CERC: Terms & Conditions on Tariff Regulations, 2019:

Observations by NBPDCL & SBPDCL, Bihar

Sr. No.	Clause reference	Clause description	Comments and suggestions
1.	Clause 7.2.5,7.2.6	**Thermal Generating Station Tariff Structure:** The Consultation paper suggests that Generation Tariff can be on three-part basis instead of two part tariff. Three parts tariff include the following: i. Fixed charge - for recovery of fixed cost consisting of depreciation for repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses. ii. Variable charge - Incremental return above guaranteed return and balance operation and maintenance expenses iii. Energy charges - Fuel cost, transportation cost and taxes, duties of fuel. 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.	Three parts tariff structure may be more rational than two parts tariff for actual consumption from generating plants. O&M cost are often bundled in the fixed cost and operational efficiency is not visible in two part tariff structure however, it would be visible and Discoms can negotiate with generators upfront. CERC also needs to define the trajectory of O&M cost during the life time of plant. Interest on working capital regarding recovery of fixed charge may be clarified. Normative Target Availability for recovery of fixed charge should be enhanced from 85% to 90% for sub critical units and to 95% for supercritical units.
2.	Clause 7.3.2, 7.3.4	**Thermal Generating Stations – Older than 25 Years** The consultation paper suggests that under the present basket of power plants several power plants have already completed their	It is to be noted that the generating stations which have completed their useful life have advantage from financial consideration. The only issue lies with operational expenditure of such plants. A Committee comprising of technical and financial expert may be constituted for performing cost benefit analysis study and

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		useful life and are not comparable with new generating stations in terms of operational norms and capital cost. A view on possible options like 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. has been invited.	determination of financially profitable life of such plants taking due consideration of the performance of modern super critical units and revised environmental norms. Such study shall be helpful in deciding future course of action and making a well informed decision regarding choosing among the available options. Out –performing Thermal Generating Units are to be subjected to R&M with life extension and for other old Generating Stations replacement with Supercritical unit or R&M with life extension after prudent cost-benefit analysis only. Replacement or R&M for old plants to be carried out with consent of Beneficiaries along with the first right of refusal.
3.	Clause 7.4.2	**Hydro Generating Stations** (i) Reformulation of fixed and variable charges as many hydro stations often find it difficult to get dispatched due to resultant higher energy charges (ii) Fixed component may include debt service obligations, interest on loan and risk free return (iii) Variable component may include incremental return above guaranteed return, O&M expenses and interest on working capital	Although states with limited / no hydro power contracted capacity would not be impacted, for states with existing capacity, this issue does not solve the problem of gross high costs of hydro power but only redistributes components for enhancing dispatch. Needs to be evaluated in greater detail since there is a significant capacity under construction and any such changes would also impact the future of such capacity.
4.	Clause 7.5.4, 7.5.5	**Inter-State Transmission System** Proposal to move to two-part structure – first part can be linked with the access service and second part with the transmission service (a) Fixed components may consist *of either*: (i) annual fixed cost of some of fixed transmission system designated for access and immediate	The intent behind the redesigning of the structure should be to avoid loading of non-relevant / redundant transmission systems costs on users who are not direct beneficiaries. This is a progressive move; however the apportionment of costs would be crucial to assess the benefits of the proposed mechanism.Bihar Discoms agree with the recommendations to introduce the norms for Inter-state Transmission losses, based on factors within control and international benchmarks More clarification needed on methodology for selection of fixed transmission system designated for access & past data of ISTS component wise as percentage of Annual Fixed Cost.

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		evacuation (ii) annual fixed cost of the evacuation transmission system or (iii) part of annual fixed cost of the entire transmission system consisting of debt service obligations, interest on loan, guaranteed return (b) 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, O&M expenses and interest on working capital.	The incentive for generating more than the normative PLF needs to be discontinued as India is surging towards green energy Regime.
5.	Clause 7.6.3, 7.6.4	**Renewable Energy Generation** Can be two-part structure – fixed component (debt service obligations and depreciation) and variable component (equal to marginal cost i.e. O&M expenses and return on equity) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff Alternatives for integration: (a) Renewable may be supplied through existing tariff for contracted capacity of thermal power plant under PPA - tariff of renewable may replace energy charges; (b) Tariff of renewable generation may be combined with the fixed and variable components of thermal to the	This would impact only those RE agreements which are on FIT and are integrated with thermal power plants. The alternatives need to be evaluated further.

