APP Comments on CERC Consultation Paper on Terms & Conditions of Tariff Regulations, for tariff period commencing from 2019

#	Clause	Existing provision	Comments/ Submissions for consideration
1.	5.2.5 and 5.2.10	In line with the notification of the Ministry of Environment and Forest, revised environmental and emission norms require installation of flue gas desulphurization (FGD) systems and other control systems such as ESP etc. in both new and old thermal power plants.	• With reference to the Environment Protection (Amendment) Rules, 2015 notified by MoEF on 7th December 2015 which has revised the environmental and emission norms require installation of FGD/ ESP and other control system in both new and old thermal power plants. Further, the requirement of these additional equipment and facilities arising out of this notification would lead to significant changes in power plant operating parameters such as auxiliary consumption, O&M expenses, SHR etc. This would also necessitate changes to be made in existing PPAs and relook of the CERC norms to absorb these changes. • Ministry of Power vide notification no.23/22/2018-R&R dated 20/05/2018 has also provided relaxation that any additional cost implication due to installation or up-gradation of various emission control systems and its operational cost to meet the new environmental norms shall be considered for being made pass through in tariff under Change in Law by Commission. • In view of above, any additional O&M expenses should be considered over & above current O&M expenses for the tariff period starting from FY 2019-20 to FY 2023-24 on account of additional repair & maintenance which is required for the equipment/system installed in compliance with revised environmental and emission norms like installation of FGD systems and other control systems such as ESP etc. in both new and old thermal power plants. • Similarly, additional auxiliary power consumption needs to be considered over & above current auxiliary power consumption for the equipment/system installed in compliance with revised environmental and emission norms.
2.	7.2.4	The possible options for tariff structure could be to offer to the procurers having low demand a menu of options for	

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		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	• Three Part Tariff is not in consonance with the Tariff Policy/ proposed amendments in Tariff Policy which mandates two part tariff for thermal project. • It is not explained as to how three part tariff will improve PLF of thermal plants. PLF is function of the demand. Unless demand is increased globally, PLF may not improve. One of the reasons for low PLF is non-cost-effective retail tariff approved by the SERCs. As a result, distribution utilities prefer load shedding instead of procuring power from generators that are placed high in MoD. In this scenario, it is perceived that there is power surplus situation. The same needs review. Recently, short term power purchase rate (which is indicator of requirement/demand) in Exchange had soared to Rs 5-6 per kWh. Also, during FY 17-18, short term bids aggregating more than 30000 MW were issued by different states and the rates therein are also in this range. The quantum has also increased. Therefore, the proposal at this stage is premature. • Recently, MSEDCL has sought permission of MERC above ceiling rate of Rs 4 per kWh fixed for short term power purchase in view of the rates discovered in its recent tenders mainly between 4.50 per kWh to 6.29 per kWh. • As per the details available in CEA periodic reports, it is observed that monthly PLF for last 5 months in current calendar year is higher as compared to corresponding figure in last Calendar Year. • Therefore, expecting the situation of low PLF to continue throughout the next tariff period of 2019-24 may prove to be a fallacious assumption in hindsight in 2024. There are multiple reports of various consultants and expert bodies which expect the PLF in coming years to rise. • Further it is not known whether the Low PLF is on account of low demand or on account of all customers not being serviced. There are still areas in the country which are not electrified / which do not have 24x7 Reliable Power Supply. Also, the outages are being undertaken by Discoms due to high AT&C losses which may be contributing to
3.	7.2.5	The tariff for supply of electricity from a thermal generating station could comprise of three parts, namely, fixed charge (for recovery of fixed cost consisting of the components of debt service obligations allowing depreciation for repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses), variable charge (incremental return above guaranteed return and balance operation and maintenance expenses) and energy charges (fuel cost, transportation cost and taxes, duties of fuel).	
4.	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.	

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			low PLF. The sovereign objective to supply power 24x7 cannot go hand in hand with situation of low PLF. • Per capita consumption of India has almost doubled in FY 2017 (1122 kwh) as compared to that in FY 2002 (559 kwh). Still it is only 1/3rd of the world's average per capita with highest per capita of about 15000 kwh for Canada and USA. The government of India is committed to increase the per capita consumption. Under these circumstances, one cannot definitely anticipate low PLF situation to continue in future and provide solution based on such a temporary phenomenon. • GOI is trying to address the problem by introducing provisions in the Standard of Performance, through the draft amendment to Tariff Policy, which shall penalize the Discoms for not ensuring 24X7 supply. With GOI's impetus on improvement in supply of electricity throughout the country, the so assumed low PLFs are bound to increase in the coming tariff period • Further, Projects are evaluated and decisions related to funding are taken based on norms prevailing at the time of project inception. Therefore, Regulatory certainty is the foremost objective for investment. Changing basis in entirety will leave investors with no clue and no investor will put the money in the power sector. • Generators have made huge investments in the Power stations considering two part tariff and recovery of their fixed cost on the basis of declaration upto target availability. Sudden change in this provision, will leave generators with non-recovery of their total fixed cost and will be totally unjustified since demand of power is not within control of Thermal Generator. • Lenders have been providing funds to power projects, considering recovery of total fixed on declaration upto to target availability. This proposed change in regulation by CERC will force the lenders to assign higher risk value to these assets, thus increasing the rate of interest. This high rate of interest will be passed on to the consumers which will increase the tariff.

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			• Issue of low PLF is already addressed by way of amendment in IEGC. • Demand for power is not within control of Thermal Generator. The proposal of Three Part Tariff affects adversely interest of generator for factors beyond his control. As rightly pointed out in Table 6 of the consultation paper, Fixed charge per unit has reduced by 21% in last 8 Years. Further, reduction in the recovery for fixed cost may lead to issue of sustainability. • O&M Expenses is essentially fixed cost and does not have any evident relationship with PLF. Therefore, there is no point in considering part O&M expense under Variable Charge. As per the proposal, almost 80% of the fixed charge will remain to be fixed charge and only 20% will convert into Variable Charge. This coupled with complexity of the proposed mechanism will not yield any effective result. • Further apart from being difficult to implement, three part tariff may not necessarily improve PLF of thermal plant as anticipated. • In view of above, it is proposed to continue with two part tariff and not shift to three part tariff as suggested. • Modality to recover Variable charge is not clear to comment.
5.	7.3.4	A clear policy/ regulatory decision are required in view of a number of thermal stations crossing the age of 25 years. Possible options could be (i) replacement of inefficient sub critical units by super critical units, (ii) phasing out of the old plants, (iii) renovation of old plants or (iv) extension of useful life etc. It is worth to note that performance of a unit does not necessarily deteriorate much with age, if proper O&M practices are followed	• One of the parameter for phasing out old units is Station Heat Rate. Stations with higher SHR could be phased out. • It will not be financially viable for the assets to undertake retrofitting of emission control equipment (such as FGD, ESP, etc.). Further, many such older plants have no additional space/ incremental water to retrofit FGD or meet cooling water requirements, etc. • A CEA report on replacement of old and inefficient units was prepared in 2015, which identified 34,280 MW capacity which was more than 25 years old. Till Mar-2018, 6,872 MW of capacity has already been retired. Even considering the initial estimates from 2015, this still leaves 27,408 MW of capacity where the time required to recover the cost of retro-fitting air pollution control equipment would be quite less and would make the plants completely unviable.

