate of LPS should be set at 2 – 2.5 times the MCLR and rebate should be prorated for payment within 30 days of receipt of monthly bill.** **Justification:** 1. As per the present methodology, the Late Payment Surcharge ("***LPS***") works out to 18.00% p.a. and the MCLR is around 7.90% (as on 01.06.2018). If the LPS is linked to some premium above MCLR, it would not be as high as 18.00%. Since LPS is a form of penalty and triggered only under exceptional circumstances, its rate should be high enough to deter the tendency for delaying payment beyond 60 days. Hence, even if the LPS is linked to MCLR, it should be pegged at 2 – 2.5 times the MCLR. 2. In our humble opinion, the application of rebate of 2% for payment within 2 days of presentation of the bill may be continued. However, the next window for availing 1% rebate for payment within 30 days may be reviewed. Beneficiaries are making payment only on 30th day in most cases and still enjoying a rebate of 1% on the billing amount. Rebate may not be allowed for such long period of 30 days

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		and should be available only for 5 days. As an alternative, the applicable rebate of 1% may be prorated for receipt of payment from 1 to 30 days. 3. Further, the energy charges are envisaged to be passed on actual subject to performance of the generating companies within the normative parameters. There is no discount available for making early payment for procurement of fuel. Hence the rebate should be applicable only on the Capacity Charges.
NON-TARIFF INCOME		
31.1	*The tariff determination under Section 62 of the Act follows the principle of cost of recovery which inter-alia provides the reimbursement of cost incurred by the generating company or the transmission licensee. The income on account of sale of fly ash, disposal of old assets, interest on advances and revenue derived from telecom business may be taken into account for reducing O&M expenses. Present regulatory framework does not account for other income for reduction of operation & maintenance expenses. However, in case of transmission licensee, the income earned from telecom business are adjusted in the billing separately. The principle of treatment of other income as applicable in case of transmission can be extended for the generation business.*	**It is submitted that the Hon'ble Commission may not introduce the provision for Non-tariff Income in Tariff Regulations for FY 2019-24 for generation business.** **Justification:** 1. As per the definition of "Non-Tariff Income" mentioned in Model Multi-Year Distribution Tariff Regulations, income relating to the licensed business other than from tariff (wheeling and retail supply), and excluding any income from other business, cross-subsidy surcharge and additional surcharge. From the above definition, it is quite evident that Non-tariff income in case of Generation business is not applicable as it is a delicensed activity as per Section 7 of the Electricity Act 2003. 2. There are many thermal projects with a capacity of over 40 GW in the sector that are categorized as financially stressed assets due to non-availability of fuel, cancellation of coal blocks, setting up of projects without linkages, lack of adequate power purchase agreements (PPAs) by states, promoters' inability to infuse equity and working capital, contract/tariff-related disputes, issues related to banks/financial institutions, and delay in project implementation, leading to cost overruns and aggressive bidding by developers to secure PPAs.

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
STANDARDIZATION OF BILLING PROCESS		
32.1 & 32.2	… *In order to avoid possible disputes in billing, it need to be consider as to whether standardization of billing process including formats, verification and timeline etc. may be done.* … *Whether electricity duty is to be linked with actual auxiliary consumption or normative consumption or lower of the two, may need to be specified.*	**Standardized billing formats are acceptable subject to specific changes which may be agreed upon between the generating companies and its beneficiaries. Electricity duty should be payable by the beneficiaries as per actual Auxiliary Energy Consumption.** **Justification:** 1. Billing formats are generally agreed upon between the Seller and Buyer. Standardization may lead to more fluency in the billing system. However, the parties may agree upon project or system specific/agreement specific changes in the formats to incorporate the agreed practice as per the respective agreement. The Hon'ble Commission may also specify the timelines for verification and payment. However, in case the PPA stipulates better timelines, the same may be adopted by the parties. 2. Electricity duty should be payable by the beneficiaries as per actual Auxiliary Energy Consumption.
TARIFF MECHANISM FOR POLLUTION CONTROL SYSTEM		
33.4 (a)	*Possibility of reducing funding cost through suitable change in debt: equity requirements. Relaxation in funding from equity may be introduced and the rate of return on equity may be aligned with the interest on debt.*	**The Hon'ble Commission may continue with the prevailing normative debt: equity ratio of 70:30 in order to ensure proper operating and financial leverage in place. Further, in case of implementing Pollution Control Systems like FGD Plant in a generating unit which has partial untied capacity, the Hon'ble Commission may devise suitable mechanism for recovery of the entire cost pertaining to such untied capacity.**