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		extent of contracted capacity, with revision of operational norms of conventional plants (c) Tariff for supply of power from renewable generation and thermal power generation may be recovered separately	
6.	Clause 10.3	**Coal based Thermal Generation** (a) Flexibility may be provided to redefine the ACC on yearly basis, which may be based on the anticipated reduction of utilization. Capacity beyond the ACC may be treated as Unutilized Capacity (UC), and the distribution licensee will have a right to recall UC 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 UC may be aggregated and bid out to discover the market price of surplus capacity, reallocated to the distribution licensee at market discovered price.	This would work well for States/ markets where the demand scenario has been stabilized. However in most Indian states still, the demand is growing at a good pace each year, which implies that UC in the current year may be completely utilized in the corresponding year. And therefore this may create a scenario of uncertainty for Distribution Licensees.
7.	Clause 10.5	**Hydro Generation** (a) Extend the useful life of the project up to 50 years from existing 35 years and loan repayment period up to 18-20 years from existing 10-12 years for moderating upfront loading of the tariff. (b) Assign responsibility of operation of the hydro power at regional level with the primary objective for balancing. The scheduling may have to be	Both these proposals are a welcome move – the first one must be implemented as it would help bring down the tariffs of Hydro based generations, improving their dispatch. The second one would ensure optimal dispatching based on banking; however the regional control should have representation from beneficiaries to periodically take their requirements into consideration.

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		delinked from the requirements of designated beneficiaries with whom agreement exists. Power scheduled can be dispatched to designated beneficiaries through banking 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. *(Also for Gas based power – 10.7)*	
8.	Clause 11.8, 11.9	**Capital Cost** Move away from investment approval as reference cost and shift to benchmark/reference cost for prudence check of capital cost; however, challenge is absence of credible benchmarking of technology and capital cost. Higher capital cost allows for higher base of equity deployed. In new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. The return on additional equity may be restricted to the extent of weighted average of interest rate of loan portfolio or rate of risk free return. Further, incentive for early completion and disincentive for slippage from scheduled commissioning can also be introduced.	This does not propose to move away much from the prevalent methodology. India has one of the largest bases of installed capacities in the world – both in terms of power generation and transmission systems. Therefore there should be enough data points available for determining benchmarks of technologies. Further with the changing market scenario, and India moving towards energy neutral scenario, it is now paramount to develop only efficient power sector resources which are affordable for a developing country like ours. <u>Principles of Cost Recovery- Approach towards Multi Part Tariff</u> Peak period should be 8 months instead of 4 months for achieving 95% PAF towards recovery of 20% of the AFC. Price needs to be same for both off-peak and peak periods.

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9.	Clause 12.6	**Renovation & Modernisation** 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. R&M may be allowed 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.	This would be beneficial, as long as this allows efficient existing systems to continue beyond their initial estimated lives, at a cost lower than that required for creating new infra. Therefore this may be done only on a case to case basis, and taking into account the views of respective beneficiaries (who would have to bear the cost of such systems, in case specifically identified). R&M expense to be approved along with period of life extension beyond designated useful life of the generating station. There should not be any provisions in the tariff regulations for special Allowance for incurring the expenditure towards R&M. Additional capitalization should be based on prudence check by the commission.
10.	Clause 14.6	**Depreciation** The paper discusses the factors affecting the depreciation viz. rate base, which includes subsequent additions also, method of depreciation and useful life. It also discusses the issues faced in assessing depreciation in cases pertaining to Renovation and Modernization, particularly in case where special allowance is allowed. The paper proposes several options for Regulatory Framework and invites comments on the same: a) Increase the useful life of well-maintained plants - Extend the useful life of the Hydro project up to 50 years from existing 35 years and the loan repayment period up to 18-20 years from existing 10-12 years for moderating	Increasing the useful life of plant would spread the depreciation over more number of years than existing today and correspondinglythe loan repayment period for Hydro and thermal Generating stations should be increased up to 18-20 years from prevailing 10-12 years, therefore would reduce the initial tariff of the plant, . CERC needs to adopt the Ind AS provisions on treatment of the depreciation.