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			• Based on the above, it can be concluded that on financial and operational yardstick, it would not be prudent to undertake financial expenditure on these plants. Therefore, Government may consider expediting action for closure of older and inefficient plants.
6.	7.4.2	The two part tariff structure of hydro generating stations seems adequate in present scenario. However, in view of large capital cost, hydro generating stations often find it difficult to get dispatched due to resultant higher energy charges. In order to address this issue, for the hydro generating stations, the fixed charges and variable charges may need to be reformulated.	• Generation from Hydro Power Stations is critically dependent on vagaries of nature and hence it is termed as non-firm in nature. • CERC's Indian Electricity Grid Code has also provided Must Run status to all Run-of River hydro power stations. Clause 11 of 6.5 of Part 6 of IEGC is reproduced below: *"11. Since variation of generation in run-of-river power stations shall lead to spillage, these shall be treated as must run stations."* • In order to utilise nation's vast untapped hydro potential, the Commission should promote hydro power. However, clause 7.4.2 of draft consultation paper is deterrent to Hydro sector investor as it is prone to risk of losing return on equity invested by Investor. • In view of above, it is suggested that earlier two part tariff structure with must run status be continued for Hydro Power Plants. • PLF of Hydro stations is fluctuating; it operates at 100% during monsoons and operates at 30% during winter. The energy charges need to be seen on annual basis not on monthly basis and long terms PPAs should be awarded to hydro plants via MOU route, to get further investment in Hydro Generations. • The share of hydro in installed capacity has reduced in recent years, with increase in share of renewable energy. • Hydro generating stations are capable of providing fast ramping & peaking support capability and they can be gainfully utilised for regulation services to meet the system requirements. • There is a need to provide strong commercial signals that allow flexible resources like hydro to provide peaking capability support during high ramp periods besides quick start/stops to take care of intermittency of variable generation from renewables. • Coordinated scheduling and utilisation of hydro generation for providing secondary and tertiary frequency control ancillary services,

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			reactive power support through synchronous condenser operation as well as black start services would greatly help in integrating Renewable Energy (RE) generation resources into the grid.
7.	7.5.4	Transmission tariff can be on two-part basis, wherein the first part can be linked with the access service and second part can be linked with the transmission service.	• At the outset it would be pertinent to recognise the difference between determination of transmission charges for a transmission asset and sharing of transmission charges by DICs. The tariff regulations of the Commission are applicable for determination of transmission tariff of an individual asset. The components of tariff would be cost components submitted by the licensee for prudence check of the commission. Further, the aggregated tariff (YTC) for all the transmission assets is shared by DICs as per the sharing mechanism. In this context, the proposed Two Part Tariff Structure for Transmission is relevant for **sharing** of transmission charges by DICs as it deliberates on the framework for recovery of tariffs of different kinds of transmission systems viz. evacuation, common transmission system etc instead of cost elements of an individual transmission asset. The extant methodology of determination of Single part transmission tariff has a rationale that it provides certainty to the licensee in terms of recovery of costs. Once the transmission line is commissioned, the licensee's duty is to remain available up to the level of target availability for recovery of tariff. Accordingly, the Tariff Regulations should ensure full recovery of tariff/cost for the transmission lines. • Further, the Electricity Act 2003 mandates the Commissions to determine, inter-alia, tariff for transmission of electricity. The Act does not give power to Commission to specify charges for accessing the transmission system. Any change incorporating access charges would be ultra vires of the Act. • In case, Two Part tariff is introduced for recovery of Transmission Tariff, either the Transmission Licensees shall be left with under recovery of their cost or some of the beneficiaries will end up paying more than their legitimate share.
8.	7.5.5 (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;	
9.	7.5.5 (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.	
10.	7.5.6	The recovery of fixed component can be linked to the extent of access (Transmission Access Charge) and variable component can be linked to the extent of use, to be recovered in proportion to the power flow (Transmission Service Charge). The fixed component may be linked to evacuation system or on normative basis based on aggregate transmission charges of the identified transmission system under the contract. The variable component may be linked with yearly transmission charges	

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		based on actual flow or actual dispatch against long term access.	*Example – Assume 2 x 500 MW customers seeking open access. Customer A is using the network for 20% energy transaction whereas Customer B for 80%. In this case, both will pay equal access charge but Customer B will bear more service charges even though there is no additional expenditure on this account.* • The Two Part Tariff structure is very complex and will be difficult to implement. • Such change will adversely affect financials of Transmission Licensees, as lenders will consider such change in methodology of recovery of transmission charges as increase in risk perception, leading to higher rate of interest which will lead ultimately lead to higher interest on normative Loan and thus will increase the AFC • Introduction of Two Part Tariff for Transmission Tariff will require amendment / Change in PoC regulation / methodology. • The Transmission Licensee is responsible for maintenance of his line and makes it available for use, while System Operator i.e. RLDC / SLDC, CTU / STU and Laws of Physics decide use of particular transmission line and its loading. The transmission licensee owning a line has no control over use / non- use of his line and hence it is not justifiable to decide tariff based on usage of the line. • Further the system is designed in a manner that there is n-1 contingency hence full capacity of transmission system will never be utilized and hence the Two Part Tariff will lead to under-recovery of Tariff for Transmission Licensee. • The Electricity Act, 2003 provides for recovery of transmission tariff for use of transmission line, while it is suggested that first part can be linked with access service, which is not recognised by the Act itself and hence, will be ultra vires.
11.	7.6.1 (b)	*"For merit order operation, the entire tariff of the renewable generation (which is of the nature of fixed cost) is to be compared with the marginal cost of the other generation (excluding the fixed cost component)."*	• Currently Renewable power plant has been granted "Must Run" Status. Developers have set up the plants under long term fixed single part tariff.

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			• Merit Order Dispatch (MoD) if made applicable on the renewable plants, projects set up under the single part Tariff PPA model, needs to be kept out of the same as they were promised a "Must Run Status" and any variation to that will impact their viability.
12.	7.6.3	Options for Regulatory framework "*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 <u>variable component (equal to marginal cost i.e O&M expenses and return on equity</u>) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff.*"	• Stand of commission in treatment of "Return on Equity"("RoE") cannot be different for different sources of energy. RoE is considered as part of Fixed tariff in case of Thermal, Hydro and Transmission. However, for Renewable, commission has proposed RoE as part of variable component tariff. It will completely discourage any investment interest as no return would come to equity investors in case of no offtake by the procurer (for no fault of the generator). • It is proposed to consider RoE as part of fixed cost tariff instead of variable cost tariff part. • Also, Renewables by definition covers wide range of Generating plants like Solar, Wind, Biomass, Bagasse, Small Hydro etc which by nature have varying fixed & variable cost of per unit generation. • It is proposed to have separate terms and condition for calculating Fixed and variable cost for all the renewable sources along with cost of battery storage and hybrid plants (Wind + Solar + Battery storage). • 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

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			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 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.
13.	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	• 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.

