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TP/CERC/02/FY 18-19
31 July, 2018

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

Subject: Comments/Suggestions on "Consultation Paper on Terms and Conditions of Tariff Regulations for Tariff Period 01.04.2019 to 31.3.2024"

Reference: No. L-1/236/2018/CERC- Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019 - Consultation Paper thereof

Dear Sir,

This is with reference to the notification published by CERC on Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019 - Consultation Paper thereof, inviting comments/suggestions on the same. Our comments to the said publication are elaborated under **Annexure I** enclosed herewith.

I, Ajay Kapoor , am duly authorised by the Tata Power Company Limited to file these comments/suggestions on its behalf. The Tata Power Company Limited further requests the Hon'ble Secretary to grant us an opportunity to present its case in person before the Commission during the hearing on the above matter.

Thanking you,
Yours truly,

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31 JUL 2018
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Ajay Kapoor
Chief - Legal, Regulatory and Advocacy
(Authorised Signatory)
The Tata Power Company Limited

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The Tata Power Company Limited

Annexure-I:

Comments in the matter of CERC-Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019 – Consultation Paper thereof**.**

<table>
<tr><th>S.No.</th><th>Reference Clause</th><th>Comments / Suggestion</th></tr>
<tr><td></td><td>7. Tariff Design: Generation and Transmission Thermal Generating Station – Tariff Structure</td><td></td></tr>
<tr><td>1</td><td>7.2.4 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.</td><td>• The suggestion is not in line with the existing Tariff Policy, 2016 which provides for a ‘two-part tariff structure’ for facilitating Merit Order dispatch and does not envisage for this further break up of Annual Fixed Cost. Even the recently proposed draft amendments to Tariff Policy don’t indicate any proposed shifting from two-part tariff to three-part tariff [Clause 6.2 (1)].
“6.2 Tariff structuring and associated issues
(1) A two-part tariff structure should be adopted for all long-term and medium-term contracts to facilitate Merit Order dispatch. According to National Electricity Policy, the Availability Based Tariff (ABT) is also to be introduced at State level. This framework would be extended to generating stations (including grid connected captive plants of capacities as determined by the SERC). The Appropriate Commission shall introduce differential rates of fixed charges for peak and off peak hours for better management of load within a period of two years.”
• In such a situation, generating station with higher power dispatch would be able to recover the entire AFC, while the generating stations with lower dispatch but exceeding normative availability would not be able to recover its full AFC. The Hon'ble Commission may appreciate that PLF/Dispatch is an uncontrollable factor for a Generating Company and linking recovery of fixed charges to uncontrollable factor shall not be prudent.
• The proposal puts the existing generating stations, in which the investments were made considering the assurance of full recovery of Fixed Cost subject only to</td></tr>
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		achieving normative availability which is within the control of generating station (except fuel), and thus, violates the doctrine of Promissory Estoppel and legitimate expectation as the Government of India in National Electricity Policy as well as Tariff Policy has repeatedly talked about financial viability and adequate return on investment to the power sector. ***National Electricity Policy:*** *5.8.4 Capital is scarce. Private sector will have multiple options for investments. Return on investment will, therefore, need to be provided in a manner that the sector is able to attract adequate investments at par with, if not in preference to, investment opportunities in other sectors. This would obviously be based on a clear understanding and evaluation of opportunities and risks. An appropriate balance will have to be maintained between the interests of consumers and the need for investments.* ***Tariff Policy:*** ***4.0 Objectives of the Policy*** *(b) Ensure financial viability of the sector and attract investments;* ***5.11 (a) Return on Investment*** *Balance ~~need to~~ may be maintained between the interests of consumers and the need for investments while laying down rate of return. Return should attract investments at par with, if not in preference to, other sectors so that the electricity sector is able to create adequate capacity. The rate of return should be such that it allows generation of reasonable surplus for growth of the sector.* *The Central Commission ~~would~~ will notify, from time to time, the rate of return on equity for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital which shall be followed by the SERCs also.*
2	**7.2.5** The tariff for supply of electricity from a thermal	• CERC in its Statement of Reason document for (Terms and Conditions of Tariff)

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	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).	Regulations, 2014 dated 24 April, has stated that Section 5.3(a) of the Tariff Policy stipulates that while laying down the rate of return, the Commission shall maintain balance between the interests of consumers and the need for investments. Thus, the proposed structure is not justified from the perspective of generation companies who have already invested and have already their assets in operation. • The very suggestion of splitting the AFC recovery and linking partially to actual dispatch (not within Generators control) and remaining with the Availability (generally within Generators control except under force majeure) is against the very foundation of 'Cost Plus' Principles of Tariff design as Generator will not be able to recover its full AFC inspite of operating efficiently and above its stipulated norms. • The National Electricity Policy as well as Tariff Policy also talks about regulatory certainty and consistency. Therefore, sudden change in tariff structure, that too after the investment has been made with the presumption of full AFC recovery subject only to operating above the norms, by converting it from two-part tariff structure to three-part tariff structure is neither correct nor warranted. National Electricity Policy: "5.8.8 Steps would also be taken to address the need for regulatory certainty based on independence of the regulatory Commissions and transparency in their functioning to generate investor's confidence." Tariff Policy: Objectives of Tariff Policy: "(c) Promote transparency, consistency and predictability in regulatory approaches across jurisdictions and minimise perceptions of regulatory risks;" • By doing this, only risk free return is guaranteed and rest will depend on dispatch of power and the assured regulatory returns are being put on stake. This would not only jeopardise financial viability of existing projects but also result in sending

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		wrong signal to the investor, who is assured of only risk-free rate of return for undertaking such a huge investment. The risk-free rate of return may be compared for an ideal capital and not for the risk capital being invested in the generating assets. This will deteriorate the investment climate in the conventional power generation sector. Thus the proposed approach would be inconsistent with the previous approach, reduce predictability and increase perception of regulatory risk which is not in consonance with the above tariff policy. • The proposed three part tariff will result in increase in per unit variable component of tariff for thermal power projects whose tariff is determined by CERC under section 62 of the Electricity Act 2003, as recovery of part of capacity charge will be dependent on dispatch. This will adversely affect recovery of capacity charges of such thermal power stations. However, recovery of capacity charge of thermal power stations having PPA under section 63 of the Electricity Act 2003 will be continued to be based on Availability as per the PPA and will remain unaffected. Thus, the amendment will adversely affect the position of the thermal power projects having PPA u/s 62 vis-à-vis thermal power stations having PPA u/s 63 and disturb inter-se merit order between these two categories of power stations. • Further, in the recent Conference of Power and New & Renewable Energy Ministers of States & UTs at Shimla on July 03, 2018 has stated as below: There is an acute shortage of coal and this is evident because the demand for power is growing. We have written to states allowing them to import coal as per their requirements. Coal will continue to be a problem for 2-3 years till new mines are opened. These mines will be opened when Coal India Ltd gets the environmental clearances. (News Article: The Hindu dated 03 Jul'18; https://www.thehindubusinessline.com/economy/states-to-resolve-for-waiver-of-transmission-charges-for-renewable-energy/article24319304.ece) • Therefore, a mechanism should be developed for ensuring AFC recovery in the

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		event of non-availability of plant due to Coal shortage till domestic coal supply is improved instead of exposing generators to further risk of under recovery of AFC. • In the view of the above it is proposed to continue with two part tariff.
3	**7.2.6** 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.	• By doing this, only risk free return is guaranteed and rest will depend on dispatch of power and the assured regulatory returns are being put on stake. This would result in wrong signal to the existing as well as prospective investor, who is assured of only risk-free rate of return for undertaking such a huge investment. The risk-free rate of return may be compared for an ideal capital and not for the risk capital being invested in the generating assets. This will deteriorate the investment climate in the conventional power generation sector and lead to more stranded/ stressed capacity. • In the proposed segregation, the cost of Interest on Working Capital is missed out from both lists i.e. from AFC as well as VC. • As all the component of O&M cost such as Salary Expenses, R&M and A&G expenses are fixed in nature and majority of which are still be to be incurred, irrespective of whether the plant is only available or dispatching also. Therefore, partial recovery of O&M cost with Availability and breaking this into variable cost is not appropriate.
4	**Thermal Generating Stations - Older than 25 years** **7.3.4** A clear policy/ regulatory decision is 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	• We welcome the suggestion of extension of the useful life of generating stations, which may still generate power at a lower rate as compared to a new plant (while considering total cost). However, there should be a clear-cut mechanism of extension of existing Power Purchase Agreements (PPA) also and the beneficiaries opting for PPA extension shall remain bound by the same till its extended expiry. • Further, near end of the useful life, the developers refrain themselves from additional capitalization because they will not be able to recover the balance depreciation after useful life. Moreover, most of the old power plants may not be