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		upfront loading of the tariff. Similar arrangement can be worked out for thermal power plants. b) Continuing the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; c) Restricting admissibility of additional expenditure after renovation and modernization (or special allowance) to limited items/equipment; d) Reassessing 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 to 50 years and bring in corresponding changes in treatment of depreciation. f) Reduce rates which will act as ceiling.	
11.	Clause 15.2	**Gross Fixed Asset (GFA) Approach** The Commission has proposed 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, instead of current approach of allowing return on Gross Fixed Assets.	Proposed methodology would result in reduction of equity after loan repayment. CERC needs to adopt this proposal based on Net fixed assets instead of Gross Fixed Assets.
12.	Clause 16.2, 16.4	**Debt-to-Equity Ratio** The consultation paper notes that utilities in private sector operate with a very high financial leverage. Further, it states that when demand for capacity addition is low, maintaining debt: equity of 70:30 may need to review. It has thus proposed	As debt is cheaper than Equity, reduction in Equity contribution would lead to reduction in return on equity. Such reduction in RoE shall be helpful in reducing the AFC and making the tariff of generating station more competitive. This norm may be revised to 80:20 based on sufficient information from the market.

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		modifying the normative debt-equity ratio to 80:20 in respect of new plants, where financial closure is yet to be achieved and invites comments on the same.	
13.	Clause 17.2, 17.3	**Return on Investment** The Consultation Paper states that the Commission may adopt either Return on Equity (RoE) or Return on Capital Employed (RoCE) approach for providing the return to the investors as per the Tariff Policy. The Commission had compared both the approaches viz. RoE and RoCE while framing the Tariff Regulations for 2014-19 and decided to continue with RoE approach.	RoCE method if adopted in the generation tariff same shall be passed on by the Discoms to its consumer. APERC was using the RoCE method to determine the tariff for the distribution licensee till FY 2008-09. DERC, In the MYT Order for the Control Period from FY 2007-08 to FY 2010-11, has adopted the RoCE approach and allowed RoCE for wheeling business and retail supply margin for retail business which includes RoCE for retail business, all expenses of retail business and additional return in such a manner that the net RoE on Wheeling and Retail Supply Business shall not exceed 16%. RoCE approach may be adopted over RoE owing to the following reasons: De-merits of RoE approach (i) No incentives for Companies to bring down cost of capital, as return on equity invested is guaranteed and actual interest expenses expenditure incurred is also a pass through (ii) Generating Utilities are not encouraged to practice financial engineering and optimize the financing mix by restructuring debt and equity, since the Debt: Equity ratio is allowed on normative basis (usually 70:30) (iii) Even if assets are depreciated fully, Generating Utilities get assured return on equity invested (iv) In case the equity on the Balance Sheet of the Utility is low, which is the case with quite a few State-owned Generating Utilities as they have been largely funded through loans, then the resultant claim for RoE is also reduced, which may hamper the Utility’s efforts to invest in future capital expenditure

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			Merits of RoCE approach (i) The ROCE approach incentivizes financial planning to optimize the debt equity mix and bring down the cost of capital. (ii) This approach recognizes that the consumers should pay for the capital employed to fund the assets used to serve the consumers. (iii) The consumers are insulated from changes in debt-equity mix and changing interest rates, etc. (iv) It also makes it easier for the Regulators as they do not have to monitor debt and equity component separately. (v) Since the returns are linked to the investment in the business, once the asset is fully depreciated, then the Utility does not earn any return on its investment, and hence, the tariffs would also reduce to that extent. (vi) State-owned Utilities, which may have a lower equity base, would not be adversely affected, since the Returns would be given on the total capital employed, rather than the equity invested in the business.
14.	Clause 18	**Rate of Return on Equity**	**Suggestions from Bihar Discoms:** The rate of return on equity for new power plants may be reviewed considering the present market expectations and risk perception of power sector for new projects. The generation, transmission and distribution utilities have different mode of operation and are entitled to different type of risks. For instance the generation and transmission utilities have less risk in terms of recovery of bill in comparison to the distribution utilities. Thus, different rate of return may be specified separately for generation, transmission utilities. Pre-tax return on equity should not be allowed as such consideration contributes to increase in the fixed cost. The generators don’t pay tax on monthly basis. Therefore allowance of such cost in advance is not justifiable. Further, the Discoms are not allowed to recover such cost in advance. Since, such cost is only

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<tr><td></td><td></td><td></td><td>allowed to be recovered by the generators and forms a part of fixed cost, it is directly affects the end consumer.

