5443/2018/CRU-CERC

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PUNJAB STATE POWER CORPORATION LIMITED

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To

The Secretary,
CERC, New Delhi

Memo No. 4291 /4/154 Dated: 17/7/18

Subject: Terms and conditions of Tariff for the Tarif period commencing from 1st April, 2019 - consultation paper thereof

Sir,

Please refer Hon'ble CERC's Public Notice L-1/236/2018/CERC dated 24.05.2018 regarding comments and suggestion on the subject cited consultation paper.

In this regard, the comments of Punjab State Power Corporation Limited on the consultation paper (3 copies + CD containing soft copy) are enclosed herewith, please.

The same have also been emailed at : info@cercind.gov.in

This is for your kind information & further necessary action, please.

D/A: as above

Chief (Fin)
DC (Fin) RP
E.O (Secy)
2/7/18

17/7/18

Chief Engineer/ARR &TR,
Punjab State Power Corpn. Ltd,
Patiala

ANNEXURE-1

Regulation		PSPCL, Comments
5.B: Coal based Thermal Generation	On the supply side, rapid capacity addition has taken place during the last five years and is being seen in the renewable energy. Due to rapid addition of renewable capacity & slow growth of demand for electricity, there has been decreasing trend in plant load factor (PLF) of thermal power plants. 5.2.4 Most of the coal is located in the eastern parts of the country and requires transportation over long distances, which often results in supply constraints. The thermal plants have been facing the issue of mismatch in quality as well as quantity of coal supplied and received. There is a need for transparency in coal quality assessment of the coal supplied. The third party sampling mechanism may need strengthening along with a mechanism for quick resolution of dispute and settlement of account. 5.2.5 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. This would have impact on the tariff as not only additional capital cost would be required but O&M cost would also increase	**PSPCL** agrees with the views expressed in the report that there is a need for transparency in coal quality assessment of the coal supplied. The compliance of new environmental norms would certainly result in heavy capital cost as well as impact on tariff due to its O&M cost. The operation of the Plant on low PLF makes its operation less efficient
5.H: Coal GCV:	5.8.2 In the entire value chain from mine end to generating station end, the loss of GCV can take place on account of grade slippage at mine end, during transportation (transit with railway) and during storage (at generating stations). The generating companies generally have no control over the grade/GCV of coal received at their generating stations. There are several cases of grade slippages between the mine mouth and at the site of generating stations. Further, there is loss in GCV during transport of coal through Railway. Therefore, the generator may receive coal of lower GCV than what is billed by the coal companies. These are beyond the control of the generating companies. 5.8.3 Since the cost of slippage in grade of coal between	Generally, there is grade slippage in the coal billed by the suppliers and the coal received at the plant and on account of this grade slippage, the generating plant has to suffer. The coal supplier company should accept the analysis results of NABL-accredited lab of received coal at plants for the purpose of payment.

	the loading point and the site of generating station is ultimately passed on to the beneficiaries, this issue needs to be looked at in terms of risk allocation between the coal company, railways and the generating stations. The issue of grade slippage is significant in case of domestic coal as the GCV measurement is being done at Free on Board (FOB) through acceptable practice. This poses specific challenges with respect to the measurement point and method/ procedure for measurement of Gross Calorific Value (GCV).	
7.2.4 to 7.2.6	**Thermal Generating Stations –Tariff Structure** The tariff for supply of electricity from a thermal generating station could comprise of three parts, namely, fixed charge (for recovery of fixed cost consisting of the components of debt service obligations allowing depreciation for repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses), variable charge (incremental return above guaranteed return and balance operation and maintenance expenses) and energy charges (fuel cost, transportation cost and taxes, duties of fuel). The 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	Variable charges should be linked to actual dispatches rather than linked to difference between availability and dispatch. Further, PSPCL appreciate the concern of the CERC regarding the low PLF of thermal power station which indirectly increases the cost of the power and try to find out the solution for this problem by introducing of the three part tariff. However, in our view idle capacity can be broadly categorized as under:- a. Season wise idle capacity (peak season / off season) b. Time wise idle capacity (day / night time) c. Old verses New Plants/ Tech. d. Location wise idle capacity (plant which are far from fuel source have less PLF / dispatches due to higher cost of fuel. Though the efficiency of such plants is better than the plants located near the fuel source due to implementation of the MoD. The tariff must be designed in such a way that can handle and give better problem solution for each type of category of idle capacity of thermal power generating station like in case of efficient plant situated in northern part of the country must be incentive wised if such plants are more efficient then located near the fuel source.
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)	In view of PSPCL, only those old plants may be renovated which can comply with environmental norms with a reasonable cost involved and there is a cut off limit must be specified for station heat rate of such plants.