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	performance of a unit does not necessarily deteriorate much with age, if proper O&M practices are followed.	complying with the revised environmental norms for emission and water consumption and modifications may have to be carried out involving capital expenditure to ensure compliance. So plants which are aging or nearly at the end of useful life should be allowed to recover the additional capitalisation by way of special allowance within the balance useful / extended life. However CERC may specify the improved operational norms for Station Heat Rate and auxiliary consumption which would be allowed after renovation of the old plant for determination of tariff. The extended life of the power plant may also be specified for computation of depreciation for the capital cost incurred in the renovation. If it is not feasible to achieve the specified operational norms after renovation, then the generating company may opt to retire the power plant • Procedurally, the generator should be allowed to approach the Hon'ble Commission with its proposal for additional capitalization for life extension with cost benefit analysis and post final approval of the proposal, the beneficiary and the generator may decide to extend the PPA period till extended life with the approved capitalization and tariff. • CERC may specify financial and operational norms for determination of tariff of such plants to enable the generating company to select an appropriate option. The return and recovery based on operational norms for the option to continue to run the plant without additional capex should be based on ROE calculated on Net Fixed assets (excluding accumulated depreciation) and new stringent operational norms and related O & M expenditure recovery.
5	**Hydro Generating Station – Tariff Structure** **7.4.2** The fixed component may include debt service obligations, interest on loan and risk free return while the variable component may include incremental return	• Similar to Thermal Generating Stations, there would be concerns around allocating part of the return on equity and O&M expenses to variable component, thereby, denying the full recovery of Annual Fixed Charges even when the generator is operating efficiently and not able to dispatch because of the uncontrollable demand restriction by procurer or water scarcity due to natural scenarios.

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	above guaranteed return, operation and maintenance expenses and interest on working capital. The annual fixed cost can consist of the components of return on equity, interest on loan capital, depreciation, interest on working capital	• Going by the same logic such segregation of AFC can't be applicable to the run of the river hydro power plant which currently have must run status. • The proposed tariff philosophy may result in higher variable cost of hydro power which will put the hydro power station to be placed unfavorably as compared to some thermal power station (may be pit head units) in the merit order. This ultimately would result in underutilization of water resources.
6	**Inter-State Transmission System - Tariff structure** **7.5.5** The tariff for transmission of electricity on inter-State transmission system can consist of fixed components and variable components. a) The fixed components may consist of either (i) annual fixed cost of some of fixed transmission system designated for access and immediate evacuation, (ii) annual fixed cost of the evacuation transmission system or (iii) part of annual fixed cost of the entire transmission system consisting of debt service obligations, interest on loan, guaranteed return; b) The variable components may consist of either (i) common transmission system or system strengthening scheme excluding immediate evacuation transmission system, (ii) common transmission system excluding evacuation transmission system or (iii) sum of incremental return above guaranteed return, operation and maintenance expenses and interest on working capital.	• Alike Generating Station, the very suggestion of splitting the AFC recovery and linking partially to actual dispatch or actual flow is against the very foundation of 'Cost Plus' Principles of Tariff design. • This proposal will be difficult to justify existence of interconnection line for load balancing with minimum evacuation as well as for the lines which are not dispatching power during normal operations due to the philosophy of N-1-1 system to ensure reliability. • The transmission licencee is responsible for erection and maintenance of the transmission line to make it available for use, while the system operator i.e. RLDC/SLDC, CTU/STU decide the use and loading of the line on which the transmission licencee has no control. Hence linking recovery of tariff based on usage may not be justifiable. • The National Electricity Policy as well as Tariff Policy talk about regulatory certainty and consistency. Therefore, sudden change in tariff structure by converting it from Single-part tariff structure for Transmission Assets to Two-part tariff structure is not warranted. ***National Electricity Policy:*** *"5.8.8 Steps would also be taken to address the need for regulatory certainty based on independence of the regulatory commissions and transparency in their functioning to generate investor's confidence."* ***Tariff Policy:***

S.No.	Reference Clause	Comments / Suggestion
		Objectives of Tariff Policy: *"(c) Promote transparency, consistency and predictability in regulatory approaches across jurisdictions and minimise perceptions of regulatory risks;"* Hence two part tariff is not advisable for transmission business. However the present system needs to be integrated with the proposed GNA mechanism to ensure that the burden of transmission charges on the power plants which are stranded or getting low schedule due to high energy charge rate or plants with seasonal dispatch pattern, is reduced.
7	**Renewable** **7.6.3** There can be Two part tariff structure for renewable generation covered under Section 62 of the Act, which comprises fixed component (debt service obligations and depreciation) and variable component (equal to marginal cost i.e O&M expenses and return on equity) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff	• The proposed structure is not justified from the perspective of Project Developer who have already invested and have their assets in operation. The proposal of putting part of return on equity under variable component shall jeopardise the viability and in variable part the assured returns are being put on stake • An important cost component – Interest on Working Capital has inadvertently remained out of the list of both fixed and variable cost components. • It is completely unfair to allocate the entire Return (RoE) and O & M expenses to Variable component and if it means that it would be linked to capacity augmentation such as storage or back up supply tariff, then it is not clear which parameters would decide the performance levels for recovery of variable cost. It will mean forcing the existing projects to make further investments (in storage and backup system) that too with the risk of under-recovery, as these parameters are not such that an individual project can ensure at its own end. For storage in existing and new projects, the market should be capable enough to provide the right technology and for back up supply, the mechanism is to be provided by the sector/Policy makers at appropriate time. For nature dependent part of generation, there is nothing in control of the project developer. • Further, if two-part tariff structure is adopted, this would not be comparable with

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		Tariffs of Renewable projects under Section 63, which are mainly based on single part tariffs. • On the contrary, for RE generation tariff to be discovered only through section 63 and the concept of feed in tariff should be abolished going forward while protecting must run status of such plants.
8	**Renewable** **7.6.4** In case of integration of the renewable generation with the coal/ lignite based thermal power plant, the following may the alternatives. a) The renewable generation may be supplied through the existing tariff for the contracted capacity of thermal power plant under PPA. In this alternative, the tariff of renewable generation may replace the energy charges; b) Tariff of renewable generation may be combined with the fixed and variable components of the thermal generation to the extent of contracted capacity under PPA. The operational norms of conventional plants may require revision such as higher target availability for recovery of fixed charges, higher plant load factor for recovery of incentive; c) The tariff for supply of power from renewable generation and thermal power generation may be recovered separately. The operational norms for recovery of tariff may have to be specified separately.	• As per point (a) the tariff of renewable generation will be equal to ECR per unit of thermal power with common schedule for entire plant irrespective of type pf generation, so that segregated scheduling from Discoms for both types of energy from a generating station may be avoided. Till now the renewables are considered must run, whereas, in proposed scenario, it would be linked to merit order dispatch and which would be subject to Discoms decision. In such cases, viability of renewable would not be there unless balance annual fixed cost is allowed to be recovered separately. • If ECR of the thermal power project is linked to renewable tariff, then it's completely inapt that the recovery of energy charges would be absolutely delinked or un-related to its actual costs and moreover the dispatch of power from thermal power project would depend on renewable tariff and not on its own operational efficiency/parameters. • With respect to point (b) Two-part tariff for renewables will partly obviate the dispatch issues for existing and new renewable plants. However, the segregation mechanism of renewable tariff into fixed and variable would be a challenge. To start with, it may be 50:50 of AFC. Since renewable's generation, particularly solar and wind, are dependent on nature, their availability and PLF are much lower than thermal plants, and the overall availability and PLF of integrated project is bound to be much lower than presently fixed targets for thermal plants. Hence, lower norms need to be fixed for combination.