Under the existing regime, there is provision of extra 0.5% of additional RoE for timely completion of projects. But, it can be observed that many projects are not completed within the stipulated time period resulting in escalation of capital cost with effect of time and cost overrun. RoE on such artificially escalated cost further adds to the overall fixed cost. Therefore, provision should be in place for penalizing the generators for delay in completion of projects.</td></tr>
<tr><td>15.</td><td>Clause 19.5</td><td>Cost of Debt

The Consultation Paper discusses the key trends observed during the recent times –

(i) Increase in corporate bonds outstanding as a % of GDP,
(ii) Availability of alternative source of funds owing to development of bond market
(iii) Reduction in lending rates of bank.

Commission is suggesting the following alternative approaches:

a) Continue with existing approach or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects
b) Review of the existing incentives for restructuring or refinancing of debt
c) Linking of reasonableness of cost of debt with reference to certain benchmark viz. RBI policy repo rate or 10</td><td>As present methodology is based on weighted average interest rate calculated on the basis of actual loan portfolio of the utility. The cost of debt thus arrived at is applied on the normative outstanding loan to compute the annual interest expenses of the utility which is given a pass through in the tariff. This approach does not motivate the Generating Company to reduce the cost of debt by arranging it through the alternate funds. Presently renewable energy companies have option to arrange the funds from multiple sources based on their credit ratings. Credit rating in turn depends upon operational efficiency of the company. It is therefore required by the generating companies to improve the operational efficiency and compete for the cheap source of funding. In view of this, CERC needs to link the cost of debt with RBI Repo rate.</td></tr>
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		year Government Bond yield and have frequency of resetting normative cost of debt	
16.	Clause 20.3	**Interest on Working Capital** The paper states the existing methodology of allowing interest on working capital. It proposes the following options and invites comments on the same: a) Following the approach of allowing IWC based on the cash credit or adopting any alternate approach b) 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 c) Option could be to de-link "Maintenance Spares" in IWC from O&M expenses. d) The normative approach of linking working capital with "target availability" can be reviewed	Maintenance spares are still part of the O&M expenses which is grossing up the inefficacy, if exist. It would be more effective, if it is linked with the normative annual availability of the plant. Truing up of interest on Working Capital against actual coal stock based on deceleration by the Generator.
17.	Clause 21.2,21.4	**Operation and Maintenance (O&M) expenses** The paper discusses challenges pertaining to specifying a fixed escalation rate owing to variation in WPI and CPI. Further, the fixed escalation rate does not capture the variation due to unexpected expenses such as wage revision etc. It proposes working out the O&M expenses on the basis of MVA capacity instead of individual components. It further discusses about variation in O&M expenses on account of economies of scale in case of expansion of capacity of an existing transmission	a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure b) Rationalization of O&M expenses in case of addition of components c) Treatment of income from other business (e.g. telecom business, testing capacity) while arriving at the O&M cost benchmarking of Bay of PGCIL should be made. d) Overcapacityof transmission bay and incentive due to availability should be looked into. There should also be penalty provision if availability of the bay falls below the 99%.

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		substation. The paper suggests rationalization/usage of multiplication factor similar to generating stations for transmission system, where the generating stations receive lower amount towards O&M expenses in case of addition of units in same generating station. The paper also acknowledges higher O&M requirement for older generating plants/transmission system.	e) O&M cost for the central transmission system and central generation system approved by the CERC is very much higher side than the expenditure incurred by the State utilities. CERC needs to relook into the O&M cost in line with the state utilities charges for O&M Bay cost.
18.	Clause 30.1,30.2	**Late Payment Surcharge and Rebate** The paper proposed to link late payment surcharge with MCLR and proposed rate of late payment surcharge can be some premium over and above MCLR. Further, as per the existing regulations, the rebate is provided if payment is made within 2 days of presentation of the bill. Valid mode of presentation of bill, (email, physical copy etc.), authorized signatory, and definition of two days (working days or including holidays) may need elaboration.	As 2 days duration are too short to take benefit of rebate due to legacy of office procedure of the Discoms. In view of this, 2% rebate may be allowed for payment within 8 working days from receipt of bill. Applicability of late payment surcharge for delay in payment beyond a period of 60 days from the date of billing may be extended to a period of 75 days keeping in view of collection from end consumers by the Discoms.
19.	Clause 22.2, 22.8	**Fuel – Gross Calorific Value (GCV)** CERC has put following options for the considerations: (a) Take actual GCV & 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	Discoms are very uncertain about the GCV of the coal for which it would be billed and there is huge variation observed within the same quarter. Revised bill is also issued to Discoms from time to time based on some correction based on GCV received. In view of this, to predict the energy charge of the Discoms it is required to standardize the GCV as received and as fired basis. Normative reduction in GCV from loading point to firing point to be specified and tariff may be calculated accordingly. Measurement of GCV of Coal used needs to be as accurate as the true representative of coal consumption. The GCV measured for determination of rate of coal at mines end is to be