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
33.4 (b)	*"Debt Service obligation during construction period and recovery of depreciation" may be provided with the condition that such depreciation may be adjusted during the remaining period.*	**Justification:** 1. In our humble opinion, with regards to the additional capitalization for meeting the new environmental norms, significant investment is required. As per the earlier directives of the Hon'ble Commission, presently CEA is evaluating the proposal for upgradation of existing system of various plants in order to arrive at the appropriate technology and costing norms. The investment for the above purpose cannot be met through equity alone by majority of the generators. Further, since the cost of equity being higher than the cost of debt, it would be inappropriate to provide a return based on the rate of cost of debt on such equity investment. The Hon'ble Commission may continue with the prevailing normative debt: equity ratio of 70:30 in order to ensure proper operating and financial leverage in place. 2. Further the Hon'ble Commission may also develop suitable mechanism to allow the developers with partial untied capacity to recover the fixed charges of the Pollution Control System in entirety.
33.4 (c)	*As the level of emission is linked to actual generation, it would be appropriate to link recovery of supplementary tariff with the actual generation or availability or combination of both.*	**The Fixed Charges on account of Environment Capex schemes may be recovered along with the Annual Fixed Charges and not to be linked with availability.** **Justification:** 1. The supplementary tariff on account additional capitalization for meeting the new environmental norms would be predominantly of the nature of Fixed Charges. Such Fixed Charges should not be linked with generation since the PLF is not under the control of the generator. In case the annual demand of the DISCOMs is reduced by the beneficiaries, it may lead to under-recovery of the Fixed Charges determined by the Hon'ble Commission and may impose financial hardship for the developer. Therefore, the additional Fixed Charges on account environmental

Paragraph	Particulars	Comments and Suggestions
		capex schemes should be allowed to be recovered along with the Annual Fixed Charges based on actual capitalized cost.
Renewable Generation by existing Thermal Generation Stations		
34.4	*Comments and suggestions are invited from the stakeholders on the possible options for bundling tariff, and alternative options, if any.*	**In our humble opinion, the Hon'ble Commission may not choose to adopt bundling of tariff for renewable generation with conventional thermal power and allow the tariff to be decided separately as per the respective tariff regulations.** **Justification:** 1. In our humble opinion, in case of bundling renewable generation with conventional power generation at the ex-bus of Generating station, the tariff for thermal as well as renewable generation should be determined as per separate applicable Tariff Regulations. It may be difficult to combine the tariff as feed-in-tariff structure is a single part tariff and conventional Generation has two-part tariff structure. 2. Further, in line with the Tariff Regulations for thermal generation, Tariff Regulations for Renewable generation should include the provisions for Additional Capitalization. 3. It is further submitted that the Ministry of Power has recently vide Letter no. 23/70/2017 -R&R dated 05.04.2018 introduced Flexibility in Generation & Scheduling of Thermal Power Stations to reduce emissions. This flexibility will provide the Thermal Power Stations an opportunity to optimally utilize Generation from RE power within their existing/future PPAs. As per the above notification, only Thermal Power projects developed/being developed under Section 62 of the Electricity Act, i.e., under Regulated Tariff based projects can qualify under the scheme. In view of the above, we request the Hon'ble