	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	
7.4.2	**<u>Hydro Generating Stations - Tariff Structure</u>** The fixed component may include debt service obligations, interest on loan and risk free return while the variable component may include incremental return above guaranteed return, operation and maintenance expenses and interest on working capital. The annual fixed cost can consist of the components of return on equity, interest on loan capital, depreciation, interest on working capital; and operation and maintenance expenses.	PSPCL agrees to the proposal of CERC , however, For hydro plants normative plant availability factor (NAPAF) must be determined in such a way so that no extra un due benefit is passed on to hydro plants as well as it should provide a reasonable incentive to achieve better availability plant load factor. In our view, incentive must be capped maximum @ 5-10% of normative plant availability factor fixed for a particular year. No incentive shall be paid where normative plant availability factor is fixed up to 80% as a benchmark or incentive to hydro station above the NAPAF must be restricted upto 25% of the fixed charges per kwh.
	<u>INTER STATE TRANSMISSION SYSTEM – TARIFF STRUCTURE</u>	
7.5.4, 7.5.5 & 7.5.6	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. The tariff for transmission of electricity on inter-State transmission system can consist of fixed components and variable components.	PSPCL agrees with the recovery of fixed components can be linked to access and value component to be linked to the usage. Further, the fixed components consist of annual fixed cost of the evacuation transmission system and the available component may consist of common transmission system excluding evacuation system.
	Components of Tariff	
9.1, 9.2 & 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.	PSPCL is of the view that CERC 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 as the various components AFC are difficult to bifurcate u/s 62 & 63 .
	Optimum utilization of Capacity **Coal based Thermal Generation**	

10.3	(a) Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the anticipated reduction of utilization. Annual Contracted Capacity (ACC) may be treated as guaranteed contracted capacity during the year for the generating company and the distribution licensee and 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 contracted capacity to be redefined on quarterly or half yearly basis, keeping in view the demand of Punjab spans only for the 4 months (June to Sept)
10.5	(a) Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-20 years from existing 10-12 years for moderating upfront loading of the tariff. (b) Assign responsibility of operation of the hydro power stations and pumped mode operations at regional level with the primary objective for balancing. For this purpose, the scheduling of the hydro power operation (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	PSPCL agrees with the proposal of CERC.

	beneficiaries as reliability charges.	
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.	PSPCL agrees with the second option given by CERC 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 as this will lead to maximum utilization.
11	**Capital Cost**	
	11.8 One of the options is to move away from investment approval as reference cost and shift to benchmark/reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost. 11.9 Higher capital cost allows the developer return on higher base of equity deployed. In the cost plus pricing regime, the developer envisages return on equity as per the original project cost estimation. The regulations allow compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred. Therefore, in new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. The return on additional equity may be restricted to the extent of weighted average of interest rate of loan portfolio or rate of risk free return. Further, incentive	Norms/ bench marking for prudence check of capital cost for Hydro power is very difficult to fix due to various challenges and dissimilarity of costs involved in such projects. However, in case of Thermal power station cost bench marks should be fixed except for land cost for different capacity of thermal units variations from benchmark cost may be allowed only after justification provided by the generating company. Especially normative capital cost must be defined for installation of Fuel Gas Desulfurization (FGD). PSPCL agrees with CERC.