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		• Option (c) is the present mechanism which does not give special consideration to integrated generation and may need some incentive mechanism.
9	**8. Deviation from norms: Competition for dispatch** **8.4** Possible option could be to develop for incentive and disincentive mechanism for different levels of dispatch and specifying the target dispatch expanding the scope of Regulation 48 above.	• We appreciate CERC's concern for market development, however, if such mechanism is adopted, even the generator with the cost plus tariff shall be forced to propose a lower ECR than as per actual cost under CERC Tariff Regulations, so as to get its power scheduled in order to avoid disincentive. In other words, generator is forced to compete in market with hit on recovery of its permissible cost of generation for reasons not attributable to it. Hence, we propose that this may please be not adopted for existing generators.
10	**9. 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.	• In case of plants with partly contracted capacity under section 62, All performance norms and related incentives calculations should be based on contracted capacity. • In case of the untied capacity, the generator should have freedom to adopt either the rates arrived under section 62 or rate discovered under section 63.
11	**10. Optimum Utilization of capacity: Coal based thermal generation** **10.3** Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual	• We do not endorse this proposition as Generator will be exposed to high level of risk, to the extent of 80-90% under-recovery of AFC for the un-contracted capacity for the year as it is not easy for the generating company to find buyer in the open market for their surplus capacity particularly in today's scenario and this will put

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	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 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 bid out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.	their project viability at stake. • Instead, the beneficiaries should be mandated to stringently adopt the existing mechanism of URS to ensure optimum utilisation of capacity and provide URS consent easily for sharing of gains under such mechanism. • Any proposal for change in Contract Capacity would require amendment in the existing PPAs which cannot be done without the consent of Generators. With the decreasing trend of PLFs of thermal power stations and increasing trend amongst distribution companies / beneficiaries seeking surrender of capacities, on the pretext of availability of surplus capacities, the only way payment obligation for full capacity can be enforced is to stick to the PPA terms. Any such proposal of annual change in contracted capacities would provide opportunity to these distribution companies/ beneficiaries to circumvent the PPA terms and escape AFC liability, which will be detrimental for generating companies. • However this mechanism can be in the form of an option of amending the contracted capacity based on mutual consent, subject to generating station's ability to contract the capacity with another buyer. The right to recall this option should be exercised with a sufficient notice equal to completion of PPA with the third party.
12	**Hydro Generation:** ***10.5*** (a) Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-20 years from existing 10-12 years for moderating upfront loading of the tariff. (b) Assign responsibility of operation of the hydro power stations and pumped mode operations at regional level with the primary objective for balancing. For this purpose, the scheduling of the hydro power operation	• We welcome the view on increasing the useful life of the project up to 50 years and it should be applicable for existing as well as new projects. However the same may be done only if there is a corresponding extension of PPA term by the present beneficiaries. Hon'ble Commission may also mandate extension of existing PPAs by the same tenure else they will become stranded assets. Increasing the loan repayment period to 18-20 years from existing 12 years is not feasible as existing projects have taken the loan for 12 years as per their existing contracts, and it is also not possible for Commercial banks and NBFC to extend the repayment period

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	(generation and pumped mode operation) may have to be delinked from the requirements of designated beneficiaries with whom agreement exists. The power scheduled to the hydro generation can be dispatched to designated beneficiaries through banking facility so that flexibility in scheduling can be achieved for balancing purpose and to address the difficulties of cascade hydro power station. Some part of fixed charge liability to the extent of 10-20% against the use of flexible operation and pumped operations may be apportioned to the regional beneficiaries as reliability charges.	because of their asset liability mismatch. In case the Commission recommends to Ministry of Power/ Ministry of Finance and Reserve Bank of India to instruct banks to offer such loans on longer repayment terms and they offer restructuring on extended term; only then such term should be made applicable. Accordingly, we propose that the extended life and loan tenure should be left as an option to Generator, rather than making it mandatory. • Similarly, the existing trajectory of depreciation should be continued without any extension to ensure liquidity towards debt servicing. • Assigning control of Hydro Stations to RLDC/SLDC is a little unfair to the designated beneficiaries which have strategized to sign long term PPAs with the Hydro Stations to ensure an economical, quick ramping rate option. By bringing Hydro Stations under RLDC ambit, it would take away the quick ramping rate advantage from the beneficiaries currently possessing it. Also making that capacity available to other regional beneficiaries for just 10-20% of the fixed cost will completely dilute the position for existing designated beneficiaries.
13	**Gas based Thermal Generations** **10.7** Scheduling and dispatch of gas based generating station may be shifted to regional level with the primary objective of balancing. After meeting the requirement of designated beneficiaries, the regional level system operator can use it for balancing power at the rate specified by the generating companies. Alternatively, all the gas based generating station capacities may be pooled at regional level. After meeting the requirement of designated beneficiaries, the balance generation may be	• The existing fuel supply agreements are mostly take or pay type which do not allow for such flexible end use based on as and when scheduling, since the gas contracts are based on government allocations linked to specific PPAs. • This system of pooling of gas based capacity should be limited to only uncontracted capacities subject to availability of gas supply without additional burden beyond normal contract rates.

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	offered for balancing purpose as and when required.	
14	**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. **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 free return. Further, incentive for early completion and disincentive for slippage from scheduled commissioning can also be introduced.	• The Consultation Paper has acknowledged the fact that there is absence of credible benchmarking of technology and capital cost. For a Developer also, it is impossible to accurately determine the actual project cost at the beginning of the project because of many external factors including cost and time overrun in project execution is due to various reasons such as delay in getting statutory clearances & Land acquisition, delay due to geographical constraints/location which will lead to increase in IDC and overheads. • Further, benchmarking is also difficult on account of following factors: i. **Economies of Scale:** A large Developer developing Mega project at multiple sites vs. small Independent Power Producer having single Plant of smaller capacity/ units; ii. **Technology and Unit Sizing:** Sub-critical, Critical, Super-Critical and the upcoming Ultra-Super Critical; iii. **Source:** Chinese, Korean, Japanese, German, Indian • The existing methodology is working well, under which Capital Cost determination is undertaken after thorough prudence check. • Further, the latest available data w.r.t Capital Cost is only till 2010 and is not reflective of the latest market scenarios, technological upgradation, etc. For effective capital cost benchmarking, the regular updation of data is essential. Moreover, there would still be a lag of 4-5 years in benchmark cost year and actual commissioning of project after gestation period of 3-4 years for thermal plants. • Further, nowadays, the new Projects are increasingly being developed under Section 63, which doesn't require capital cost determination and hence, getting data

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		is difficult. • Besides above, in Transmission projects, Land should be allowed to be capitalized on commencement of particular transmission asset instead of waiting till the entire transmission asset is commissioned. This will encourage transmission licensees to acquire land in advance stage of project to avoid tariff impact due to escalation of land prices. • Further benchmarking can be done under identified conditions and appropriate allowance should be made for deviations of any conditions. The return on additional equity must be at the weighted average cost of capital of generating company.
15	**Financial Parameters** **Depreciation** **14.6** a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff; b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; 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; 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	• a) We welcome the suggestion of extension of the useful life of well-maintained generating stations, provided corresponding PPAs are also mandatorily extended as section 62 jurisdiction is for subsisting PPAs with DISCOMs, otherwise after expiry of PPAs there will not be any surety of recovery of balance depreciation. However, the criteria of deciding, whether the plant has been well-maintained or not, need to be detailed, well defined and objective. Further, the increase in life and corresponding capex requirement for R&M would need detailed cost-benefit analysis, which would depend on case to case basis. However, as the depreciation for initial 12 years is linked to repayment of loan component @ 70%, the depreciation rates for first 12 years should not be decreased. In fact, in many cases loans tenure offered is lesser at 8-10 years, thus, there is a case for increase in depreciation rate in the initial years. Further, in all cases recovery of 90% of the approved capital cost should be ensured through depreciation during the useful life.

