To,
The Secretary,
Central Electricity regulatory Commission,
3rd & 4th Floor, Chander lok Building,
36, Janpath, New Delhi- 110001

Date 23-01-2024

Sub: comments on draft CERC tariff regulations 2024 for control period 2024-29

Sir,

The CERC ('Commission') has placed on its web site above draft regulations for comments by 05/02/24.I am submitting comments thereon for the reference of the Commission. Suggested changes are highlighted in bold. I shall not take part in hearing ,if held.

2. Reg. 3 (10) defines that the 'Beneficiary' in relation to a generating station covered under clauses (a) or (b) of sub-section 1 of section 79 of the Act, means a distribution licensee who is purchasing electricity generated at such generating station by entering into a Power Purchase Agreement either directly or through a trading licensee on payment of capacity charges and energy charges; It also provided that beneficiary shall also include any person who has been allocated capacity in any inter-State generating station by the Government of India.

For Central sector power stations allocation is for the Rajasthan state and not for individual licensee in the State. Rajasthan Govt. specifies the breakup of this alloction among 3 public sector discoms {viz Ajmer Vidhyut Vitran Nigam Limited (AVVNL), Jaipur Vidhyut Vitran Nigam Limited (JVVNL) and Jodhpur Vidhyut Vitran Nigam Limited(JdVVNL)}.The Government of Rajasthan has formed a company , namely Rajasthan Urja Vikash Nigam Limited (RUVNL), to carry out Power trading business for AVVNL,JVVNL and JdVVNL. All PPAs are thereafter executed by RUVNL on behalf of AVVNL,JVVNL and JdVVNL. RUVNL annual report of FY22-23 does not indicate their status as trading licensee.If so,these discoms will not fit in the definition of beneficiaries and **definition should be amended to cover discom for whom a Govt company constituted by the state Govt. executes PPA and carry out trading as benefiary.**

3. **Plant load factor (PLF) is defined at reg 3(61) based on energy scheduled. PLF is allowed on actual generation and it should not**

be defined on scheduled generation basis but defined on the actual generation plus generation backed down on real time basis (i.e during 0.00 to 24.00 hours of the day of operation) by the regional or state load despatch centre. In other words, it has to exclude from schedule the backdown by generating company at their own due to any problem in generating unit or any other cause.

4, Proviso below reg 10 (3) provides that in case the final tariff determined by the Commission is lower than the interim tariff by more than 10%, the generating company or transmission licensee shall return the excess amount recovered from the beneficiaries or long term customers, as the case may be with simple interest at 1.20 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis points prevailing as on 1st April of the financial year in which such excess recovery was made. .**It is submitted that this implies that in case the amount of difference between interim tariff and final tariff is less than 10% of interim tariff, it will not be refunded. This will be undue enrichment of generating company or transmission licensee at the cost of purchaser / user (in most cases distribution licensee) and will be unfair and illogical. It will consequentially burden ultimate consumers and will be against the principle of the protecting consumer interest vide preamble of the Electricity Act 2003. This provision of 'by more than 10%' may therefore be deleted.**

5. Similarly in reg 10(8), non refund of excess tariff recovered on account of difference up to 10% between projected additional capitalisation and actual additional capital cost would be unfair and as such reg. 10(8) may be deleted.

6. Reg. 13(1)&(2) provide for truing up of tariff for capital cost and O&M expenses (for input price of coal /lignite from integrated mine). This regulation does not provide for truing up of total annual fixed cost. As lending for generation or transmission project is based on variable rate of interest so weighted average rate of interest actually paid may differ from that on which tariff is determined. In view of this, total annua fixed cost is required to be trued up. **Truing up of annual fixed cost may therefore be provided in reg 13.**