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		recovered separately. The operational norms for recovery of tariff may have to be specified separately.	• 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. • Option (c) is the present mechanism which does not give special consideration to integrated generation and may need some incentive mechanism.
14.	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.	• Development of incentive and disincentive mechanism for different levels of dispatch need not be part of Regulation. • The option for development of Incentive and disincentive can be a bilateral arrangement. • 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.
15.	9.0	Components of Tariff 9.1 Unlike the Central Generating Stations, for privately owned generating stations, not all the generating capacity may have tied up power purchase agreements. In such case, part capacity may have been tied up under Section 63 and/or Section 62 of the Act and balance may have remained as merchant capacity. 9.2 Section 62 of the Act provides that the Appropriate Commission shall determine the tariff for (a) supply of electricity by a generating company to a distribution	• It is suggested that appropriate regulatory commission should determine tariff for the power station / unit wise as a whole irrespective of the quantum of power contracted under Section 62 to the Discom and then, this tariff can be applied to capacity contracted under Section 62 while for the balance, tariff discovered through competitive bidding can apply. This is akin to the procedure being followed now by Regulatory Commissions.

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		Licensee, (b) transmission of electricity, (c) wheeling of electricity and (d) retail sale of electricity. Section 61(b) of the Act provides that the Appropriate Commission shall specify the terms and conditions of tariff for generation, transmission, distribution and supply of electricity are conducted on commercial principles. The commercial principles inter-alia emphasize the risk allocation through contractual arrangement such as power purchase agreement in case of generation and transmission service agreement or long term access agreement in case of transmission service. Options for Regulatory Framework 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.	
16.	10.2	If the unutilized capacity of the generating station is allowed to be utilized by other distribution companies or through open market, the obligations of the distribution companies may reduce to the extent of utilization.	• There should be a possible option of penalty mechanism for the Discoms after certain level (which needs to be specified) of unutilized capacity. Even if generators sell their power in open market there are no certainties in respect to power prices, which will directly hamper the financial health of a generating plant.
17.	Optimum utilization of Capacity: Coal based Thermal Generation	Options for Regulatory Framework (a) Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the	• Lenders/investor have invested in projects as per the executed PPA and expected cash flow on the said PPA. If there is any change in contracted capacity and revenue thereon the same will impact the debt servicing and viability as there is no confirmed open market prices for the sale of power at profitable rates.

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	10.3	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 bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.	• The demand / rates in the open market are fluctuating in nature and cannot be relied for viability of project. Hence contracted period should not be disturbed • Fixed Charges obligation should be with Discoms only. • For optimum Utilisation of Capacity, suitable mechanism can be developed similar to concluded PPAs executed as per Competitive Bidding Guidelines under section 63. • In the current scenario of low PLFs and stranded capacities for want of PPAs, the policy of new capacity addition at very high cost (Rs. 8.7 Cr per MW for 1980 MW Ghatampur project; Rs. 7.9 Cr per MW for 1320 MW Udangudi project; Rs. 9.6 Cr per MW for THDC Khurja project; Rs. 8.9 Cr per MW for Marwa project) begs review. • Looking at the quantum of under-utilised/ idling/ under-construction capacity, and the NEP projections, the solution which suggests itself is that there should be a 'hiatus' in terms of building any new capacity. Trigger point for starting new capacity building could be absorption of the entire existing capacity and avg. PLF of around 70%. This would leave adequate time for new capacities to come up. • Mandatory PPAs – as granted to Public sector Generators – pre-empt the entire space of PPA & Coal. Such PPAs also block the Coal availability for private sector as Central/State PSUs get granted Coal linkages and Coal block on priority from the Government. • It is noteworthy that NTPC is yet to sign a single competitively bid project, and in order to avoid competition, NTPC has started entering into Joint Ventures with States to remain under cost plus regime. • With sufficient Generation capacity available, such exemption from competitive framework is neither needed nor desirable. • Further, the competition should be extended so that only cost effective and efficient plants get dispatch – which can be based on a new framework with combination of variable cost and SHR.
18.	Optimum utilization of Capacity:	Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-	• 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

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	Hydro Generation 10.5 (a)	20 years from existing 10-12 years for moderating upfront loading of the tariff.	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 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.
19.	Optimum utilization of Capacity: Hydro Generation 10.5 (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 (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.	• Individual generators and beneficiaries cannot decide on the said arrangements and it will involve central and state regulators for the fixed charges apportionment. • It requires more deliberation with a clear process of implementation mechanism. A Discussion Paper needs to be prepared on this subject, with inputs/ consultations from all stakeholders. • Hydro and Gas based generation can efficiently and effectively provide balancing and ramping requirements of the Grid in view of high RE integration. • Coordinated scheduling and utilization of hydro generation for providing balancing and peaking can help cope with the huge target of renewable capacity addition. • The non-availability of Domestic Gas has limited the utilisation of Gas based power plants for balancing the grid. However, Gas based

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20.	Optimum utilization of Capacity: 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 offered for balancing purpose as and when required.	power plants can provide peaking and balancing capacity to some extent if certain provisions for making Gas available are allowed – o Reintroduction of E-RLNG scheme for six months of summer season for 3 years; o 2.50 MMSCMD of ONGC Gas from deep water fields allocated to Power sector – with separate bucket for Power sector, and aggregator like GAIL to bid on behalf of Power plants; and o Balance Gas requirement to be met from RLNG.
21.	11.0	Benchmarking of Capital cost	• It is submitted that restriction of Return on Equity corresponding to the normative equity as envisaged in the investment approval or on benchmark cost and allow only weighted average interest rate or rate of risk free return on additional equity invested for new project would discourage investment in power generation / transmission sector. • Reduction in the Return on Equity will dissuade investors from making investment in the Power Sector in the country. • Accordingly, the existing approach, which allows 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, may be continued. • Further, given the difference in various technologies and geographical differences leading to different designs and equipment including varying land and transmission cost, it is proposed that no Benchmark Capital Cost is notified for Wind and Solar Projects any longer. • Cost of competitively bid power is less than cost plus regime. The question that comes up is do we need benchmarking at all. All power procured should be on bid discovered fixed cost, as fuel cost comes from coal price, distance of transportation, etc. • Further, efficiency should be given in bidding as quotable factor for SHR, so that efficiency of conversion can also come in to the picture. As benchmark will always involve subjective discretion, therefore the