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	treatment of depreciation thereof; 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. 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).	• b) In case of gradual commissioning of units, the balance depreciation of a unit, whose useful life has ended should spread to the useful life of existing unit to ensure that overall 90% of the total Plant's cost is recovered. The present weightage average depreciation approach may not ensure recovery of 90% of the cost of unit, which is phasing out. • c) Rather than restricting additional capitalization to limited items/equipment, the list should be exclusive and exhaustive, i.e. items which shall not be permitted, to cover genuine items, which may not be in the list of permitted items. • d) same as that for (a) • e) The Consultation Paper is not clear on the suggestion as to how reduced rates would be set or how 90% depreciation would be ensured at reduced rates. The same needs more clarity for making a comments. • f) The existing policy of charging depreciation is working fine and may be continued. Regarding charging of lower depreciation rate subject to ceiling limit should be allowed, as long as the lower depreciation rate suo-motu opted by the developer for a control period is not treated as the new ceiling rate, and is allowed to recover 90% over useful/ extended life of asset for the purpose of computing deprecation for the purpose of tariff determination.
16	**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.	• This proposed structure is not justified from the perspective of Generating companies who have already invested and already have their assets in operating stage as this will be change in rules mid-way which would significantly impact their returns over the useful life. • Present GFA approach must continue to maintain regulatory certainty to investors for plant which demonstrate efficient performance exceeding norms. However the option of modified returns based on NFA (net of depreciation) can be adopted for

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		inefficient plants after their useful life.
17	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.	• According to the 37th report of Standing Committee on Energy, generating assets with installed capacity of 40,000 MW across 34 projects have been termed as stressed power projects, with an outstanding debt of ₹1.8 lakh crore and by February 13 2018 circular, the Reserve Bank of India had asked banks to scrap all debt restructuring mechanisms and begin the resolution process if a company delays payment even by a day, and with this resolution more plants will be under NPA, and thus, Banks will be sceptical to give loan to power sector, especially the standalone generating plant developer from private sector. • Further, the Tariff Policy (including the draft amendments) continue to include Debt : Equity ratio of 70:30 for new projects. • Considering the above points, there is no case for modifying the normative Debt : Equity ratio of 70:30 to 80:20. In any case, the given ratio is only ceiling ratio, and the Equity is allowed at 30% or actual, whichever is lesser. Therefore, there is no need to modify this ratio.
18	**RoI Option of RoE/RoCE** 17.4 Comment and suggestion are invited from the stakeholders on the continuation of fixed rate of return approach or alternative, if any.	• For reason as for Section 15.2 Gross Fixed Asset (GFA) approach in S. No. 17, it is proposed to continue with RoE approach which takes into account the fact that there is no legal provision for taking out the equity invested in a company other than liquidating the company generally after the useful life. Thus, equity remains locked in the company for its entire life and hence, RoE approach throughout life is justified.
19	**18 Rate of Return on Equity** 18.6	• a) The Monitory Policy Committee on June 7, 2018 has increased repo rate by 25 basis points, thereby bringing an end to the falling interest rate regime. Further, at global front, the Federal Reserve Bank of USA has already put an end to the

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	According to CEA there is market dynamics which favors reduction of rate of return. 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. 18.7 (a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects; (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; (c) Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects; (d) In respect of Hydro sector, as it experiences geological surprises leading to delays, the rate of return can be bifurcated into two parts. The first component can be assured whereas the second component is linked to timely completion of the project; (e) Continue with pre-tax return on equity or switch to post tax Return on equity; (f) Have differential additional return on equity for different unit size for generating station, different line	Quantitative Easing and the federal rates are gradually hardening. Further, other key events like increasing Crude Oil prices, depreciating rupee along with fear of Trade war has also impacted the overall growth sentiments, resulting in a negative impact on the availability of cheap funds to key emerging economies including India. Therefore, the era of falling interest rate is not likely in near short to medium term future and the rate of return for next 5 years need not be reduced. • We would also like to draw the attention to the fact that proportion of stressed assets is all time high and this infers that in current scenario as well, there are numerous risks associated with setting up of generating stations which may not be reflected in general market trend. CAPM doesn't capture such risks as most of the companies are not listed • Considering all these aspects, and the increasing interest rates and enhanced risk perception, there is a case of considering increase in the RoE. As stated above, there is no reason for making an artificial difference between existing/ new assets for the purpose of rate of return. • b) If we compare the risk factor of conventional generation and transmission business, the risk associated with a generation asset is much higher than a transmission asset, considering construction as well as the operational risk. The generating asset is posed with the risks of fuel shortage, paucity of demand, etc. which the transmission asset don't have to confront. As CAPM model is applied by CERC (SOR Terms & Condition for tariff determination 2014-19) in which they have merged Beta (riskiness factor) of both transmission and distribution companies. If separately calculated Beta of generation companies will be higher than transmission. Therefore, there is a need to consider for increasing the rate of RoE for generation as compared to transmission sector. CERC may specify financial and operational norms for determination of ROE of aged and nonefficient plants to enable the generating company to select an appropriate option.

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	length in case of the transmission system and different size of substation; (g) Reduction of return on equity in case of delay of the project;	The return and recovery based on operational norms for the option to continue to run the plant without additional capex should be based on ROE calculated on Net Fixed assets (excluding accumulated depreciation) and new stringent operational norms and related O & M expenditure recovery. c) We support the view of considering a differential rate of return for thermal and hydro projects (higher) with additional incentives to storage based hydro generating projects owing to higher risks; d) Linking the incremental rate of return to timely completion of hydro project is not warranted, as the present regulations already allows addition Roe @ 0.50% for timely completion which also acts as dis-incentive in case of delay in completion. There shouldn't be any penalty/linkage of the rate of RoE with timely completion of project. e) we support the continuation of pre-tax return of equity for the reasons given in previous tariff regulations. f) we do not support the idea of differential additional rate of RoE for different unit size for generation, etc. as the cost of equity has no linkage to the size of unit, length of line or size of substation. The effort should be to promote investment in the optimal size of the asset rather than promoting larger size which itself is dictated by the regulated rate of return. g) we do not support any reduction in RoE in case of delay of the Project, as it is already being penalised by allowing lower rate of RoE as compared to the projects completed in time. There shouldn't be double penalisation.
20	Cost Of Debt 19.4 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	• The single most challenge in benchmarking the interest rate is that the interest on loan financed by the Financial Institutions/Banks varies depending on the financial strength and other operational conditions of the entity. This also varies between public sector and private sector, status of the borrowing entities and even between the central sector companies and state level companies and also between large size

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	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. 19.5 (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 Government Bond yield and have frequency of resetting normative cost of debt;	private sector developer and medium to small size private sector developer. Thus, it would not be appropriate to specify the same mid-level benchmark interest rate for all the entities as the same may result in wind fall gains for some entities and substantial losses for other entities setting the lowest rate as benchmark would make most of existing entities incurring losses on this count due to their incapability to get such low rates. • During the past few years, there is significant volatility has been witnessed in the interest rates. Accordingly, at this stage it may not be appropriate to benchmark the interest rate with Prime Lending Rate, MCLR and G- Sec rate. • a) For reason given in previous section in para 19.4, it is suggested to continue with present approach. • b) We agree that developers should explore opportunities for refinancing of loan and that too wherever there is drop in interest rates, hence it would be appropriate to increase the sharing ratio for the developer to encourage for such refinancing for the balance tariff period. Currently the sharing ratio for re-financing (controllable parameter) is stipulated as 2:1 between beneficiaries and generating company. It is further suggested that since the entire effort for refinancing is made by the developer, the sharing ratio of benefit of refinancing between beneficiary and generating company need to be revised to 1:2, to promote the refinancing. Besides, there is a need to define and clarify the methodology of computation of benefits of refinancing and their sharing process in order to bring in more clarity and transparency. c) Testing reasonableness of cost of debt with market benchmarks like RBI policy repo rate or 10 year GoI bond yield would not adequately factor in sector specific risk, and