7. Operation and maintenance expenses (O&M exp.) is specified as one of the component of the annual fixed cost at reg. 15(1). Definition of it at reg 3(56) defines it to include the expenditure on manpower, maintenance, repairs and maintenance spares, other spares of capital nature & additional capital expenditure of an individual asset costing up to Rs. 20 lakhs, consumables, insurance and overheads and fuel other

than used for generation of electricity. Reg 34(a)(vii) specifies O&M expenses to include water charges and security expenses to determine working capital for coal/lignite thermal stations. Reg 30(6) specifies that Water Charges, Security Expenses and Capital Spares for thermal generating stations shall be allowed separately i.e shall be in-addition to O&M expenses. Thus provisions of regulations are differing. Further, regulations of various SERC's specifie terminal benefits {viz, contribution towards provisions of leave encashment and gratuity on retirement, contribution to pension funds etc under IAS 19 (Indian accounting standards-19)}. in addition to normative O&M expenses. **Definition at reg. 3(56) may therefore indicate the inclusion / exclusion of water charges, security expenses and terminal benefits etc and accordingly reg. 30(6) may be specified and in addition, any of these items excluded may be added below sr.no. (e) of reg 15(1) and below sr.no.(vii) of reg 34(a).**

8. Reg.17 provides that for operation of thermal station beyond useful life of 25 years, the generating company and the beneficiary may agree on arrangement including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation. **This implies that in case of disagreement , till agreement is reached, only energy charges as per this regulations will be payable. This may kindly be provided clearly and in addition it may be provided that in case of disagreemt, the commission will adjudicate or refer it to arbitration.**

9. Force majeure is not controllable factor so **at the end of reg. 22(1)(b) "except for force majeure" may be added.**

10. **At the end of Reg 26(2) also words "and shall be met by Generating company and Transmission licensee through normative O&M charges only." may be added on the lines of such proviso below reg 25**

11. Return on equity as per reg. 30 of draft CERC tariff reg 2024, CERC tariff reg.19 and CERC RE tariff reg. 20 are as under:

Sr. no.	Particulars	Base rate of ROE as per		
		Draft CERC tariff Reg.24	CERC Tariff reg 19	CERC RE tariff reg.20
1.	Thermal generating	15.5%	15.5%	

	station,and run-of-river hydro generating station	(existing) 15.5%(new)		
2.	transmission system including communication system	15.5% (existing) 15.0%(new)	15.5%	
3.	Storage type hydro generating stations, pumped storage hydro generating stations. and	16.5%(Existing) 17.0%(New)		
4.	run-of- river generating station with pondage;	16.5%(Existing) 17.0%(New)	15.5%	
5.	additional capitalization beyond the original scope, including additional capitalization on account of the emission control system, Change in Law, and Force Majeure	base rate of one-year marginal cost of lending rate (MCLR) of the State Bank of India plus 350 basis points as on 1st April of the year, subject to a ceiling of 14%;	weighted average rate of interest on actual loan portfolio of the generating station or the transmission system;	
6..	RE power plant	-	-	14%

Out of various power generation projects and transmission system, risk associated is the highest for RE power plant and **in considerations to it, there is no justification of considering higher ROE for others and there should be uniform ROE of 14% for sr.no.1 to 5 above. Other associated risks (e.g. geological faults for Hydro plants) may be covered by additional capitalisation, O&M charges and insurance charges**.

12. **In reg.31(2),** ‘t’ is not defined in the equation “ Rate of pre-tax return on equity = Base rate / (1-t)”, therefore, **‘t’ may be defined as ‘effective tax rate’ applicable as per reg.31(1).**

13. Reg 32(3). This regulation provides that the repayment for each of the years of the tariff period 2024-29 shall be deemed to be equal to the depreciation allowed for the corresponding year/period. Intent of this regulation must be reduction of normative loan by the depreciation but since repayment is normally conceived as for actual loan so this reg.may be worded as “**The repayment of normative loan for each of the years of the tariff period 2024-29 shall be deemed to be equal to the depreciation allowed for the corresponding year/period”. Further, this regulation should provide for contingency where normative loan is fully repaid and thereafter depreciation provided should either notionally reduce the equity or should be credited to ‘depreciation reserve fund’ and normative loan for additional capitalisation due to renovation and modernisation, change in law, revised emission standards, higher safety and security requirement, upgradation etc, should be deemed to be first met by depreciation reserve and depreciation for the year and balance considered as normative loan of additional capitalisation**

14. Reg 35(1) provides that in case of decommissioning of generating station / unit or transmission system, on account of factors mentioned therein and not attributable to generating company or a transmission licensee, the unrecovered depreciable value may be allowed to be recovered after duly adjusting the actual salvage value post disposal of such project. It is submitted that factors, mentioned therein, are also not attributable to discoms so recovery of depreciation charges from discom shall be illogical and thereby not in consumer’s interest. **This reg. may therefore be deleted**.