	for early completion and disincentive for slippage from scheduled commissioning can also be introduced.	
12	**R & M**	
	12.6 The R&M of transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Up gradation 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.	PSPCL agrees with the alternative option of CERC i.e. 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. However, the special allowance for R&M of transmission assets should maintain under separate account head. The expenses met through special allowance should be intimated to all the beneficiaries in due course. Further PSPCL is of the view that special allowance towards R&M for coal / lignite based thermal plants should be discontinued due to uncertainty of carrying out of actual R&M after the completion of useful life of the plant.
13	**Financial Parameters**	
		PSPCL agrees that more weightage may be provided for normative parameters to induce greater efficiency during operation as well as in development phase.
14 **Depreciation**	14.6 Options for Regulatory Framework a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff; b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; c) Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment; d) Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Ind AS and corresponding treatment of	PSPCL is of the view that the useful life of the transmission assets and hydro station be extended to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation. a) increase in useful life of well-maintained plants will result in lesser tariff which needs to be compensated by some incentives to maintain the plant. b) Agreed, no comments however, the life of assets added after commissioning be depreciated with in life of plant. c) Regarding additional expenditure at the end of life, the life of such asset needs to be reassessed and the depreciation up to 90% of such additions be exhausted in the extended life span. d) Reassessing life at the start of every control period is cumbersome job and not possible to implement

	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).	e) For the hydel generating stations which have completed their 18 years of life, the extension in life span for AAD to 18 years will not be beneficial and increase in useful life of hydel generating stations will further decrease the provision of depreciation in the accounts and ultimately less claim in ARR. On the other hand, in case the life span of hydel generating stations is enhanced the power purchase cost from hydro generating stations will be decreased. f) Reduction in rate of depreciation will directly affect the flow of company disadvantageous as such cannot be agreed to so far as PSPCL is concerned. However, the same is beneficial in case of purchase of power g) agreed to the proposal
15 **Gross Fixed Asset (GFA) approach**	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.	PSPCL agrees with the proposal of CERC.
16 **Debt Equity ratio**	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.	PSPCL agrees with the proposal of CERC.
17 Return on Investment	17.3 Over a period of time, allowing fixed rate of return on equity has evolved as an acceptable approach and the same has been followed by most of the State Electricity Regulatory Commissions. The RoE approach has been widely accepted by investors in the sector. The large scale investment in the power sector is attributable to the approach of fixed rate of return. 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 with the following observations in the Explanatory Memorandum; "As the tariff is determined on multiyear principles, it is important to maintain certainty in approach over each control period to maintain the confidence of investors and regulated entities. In view of the fluctuating interest rate, shallow debt market and considering the financial health of Utilities and the other serious issues	PSPCL agrees with the proposal of CERC to continue with the return on investment.

	faced by Developers in sector such as fuel shortages etc., it appears that it is not the desirable to switch to ROCE approach and thus the Commission proposes to continue with the ROE approach for next Tariff Period. Further most of the stakeholders have suggested for continuing the existing ROE approach."	
18 Rate of Return on Equity	According to CEA, the capacity addition is no more a major challenge and adequate installed capacity (along with currently under installation) exists to meet the demand for the next 8-10 years. Further, the rate of interest has also come down in recent times. Therefore, there is market dynamics which favors reduction of rate of return. However, any such reduction will have negative impact on the equity already invested in the existing and under construction projects, creating further financial stress on such projects. Different rate of return for new projects (where financial closure is yet to be achieved), may be thought of, with different rates for generation and transmission projects. (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;	PSPCL agrees with the proposal of CERC given from (a) to (d) & (f) (g). Regarding (e) it is proposed to continue pre-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; (g) Reduction of return on equity in case of delay of the project;	
19.5	(a) Continue with existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan, or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects; b) Review of the existing incentives for restructuring or refinancing of debt; c) Link reasonableness of cost of debt with reference to certain benchmark viz. RBI policy repo rate or 10 year Government Bond yield and have frequency of resetting normative cost of debt;	Actual cost of debt should be allowed instead of normative
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.	Actual cost of interest on working capital should be allowed.
21 **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; (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	PSPCL agrees with the complete proposal of CERC.