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		hence borrowing cost for electricity sector, unless a relationship between these benchmarks and borrowing costs of sector can be established with long historical data. As such, we do not support the proposed test/link.
21	20. 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. (b) As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken. (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. (d) Maintenance spares in IWC which is also a part of O&M expenses results in higher IWC for new hydro plants with time and cost overrun. For old hydro stations, the higher O&M expenses due to higher number of employees also yield higher cost for "Maintenance Spares" in IWC. Therefore, option could be to de-link	• a) The existing approach should continue, as it provides sufficient incentive to the stations to efficiently manage their short term funding and disincentive for poor management. Further, due cognizance should be given to outstanding receivables / dues from beneficiaries (Discoms). • b) The proposed new benchmark will necessarily reflect a lower than average/normative level of coal stocks at generating stations owing to coal supply issues over the last two-three years. However, the fact to be appreciated is that current mechanism provides sufficient incentive for stations to keep a considerable stock, which otherwise would impose high risk of fuel shortage on procurers. Impact of fuel shortage is likely to me more on Power Purchase cost of the Procurer as compared to loss of FC due to lower availability (due to lower stock). Hence it is proposed that present normative stock requirement may be continued. • c) and d) 100% of Maintenance spares is part of Working Capital and being 15% of O&M expenses on normative basis need to be continued. • d) Normative O&M for Working Capital may be worked our excluding the abnormal expenses which is largely within control of generator • e) There is no reason to de link the Working Capital requirement from target availability. To make the plant capable to respond to increase in demand by Procurer, Seller shall have to block this WC to meet the normative availability requirements. So, the amount of WC shall be kept linked to target availability. • One possible solution to optimise on cost , could be using 50-50 % weightage for PLF and availability to calculate fuel stock for the purpose of working capital

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	"Maintenance Spares" in IWC from O&M expenses. (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.	• However, there is a need of undertaking truing-up of the interest amount on account of the following factors, which are beyond control of the generator: - Change in Interest Rates within the Control Period; - Change in prices of coal within the Control Period; In case, there is any benefit/ loss, the same shall be shared with the beneficiaries through truing-up mechanism. • **Rate of Interest on Working Capital Loan:** Cognizance of prevailing scenario of delayed payments by DISCOMs, lack of adequate payment security mechanism – especially for private generators, pose greater risk perception by bankers towards working capital loan to the private generating companies. Therefore, there is a need to allow higher interest rate on working capital in the MYT Order (say base rate plus 350-400 basis points instead of 250 basis points), which we have already suggested for truing-up at actual rates. As long as change of regime from Base rate to MCLR would not result in lower normative interest rate, which is mandated under RBI circular quoted in the paper, we have no objection to switching to MCLR system.
22	**21) O&M Expense** **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	• Plants having multiple units of large capacity in different parts can procure O&M supplies at lower cost owing to economies of scale. The O&M Norms should be prepared considering the generating companies having single plants also. • a) The existing escalation mechanism linked with WPI & CPI index takes care of the inflation on routine O&M Expenditure incurred by generating company, especially which is in-house. However, in many instances, where the O&M activities are outsourced for a long duration (say 2-3 years), the renewed contracts, even though

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	Capital Expenditure (CC) for new hydro projects; (d) Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naptha 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 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	awarded through competitive bidding process, may not necessarily be driven by WPI/CPI indices and in many cases the generators are unable to cover the same under normal escalation rates. Ther is need for detailed analysis of sensitivity of cost items based on WPI and CPI accordingly the ratio of WPI/CPI can be fixed, which may be plant specific. • Ash handling and disposal charges should be given over and above O&M expenses, similar to water charges, as these are incurred on account of MoEF Notification and the expenses are dependent upon various factors – availability of land for ash dyke, quality of coal burnt, distance to be travelled for disposal, covering top soil with grass etc. Further, the income, if any, from ash disposal has to be utilized for environment protection and hence, cannot be deducted from the cost of handling/ disposal. Present norms of O&M expenses based on NTPC's plants do not cover such expenses for most of its plants as they have ash dykes for which capitalization is allowed separately. • Also, in case of Transmission Assets, way leave charges are required to be paid to railways and other statutory bodies like Highway, PWD, MMRDA etc. Such charges cannot be contained within normative O&M expenses, and hence, should be given over and above Normative expenses. • b) Additional O&M expenses shall need to be incurred on installation of pollution control system and mandatory use of treated sewage water by thermal plants, which need to be additionally provided while deciding the norm. Since, these expenses won't have a historical trend, therefore, these may be allowed on actuals over and above the norms for this Control Period, before a reasonable trend is arrived at, provided such expenses are accounted for separately. • c) O&M cost based on percentage of Capital Expenditure for new Hydro Projects may be undertaken, taking into consideration the peculiarity of the specific hydro

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		project. • d) the majority of O&M expenses components are fixed in nature and are a sunk cost to the generating station, irrespective of the continuous low level of operation, which may be on account of low demand and MOD stacking. However, a generating station needs to keep itself 'Available', whenever required, therefore, the suggestion of linking the O&M expenses norm with level of operations is not supported. • e) Applying 'multiplying factor' on O&M expenses norms, in case of addition of units in existing stations is not supported as the additional unit may be of different size, technology, vintage (of-course), requiring costlier and higher skilled manpower, etc., and there cannot be always a case of economies of scale for the generator. As such, no multiplying factor should be applied. • f) We strongly support the suggestion of having separate norm for O&M expenses on the basis of vintage of generating stations and taking into consideration their historical trend of O&M expenses. As rightly pointed out, older assets of different age range will have higher O&M expense. The additional expenses on such assets should be linked with stricter operating performance norms. • g) Income from other Businesses, other income, e.g, treasury income such as Interest Income, etc. should not be considered at all for sharing/reduction in AFC, as the risk of loss on these accounts (Other Business / incidental income) are not shared by the beneficiaries of the generating companies. There is no provision similar to that for Transmission licensee's other business revenue adjustment in the EA 2003 permitting such adjustment for generating company. Further, the other businesses of the generating company are non-regulated business (even if regulated, may come under a separate authority/statute), thus, the income from the same cannot be adjusted. Only in cases of revenue attributable to the utilisation of common assets may be considered, and that too should be allocated on the basis of cost sharing /

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		utilisation factor as Hon'ble APTEL's judgment dated 04 Apr'07 in Appeal No. 251 of 2006, clearly stipulates that core and other businesses should be kept in water-tight compartments. No one should subsidize the other. " *The consumers in the licensee's area must be kept in a water tight compartment from the risks of other business of the licensee and the Income Tax payable thereon. Under no circumstance, consumers of the licensee should be made to bear the Income Tax accrued in other businesses of the licensee. Income Tax assessment has to be made on standalone basis for the licensed business so that consumers are fully insulated and protected from the Income Tax payable from other businesses. We, therefore, allow the appeal in this respect.*"
23	**22 Fuel – GCV** (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, 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	• a) We appreciate the concern of the Hon'ble Commission and intention to contain losses. However, Identification of losses to coal supplier or railways, and recovery of GCV/quantity loss from CIL or Railways, is impossible as both are monopoly and government instrumentality. Any such suggestion would be a total loss to the generating company only. Further, it is not possible to determine normative losses for GCV and quantity for each mode of transport and distance between the mine as there will be different challenges at different geographical location in India. • b) Regarding treatment of loss in the heat value of coal between "as received" and "as fired" for the purpose of determination of tariff allowed to generators on normative basis, CEA vide letter No. 228/MISCITPP&D/C EA12017/2437 dated 17/10/2017 has informed that the margin of loss in GCV between as fired and as received 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 pit head station and a margin of 105-120 kcal/kg for a non-Pit head to be considered as a loss of GCV of coal between " as received " and "as fired ". We support this contention as such loss is inevitable in the process of generation and may be fixed as 100kCal/kg for pit head and 120kCal/kg for non-pit head stations. • c) It should be "as received" basis for domestic and international coal as generator