15. **In reg.38(II)(b) and (e), word ‘coal’ may be replaced by ‘coal/lignite’** as these regulations will be applicable for lignite also.

16. Cost of overburden (OB) removal up to lignite/coal seam, incurred before commencing mining operation, is amortised for the life of the project. This is not specifically provided as component of annual extraction cost under reg. 43. **New subclause (vii) may be provided as under:**

> **“(vii) cost of amortisation of overburden (OB) removal up to lignite/coal seam, incurred before commencing mining operation and amortised for the life of the project.”**

17. **O&M expenses of mines vide reg.46(a) and (c) may also be subject to ceiling O&M expenses and annual escalation of O&M expenses as may be specified by the commission**.

18. Reg.51(4)(ii) defines Annual Stripping ratio as the ratio of the volume of overburden to be removed for one unit of coal or lignite as specified in the Mining Plan. As per reg 51(4)(ii), unit is 'tonne'.**It would be appropriate to specify <u>the units of volume (say cubic meters)</u> and weight (say tonne) in definition at reg 51(4)(ii).**

19. Reg.62(3) : This regulation specifies Peak and off peak hours as 4 and 20 hours respectively. The multiplying factor of 0.2 to AFC for peak hours have been considered at reg.62(2) as 120% of peak hours /24 (=1.2x4/24) in formula for CC_{p1} to CC_{p12} and remaining AFC is considered for off peak hours in formula for CC_{op1} to CC_{op2}. First proviso of reg 62(3) provides that RLDC shall declare Peak Hours so as to coincide with the majority of the Peak Hours of the region. In such case, peak hours can be different from 4(four). To cover such contingency, following may be added at the end of first provision of reg 62(3).

> **"Provided that in case, peak hours so declared differ from four, then factor 0.20 and 0.80 employed in formula for CCp1 to CCpn and CCop1 to CCopn shall be replaced respectively by 1.20*declared peak hours/24 and 1.00-1.20*declared peak hours/24".**

This is also required because in RE rich state (like Rajasthan), peak hours occurring twice a day in morning and night hours and each are of about 3 hours duration.

20. **In the second and third proviso of reg 62(3), 'PAF' is to be considered on monthly basis as such in these sub regulations provisions needs to be classified as 'PAF(monthly)'. PAF on annual basis may then be classified as 'PAF(annual).**

21. In the formula 'ECR = {(SHR - SFC x CVSF) x LPPF / *(CVPF* + SFC x LPSFi + LC x LPL} x 100 /(100 - AUX)', <u>bracket before CVPF needs to be placed after it</u>**,** that is, '(CVPF' needs to be replaced by 'CVPF)'.<u>corrected formula for ECR in reg 62(3) will then be ECR = {(SHR - SFC x CVSF) x LPPF / **CVPF)** + SFC x LPSFi + LC x LPL} x 100 /(100 - AUX)</u>

22. Reg. 64(3)(d) provides that in the case of blending of fuel from different sources, the weighted average Gross calorific value of the primary fuel shall be arrived at in proportion to the blending ratio. In case

of blending of fuel, this provision will not give correct value of ECR because term of Gross Calorific Value of Primary Fuel(CVPF) is in denominator. For calculating exact ECR, weighted average of ratio of landed price of primary fuel and calorific value of primary fuel (i.e. 'LPPF/CVPF') is to be considered. In case of imported fuel, LPPF and CVPF vary significantly from indigenous fuel it is more important. As such provision may be that **in case of blending of two fuels in the ratio of m:n by weight, in formula at subclause (a) , 'LPPF/CVPF' is to be replaced by:**

k1xLPPF1/CVPF1+k2xLPPF2/CVPF2
where
k1=m/(m+n)
k2=n/(m+n)
CVPF1 and CVPF2 =calorific value of primary fuel 1 and 2 respectively.
LPPF1 and LPPF2 = landed price of primary fuel 1 and 2 respectively.