	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.	
22.8 A, B, C	(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.	PSPCL agrees with the suggestion 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.
23 **Fuel Blending of imported coal**	23.6 Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.	PSPCL agrees with the proposal of CERC.
24 **Landed cost of fuel**	(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 list of landed cost components may be specified. The source of coal, distance and quality of coal may be specified for a minimum period, so that the distribution company will have reasonable predictability over variation of the energy charges.
25 **Alternate Fuel Source**	(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.	PSPCL agrees with the proposal of CERC.
26.3.1,26.3.3,26.3.4,26.3.6	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 26.3.3 In the present scenario, most of the coal/lignite/gas based thermal power plants are running at low utilization (PLF) levels due to various reasons including shortage of coal/gas, lower demand etc. Machines working at lower PLF have adverse impact on the operational norms and hence, the existing heat rate norms for the new and existing generating stations are required to be reviewed along with the need for margin. 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. 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. 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.	Due to cyclic power demand, huge variation is faced in power demand during day and night hours as a result of which thermal units are subjected to operate at partial load or even have to shut down due to low power demand. These operating conditions badly affect plant performance and Station Heat Rate. Accordingly, it is not feasible to achieve the targets set and hence the norms for SHR may be revised according to the reasons cited above.
26.3.2 GCV measurement of coal	The GCV measurement of coal was shifted to “As Received” basis for the purpose of energy charges	Normally, the thermal stations are situated far away from the coal mines and stock of coal has to be maintained for 25 days as

	computation in the Tariff Regulations for the period 2014-19 as per the advice of Central Electricity Authority.	per CEA guidelines. This results in huge variations in coal stock which affects the quality of coal and hence the quality of the received coal and fired coal cannot be considered as same. Owing to this, the GCV of coal as fired is bound to decrease. Also due to higher back down, Reserve Outage and lower running of units Coal stock may remain in yard for longer time resulting in decrease in GCV. Accordingly suitable compensation should be given between received coal and fired coal GCV.
26.3.7 Sp. Fuel Oil consumption	The existing norm for the Secondary Fuel Oil Consumption is 1.00 ml/KWh for lignite based CFBC technology with some exception in case of TPS-I and 0.50 ml/KWh for Coal based project with the provision for sharing of savings with the beneficiaries. Further reduction in specific secondary fuel oil consumption norms may adversely affect the boiler operations under different operating conditions including partial loading of units due to fuel shortage conditions. With contribution from renewable generation increasing in the grid, thermal power plants are facing frequent regulations of supply and operations at lower PLF up to technical minimum. The consumption of secondary fuel oil would change on account of nature of operations.	Oil is consumed mainly for start-up of the units and sometimes for flame stability when the units are run at part load and some problem arises like poor coal quality, equipment failure etc. Oil consumption is directly proportional to number of starts of the units and more the stoppage time more quantity of oil is required for startup. So Keeping in view of continuous start/ Stops of units due to cyclic power demand, Specific fuel oil consumption may be relaxed depending upon no of start stops due to back down and reserve outage.
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 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.	The Auxiliary Power Consumption (MUs) does not decrease proportionally when the units are operated at partial load and also the power is required to run the minimum essential standby auxiliaries of the stopped units to safeguard the main equipment. Thus, the running of units at partial load increases the auxiliary power consumption percentage (%) owing to less generation. So Auxiliary consumption be relaxed and base of relaxation may be taken as reserve outage.
26.3.9	Presently, the auxiliary consumption of 800 MW is fixed based on 500MW sets. The auxiliary consumption of 800 MW sets may vary depending on the size of the unit and	Aux. consumption of 800 MW needs to be fixed separately