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		have no control over moisture content till coal reaches its boundary.
24	**23 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.	• Normative blending ratio cannot be fixed, as it is highly dependent upon the boiler design and characteristic of the existing domestic coal and the proposed specific lot of the imported coal. Even for same plant having specific domestic coal supply, the blending ratio may differ for specific imported coal source. • The generating companies have been forced to resort to blending largely because of insufficient supply of domestic coal. Therefore, in case the beneficiary(ies) do not provide their consent for allowing the blending, then the generator should be considered deemed available or the target availability may be reduced corresponding to fuel shortage, and the resulting lower availability on account of lower availability of fuel should be ignored. Alternatively, there should not be any requirement for taking consent from beneficiary to the extent of imported coal replacing shortage of domestic coal. A process for procurement of such coal may be defined, and all costs allowed as pass through once the process is followed. • Further, there is a need to develop a mechanism for compensating the loss of incentive to the generating stations, which have opted for blending the imported coal (after taking consent from the beneficiary) and they fall out of MOD stack due to higher ECR, resulting from higher cost of imported coal blended, and thus, losing the generation incentive and economies on account of higher PLF. • Similarly plant which are designed for imported coal and blending domestic coal to reduce cost are subject to loss of efficiency and related incentives due to lower operational performance as compared to norms. In such scenarios the Hon'ble Commission should ensure adequate relaxation in norms to promote cost reduction through blending. • Appeal No 261 of 2013, Petition No. 166/MP/2012 by Hon'ble Appellate Tribunal passed the order to Maharashtra State Electricity Distribution Co. Ltd (MSEDCL) to pay capacity charge to Ratnagiri Gas and Power Pvt. Ltd as the later used R-LPG as

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		primary fuel in place of Natural gas. So, it should be left to generators how they arrange fuel to ensure availability and the capacity charge should be paid by Beneficiary accordingly.
25	**24** **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; (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.	• a) Existing regulations may clarify, all costs upto unloading point are allowable. The standard cost components for fuel landed cost, if at all be decided, should be an 'inclusive list'. Emphasis should be on coverage of all genuine cost heads and not on the specific nomenclature used by the generator or its service provider/vendor. The Commission may consider to define the process of outsourcing supplies/ services contracts, and all incidental costs incurred by Generating Company to bring coal up to the unloading point should be allowed, as long as the generating company has incurred the cost and followed the specified process. • b) The existing mechanism of pass through of landed fuel cost is already defined and working well, therefore, there is no need for modification in the same. The variation in fuel cost on month on month basis is not miniscule and the generating company would not be in a position to absorb the differential cost. In any case, the DISCOMs have been allowed by the State Regulators to regularly (generally quarterly) pass through the difference (cost/benefit) to the consumers, vide FCA mechanism, therefore, there is no need of reasonable predictability over variation in ECR.
26	**25 Fuel Alternate Source** **25.2** (a) Stipulate procedure for sourcing fuel from alternate source including ceiling rate;	• The proposal for stipulating procedure for sourcing fuel from alternate source is supported. However, putting a ceiling rate shouldn't pose a risk of unavailability of the generating capacity and adequate mechanism for ensuring recovery of AFC should also be kept in mind. • b) It will expose the generating companies to unknown risk because fuel prices and

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	(b) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014.	availability of coal supplies from agreed sources are unpredictable and it will erode generator's equity • Considering the full recovery of AFC as first requirement for generators, to source coal from alternate sources, the methodology should be developed considering crucial constraints being faced today including: - delay in delivery of e auction coal causing huge uncertainty; - constraints due to railway infrastructure bottlenecks; - costs associated with alternate fuel sourcing; - impact on other costs like ash disposal, etc. due to alternate sourcing; - mechanism of arriving at/regulate prices of other coal washeries;
27	26. **Operation Norms** **Station Heat Rate** **26.3.3** In the present scenario, most of the coal/lignite/gas based thermal power plants are running at low utilization (PLF) levels due to various reasons including shortage of coal/gas, lower demand etc. Machines working at lower PLF have adverse impact on the operational norms and hence, the existing heat rate norms for the new and existing generating stations are required to be reviewed along with the need for margin.	• We support the view that low PLF has adversely affected the SHR of the generating stations. As per CEA Executive summary report dated 31 March 2018, the Stations under Centre, State and Private have low PLF of 78.47%, 68.66%, 52.59% respectively. So, there is a need to review the operational norms which has to be over and above the heat rate guaranteed by OEM, particularly for private stations operating at very low PLF. New norms should be made keeping in mind the age of stations, as older plants are not able to achieve the same SHR as the new plants. Norms should not be tighter or rather be relaxed from the norms in regulations prevailing at the time of commissioning of the unit/project.
28	**26.3.7** **Specific Secondary Fuel oil Consumption** 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	• An additional Specific Secondary Fuel Oil Consumption should be allowed as in case the generating stations are required to back down for reasons beyond their control, the generating station is getting affected on account of frequent backing down for reasons beyond its control.

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	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.	
29	**Auxiliary Energy Consumption** **26.3.9** Presently, the auxiliary consumption of 800 MW is fixed based on 500MW sets. The auxiliary consumption of 800 MW sets may vary depending on the size of the unit and economies of scale. **26.3.10** 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	• As estimated in the National Electricity Plan by CEA in its report that PLF of thermal stations is likely to come down to around 56.50% by 2021-22, taking into consideration demand growth of 6.34%, performance of generating stations cannot be sustained in the coming years as unit loading is expected to be low in view of the inadequate fuel availability, lower demand/schedule by customers, ageing of units, renovation & modernization, etc. All these aspects should be considered and warrants a higher AEC norms for generating stations. • Existing AEC norms should be continued with provision of additional AEC on account of new technologies like FGD, desalination plant, pipe conveyors, ash disposal system, etc. • Regarding the possibility of gaming in declared capacity on account of lower AEC (if any), the same may be on account of different procedure adopted by different RLDCs, therefore, needs clarification for enforcing identical approach everywhere. • Regarding the colony consumption, there is need for defining the same with more clarity, especially the different approach/treatment for colonies contiguous to the generating plants (and hence supply without using the network of incumbent

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	availability after reduction of normative auxiliary consumption and colony consumption need elaboration.	DISCOM) and colonies away from the plant, need to be brought to the same pedestal, for denying any undue benefit on account of savings in O&M expenses being passed on through AEC norms. Since colony consumption is not part of AEC now, the cost of procuring electricity should be allowed in addition to the normative O&M expenses, which do not include such expenses.
30	**Normative Annual Plant Availability** **26.3.13** As per present regulatory framework, the recovery of annual fixed charges is based on cumulative availability during the year. There may be a chances of declaring lower availability during the peak demand period when the beneficiaries may be required to resort to procurement from short term market to meet their demand. However, during low demand period, the generating station may declare higher availability so as to achieve the target cumulative availability on annual basis to recover the full annual fixed charges. In this process, the beneficiaries may not get the electricity when required at the time of high demand. **26.3.14** In case of partly tied up capacity, the plant availability factor for whole plant may not be relevant. The consideration of merchant capacity for the purpose of plant availability declaration is not relevant.	• In case of Time of Day Scheduling, there is a need to clearly define the Controllable and Uncontrollable factors for availability. The generating stations shouldn't get penalised for non-availability on account of uncontrollable factors. • If full Capacity is not tied up availability should be beneficiary wise, which is based on declared capacity/ contracted capacity for that beneficiary. • As decided by CERC in Petition No. 192/MP/2016 & Petition No. 28/MP/2016 the certification of DC and computation of PAF for IPPs who are ISGS and whose capacity has not been fully contracted shall be done by Respective RPCs and RLDC and the PAF shall be computed considering "contracted capacity" instead of "installed capacity" in the denominator of the formulae for computing PAF This aspect may be covered in the Regulations. • The Hon'ble Commission may, while stipulating norms for PAF clarify for fully contracted ISGS, and for partially tied-up ISGS to avoid any future disputes. • Generator have the flexibility within own capacity to sell the power to the beneficiary of their choice as per PPA, why do generator needs permission to sell their own power where whole unit is dedicated they can't but where quantity is dedicated they can choose the beneficiary they want to sell power to. • Shifting of fixed cost recovery from annual cumulative availability basis to a lower periodicity, such as monthly or quarterly or half yearly basis should not be done. Recovery of fixed cost from annual cumulative availability should be on yearly basis it will give generators sufficient time to recover losses from any planned shutdown