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		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.	considered for computation of ECR. Coal supplier is benefited due to improper sampling Wagon Top. Loss in GCV has already been taken care of in determination of SHR The reduction in GCV during handling inside Power Plant is insignificant. National electricity plan clause 9.4.2, Volume I , Generation talks about coal sampling by third party CIMFR at loading and unloading point to resolve issues of quality and grade slippage of the coal supplied to power utilities in their power plants. There needs to be monthly reconciliation between the generator and coal supplier towards payment of coal charges.
20.	Clause 23.3, 23.4	**Fuel - Blending of Imported Coal** CERC seeks suggestion on the following: (a) There is difficulty in verification of GCV of blended coal, due to unavailability of separate value of GCV of domestic and imported coal on "As Fired Basis". It may therefore, be necessary to provide for payment of energy charges based on "As Received" GCV of domestic and imported coal with suitable margin and adjustment for arriving at "As Fired" GCV. This would require development of norms for such adjustment. (b) Alternatively, normative blending ratio may be decided in advance in consultation with the beneficiaries in terms of technical limitation of steam generator. The blending ratio in the domestic coal based plants may vary depending upon the quality of coal, the quality of actual coal being received, age of plant, unit loading etc.	CERC has rightly put the issue due to not fixing the normative blending ratio for optimum utilization of the generation plant. Therefore, it would be pertinent to predefine the blending ratio and true-up may be carried out latter.

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21.	Clause 24.5	**Fuel- Landed Cost** CERC has proposed the following options for the discussions: 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	Fuel landed cost has various cost heads such as basic run of mine (ROM) price, sizing charges, surface transportation charges, royalty, stowing excise duty, fuel surcharge, cess etc. Further, the components may vary depending upon the source of coal. In case of railway transport, it involves basic freight, terminal charges, busy season surcharges etc. In case of imported coal, it includes the FOB price, over sea transportation, port handling charges, rail transportation, road transportation etc. As a result, there is wide variations in terms of cost and number of cost components involved in the landed fuel cost, changes in which cause corresponding fluctuations in the tariff. The energy charges largely depend on the fuel cost which is determined by the cost components allowable as part of tariff. Under the current regime, the generating companies now have various alternatives for procurement of coal viz. through Coal India Ltd, Open market, e-auction mode, captive mine etc. with option for flexible utilization of coal under the existing fuel supply agreement. It can be said that the generating companies have options to optimize the cost of fuel. Standardization of landed price of fuel should be put in place for regulating the energy charge. Standardization may be made on fuel cost, transportation cost, slippages, sizing charges etc. Discoms rarely get all the above details of fuel charges which can indicate the optimization carried out by the generating companies. As tariff is cost plus basis and all fuel charges are passed through, it would be more helpful to Discoms if break-up of the energy charges are clearly captured in the invoice in a specified format with standardization of fuel cost.
22.	Clause 26.3.3, 26.3.5, 26.3.6	**Thermal Generation (Coal based) Station Heat Rate** In the present scenario, most of the coal/lignite/gas based thermal power plants are running at low utilization (PLF) levels due to various reasons including shortage of coal/gas, lower	The heat rate is the most important 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 require to be seen in the light of efficiency