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			best way forward is to have a transparent, fair, and competitive process – in line with the philosophy of the Act to move towards competitive power market. • In line with the above, CERC should dispense away with benchmarking and tariff fixation under Sec 62.
22.	Capital Cost (Thermal & Hydro Generating Stations) 11.6	There are specific issues and challenges in respect of thermal generating stations. i) The claims of deferred works were allowed to be capitalised up to the cut-off date under the head "works deferred for execution/deferred works" but there is no provision for allowing such expenses after cut-off date. In some of the cases, expenditure was allowed even after cut-off date;	• There should not be any cut-off date for essential expenses. If there is prudent reasoning for any work be it originally envisaged or other-wise at any time during the tenure of the project, there is no reason to deny the same. • The Commission may include provision related to additional capital expenditure to meet exigency without approaching the Hon'ble Commission beforehand. The Commission may define broad heads in this regard. • Control systems, system software, etc. are prone to obsolescence due to rapid technological advancement and the same needs to be suitably allowed under additional capital expenditure.
23.	Capital Cost (Thermal & Hydro Generating Stations) 11.9	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	• No. of variable factors in a generation plant or in transmission lines are so high that each plant is unique in itself, as far as design and investment is concerned and therefore, it is practically impossible to define the benchmark cost. • There is no regulatory sanctity for Benchmarking Norms or Investment Approval. The Commission has dispensed off with the requirement of prior capital cost approval also. • Once prudence check has been performed and only legitimate costs are allowed, then such costs alongwith the costs related to its financing plan are to be also allowed. • For increase in capital cost due to uncontrollable factors, developer will have to incur the equity which otherwise would have earned the same return / higher return of equity from investment in other businesses (Cost of Equity). • It is to be appreciated that cost over-runs are not completely funded by debt. Proportionate equity has to be brought in by the Promoter. Equity has an opportunity cost. However, this cost does not get

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		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.	recorded in books of accounts. Though the Regulation allows 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 but it is not clear that cost of equity (which is a universal concept) will be allowed as compensation also since it is not recorded in books of accounts and whatever is not recorded in the books of account will not be certified by Auditors and whatever is not certified by auditors might create dispute. • On the other hand, if the increase is due to controllable factors, then the Commission does not allow such capital cost at all. Therefore, there is no point in restricting Return on additional equity to weighted average loan portfolio.
24.	12.4	The old transmission lines and substations are sometimes inadequate to cater to the new demand due to capacity degradation and obsolesce of technology. However, construction of new transmission lines and sub-stations require high initial capital investment and substantial time towards seeking approvals, tackling right of way (ROW) issues and environmental clearances. R&M with and without up-gradation of existing projects is one of the cost effective alternatives to increase the power transmission capabilities. The upgradation of transmission line and substation to higher voltages has emerged as a viable alternative to cater to the load growth or transmission requirements. It also offers commercial advantages as some of the original foundations, structure, or equipment can be re-used with minimal modifications.	• The Up-gradation of transmission lines to higher voltages renders the existing foundations, structures and useless because the existing foundation, structures have been built for a particular tensile load. With increase in voltage the re-usage of existing foundations, structures is not possible
25.	12.5	In coastal areas, line structures/ towers, hardware, conductors etc. get rusted due to saline atmosphere. Lines passing through chemical zones also require to be strengthened by stub strengthening, replacement of conductors, hardware, insulators, earth-wire etc. The transmission lines which are in service for more than 25	• Thermal power stations located near coastal areas are also subjected to rusting and require strengthening as well as suitable replacements. Hence similar R&M provision may be included for coastal plants as well.

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		years are affected due to atmospheric conditions and aging.	
26.	Renovation & Modernisation 12.6	The R&M of transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow Renovation & Modernisation (R&M) for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, the Commission may allow special allowance for R&M of transmission assets. Such provision will enable the transmission companies to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/transmission line without any need for seeking resetting of capital base.	• Depreciation on additional capex should be allowed to commensurate with the residual life of the assets. • At the end of useful life of the assets, beneficiaries should be obligated to pay for the residual value.
27.	Financial Parameters 13.1	The performance based cost of service approach; a combination of actual cost and normative parameters has been evolved for the Tariff regulations. Components like return on equity, operation & maintenance expenses and interest on working capital have been specified on normative basis whereas cost of debt has been allowed based on actual rate of interest on normative debt. The normative parameters are expected to induce operational and financial efficiency. While continuing with the hybrid approach, more weightage may be provided for normative parameters to induce greater efficiency during operation as well as in development phase.	• At present Interest on Loan as a component of tariff = (Average Normative Debt) x (Weighted Average Interest Rate of Actual Portfolio) • It is suggested to continue with existing methodology of cost of debt being allowed on actual basis on normative debt, since different Generators/Licensees get loans at different rates which is not entirely in their control. PSUs like NTPC/PGCIL get loans at Cheaper rates because of Sovereign Ownership and Implicit Guarantee whereas Private Sector Players get loans at a comparatively higher rate. Now if normative interest rate is fixed PSUs will tend to gain and private sector entities will tend to lose. To create a level playing field it is essential that existing formula may be retained.
28.	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;	• Depreciation allowed under the regulatory mechanism is a major component of tariff and assures the cash flow for the project. Frequent revision in depreciation will result in uncertain cash flows and this will create problem in arranging finance for the project. Therefore, it may not be desirable to reassess life and recomputed depreciation at start of every tariff period.

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		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 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).	• In fact, with more RE sources coming into Grid, useful life of thermal power stations get affected due to frequent cyclic loading, which induces fatigue. Further, frequent shutdowns due to RSD and low PLF will also affect the useful life of the plant which may not be even 25 years. Hence the depreciation shall be maintained for 12 years • Ideally, option g seems the best, as it tends to protect the interest of the existing stakeholders however the residual value/scrap value may be changed to 5% instead of 10% in line with Companies Act, 2013. • Alternatively, depreciation may be linked to debt repayment rather than linking it to useful life of the asset since, loan tenure in most cases is such that a depreciation of 7-8% is needed to repay the loan ever year. Therefore, it is suggested to reassess the depreciation rate which need be enhanced and the salvage value to be considered at 5%. In consonance with Companies Act, 2013 • Depreciation on additional capex should be allowed to commensurate with the residual life of the assets. • At the end of useful life of the assets, beneficiaries should be obligated to pay for the residual value.

29.	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.	• To continue approach of RoE, since:
			  ○ Unlike debt, developer does not earn return on equity during construction period.
			  ○ Power Sector is going through critical phase and private investment has died down in generation and transmission projects. Also, existing projects, when conceptualized, were evaluated considering RoE till the supply/service continues.
			• Tariff Policy mandates regulatory certainty and any such move will demotivate the prospective investors.
			• During the past Tariff Regulations, the returns on modified GFA arrived at by reducing depreciation has not been used after elaborate discussion (ROE versus ROCE approach).

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			• Accordingly, this proposal may be disregarded since all past implemented projects achieved financial closure assuming returns on GFA basis and not modified GFA. Tinkering with the methodology will increase the perceived risk and banks will charge a higher interest rate which will be passed on to beneficiaries and thereby negating the gains achieved by basing the returns on modified Gross Fixed Assets.
30.	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.	• Most of the projects may not be able to service the debt as the DSCR may fall below the guidelines established by the Financial Institutions, if the debt: equity ratio of 80:20 is implemented. • Tariff Policy mandate debt: equity ratio of 70:30 • Norms for lending have become stringent after recent changes in rules and operating guidelines. Banks have lowered the Loan to Value ratio and are asking for higher equity contribution (skin in the game) hence 70:30 ratio may be retained.
31.	17	Return on Investment	The existing RoE approach for return on investment may be continued due to following reasons: • It avoids regulatory uncertainty for investment to be made or planned • Limited estimation required related to RoE • No differentiation between old and new projects • Benefit in terms of refinancing of debt • This approach has been widely accepted by investors. • This approach provides minimum guaranteed return on investment made in the control period. • RoE approach is being able to attract the investor in the sector. • Further, in the scenario of high interest rate fluctuations there is no certainty about guaranteed return on investment made in the ROCE approach.
32.	18.6	According to CEA, the capacity addition is no more a major challenge and adequate installed capacity (along with currently under installation) exists to meet the demand for the next 8-10 years.	• The existing pre tax return on equity by grossing up ROE with applicable MAT/Corporate Tax should continue.