23. **In reg 62(5) and 64(3)(d) the term (∆ECR)(delta ECR) may preferably be also elaborated by**

(∆ECR)=ECR x [(-AUXn)/{100- (AUXn +AUXen)}]

[derivation-
ECRe = {(SHR - SFC x CVSF) x LPPF / *(CVPF* + SFC x LPSFi + LC x LPL} x 100 /(100 – (AUXn+AUXen)
ECR = {(SHR - SFC x CVSF) x LPPF / *(CVPF* + SFC x LPSFi + LC x LPL} x 100 /(100 - AUXn)
(∆ECR)=ECRe-ECR=ECR x [ECRe/ECR-1]n
=ECR x [(100-AUXn)/{100-(AUXn+AUXen)}-1]
=ECR x [(100-AUXn)- {100-(AUXn+AUXen) /{100-(AUXn+AUXen)}]
=ECR x -(AUXn) /{100-(AUXn+AUXen)}]

24. Reg 65(4)-Frequency Response Performance is defined in IEGC. It needs to be referred in this reg. accordingly. Suggested correction:

"ß = Average Monthly Frequency Response Performance , certified by RPCs **as per IEGC reg. 3(1)(59),30,40 and Annexure-2 and**, which shall be computed by considering primary response as per the methodology prescribed by the NLDC and shall range between 0 to 1.

25. Reg, 66: Pumped storage hydro plant can be of following categories:

(1) Exclusive pumped storage hydro plant ,that is, hydro plant having turbine – pump units which are utilised only for pumped storage and retrieval of energy stored and there is no / negligible generation from water stored from river flow. In otherwords, design energy is zero or negligible; or

(2) Pumped storage cum hydro generation power plant having substantial reservoir storage fully filled by river flow. That is, such power plant having substantial design energy and it may utilise full generate capacity during rainy season to avoid spillage of water and consequent loss of zero cost energy and in other season may pump during some hours in day and during other hours operate on river water pondage and pumped storage.

(3) Pumped storage hydro plant may operate such that it is service provider for pumped storage and retrieval of stored energy, that is it utilises RE power supplied by beneficiaries/ traders for pumping water from lower level to higher level and regenerate it up to minimum 75% of RE supplied and supply it to those beneficiaries /traders as per their schedules and charge only capacity charges and O&M charges.

(4) Pumped storage hydro plant purchasing RE power and supplying to RE purchasers at separate RE tariff consisting capacity charges and energy charges.

It is submitted that Capacity and energy charges for all cases can not be determined by the formula as specified at reg 66(2) to (4). For category (3), Tariff will be as per agreements among generator and beneficiaries and for category (4) as per agreements with RE purchasers or as per bidding in power exchange. In respect of category (1), exclusive pumped storage plant, it is submitted that:

(i) Formula specified vide reg. 66(2) for the fixed charges payable for the month (FCm) are based on Annual Fixed charges (AFC) and overall efficiency of pumping and regeneration of 75% or higher are as under

(a) in case of actual Generation during the month being ≧ 75 % of pumping energy consumed, formula is FCm= (AFC x NDM / NDY).This will result in payment of full monthly fixed charges ;

(b) in case of actual Generation during the month being < 75 % of pumping energy consumed, formula is FCm = (AFC x NDM / NDY) x (Actual Generation during the month during peak hours/ 75% of the Pumping Energy consumed. This will not result in payment of full monthly fixed charges as firstly actual generation is less than 75% of pumping energy consumed and that generation during peak hours will be even less than it.