	economies of scale.	
26.3.10	Generating stations which have less auxiliary consumption than the norms, are able to declare higher availability by making adjustment of difference between actual (lower) and normative auxiliary consumption. Further, colony consumption is not a part of auxiliary consumption w.e.f. 1.4.2014 and therefore, the same cannot be accounted for against auxiliary consumption while declaring availability. Methodology of declaring availability after reduction of normative auxiliary consumption and colony consumption need elaboration.	Declaring availability should be evaluated after reduction of both normative aux. consumption and colony consumption
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.	Fixed cost recovery may be on half yearly basis.
27.5 Incentive	Options for Regulatory Framework 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) PSPCL agrees with CERC proposal (b) PSPCL is of the view that current methodology being adopted for calculation of incentive under 2014-19 Regulations may be continued. (c) PSPCL agrees that the incentive and disincentive needs to be reviewed under introduction of compensation for operating plant below norms. Further, in our view, incentive must be capped maximum @ 5-10% of normative plant availability factor fixed for a particular year. No incentive shall be paid where normative plant availability factor is fixed up to 80% as a benchmark. (d) PSPCL agrees.

29 **Sharing of gains in case of Controllable Parameters**	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.	PSPCL is of the view that methodology for sharing of gain should be adopted annually
30.2	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. 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, definition of two days (working days or including holidays) may need elaboration.	PSPCL suggest that the receipt date of physical copy of bill be treated as the date of receipt of Bill and due date of the bill should be calculated from the date of receipt of bill. Graded rebate per day basis required to be introduced as rebate is only a refund of interest paid by beneficiary by way of interest on working capital. In today's era, rate of interest is purely based on MCLR. Thus, the late payment surcharge should relate to MCLR and no premium should be added to MCLR. Further, as per existing regulations, rebate is provided if payment is made within 2 days of presentation of bill but it needs to be reviewed and the rebate should be allowed if the payment is made within 3 clear working days
31 Non-Tariff Income	31.1 The tariff determination under Section 62 of the Act follows the principle of cost of recovery which inter-alia provides the reimbursement of cost incurred by the generating company or the transmission licensee. The income on account of sale of fly ash, disposal of old assets, interest on advances and revenue derived from telecom business may be taken into account for reducing O&M expenses. Present regulatory framework does not account for other income for reduction of operation & maintenance expenses. However, in case of transmission licensee, the income earned from telecom business are adjusted in the billing separately. The principle of treatment of other income as applicable in case of transmission can be extended for the generation business.	PSPCL agrees with CERC proposal

	31.2 Presently, the revenue from telecom business is adjusted at the rate of Rs 3000/- per KM, which was fixed in 2007. It may need review.	PSPCL agrees with CERC proposal
32.2 Standardization of Billing Process	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 is to be linked with the actual auxiliary consumption or normative consumption whichever is lower
33.4 **Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants)**	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 ` with the interest on debt; b) "Debt Service obligation during construction period and recovery of depreciation" may be provided with the condition that such depreciation may be adjusted during the remaining period; c) As the level of emission is linked to actual generation, it would be appropriate to link recovery of supplementary tariff with the actual generation or availability or combination of both.	PSPCL agrees with CERC proposal PSPCL agrees with CERC proposal Recovery of supplementary tariff should be linked with the actual generation
34.2 **Renewable Generation by existing Thermal Generation Stations**	One of the options is to install renewable project at the same location using the common facilities and land and bundle RE power with the conventional power prior to delivery point i.e. before ex-bus bar. Other option is to establish the renewable project at different location and pool the generation capacity on external basis beyond the delivery point. In both the cases, the annual fixed charges for thermal project and renewable project may be determined separately, based on separate set of tariff principles.	PSPCL is of the view that renewable project may be installed at the same location using the common facilities and land and bundle RE power with the conventional power prior to delivery point i.e. before ex-bus bar. The annual fixed charges for thermal project and renewable project may be determined separately, based on separate set of tariff principles.