<table>
<tr><th>PARAGRAPH</th><th>PARTICULARS</th><th>COMMENTS AND SUGGESTIONS</th></tr>
<tr><td></td><td></td><td>Commission to allow all Thermal Power projects which are developed under either of the two routes, i.e., Section 62 (regulated route) or Section 63 (competitive bidding route) available under the Electricity Act 2003 to be qualify under the scheme.</td></tr>
<tr><td colspan="3">COMMERCIAL OPERATION OR SERVICE START DATE</td></tr>
<tr><td>35.5</td><td>Comments and suggestions are invited from the stakeholders on possible options for dispute-free and practical mechanism for declaring commercial operation date. Comments and suggestions are also invited on the following.

a. Addressing the shortcomings in existing methodology for the trial run of generating station and trial operation for transmission element through appropriate regulatory mechanism;

b. Issue of trial operation and commissioning of the project when a generating station is ready but cannot be operated due to non-availability of load or evacuation system;

c. Issue of acceptance of COD of transmission line if the generating project or upstream/downstream transmission assets are not commissioned;

d. Pre-requisite of completion of data telemetry and communication facilities for declaring COD of</td><td>The comments on the issues as enumerated in the instant Consultation paper is provided in the following paragraphs:

1. The existing regulations provide for declaration of COD after demonstrating maximum continuous rating (MCR) or installed capacity through a successful trial run after notice to all beneficiaries. In our humble opinion we request the Hon'ble Commission that the existing methodology is well established and accepted and therefore may be continued. Further, we suggest the Hon'ble Commission that it should be made mandatory for RLDCs or SLDCs to schedule the power projects undertaking trial run or commissioning test on full load basis during the period and such plants should be considered as "Must Run".

2. In case the Power Station is ready but the Procurer/Transmission Licensee fails to make arrangement for the Transmission evacuation within the stipulated time, then it should be treated as deemed available after inspection by representative of beneficiaries and independent personnel from RLDC/SLDC. The delay in commissioning due to non-availability of load or issues in evacuation may lead to increase in IDC, IEDC and other Project Cost components. In such case, the developer should be suitably compensated in order to service its debts, i.e., to ensure the recovery of IDC of the corresponding period. Alternatively, we request the Hon'ble Commission to evolve a compensatory mechanism, wherein the generator is suitably compensated for loss of generation for the period the plant</td></tr>
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PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
	transmission system and operationalization of RGMO for declaring COD of generating station; e. *Linking of commercial operation date with schedule commercial operation or schedule commencement date of the Power Purchase Agreement or Long-Term Access Agreement respectively;* f. *Linking the commercial operation date of the transmission system with the commissioning of the generating units or stations;* g. *Separation of the commercial operation date of the unit or stations, the transmission element or system from the service start date under the contract.*	could not operate due to unavailability of evacuation system, at a rate determined by the Hon'ble Commission. 3. Further in case of mismatch between commissioning dates of generating unit or transmission lines, the gestation period of the affected party, i.e., the party which commission its assets earlier, increases. Therefore, the Hon'ble Commission may develop suitable mechanism for compensating the IDC accrued for the period of delay to the affected party. 4. The suggestion on pre-requisite criteria of completion of data telemetry and communication facilities by RGMO for declaring COD, may not be appropriate at this point of time. Power market is in developmental stage and is yet to be fully developed and under that scenario, such a mandate shall unduly constrain the developer and may also lead to delay in COD. 5. It is suggested that Scheduled COD should be linked to the SCOD appraised by the lender as finalized in the Common Loan Agreement. Further, there should also be a provision to revise Scheduled COD & start/zero date for reasons not attributable to the generator.
ENERGY STORAGE SYSTEM		
36.7	*Comments and suggestions are invited from the stakeholders on the possible options discussed above and alternatives, if any.*	**It may be more prudent to introduce such scheme in the next control period as deployment of grid storage is at an emerging stage and there is no policy or regulatory framework as regards to batter energy storage. However, its importance is well recognized and the need of grid level battery storage cannot be undermined in areas such as frequency regulation, renewable generation, generation shift etc.**