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	26.3.15 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;	and if there is some uncontrollable shut down then there should not be penalty for uncontrollable shutdown. We support having lower availability target due to present day constraints but any target fixed may not sufficiently cover all the unforeseen/ uncontrollable eventualities. It is therefore suggested, to give a further window for allowing further reduction in target availability for such reasons.
31	**Transit and Handling Loss** 26.3.18 A regulatory option could be that the generating station shall only pay for coal “As Received” at the plant plus normative transmission loss of GCV and quantity as per CERC norms. This can be addressed in the Tariff Regulation. By indicating GCV as “As Received at plant end” and customization of Form- 15 regarding the GCV.	• Generating station shall only pay for “As Received” will CIL agree with this as it is a government monopoly. CERC had specified norms of 0.2% for pit head station and 0.8% for non-pit head as loss in transit & handling, but as per the past data, there are quantity and grade slippages more than the specified norms as there are many challenges in infrastructure like road, railway and weigh-bridge. • The quantum, price and quality of Coal is controlled by Coal India Ltd. (Govt. monopoly), evacuation of Coal from pithead to Plant by Indian Railways (Govt. monopoly), Transmission of Power generated by Power Grid Corporation (Govt. entity), Off-take and payment of Power by Discoms (mostly State Govt. owned utilities). In this entire chain, the generating companies, especially the private developer has no control and is completely dependent on Govt. controlled monopolies. • Therefore, it is very essential that a policy framework governing coal allocation, conditions of coal access, evacuation, off-take agreements and payment security mechanism etc. are designed equitably without any preferential treatment based on responsibility of all constituents; but this is to be done with the consent of Ministry of Coal, Power and Railways.
32	**26.5 Transmission System** **Transmission Availability Factor**	• Transmission Availability Factor for recovery of fixed charges should be on cumulative basis, as in case of Generation and not only on Monthly TAFM

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	26.5.5 a) Existing approach for computation of Transmission system availability and weightage factors to be applied for outage hours for transformer and reactors; b) Review of the incentive formula for HVDC bi-pole and HVDC back-to-back stations at par with AC system; c) Specify appropriate region (import or export) for certifying the availability of Inter-regional links (AC and HVDC line) for the purpose of incentive and recovery of annual fixed charges; and d) Review of the existing methodology or procedure for computation of availability, monthly availability and cumulative availability;	• Multiple trippings due to human intervention, damage of equipment by other parties, shutdowns for repairs to be excluded from Availability calculation as the same is reasonably beyond the control of project owner. • Incentive, even for TAFM >99.75% is restricted to 99.75% as per existing formulae laid down by Hon'ble Commission TAFM >99.75%, AFC x (NDM/ NDY) x (99.75%/98.5%), Therefore, same requires to be replaced with actual TAFM . •
32	**27 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 (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	• a) We support the suggestion that there is a need for different incentive for new and old plant because old plant should be incentivised more and some relaxation should be there as efficiency of machinery will deteriorate with time. • Incentive linked with Normative PAF should come back, As per CEA Executive summary report Dated 31 March 2018, the Stations under Centre, State and Private have PLF of 78.47%, 68.66%, 52.59% respectively. As estimated in the National Electricity Plan of CEA, the PLF of thermal stations is likely to come down to around 56.50% by 2021-22, taking into consideration demand growth of 6.34%. So linking incentive with PLF in these conditions makes no sense. • b) Incentive should be with respect to each beneficiary separately rather than plant

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	considered (c) Review the incentive and disincentive mechanism in view of the introduction of compensation for operating plant below norms.	as a whole. Higher incentive may be provided for peak period availability. In case of differential incentive mechanism for off peak and peak periods, if the plant is not available due to uncontrolled factors, then it should not hamper Generator's PAF, and it should also be noted that force majeure for third party in case of FSA is force majeure for Generator also. • c) Incentive is given wholly on the basis of better operational management of the plant and this additional cost is given for the efficiency of the plant going down due to lower scheduling by beneficaries, RLDCs, which in many cases may not cover the increased costs. There can be many constrains like fuel constraint, quality of fuel is a major factor in maintaining the operating norms. Technological constraints & ageing of plant are also some factors that play an important factor in maintaining the operating norms of the plant. So there should not be a disincentive for the stations which are not able to meet the operating norms due to such uncontrollable factors. As such, incentive should not be linked with compensation for operating below norms.
33	**28 Implementation of Operational Norms** **28.2** Comments and suggestions of stakeholders are invited whether the operational norms of the new tariff period should be implemented from the effective date of control period irrespective of issuance of the tariff order for new tariff period.	• New norms may be applied from start of control period even though tariff order may follow subsequently.
34	**29 Sharing of gains in case of Controllable Parameters** **29.1**	• As per the present regulation incentive on operational norms are shared on the ratio of 60:40 between generator and beneficiary it should be reviewed and changed to 80:20 because all the risk here is taken by the generation company there are many

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	The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratios 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. In view of the compensation mechanism, it need to be considered as to whether the ratio of sharing of benefit may be reviewed. **29.2** 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 merit order operating can be linked with the PLF in such a way that the Plant under section 62 may be encouraged to compete for maximum PLF	challenges like unavailability of fuel, maintaining operation norms in old plants and if stations are not able to maintain the operating norms then also no risk is shared with the beneficiary in this case risk lies with the developer only. Therefore, the generating companies should be rewarded for efficient performance and same ratios need to be applied for sharing loss as well. As already stated above, compensation for lower loadings is to cover higher costs of operation and any saving of operational parameters needs to be shared with the generator as it is due to his efforts. • It is a stated fact that generating stations are running at low PLF has high energy cost so they will be out of MOD (Merit order Dispatch). So to bring level playing field energy cost of these plants needs to be calculated as normative parameters only for the purpose of MOD. Thus normative parameter for billing should be different (as per compensation mechanism) than those for MOD.
35	**30** **Late Payment Surcharge & Rebate** **30.1** The present regulatory framework provides for late payment surcharge at the rate of 1.50% per month for delay in payment beyond a period of 60 days from the date of billing. In view of the introduction of MCLR, the rate of late payment surcharge may need to be reviewed.	• The present regulatory framework of fixed high percentage acts as a deterrent for non-payment and should be continued as MCLR will change very frequently and it can cause disputes in some cases. Rather the rate may be increased from 1.5% to 1.75%. • In order to discourage late payment, there is a need to introduce graded penal rate, which increases by 0.25% after every month to discourage long overdues. Long delays from DISCOMs are badly affecting generating companies' capacity to pay to vendors, lenders and financial viability. Clarity is required on computation of Late

