5306/2018/CRL-CERC SPEED POST (6)

/URGENT/

MP POWER MANAGEMENT COMPANY LIMITED

(A Govt. of M.P. Undertaking)

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No..Regulatory/CERC/Regulation/ 259 Jabalpur Dated : 13.07.2018

To,

The Secretary,

Central Electricity Regulatory Commission,

3rd &4th Floor, Chanderlok Building,

36, Janpath,

New Delhi 01

Sub: Terms and Conditions of Tariff for the tariff period commencing from 1st April 2019- Consultation Paper thereof

Ref: L-1/236/2018/CERC, dated 24.05.2018

As desired in the public notice under reference, please find enclosed herewith the considered comments on the consultation paper.

Soft copy is being mailed separately.

Chief (Fin)

Encl:. As above in 3 copies

Chief General Manager (Commercial)

MP Power Management Company Limited,

Jabalpur (MP)

MPPMCL comments on "Terms & Conditions of Tariff Regulations" for 01.04.2019 – 31.03.2024			
S. No.	**Section/ Clause of docu-ment**	**Particulars**	**MPPMCL Comments/ suggestions**
1	**7.2.5**	**Thermal Generating Stations – Tariff Structure :** Options for Regulatory Framework 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).	i) Fixed return shall be limited to 7-8% ii) Now every beneficiary has opened LC and escrow account and the payment of generator is secure. The incremental return therefore, must be limited to 4-4.5% at the maximum.
2	**7.3.4**	**Thermal Generating Stations – Older than 25 years** Options for Regulatory Framework 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 (ii) phasing out of the old plants,	(ii) Benchmarks shall be framed for phasing out such plants. Plants that are continuously below 50% PLF for last three years shall only be considered.
3	7.6.1	**Renewable Energy Generation–Tariff Structure:** The feed-in tariff structure does not offer the advantage of economic efficiency. Further, the feed-in structure has its limitations. a) In case of regulation of supply of the renewable generation, it may not be possible to compensate generators with minimum charges. 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). c) In case of bundling renewable generation with conventional power generation at the ex-bus of generating station, it may be difficult to combine the tariff as feed-in-tariff structure is a single part tariff and conventional generation has two part tariff structure.	Procurers shall not be penalised for non-fulfilment of RPO obligation due to exit of any unit of renewable energy due to Merit order dispatch (MOD).
4	7.6.2	The tariff structure of the renewable generation may	All Renewable energy, other than

		be rationalized.	MSW to E shall be procured under section 63 of the Act.
5	9.3	**Components of Tariff** : Options for Regulatory Framework. 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.	a) Tariff fixation under Section 62 shall be transparent and all financial data submitted by the generator shall be made available to procurer in the interest of consumers. b) It shall be binding on the generator to share all details of sale of power under long term PPA to appropriate Commission every year and the Commission shall take cognizance of the same. The profit earned by the generator in such a way shall be passed on to the consumers by the Commission while deciding the tariff for the next year.
6	10.3	**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 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.	However, flexibility may be provided to the generating company and distribution company on quarterly basis in place of annual basis to make the annual contracted capacity flexible or Discom shall be awarded right to recall with certain time lag.
7	10.5	**Hydro Generation** : Options for Regulatory framework (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	The right of first refusal should rest with the original beneficiary. It is also proposed that due to banking of energy the losses should be borne by the beneficiary who availed the power.

		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.	
8	10.7	**Gas based Thermal Generations** Options for Regulatory framework 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.	It is proposed that the corresponding charges including losses shall be borne by the beneficiary who availed the power.
9	11.9	**Capital cost** Options for Regulatory Framework 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 the 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.	Fixed rate of return on equity shall be restricted to normative equity as envisaged in the investment approval or on benchmark cost. The return on additional equity should be based on risk free return on Government Securities or RBI bank rate on average of interest rate of loan portfolio. Further, the Commission should publish detailed regulations on how and on what basis the actual capital costs may be allowed to exceed the projected capital cost.
10	12.6	**Renovation & Modernization** Options for Regulatory Framework 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	The details submitted by the generator with its claim shall be shared with the procurer. R&M on capex may only be allowed part

		(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 50 years for Tr. Lines of sub-station/transmission line without any need for seeking resetting of capital base.	prudence check.
11	14.6	**Depreciation :** Options for Regulatory Framework a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff;	a) The increase in the useful life of well-maintained plants may be further elaborated with norms for designating well maintained plants for the purpose of determination of depreciation for Tariff. b) Depreciation earned over and above 70% should be utilised to reduce equity. This will reduce the burden on the end consumer. c) Life of plants may be extended up to Thermal Plants – 35 Years Hydel Plants – 60 Years Transmission lines – 50 Years
12	19.5	**Cost of debt** Options for Regulatory Framework a)Continue with existing approach of allowing cost of debt based on actual weighted 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;	The concern of regulation is to address real interest rate on debt. To achieve this, it is suggested that transparent independent market parameters such as MCLR/RBI policy repo rate/G-sec rate shall be linked for determination purpose. Saving on account of restructuring of loan should be shared on 50:50 basis
13	20.3	**Interest on working capital** Options for Regulatory Framework (b) As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken.	As the availability of coal in country is lesser than the norms specified by the commission, the coal stock for the purpose of computing work capital should be revisited and can be kept as monthly average on actual stock