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		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 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. 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.	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. There can be different heat rate for different plants based on age of the plant. Actual heat rate might be more than the specified plant rate during the course of operation period. It would be prudent to predefine the trajectory of Heat Rate by CERC. SHR to be determined based on Turbine heat rate, Boiler efficiency and related heat loss. Determination of SHR, based on historical data, furnished by Generators, to be compared with historical data and lower value should be taken as input for calculation of ECR
23.	Clause 26.3.8, 26.3.9, 26.3.10	**Auxiliary Energy Consumption** The existing norms of auxiliary consumption of coal based generating station varies from 5.25% for unit size of 500 MW and above to 8.5% for 200 MW series units with steam driven boiler feed pumps and electrically driven boiler feed pumps and relaxed norms for specific generating stations of smaller size. Auxiliary consumption for gas based generating station varies from 1.0- 2.5% depending on open or combined cycle operation. The existing norm of auxiliary consumption of lignite based generating station is 0.5% more than coal 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	CERC suggestion on elaborate procedure on declaration of auxiliary consumption is welcome step. Generating companies need to declare the actual auxiliary consumption and housing colony consumption to have a regular check on the plant availability. It is also suggested that auxiliary consumptions treatment should be based on normative availability to share the benefit of new technology with the Discoms is developed for the benefit of all applicants.

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		construction power consumption. Presently, the auxiliary consumption of 800 MW is fixed based on 500MW sets. The auxiliary consumption of 800 MW sets may vary depending on the size of the unit and economies of scale. CERC proposes to have further elaboration on the methodology of declaring availability after reduction of normative auxiliary consumption and colony consumption.	
24.	Clause 26.3.11, 26.3.13, 26.3.15	**Normative Annual Plant 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. As per present regulatory framework, the recovery of annual fixed charges is based on cumulative availability during the year. There may be a chances of declaring lower availability during the peak demand period when the beneficiaries may be required to resort to procurement from short term market to meet their demand. However, during low demand period, the generating station may declare higher availability so as to achieve the target cumulative availability on annual basis to recover the full annual fixed charges. In this process, the beneficiaries may not get the electricity when required at the time of high demand. The existing norms of annual plant availability may need review	CERC has brought out the issues that Discoms are facing in relation to the availability of the generating plant. There are significant improvements in the generation technology and plant may run at more than 100% TMCR for significant duration within a year. It has been observed that there is trend of supplying lesser energy during the peak season/duration and then compensating this by higher generation when Discom may not need it. Provision of minimum plant availability of 85% is often flouted by generator. As energy exchange rates are seeing the upward trend and reaches peak during the peak season/duration, generators found it opportune time to deviate the power to the energy exchange during the peak time by reducing the power availability to Discoms. It would be more rational to link the availability based on plant technology and peak season demand of the Discoms.

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		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.	
25.	Clause 32.1	**Standardization of Billing Process** The Paper suggests standardization of billing process including formats, verification, timeline etc. to avoid possible disputes in billing.	(i) CERC has rightly brought out this issue experienced by Discoms for long. (ii) There have been instances of getting power purchase invoices up to 4 revisions for the same period and Discoms could not trace the proper reasons for the same (iii) It is high time to standardize all the billing procedures including formats, verification, timeline etc. to avoid possible disputes in billing.
26.		**Commercial Operating Date**	• All expenditure up to the cut-off date, as per Project Approval for new generating station is to be considered towards capital cost. No additional capitalization is to be allowed up to the cut-off date, during this period de-capitalization if any is to be allowed. • Trial run in case of a generating station can be considered for a generating unit only but not for the whole generating station. Accordingly, the clauses need to be modified.
27.		**Force Majeure Condition**	• To be re-defined as it is ambiguous due to the fact that as per Regulation – 3(25) of CERC Tariff Regulations, 2014 the general statement is 'beyond the control of the Generating Company or Transmission Licensee' including the Acts of God & others
28.		**Sharing of Gains in case of Controllable Parameters**	• When the Generators are compensated as per the 4th Amendment to IEGC Regulations, 2014, there is no justification in passing on any benefit to the Generators, which should be fully passed on to the Consumers.
29.		**<u>Transparency in Billing and Accounting of Fuel</u>**	Monthly Energy Bills to be supported by the following documents:

Sr. No.	Clause reference	Clause description	Comments and suggestions
			• Coal Company Bill for each consignment, • Debit/Credit Bill, • Coal Test Reports for GCV & moisture for each consignment, • Certified by third party (CIMFR). • Transportation Bill, • Credit Bill for excess moisture and stone.
30.		**New pollution control norms for Thermal Power plants**	It would be prudent to install the Emission Control Systemsfor pollution level at average PLF60%, otherwise it will burden the consumers financially. TPPs having higher pollution level, the Emission Control Systems with proven technology and performance be procured through competitive bidding. The cost of the Emission Control Systems should be met from Power System Development Fund (PSDF)) and Clean Energy Fund