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		Further, the rate of interest has also come down in recent times. Therefore, there is market dynamics which favours reduction of rate of return. However, any such reduction will have negative impact on the equity already invested in the existing and under construction projects, creating further financial stress on such projects. Different rate of return for new projects (where financial closure is yet to be achieved), may be thought of, with different rates for generation and transmission projects.	• Considering no return during gestation period and prevailing high uncertainty and risk in Indian Power Market higher ROE should be given to developers. • The generation assets are currently fraught with several risks such as non-availability of fuel, chances of default of the customers, delay in project clearances, despatch of power etc. Further, there would be additional burdens like (a) lower off take (b) increased stress on machines due to variation in dispatch (c) future R&M to be funded through equity only and (d) change in environment law and grid requirement leading to additional expenses (over & above R&M). Hence, the existing RoE of 15.5% needs to be revised upward.
33.	Rate of Return on Equity 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 length in case of the transmission system and different size of substation;	• 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 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. • 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.

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		(g) Reduction of return on equity in case of delay of the project;	• 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 does not 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. 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; • 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

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			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.
34.	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 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.	• The existing method should continue which assure the developers to recover actual rate of interest on weighted average basis calculated on the basis of actual loan, actual interest rate and scheduled loan repayment. • Further, Generators shall be incentivised for the restructuring of loan portfolio which results in to reduction in cost of debt, currently the benefit of it is available to beneficiary by way of reduction in AFC but there is no incentive available to generator / transmission agency. • Opting for normative cost of debt will be difficult since the debt market in India is still not fully developed. Cost of Debt is decided by the lenders on the basis of a range of consideration including specific risk profile of the project such as Fuel availability, Long term PPA, evacuation, etc., credit rating of agencies, etc. • Allowing normative rate of interest will lead to under or over recovery of interest cost in rising interest rates or reducing interest rate as the case may be.
35.	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;	• Looking at current market scenario, lenders are reluctant to lend money • Norms for lending have become stringent after recent changes in rules and operating guidelines. • RBI has shown inflationary trend and increased Repo Rate from 6% to 6.25%. Private investment is at the lowest level in last decade • Therefore, existing incentive structure for restructuring may be made more lucrative for generator/ transmission licensee to induce more

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		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;	efforts by considering Actual cost of debt at the start of control period as Normative debt and any saving /loss due to restructuring may be considered on account of Generator/ Licensee during entire control period.
36.	Interest on Working Capital (IOWC) 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.	• Existing methodology for calculation of IOWC should be continued with following changes. • Receivables equivalent to 70 days of capacity charges and energy charge for sale of electricity as generator raises invoice on beneficiary after finalisation of SEA which are normally finalised by SLDC within 10 days after completion of month. This means generator will be getting late payment surcharge only after completion of 70 days from the end of supply month. • To allow fifteen days fuel stock of LNG to gas based generator. Due to shortage of domestic gas, Gas based generators are forced to import and kept a stock of LNG. • Due to increased penetration of renewable, the variation in load has increased. The same will lead to further stress on machine leading to requirement of higher maintenance spares. • The spares of gas turbines are generally required to be procured from OEM (due to technology issue) and the maintenance contract is also need to be awarded to OEM (due to lack of manpower equipped to manage such technology and proprietary nature of technology). Please note that such maintenance contracts are required in terms of availability of the plant and not directly linked with the PLF %. Hence, the spares of gas-based power plants are more costly and its maintenance contracts are fixed cost in nature. • Major part of the cost of such components and spare parts are payable in foreign exchange and its variation vis-à-vis rupee has impact on the escalation of O&M expenditure. • However, the above-mentioned cost of maintenance also provides high reliability and availability which may be verified with actual data. Needless to mention, such high reliability and availability are also becoming important due to increased penetration of renewable

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			generation. The Commission has also recognised importance of gas based power plant for balancing needs of the grid. However, such balancing need can only be met by above-mentioned measures. • Further, it may also be noted that there is no incentive for maintaining 100% availability against 85% target availability being considered in the regulations. However, the plants are still being maintained at almost 100% availability. Based on the same, it is humbly submitted that the Commission may consider providing higher parameters rather than reducing the parameters.
37.	20.3 (b)	As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken.	• To allow fifteen days fuel stock of LNG to gas based generator. Due to shortage of domestic gas, Gas based generators are forced to import and kept a stock of LNG.
38.	20.3 (c)	While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say, 15% maintenance spares being made part of working capital or O&M expenses.	• It is proposed that actually the level of Maintenance of spares need be increased appropriately from time to time with the aging of the plant. The higher cap of maintenance spares is due to reasons such as given at (a) above, these spares are imported and overall cost always increases due to Rupee depreciation and higher import duty. Accordingly, the value of working capital needs also to undergo change.
39.	20.3 (e)	In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with "target availability" can be reviewed.	• The gas-based generators are required to maintain highest availability of the plant. So, the components under IOWC cannot be linked to the actual dispatch of the plant. • Further, variability in the generation from the renewable plants, availability of gas-based power plants for generation at short notice is very critical. • In view of the above normative approach should be continued.
40.	Operation and Maintenance (O&M) expenses 21.7	Operation and Maintenance (O&M) expenses (a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure;	• 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.

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		(b) Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost. (c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects; (d) Review of O&M expenses of plants being operated continuously at low level (e.g. gas, 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.	• 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 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. There 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

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			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 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. 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

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			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."*
41.	Fuel – Gross Calorific Value (GCV) 22.8	Fuel – Gross Calorific Value (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.	• Generator does not have any control on the GCV loss between "As Billed" and "As Received" basis. Hence, it does not make sense to specify normative GCV loss between "As Billed" and "As Received" basis. • Since Grade slippage is not attributable to Generating Company, there will be under recovery, if not allowed. Therefore, GCV used for calculation of Energy charge should be on "As fired" basis. Alternatively, GCV "As received" at plant end - actual stacking loss may be considered. CEA has also recommended consideration of stacking loss. • CERC should clarify that the GCV for computation of fuel cost shall be ARB and not ADB in order to avoid ambiguity and conflicts between stakeholders.
42.	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.

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			• 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 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 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.