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	One option is to add some premium over and above MCLR.	Payment Surcharge/ Rebate, and its period.
36	**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.	• Income from other Businesses, other income, e.g, treasury income such as Interest Income, etc. should not be considered at all for sharing/reduction in AFC, as the risk of loss on these accounts (Other Business / incidental income) are not shared by the beneficiaries of the generating companies. Further, the other businesses of the generating company are non-regulated business (even if regulated, may come under a separate authority/statute), thus, the income from the same cannot be adjusted. Only in cases of revenue attributable to the utilisation of common assets may be considered, and that too should be allocated on the basis of cost sharing / utilisation factor as Hon'ble APTEL's judgment dated 04 Apr'07 in Appeal No. 251 of 2006, clearly stipulates that core and other businesses should be kept in water-tight compartments. No one should subsidize the other. *" The consumers in the licensee's area must be kept in a water tight compartment from the risks of other business of the licensee and the Income Tax payable thereon. Under no circumstance, consumers of the licensee should be made to bear the Income Tax accrued in other businesses of the licensee. Income Tax assessment has to be made on standalone basis for the licensed business so that consumers are fully insulated and protected from the Income Tax payable from other businesses. We, therefore, allow the appeal in this respect."* • Loss/profit on disposal of assets to be allowed as pass through in AFC. Balance depreciated cost to be allowed to be recovered from beneficiary in case of expiry of Long term PPA
37	**33 Tariff Mechanism for pollution control system** **33.4**	• a) Possibilities of financing through National Clean Energy Fund at risk-free rate should be explored and used to finance FGD, so as to minimise the impact on the

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	(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; (b) 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. (c) Feasibility of undertaking implementation of new norms with R&M proposal for plants having low residual life, say, less than 10 years. (d) Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipments.	energy tariff and the same shall be passed to beneficiaries. • b) The Central Government has directed Hon'ble Commission under section 107 of EA, 2003 that MoEF's new environmental norms requiring the generator to install equipments to meet these norms shall be treated as change in environmental laws prescribing stricter norms. Thus meeting these norms will increase not only capital cost, but also the SHR, Auxiliary power consumption, O&M expense. Increase in energy cost due to installation of equipments etc. should not be taken into account during MOD process in SLDC/RLDC • c) A clear mechanism should be defined for ensuring recovery of the cost to be incurred on account of implementation of new norms for plants having low residual life, as this additional capex requirement is on account of change in law. It is suggested to provide a procedure to award the contracts competitively and then allow such costs in tariff. Environmental capex may be seen together with life extension R&M with a provision for mandatory extension of PPA • d) The impact of additional AEC and other operational norms on the ECR on account of implementation of pollution control equipment, should be excluded while computing MOD stack, so as to protect the dispatch ability of the generating station and additional AEC and O&M expense on actual basis needs to be provided for FGD or other installations to meet environmental norms.
	37 Alternate Approach of Tariff Design Normative Tariff by Benchmarking of Capital Cost	• The suggestion of benchmarking of capital cost is a welcome step, as it would provide certainty to Investors for both existing and future projects. • For existing stations, at the time of switchover from existing system to benchmarking regime, it should be ensured that the levelised tariff over the balance useful life with normative parameters should not go below the levelised tariff with

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		existing cost plus regulations. Further, there should be a provision for Change in Law or Force Majeure events beyond the control of Generator. • Benchmarking of Capital cost will reward procurement efficacy and project management operational efficiency. • However, while benchmarking the capital cost for new projects, due consideration should be given to different technologies, unit size and impact of economies of scale and site specific unique parameters. Further, due consideration should also be given to cost of land, civil work requirement, geographical location, which cannot be benchmarked. • Further, if benchmarking of capital cost and other components of AFC is implemented, then prudency check and verification of actual cost incurred as per audited accounts should be dispensed with. • Benchmarking of capital cost should be implemented only for new projects and there should be no benchmarking for additional Capitalisation because it is very project specific.
	Normative Tariff by fixing each component of AFC as a percentage of total AFC	• The effort made in undertaking the detailed analysis is well appreciated. It is proposed that instead of dividing the components of AFC into two clusters of increasing and decreasing components, Hon'ble Commission should take individual components of AFC and calculate the escalation/de-escalation factor of each component and then come up with an index for each component for existing stations on case to case basis as they may be at different stages of life and fix these factors for new stations in the regulations. • One challenge that would come will be how to capture unexpected cost in the O&M expenses, which normally comes on account of selection of outsourcing agency through a competitive bidding process. It will be impossible to estimate a figure for any escalation in such outsourcing expenditure and would be difficult to be

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		indexed. Such type of expenditures, if incurred through a defined process should be allowed on actual basis, over and above the indexation factor. • However, there may be challenges after forming index of the components of AFC. Consider a case wherein interest rates have reduced on account of reduction in repo rate by the RBI. Though, the same will be captured in the indexation, however, there is a possibility that the lenders/bankers may not have passed on the entire benefit of rate reduction by RBI to the developer. In such cases, indexation would result in loss to the developer. Therefore, in case the indexation of AFC is adopted, then in such cases, there should also be a mechanism for cases, wherein the AFC recovery falls short of the norm and the same may be allowed if sufficient rationale is provided by the developer.
	Principles of cost Recovery- Approach towards Multi – Part Tariff	• It has been suggested that 80% of the AFC should be recovered upon declaration of 80% PAF during the year & remaining 20% AFC to be paid upon achieving 95% PAF during peak period of 4 months & there should be higher peak price i.e. 25% over the off Peak price. There are several issue in this proposal that are stated below- • In case of generating stations having multiple beneficiaries in multiple states/regions, the peak & off peak season will be different for e.g. Peak season of West Bengal will be different from Peak season of Kerala; • Forced outage of the generating plant in the proposed 4 months of peak season should not be penalised. It is suggested that the proposed scheme should be devised in such a way that there should be an incentive for peak season availability, however, there shouldn't be any penalty on unavailability on account of any reason during such time. • The proposal of bringing all the scheduled outages / shut downs in the remaining 8 months of off-peak seasons would put tremendous pressure on the generation

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		plants and if all the generating plants will have the same window with lesser flexibility for scheduling outage, the envisaged off-peak season may very well turn into peak season considering the unavailability of a number of plants at the same time. • The proposed scheme theoretically allows a maximum recovery of 105% of total AFC, which is marginally higher than the AFC. However, the associated risk is too high and thus the proposed mechanism is not balanced. For example, in case a generating station is not able to ensure availability due to some uncontrollable factor, then there would be no possibility of recovery of full AFC, even if it is fully available during the entire off peak season, and also cumulatively achieves 85% for the year as a whole. In view of the above, we propose that this scheme should not be implemented.
	Additional Suggestions for Generation	• To avoid uncertainty in Capital cost finally admitted by CERC, it is proposed that a two-step approval process may be adopted for Capital cost and additional capitalization. (i) In-principle approval, and (ii) Final approval post actual Capitalization • Time/ Cost overrun in Land cost due to legal process of acquisition should be considered as uncontrollable factor. • Depreciation rate may be fixed separately for important high value equipments having shorter life spans of, say, 4 to 7 years, considering their useful life. For ex: Gas Turbines – has useful life less than 25 years and also needs R&M every 5-7 years; similarly Air preheater baskets – needs to replacement in 4-5 years, Burners etc have even shorter life & higher R&M but all these equipment has the same Depreciation rate • Depreciation on add-cap may be allowed to be recovered in balance PPA term. • Normative IDC to be allowed on equity in excess of 30% for add-cap

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		• RoE should be allowed on equity invested during construction period also, and should be allowed to be capitalized as equity capital. • The rate of Compensation allowance is too small to meet R&M expenses, and need to be increased substantially gradually increasing with life of generating stations. • PLF needs to be computed with contracted capacity instead of installed capacity for each beneficiary separately where full capacity is either not tied up or not under section 62 PPA • Continuous trial run operation for a period of 72 hours is required for COD, which needs to provide additional cushion for exigencies like backing down instructions, or short time trippings, or some other grid constraint. • Technical minimum to be fixed on case to case basis as per OEM's recommendations and in case of a different technical minimum, additional capex to meet such levels should be allowed. • URS capacity consented or not consented by beneficiary should be considered as deemed generation for the purpose of PLF and incentive. • Rebate to be linked with interest rate allowed on working capital. • Change of Law cases decided by CERC in other petitions should be allowed to be applied in similar cases by generator/ beneficiary to avoid further petitions on same issues. • Norms for AEC of standby units may be fixed based on CEA/CPRI certificates. • Need for clarity on computing carrying costs i.e. from bill date or due date and upto date of raising supplementary bill or date of actual payment.