35 **Commercial Operation or Service Start date**	a. Addressing the shortcomings in existing methodology for the trial run of generating station and trial operation for transmission element through appropriate regulatory mechanism; b. Issue of trial operation and commissioning of the project when a generating station is ready but cannot be operated due to non-availability of load or evacuation system; c. Issue of acceptance of COD of transmission line if the generating project or upstream/ downstream transmission assets are not commissioned; d. Pre-requisite of completion of data telemetry and communication facilities for declaring COD of transmission system and operationalization of RGMO for declaring COD of generating station; e. Linking of commercial operation date with schedule commercial operation or schedule commencement date of the Power Purchase Agreement or Long Term Access Agreement respectively; f. Linking the commercial operation date of the transmission system with the commissioning of the generating units or stations; g. Separation of the commercial operation date of the unit or stations, the transmission element or system from the service start date under the contract.	PSPCL is of the view that the commercial operation date of the transmission system may be linked with the commissioning of the generating units or stations. Further regarding (a) to (d) PSPCL is of the view that due to delay in CoD of generating unit or transmission unit / elements will always lead to the delay in overall commssioning of unit.
37.6 **Alternative Approach to Tariff Design**	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?	As the capital cost is a base for 30-40% of the tariff, benchmarking of capital cost must undertake econometric analysis of large samples of projects to arrive at a benchmark while benchmarking the capital cost components must be divided in controllable and un controllable components. Land and site development may be categorised in uncontrollable factors and may be spared from benchmarking. Other components like cost of plant & machinery and cost of capital deployed (debt + equity) may be further bifurcated on the basis of sub and super critical nature of the project. However, in case of Hydro plants capital cost varies due to location and nature of the plant and it is difficult to benchmarking

	c. Any other methodology for benchmarking the capital cost for generation and transmission projects?	the capital cost in such cases. Benchmarking of capital cost must be fixed in such a way so that there is little difference between the actual cost and the bench mark on the one side and the other side it will give incentive to projects which are able to achieve it and discouragements to projects which over run the costs.
37.9	a. Whether it is a good idea to determine AFC as percentage of Capital Cost on normative basis? b. What could be the possible methodology to establish the relation between AFC and Capital Cost so that it meets the interests of both buyers and sellers?	As suggested by the study conducted by the CERC on sample data, there is a little co-relation between capital cost and AFC as Industry as a whole. So in PSPCL view fixing of AFC as a percentage of capital cost on normative basis is not a good option till the study of a larger samples. However, benchmarking for different components of AFC can be determined with respect to capital cost
37.17	a. Whether clustering the components of AFC based on their nature to increase/ decrease in order? Any other possible method to cluster the AFC components? b. What methodology should be adopted to determine the escalable (increasing)/ non-escalable (decreasing) factors? c. Whether escalable (increasing) / non-escalable (decreasing) factors should remain same for all plants/transmission systems (or) they be separate for each of the plants/transmission systems based on vintage / capacity / fuel type/ fuel linkages etc. d. Whether isolation of “Additional Capitalization” as a separate stream of revenue would provide for recovery of AFC on a normative basis in realistic terms? e. Alternatively, do you suggest any other methodology to treat “Additional Capitalization” for determination of AFC on normative basis? f. Whether applicability of change in tariff principles in each	PSPCL agrees that the clustering of the components of AFC based on their nature to increase / decrease is in order. A special index giving due weightage to components of AFC may be created for the escalable components. As proposed by this office, bench mark for Fixed cost must be determined keeping in view the sub and critical nature of the plant so components of AFC indirectly automatically calculated after taking care of such parameters. Additional Capitalization should continued be allowed on the basis of earlier policy after prudence check as it is very difficult to assign the additional capital as a percentage of capital cost / AFC.