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43.	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.	• The power plants in the country face shortage of fuel (coal/gas) on account of inability of fuel supplier to produce sufficient coal or due to transportation constraints. Under these circumstances Generating Company may not fully dependent on single source of fuel supply. Further, the Coal companies also give dispatch from different mines based on the Production. These mines often have distance variation of over 100-200 km. Hence, specific list of standard cost components may not be workable option. • In view of above, the existing approach considering all components of landed cost of fuel up to the delivery point of the generating stations may be continued.
44.	25.1	The present regulatory framework provides that the generators resorting the alternate source of fuel, other than designated fuel supply agreement, require prior consultation only if the energy charge rate exceeds 30% of the base energy charge rate or 20% of energy charge rate of the previous month. These provisions were introduced w.e.f. 1.4.2014 in view of the shortage of fuel at that time.	• Alternate source of fuel cost should be completely pass through to the DISCOMS because this is an additionally incurred cost for generators and it is putting extra stress on financial health of generators.
45.	25.2	(a) Stipulate procedure for sourcing fuel from alternate source including ceiling rate; (b) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014.	• 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 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: o delay in delivery of e-auction coal causing huge uncertainty; o constraints due to railway infrastructure bottlenecks;

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			○ 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.
46.	Operational Norms 26	-	• Operation norms (for SHR, Auxiliary Consumption, SFOC etc) depend upon various design considerations. Suitable buffer is provided to factor in departure of actual site conditions as compared to design parameters. Norms so fixed act as ceiling norms. Therefore, the norms once fixed cannot be reduced based on actual performance. • Current regulations do not provide for degradation in operational parameters on account of ageing. It is proposed that a suitable margin be added in the norms to capture the same
47.	Operational Norms (SHR) 26.3.1	Thermal Generation (Coal based) Station Heat Rate 26.3.1 Station Heat rate (SHR) refers to the conversion efficiency of thermal heat energy into electrical energy and used for computation of energy charges. The Commission while framing the Regulations for terms and conditions of tariff for different tariff periods has been considering the operational data of the generating stations for the past 5 years. The methodology of considering 5 years data ensures that the generator is able to recover the cost of electricity in a reasonable manner and covers the reduction in the generation level.	• Heat Rate is a design parameter. Margin provided over such design HR depends upon variance in actual site conditions as compared to parameters considered while designing the machine. Once the margin is fixed for any machine based on COD, the same cannot vary. Therefore, Margin needs to be fixed based on COD and to be continued for entire useful life. • For machine having COD between 01.04.2009 to 31.03.2014, margin considered in Tariff Regulation 2009-14 was 6.5%. The same was reduced to 4.5% in Tariff Regulations, 2014. In view of above, it is suggested to restore 6.5% margin over guaranteed Heat Rate • In fact, there is a need to factor in degradation in Heat Rate due to vintage/ wear & tear of the machine year over year. Suitable margin may be added in the heat rate. • Also, such SHR being the ceiling norms, only actual SHR is considered in case the same is lower than normative SHR.
48.	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	• The adverse current scenario for power sector (i.e. slow growth in electricity demand, large scale installation of renewable and availability of cheap power at power exchange, etc.) has resulted

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		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. The norms of heat rate will be over and above the heat rate guaranteed by the OEM based on actual performance data during the last five years.	into lower schedule of power by beneficiaries and fluctuations in generation. The same has further increased stress on the performance of the plant. In view of the same, the normative Heat Rate and Aux norms should be increased.
49.	26.3.4	The heat rate is a crucial parameter as it has substantial impact on tariff. The gain/savings on account of heat rate are to be shared with the beneficiaries. Therefore, heat rate is required to be specified giving due consideration to all relevant factors including shortage of domestic coal supply in the country. The heat rate norms would also required to be seen in the light of efficiency improvement targets achieved by the generating stations under the PAT scheme. The heat rate norms varies with the passage of useful life of the project due to degradation and therefore, the norms specified based on the recently commissioned plants may not be attainable by older plants.	• Large scale addition of renewable capacity and availability of cheaper power at IEX has resulted into lower PLF and frequent load variation • Lower PLF along with frequent Ramp up / Ramp down to cater the grid requirement leads to higher stress on machine performance which results into higher Heat Rate. • In view of this the existing normative heat rate should be increased by 25 kCal/kWh for Gas based Power Plant.
50.	26.3.5	The existing regulations provides for calculation of Gross Station Heat rate for new stations based on Designed Heat Rate with margin of 4.5%. This margin specified for gross station heat rate is based on recommendation of the Central Electricity Authority	
51.	26.3.6	Approach for determination of station heat rate may need review including the criteria for specifying heat rate of old plants, continuation of relaxed norms for specific stations and possible changes required in the existing norms given in Tariff Regulation 2014-19.	

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52.	Operational Norms (SFOC) 26.3.7	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.	• The norms of 0.5 ml/kwh does not capture the consumption of fuel related to frequent start-stop or higher oil consumption at low PLF. IEGC provides for compensation of start-stop only after 7 operations. Therefore, SFOC norms may be increased to 1 ml/ kwh in order to take care of frequent switching operations and running at technical minimum.
53.	Operational Norms (AEC) 26.3.7	-	• Normative AEC for any plant needs to be linked with COD of machine and once, it is fixed, there should not be any revision in such ceiling norms. • Saving in AEC needs to be shared with predominantly higher benefit to the developer in order to create more impetus. • Additional AEC and SHR may be considered for implementation of Env. Norm. • Operational norms do not capture impact of RSD. During RSD, Several auxiliaries would be running for equipment / system protection. Cooling water system of the Main TG Condenser, Lubricating Oil system of the Main Turbine, Turbine seal oil system, Turbine BFP, Lube oil system of Mills, Compressed air system, Control & Instrumentation system, HVAC system, Lighting system, Furnace Scanner Cooling air system etc. would be in service during RSD resulting into higher Aux. Consumption. Such time bound increase in Aux. consumption cannot be made up on cumulative basis since the norms consider normal operation and not RSD. Hence, suitable compensation need to be provided for the same. • Impact of Ageing may be considered additionally over current norms. • The norm for 800 MW can be fixed based on analysis of actual auxiliary consumption for some 800 MW units operated under different conditions.
54.	26.3.8	The existing norms of auxiliary consumption of coal based generating station varies from 5.25% for unit size of 500 MW and above to 8.5% for 200 MW series units with steam driven boiler feed pumps and electrically driven boiler feed	• Power for colony consumption should be included in Auxiliary Energy Consumption

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		pumps and relaxed norms for specific generating stations of smaller size. Auxiliary consumption for gas based generating station varies from 1.0-2.5% depending on open or combined cycle operation. The existing norm of auxiliary consumption of lignite based generating station is 0.5% more than coal based generating station with electrically driven feed pump and 1.5% more if the lignite fired station is using CFBC technology. The auxiliary consumption does not include colony power consumption and construction power consumption.	• 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 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 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. • Higher Auxiliary Consumption percentage for Gas based power plant should be given considering operation of plant at lower load than availability due to lower schedule by beneficiaries and frequent load variation of plant on account of large scale addition of renewables.
55.	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 availability after reduction of normative auxiliary consumption and colony consumption need elaboration.	
56.	26.3.11	In control period 2014-19, the target availability has been determined based on the data available for the past years.	