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
ALTERNATE APPROACH TO TARIFF DESIGN		
37.6 (a)	*Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost?*	**It would not be fair to compare the Capital Cost of the projects already implemented with any benchmark cost derived on the basis of market estimates prevailing at a retrospective date. However, it would be beneficial for the new players to have a benchmarking cost available with them before the start of the Project. If the Hon'ble Commission can develop suitable benchmarking costs for each project packages for projects whose investment approval are yet to be accorded, through forward interpolation of cost trends, it would give a clear direction for the new developers and certainty of cost structure for the entire sector.** **<u>Justification:</u>** 1. The concept of benchmarking works through comparison of performance metrics with the best available in the industry. Hence it is essential to benchmark like-to-like components for assessment of overall competitiveness. The benchmarking of Capital Cost for generating stations and transmission systems would therefore require the best available cost for all the elements of the Capital Cost. The Hon'ble Commission would appreciate the fact that there are various factors such as cost of land & site development, technology & equipment, material handling system, water and climatic conditions, financial metrics like IDC, financing charges, interest rates, source of funding, taxes and duties etc. have considerable bearing on the Project Cost. It is very difficult to arrive at single benchmark cost for all the elements since the above factors have varied influence on such elements. For e.g. the coal handling system requirements are different for road and rail mode of receipt, the water handling and management is different for inland and coastal plants etc. True benchmarking exercise would require regression analysis of all such variables against each other to arrive at the benchmarking cost for a
37.6 (b)	*What are the variables that should be considered for the purpose of determining Capital Cost on normative basis?*	
37.6 (c)	*Any other methodology for benchmarking the capital cost for generation and transmission projects?*	

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		generating station or transmission system of particular size, capacity, geographical location etc. 2. However, the benchmarking of Capital Cost of the Project as undertaken earlier by this Hon'ble Commission had produced values which were utilized for the purpose comparison with the actual costs of the Projects. Such benchmark norms are never adopted as normative costs because of the following shortcomings: a) such norms reflect the costs prevailing at the time of the exercise and b) such norms vary considerably with actual element-wise costs on account of the above reason. 3. In our humble opinion, the availability of resources and capital to each and every developer substantially vary across the country and thus cannot be assumed or compared in an equal manner. Each and every Project has its own challenges and the same is mitigated by the developer utilizing the available resources. Therefore, it would be unfair to compare the Capital Cost of the projects already implemented with any benchmark cost derived on the basis of market estimates prevailing at a retrospective date.

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
37.9 (a)	*Whether it is a good idea to determine AFC as percentage of Capital Cost on normative basis?*	**The proposed methodology to determine AFC as a percentage of Capital Cost may not capture the true picture of the variation in the Fixed Charges on account of components which are not related to the Capital Cost. Hence AFC may be determined and allowed as is done in the existing framework.** **<u>Justification:</u>** 1. With the Capital Cost remaining constant, the Annual Fixed Charges ("***AFC***") involves various components which remain constant over a period (*viz.* depreciation, RoE) while others vary over the same period (*viz.,* Interest on Loan) and some others have no relationship with the Capital Cost (*viz.,* O&M Expenses, IoWC). In our humble opinion, normative Capital Cost with respect to some benchmark cost is not sustainable in view of the reasons as explained above. Further, it would be impractical to link the AFC with the Capital Cost in view of such varying relationship of the AFC elements with the Capital Cost. Such methodology will not furnish the correct picture of the variations in the AFC in case of loan restructuring, variation in cost of working capital components and decapitalization. 2. Further, the Capital Cost shall not remain constant throughout the useful life of the Project. Additional Capitalization is necessary based on the nature of requirement of the Project which would call for change in Capital Cost. The corresponding change in the FC may not reflect the actual impact of the addition/deletion in the Capital Cost. 3. Further, it is also essential to factor the escalation in the O&M Expenses to reflect the effect of inflation on the operational cost. Such increase is irrespective of the status of the Capital Cost of the Project. Therefore, the proposed methodology of linking AFC with normative Capital Cost will always result in under-recovery/over
37.9 (b)	*What could be the possible methodology to establish the relation between AFC and Capital Cost so that it meets the interests of both buyers and sellers?*	