	control period for the new plants would allow regulatory certainty to the existing plants? g. Alternatively, is there any other methodology to minimize the impact on AFC on account of change in control period?	The initial capital cost of the plant is fixed as per the tariff policy prevalent at the time of CoD. Minor changes in calculation of AFC does not impact the stability and predictability of the tariff for the plant point of view. Current Regulations fixes the AFC more or less on the basis of actual expense of the project whereas in future policy should be transform to normative basis from actual basis which will helps to remove the in efficiency in the system.
37.21	a. Does the proposal of differential recovery of AFC by segregating into peak and off-peak periods balance the need for both the buyers and sellers? b. What could be the weightage factors for peak and off-peak periods along with the PAF for each segment? c. What could be other mechanisms to arrive at peak and off peak AFC tariffs?	PSPCL agrees that the differential recovery of AFC by segregating into peak and off-peak periods will balance the need for both the buyers and sellers. PSPCL agrees with CERC proposed weightage factors for peak and off peak periods i.e. recovery of 80% of AFC, upon declaration of 80% PAF during the year and remaining 20% of AFC upon achieving 95% PAF during the peak period, say of 4 months. However, regarding Higher peak price PSPCL suggest that higher peak price may be provided by 20% over the off-peak price. -
38.1 **Transparency in Billing and Accounting of Fuel**	The regulatory approach of pass through of coal cost to the procurer directly on the basis of certification has been well adopted. Comments and Suggestions are invited for further strengthening the existing system.	PSPCL is of the view that relevant supporting documents alongwith certificates be provided with the bills by the generators.
39.1 **Relaxation of Norms**	The present regulatory framework provides for specifying normative operational parameters. However, there may be situations where the normative level due to the site specific features	PSPCL is of the view to continue with the current practice.

	such as FGD, Desalination plant, increase in length of water conductor system etc. may lead to power consumption in excess of the norms. In such situations, the present regulatory framework provides for relaxation of norms.	
40.1 **Merit Order Operation** **40.2**	Though merit order is a dispatch issue, scheduling/ non-scheduling has its impact on purchase cost. It is seen that in respect of certain old plants having low fixed costs, their power may not get dispatched as the merit order is based on variable cost, which may be high. The merit order operation is important for economic operation of the plants and optimum despatch of economic resources. The consideration of other factors such as distance of transportation, secondary fuel oil consumption may provide the option to distribution utility to optimize the despatch. Present merit order is based on the fuel cost of the past data, with time lag of up to two-three months in billing cycle.	PSPCL is of the view that merit order be prepared by considering variable rate as well as fixed rate.
41 **Application for Tariff Determination: Review of Process in Case of Transmission System**	alternative to simplify the process is to determine the tariff of existing assets based on actual capital expenditure instead of projected capital expenditure, so that two applications of existing assets can be reduced to one in each tariff period.Further, the tariff of new assets can be determined during tariff period after commissioning of the new assets. 41.3 Further in case of new assets of transmission system, single petition may be admitted for all the individual elements of the project which have been commissioned within a year. Then annual fixed charges may be determined on consolidated basis and apportioned on proportion to the capital cost of individual elements. The true up maybe carried out on completion of the project based on balance sheet of individual project.	PSPCL agrees
42 **Goods and Service Tax (GST)**	(1): Royalty is applicable as per Notification 3367 dated 1.8.2007-GSR 522(E). Subsequent to above, GoI, Ministry of Coal, vide Notification no. G.S.R. 349 (E) dated	PSPCL agrees with the proposal of CERC regarding prudence check.

	10.05.2012, has increased the rate of Royalty on Coal to 14% ad-valorem on the price of coal. (2) Central Excise Act, 1944, MoF, GoI issued a Notification No.1/2011-CE dated 01.03.2011 wherein Excise Duty was imposed on domestic coal classified under Chapter 27, serial No. 2701 of the First Schedule to the Central Excise Tariff Act, 1985. (3) CST and VAT is applicable based on location of mines and hence considered as generic applications. (4) Subsequently, vide Notification Nos. 1/2010 and 3/2010 dated 22.06.2010, Clean Energy Cess was levied under the Tenth Schedule to the Finance Act, 2010 @ Rs. 100 per tonne. Subsequently it is revised to Rs 400 per tonne from 2016-17 and repealed by GST compensation cess.	