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		The recovery of fixed charges was linked to availability. The availability of 85% is specified with exceptions of specific plant wise availability. The existing availability norms are uniform for all the generating stations. Now with the increase of private participation, access to imported fuel by private developers and technological improvement may have improved the availability. The issue of different availability norms for existing and new plants can be contemplated.	• In a normal fuel availability scenario, we propose to continue with existing cumulative availability of 85%. • In case of shortage of domestic fuel, in particular for gas based power plant, the normative availability should be aligned with the quantity of domestic availability of fuel. • In case of alternate arrangement of fuel by generator, beneficiary, if do not agree to alternate fuel contracts despite the plant having technical available then units should be considered deemed available to extent of the technical availability for recovery of full fixed costs. • Considering the criticality of plant availability, incentive should be linked with Normative Annual Plant Availability instead of Normative Plant Load Factor.
57.	26.3.12	Shortage of domestic fuel affects availability of the plants and their scheduling. The existing norm for availability may therefore to be revisited. In the event of bridging gap through e-auction or imported coal (other than fuel arrangement agreed in purchase agreement), the need of prior consent of beneficiary, maximum permissible limit of blending etc. also need to be deliberated.	
58.	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 chance 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.	• We propose to continue with cumulative availability during the year for recovery of annual fixed charges
59.	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.	• Like PLF, PAF is also to be calculated for entire plant and we propose to continue with existing provision of calculating PAF of entire plant for recovery of AFC from beneficiary.

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60.	Operational Norms (Normative Annual Plant Availability) 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	• Consideration of annual plant availability as a basis for fixed charge recovery is mainly considering the fact that generator requires continuous planned outages for no. of days for COH/ AOH and if availability is to be considered monthly or quarterly, it will result in reduction of availability in such months. Moreover, prior permission of Discoms is taken before COH/AOH. Further, forced outages due to equipment failures, water availability, Seasonal disturbances are unpredictable. • Above factors reduce availability considerably and if the periodicity is reduced to monthly or quarterly or half yearly, it will result in severe cashflow issues for Generators. • Therefore, Periodicity for availability cannot be reduced to any lower period than a year. In fact, concerns related fuel availability has made it difficult to achieve annual PAF stipulated at present. Therefore, level of 85% may be reduced to 65% for the purpose of recovery of fixed cost.
61.	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

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			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.
62.	Operational Norms (Transmission Availability Factor) 26.5.1	26.5.1 Availability of Transmission System/ elements is expected to increase with introduction of new technology like polymer insulators etc. Thus, the mechanism of payment of transmission tariff based on availability of transmission system may need review.	• 26.5.1 CERC has already fixed stretched norms for Transmission availability of AC system. Therefore, there is no scope of any further reduction. Introduction of polymer insulator would only help in maintaining the availability at current level. Further it is to be noted that Polymer insulators are not installed in all operational lines and even stability and reliability of silicon rubber insulator is not established. It is also observed that polymer insulators are also failed in a span of 7 to 8 year life cycle. Hence, cannot be considered rational for increase of availability.
63.	26.5.5	Review of the incentive formula for HVDC bi-pole and HVDC back-to-back stations at par with AC system;	• Incentive formula for HVDC system should not be at par with AC system for following reasons: • Since, line length of HVDC system is more than AC system (3 to 4 times length AC line) and also line covers various region/ terrain/ weather conditions, cannot be comparable with AC system. • HVDC is state of art technology which involves complex controls and logic function and cannot be compared with AC system. • In HVDC system, both terminal stations along with line is considered as a one element. Hence, should not be equivalent to AC system. • Specialised technology (valve hall, pole control and station control) involved during maintenance activities which required longer outage period. • Transmission Availability Factor for recovery of fixed charges should be on cumulative basis, as in case of Generation and not only on Monthly TAFM • 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.

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			• 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.
64.	26.5.5	d) Review of the existing methodology or procedure for computation of availability, monthly availability and cumulative availability;”	• The incentive & tariff calculations need to be consolidated annually, and the final settlement to be done on annual availability. • At the present, it is very difficult to get RoW for maintenance of transmission line and hence hampering the regular maintenance activities. Therefore, present provision of loading of 12 hrs non-availability after second tripping needs to be revised to allow at least 4 tripping on annual basis, besides working out availability on Annual basis.
65.	Incentive 27.1	27.1 For generation, the incentive prior to 2009 was linked to normative PLF and 25 paise/kWh was paid for generation beyond normative PLF in case of thermal generating station. The incentive, in case of hydro generating station, prior to 2009 was linked to the capacity charges and capacity-index. The incentive during tariff period 2009-14 was linked to normative availability and generation beyond normative availability was payable at the fixed charge rate for the stations which are more than 10 years old or at 50% of the fixed charge for the stations up to 10 years old. In case of hydro generating stations incentive was linked to the capacity charges (50% of annual fixed charges) and normative availability. During the Tariff Period 2014-19, incentive for coal based generating plant was again linked to normative PLF of 85% @ 50 paise. 27.2 At present there is same incentive for availability during peak and off peak period. There may be a need for introducing differential incentive during peak and off peak periods.	• Incentive represents the efficiency of the Generator and ought to be captured prudently. • Current Regulation to provide incentive based on PLF is not correct, since it is not in the control of the generator and is based on the schedule decided by the Discoms. Therefore, Incentive shall be linked to availability.

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66.	Incentive 27.3	As regards transmission system, incentive is being recovered only through monthly formula of billing and collection of transmission charges. In the absence of clear provision regarding reconciliation of annual transmission charges and incentive with monthly billing, the concept of NATAF specified by the Commission in Tariff Regulations, 2014 requires review.	• There is no logic in specifying the recovery of incentive for transmission lines on a monthly basis, as the lines are taken out for maintenance, only for some time in a year and not on monthly basis. Therefore, it should be made applicable on an annual basis, as is done for the generation assets. Further normative availability is specified on Annual Basis and hence incentive should be calculated based on Annual cumulative availability, however, incentive should be paid on monthly basis.
67.	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 considered. (c) Review the incentive and disincentive mechanism in view of the introduction of compensation for operating plant below norms. (d) Review the norms for availability of transmission system.	• 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) 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

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			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.
68.	Implementation of Operational Norms 28	28.1 The tariff regulations … keep charging the tariff based on previous tariff order including operational norms. The operational norms notified by the Commission in new tariff regulations take effect much after the date of coming into force of new tariff regulations. Consequently, the benefits of the improved operational norms are passed to beneficiaries only after time lag of few months. Comments/ Suggestions 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.	• Till the time operational norms are notified, there is no avenue of implementing the same. Therefore, retrospective implementation of the norms is not possible.
69.	Sharing of gains in case of Controllable Parameters 29	Sharing of gains in case of Controllable Parameters 29.1 The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement in controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil consumption, refinancing of loan and the true up of primary fuel cost. Subsequent to above, the compensation mechanism has been introduced for operation in CERC (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016. The compensation mechanism aims to provide compensation if generating plant is operated at improved norms than ones specified in the amended IEGC Regulations of 2016. In view of the compensation mechanism, it needs to be considered as to whether the ratio of sharing of benefit may be reviewed.	• Any gain and loss due to variation from the normative parameters shall be to the account of developer. This will be the true reflection of the spirit of defining normative parameters and the Commission will also be saved from the task of scrutinising the accounts, year after year. • At the time of fixation of existing norms, issue of lower PLF was not in existence and therefore, not factored in the norms. Considering the same, due to emergence of low PLF situation, the Commission has provided compensation in degradation of operating parameters through IEGC. Therefore, the compensation under IEGC has no relevance with the ratio of sharing of gains. • Even otherwise, if CERC is inclined to share the gains, the same may be predominantly higher for Generators/ Licensee so as to keep them motivated to achieve the higher efficiency. • Sharing of gains may be reconciled on annual basis