		(c)While working out requirement for working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance service 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.	basis. 5% of maintenance spares may be made part of O&M expenses. This should be totally delinked from WC.
14	21.7	**O&M expenses** <u>Options for Regulatory Framework</u> g. Treatment of income from other business (e.g. telecom business business) while arriving at the O&M cost.	Income on account of other businesses shall be utilized for reduction in O&M cost.
15	23.6	**Fuel-Blending of Imported Coal** <u>Option for Regulatory Framework</u> Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.	a) Bridging of gap through e-auction and imported coal shall be limited to 10% increase in variable cost determined in the tariff order. If there is any increase beyond this limit, consent of beneficiary shall be made mandatory. b) Variable cost shall also be notified along with Declared Capacity in 96 time blocks on day ahead basis. Above variation shall be subject to merit order dispatch of beneficiary.
16	24.5 (b)	**Fuel - Landed Cost** <u>Option for Regulatory Framework</u>: (a) All cost components of the landed fuel cost may be allowed as part of tariff. Or alternatively, the list of standard cost components may be specified;	(a) The individual standard cost component of the landed fuel cost may also be elaborated.
17	25.1	**Fuel - Alternate Source** 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.	The prior consultation for resorting the alternative source of coal to be considered only if the energy rate exceed 10% of the base energy charge since the states are being surplus in power and further renewable energy is being added with high growth and subject to qualification of MoD of Beneficiary(ies).
18	26.3.16	**Thermal Generation (Coal based)** **Transit & Handling losses** The Commission had specified norm of 0.2% for the pit head station and 0.8% for the non- pit head stations as loss in transit & handling. The same may have to be reviewed based on the actual data of the past period.	There is great necessity to define “Pit-head” station. The maximum distance in Km between the Plant and mine head may be specified in order for a Plant to qualify for Pit

<table>
<tr><td></td><td>26.3.18</td><td>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.</td><td>head Plant. This is of great importance as many Plants, who are less than 60 Km away from mine head, call themselves Non-Pithead Plants and avail 0.8% transit losses, amounting to millions of MT of extra coal whose cost although is burdened on the Procurer, but is not used for his share of power as it is considered “lost during transit”.

Transit loss for Non-Pithead Plants should not be lumpsum0.8% but must be graded based on distance between mine and Plant. The transit and handling losses for non-pit head based stations should be linked to distance of transportation from the coal mine

It is proposed that following graded transit loss may be considered :
<table>
<tr><th>Sl. No.</th><th>Distance between mine and Plant (In Km)</th><th>Proposed transit loss</th><th>Remarl</th></tr>
<tr><td>1.</td><td>0 - 200</td><td>0.1 %</td><td>Pithead Plants</td></tr>
<tr><td>2.</td><td>201 - 500</td><td>0.2%</td><td></td></tr>
<tr><td>3.</td><td>500-800</td><td>0.3%</td><td></td></tr>
<tr><td>4.</td><td>800-1000</td><td>0.4%</td><td></td></tr>
<tr><td>5.</td><td>1000-1200</td><td>0.5%</td><td></td></tr>
<tr><td>6.</td><td>1200-1600</td><td>0.6%</td><td></td></tr>
<tr><td>7.</td><td>1600-2000</td><td>0.7%</td><td></td></tr>
<tr><td>8.</td><td>Above 2000 Km</td><td>0.8 %</td><td></td></tr>
</table></td></tr>
<tr><td>19</td><td>26.5.4</td><td>26.5 Transmission System:
Transmission Availability Factor
As per the existing regulations, the maximum incentive for AC system is around 1.27% (99.75/98.5) while for HVDC, it is around 3.91% (99.76/96). Further, in case of inter-regional links, the present framework requires certification as to whether it is export region or import region.</td><td>Denominator of 98.5 for AC and 96% for HVDC needs to be increased to 99.</td></tr>
<tr><td>20</td><td></td><td>Transmission Losses</td><td></td></tr>
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	26.5.7	26.5.7 The transmission losses considered in the present scheduling framework is about 4.5-5% for inter-state transmission system and 4-4.5% for intra-state transmission system. As a result, the net power delivered to the distribution periphery is reduced by about 9-10%, which has an impact on the cost of supply. An option could be to introduce the norms for inter-state transmission losses based on factors within control and international benchmarks.	To be reduced to 3 %. Norms shall be fixed. This will result in increased availability (of energy) and downward impact on cost of supply. However, if norms are not followed, recovery of transmission charges shall be reduced by an appropriate factor.
21	30.1	**Late Payment Surcharge & Rebate** 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.	a) In view of low interest rate scenario currently prevailing in the country, the Commission may link late payment surcharge with MCLR. b) In view of process involved in verifying and passing of bills, 10 days may be allowed instead of presently 2 days for availing the benefit of 2 % rebate. c) Late payment surcharge may be waived off or relaxed in case no schedule has been given for the billing period.