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		recovery for developers and interim reviews might not be sufficient to address cash flow issues of the developers. Thus, the present approach of linking normative O&M Expenses with installed capacity of the project may be continued.
37.17 (a) to (g)	*Whether clustering the components of AFC based on their nature to increase/ decrease in order? Any other possible method to cluster the AFC components?* *What methodology should be adopted to determine the escalable (increasing)/ non-escalable (decreasing) factors?* *Whether escalable (increasing) / non-escalable (decreasing) factors should remain same for all plants/transmission systems (or) they be separate for each of the plants/transmission systems based on vintage / capacity / fuel type/ fuel linkages etc.* *Whether isolation of "Additional Capitalization" as a separate stream of revenue would provide for recovery of AFC on a normative basis in realistic terms?*	**In our humble opinion, the present method of tariff determination based on prudence check of each and every component of the tariff may be continued.** **<u>Justification:</u>** 1. In our humble opinion, clustering of AFC components on the basis of escalable and non-escalable factors would evolve a scenario similar to earlier bid-based tariff structure under Case -1 projects. Such tariff structure may transform to a normative tariff approach as envisaged by the Hon'ble Commission. The shortcomings of such normative tariff approach have been elaborated in the above paragraphs and is not repeated herein for the sake of brevity. 2. It is not only the additional capitalization which affect the trend of tariff. Other important factors can be loan restructuring, variation in cost of working capital components and decapitalization. Incorporating all such changes in the normative tariff structure may lead to complications in determination of tariff and subsequent recovery. 3. Additional Capitalization is an integral part of the tariff as it impacts 4 out of 5 components of the fixed charges. Hence Additional Capitalization cannot be considered separate to the fixed charge stream on normative basis and should be

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
	Alternatively, do you suggest any other methodology to treat "Additional Capitalization" for determination of AFC on normative basis? *Whether applicability of change in tariff principles in each control period for the new plants would allow regulatory certainty to the existing plants?* *Alternatively, is there any other methodology to minimize the impact on AFC on account of change in control period?*	considered at actual. Adoption of normative basis for determination of Additional Capitalization may disrupt the process of prudence check by the Hon'ble Commission. Hence the present method for tariff determination based on prudence check may be continued.
TRANSPARENCY IN BILLING AND ACCOUNTING OF FUEL		
38.1	*The regulatory approach of pass through of coal cost to the procurer directly on the basis of certification has been well adopted. Comments and Suggestions are invited for further strengthening the existing system.*	**The Hon'ble Commission may include the Incentive payment to the coal companies for lifting of Coal beyond 90% of the ACQ as pass through in Landed Price of Coal in view of the ratio that such Coal if procured from outside (e-auction/imported) would result into higher cost.** **Justification:** 1. Recently, Coal India Limited (CIL) announced that they will migrate to new coal pricing mechanism, i.e., GCV based pricing in which the consumers will be paying a price for the exact heat content of coal supplies, evaluated through third party sampling process. After the implementation of the new pricing mechanism specified normative GCV loss between "As Billed" and "As Received" at the generating station will automatically booked to Coal supplier or Railways. In view of the receipt of lower grade/quality of coal, the generating companies are often compelled to procure additional coal from the coal companies in order

PARAGRAPH	PARTICULARS	COMMENTS AND SUGGESTIONS
		to bridge shortfall in quantity of coal created due to such grade slippage. If procurement of such additional coal qualifies for Incentive for CIL under the terms & conditions of FSA, the same is required to be paid by the generating companies to the coal companies. Therefore, we request the Hon'ble Commission to include such Incentive payment to the coal companies as pass through in Landed Price of Coal.
RELAXATION OF NORMS		
39.2	*Comments and suggestions are invited on whether to continue with the practice or change the parameters during the intervening stage.*	**It is not possible to foresee all events, conditions and circumstances which may lead to any hardship for the project developers to comply with the general operational and financial norms during the next five years. It is essential for the Hon'ble Commission to look into such cases to establish equitable treatment for all the stakeholders. Hence, it is necessary to continue with the provisions for relaxation of norms which may be exercised by the Hon'ble Commission to accommodate different features specific to a project etc.**