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		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, the merit order operation can be linked with the PLF in such a way that the plants under Section 62 may be encouraged to compete for maximum PLF. 29.3 Further, different generators adopt different methodology for sharing of gain, say on monthly or annual basis. Thus, procedure for the monthly reconciliation or annual reconciliation mechanism may need to be prescribed.	
70.	Late Payment Surcharge 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. One option is to add some premium over and above MCLR.	• LPS should act as deterrent for non-payment and hence, should be made more stringent. Accordingly, LPS should be increased to 2.0% per month. • 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. • It may also be noted that LPS is calculated on a simple interest basis while all the accounting is on compounded basis. Therefore, LPSC should be on higher side otherwise we will be incentivising the delays in payment. • Payment appropriation norm needs to be specified in the regulation. i.e. LPS followed by past dues followed by current dues.
71.	Non-Tariff income 31.1	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	• Presently, O&M Norms are fixed taking into account actual expenditure for past period. While doing so, revenue on account of disposal of old assets, interests of advances, revenue for telecom business etc. are already taken into account. • Disposal of fly ash is new event and Generators are required to incur the additional expenditure for utilization of Ash which is not covered

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		business may be taken into account for reducing O&M expenses. Present regulatory framework does not account for other income for reduction of operation & maintenance expenses. However, in case of transmission licensee, the income earned from telecom business are adjusted in the billing separately. The principle of treatment of other income as applicable in case of transmission can be extended for the generation business.	under O&M Expense at present. Therefore, there is no avenue for reducing the same from O&M Expense. In fact, recently, CERC has issued orders granting additional expenditure as pass through in terms of MoC notification after netting off the revenue if any. • It is worth noting that as per the MoC Notification, Generator is required to maintain separate account for any revenue earned and need to utilize the same as provided therein. Therefore, it cannot be considered as Non-tariff income.
72.	Standardization of Billing Process 32.2	32.2 Some of the States are imposing electricity duty on the actual auxiliary consumption which may be higher or lower than the normative auxiliary consumption. Such electricity duty is passed on to the beneficiaries along with the monthly bill. Whether electricity duty is to be linked with actual auxiliary consumption or normative consumption or lower of the two, may need to be specified.	• Electricity Duty being uncontrollable factor, the same needs to considered as actual • Linking Electricity Duty payment to normative Auxiliary Consumption will lead to double penalty to Generator. • Auxiliary power consumption is the cost for generation for supplying power into the grid. Imposition of electricity duty on the auxiliary consumption is irrational. • It is recommended that electricity duty shall not be linked with the auxiliary consumption and shall not be levied.
73.	Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants) 33.		• CERC may introduce norms for recovery of Capital and Operational expenditure including additional Auxiliary consumption in consultation with CEA. • The same norms may be made applicable to projects under 63 as well similar to the provisions made for low PLF in IEGC
74.	33.4	(a) Possibility of reducing funding cost through suitable change in Debt: Equity requirements. Relaxation in funding from equity may be introduced and the rate of return on equity may be aligned with the interest on debt; (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.	• 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 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&CC's new environmental norms requiring the generator to install equipment to meet these norms shall be treated as change in environmental laws prescribing stricter

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		(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 equipment.	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 equipment 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. • 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 needs to be provided for FGD or other installations to meet environment norms.
75.	34.	The Revised Tariff Policy dated 28th January,2016 provides for setting up of renewable energy generation capacity by existing coal based thermal power generating station	• Due to stress in power sector, Private Generators may not be able to bring equity and lenders will also not give loan for the same.
76.	Commercial Operation or Service Start date 35.3	Data telemetry, communication and restricted governing mode of operation are requirements of system operator to monitor real time grid operation and for grid stability. There is a need to ensure completion of data telemetry and communication by RLDCs/ NLDC/ SLDCs for declaring COD of transmission system/ generating station and operationalization of Restricted Governing mode of Operation (RGMO) in case of generating station.	• Transmission licensee does not have any control over RLDC / NLDC / SLDC and should not be made to suffer o account of any inefficiencies of RLDC / NLDC / SLDC.
77.	Commercial Operation or Service Start date	Delay can occur in the commercial operation due to factors beyond control or non-commissioning of associated transmission system. In case of the transmission system, the delay on account of non-commissioning of	• The obligations of all the parties are well defined in TSAs and all commercial decisions should be in line with the provisions of TSA. Moreover, one person cannot be made to suffer on account of inefficiency of other persons, on whose action the first person does

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	35.4	downstream or upstream system is more relevant. Since the declaration of commercial operation date attracts the liability of fixed charges or the transmission charges, as the case may be, the parties dispute the commercial operation date. In order to streamline the process of the declaring commercial operation date in case of the delay and to make aware the parties upfront about the consequences of delay, provisions could be made for demarcation of responsibilities or for Indemnification Agreement.	not have any control. In the past, there have been decisions wherein the defaulting parties have been asked to make payments beyond the provisions of TSAs, which is against the set doctrines of legal process.
78.	37.6	Views and comments are therefore being solicited on the following questions: a. Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost? b. What are the variables that should be considered for the purpose of determining Capital Cost on normative basis? c. Any other methodology for benchmarking the capital cost for generation and transmission projects?	• We submit to continue with the existing provision of deciding Capital Cost. Benchmarking of capital cost is not appropriate in view of different attribute applicable to different plants.
79.	Alternative Approach to Tariff Design (Normative Tariff by fixing AFC as a percentage of Capital Cost) 37.9	……	• As discussed earlier, it will not be appropriate earlier to change the tariff design approach at this stage, considering the several issues Generators are already struggling with.
80.	37.17, 37.21, 38.1, and 39.2		• We submit to continue with the existing provisions for determining AFC.
81.	40	Merit order operation	• Currently SLDCs/TRANSCOs are backing down the renewable power despite of 'Must Run' status in the name of grid security without any compensation. Additionally, generator may be forced to bear the

#	Clause	Existing provision	Comments/ Submissions for consideration
			additional cost of DSM charges during such unplanned back down, as there is little clarity about such scenarios in the regulations. • Inclusion of renewable power in MoD will benefit the sector where in they will be compensated for the back down. Also, since variable cost will be very low for renewables as compared to thermal power. Renewable power will not be back down or curtailed. • It is submitted that complying with MOEF&CC's notification with regard to emission control has implications on the tariff which further impacts the position in the Merit Order. Decreased ranking in the merit has placed the environment friendly plants at a disadvantaged position. In order to address the above issue, suitable provision may be incorporated in the Regulations to consider Fuel Charges without the impact of new norms in the Merit Order Dispatch till 2022-23.
82.	-	Additional suggestions	• Depreciation rate may be fixed separately for important high value equipment having shorter life spans, in comparison to their useful life, e.g. Gas Turbines have useful life less than 25 years and also need R&M every 5-7 years; similarly, Air preheater baskets need replacement in 4-5 years. Other equipment is there which has even shorter life & higher R&M. However, all equipment has the same Depreciation rate. • 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. • Norms for Annual Energy Consumption of standby units may be fixed based on CEA/CPRI certificates.