In view of (a) and(b) above, generating company will not be fully compensated for annual fixed charges even if considering all 12 months of the year it has generated 75% of energy supplied for pumping. Further, for maintaining efficiency better than 75% there is no incentive to generating company. Further, if supply of energy generated from pumped storage is less than 75% of pumping consumption, then it can be due to:

(i) low scheduling by beneficiaries, in that case pumped water will remain stored in reservoir and may be utilised to generate additional energy in subsequent months. To cover this contingency, there should be adjustment in fixed charges for water stored and subsequent regeneration.

(ii) Poor efficiency of pumped storage and regeneration. In that case, generating company should pay penalty by way of reduction in fixed charges.

In view of above adjustment to fixed charges should be based on energy generated. **Following formula are suggested (where in second term reduces/increases fixed charges as per energy generated in excess / lower than 75% of energy consumption of pumping):-**

$FC_p=FC_n+R \times (G_n-0.75 \times C_n)$ for $G_n<=0.75 \times C_n$
$FC_p= FC_n+R \times [G_n-0.75 \times C_n-E_{xn}]$ for $G_n>0.75 \times C_n$
Where
FC_p=Fixed charges payable
FC_n=Fixed Charges for n_{th} month of the financial year
= AFC*NDM/NDY for exclusive pumped storage
R = P/0.75 where P is price/kwh of renewable energy supplied for pumping. It is to be limited to value which does not result in fixed charges to be -ve with zero generation say for consecutive 30 days.
G_n=Generation in kwh from stored energy during the n_{th} month of the financial year
C_n=Energy consumed in kwh for pumping during the n_{th} month of the financial year $G_{cn}=G_1+G_2+….+G_n$
$C_{Cn}=C_1+C_2+……+C_n$

E_{xn}=positive value of {positive value of(G_{cn}-0.75xC_{cn})}-{positive value of($G_{c(n-1)}$-0.75x$C_{c(n-1)}$)}

For annual generation from pumped storage greater than 75% of annual consumption for pumping, the difference will attract incentive of Rs.0.20 per kwh.

(ii) The formula for Reg. 66(2) (or that suggested above) will not apply for category (2). **For hydro generation cum pumped storage plant, AFC will have to be allocated on monthly basis in proportion to number of days in a month and monthly FCm so worked out to be further allocated to hydro generation and pumped storage as under:**

FChn=FCm x (GCh+GCp x Hph/(24 xNDM))/(GCh+GCp)
FCpn= FCm x (GCp-GCp x Hph/(24 xNDM))/(GCh+GCp)
Where
FCm= AFC x NDM / NDY
GCh= Hydro generators' capacity
GCp= Pumped storage generators' capacity
Hph=number of days pumped storage generator capacity is scheduled exclusively for hydro generation.
FChn= fixed charges for hydro generation for nth month
FCpn = fixed charges for pumped storage for nth month

Second term for FChn and FCpn accounts for utilisation of pumped storage capacity for hydro generation during rainy season to avoid spillage of water from dam during rainy season.

Provisions of Reg 65 will then apply with FChn considered for (AFC x NDM / NDY) and of reg 66(2) (as suggested above) with FCpn considered as FCn.

(iii) **Incentive of 20 p/kwh (vide reg 66(3) and (4) will applicable for generation in excess of 75% of consumption for pumpig for exclusive pumped storage or for generation in excess of design energy +75% of energy s**upplied for pumping only to beneficiaries of hydro generation as in this case hydro-generation from pumped storage may be difficult to workout.

26. Req. 66(3): Design energy is based on long term average of annual generation. It considers high generation during rainy season and low generation during winter season and also annual generation variations. As such generation in excess of design energy can not be

determined on monthly basis. On this account, **payment of incentive of 20p/kwh vide provisions of reg 66(3) may be worked out on annual generation basis only.**

27. Reg. 93(4) and (5) provides that no New ISTS lines shall henceforth be planned and developed by State Transmission Utility unless agreed by CTU in consultation with RPC and approved by the Ministry of Power and that New transmission lines which have been conceived as ISTS lines at the planning stage shall be considered as part of the ISTS system provided that such lines have not been developed for the sole purpose of the beneficiary(ies) of a single State. It is submitted that Intra-state and inter-state transmission lines are operated in integrated manner and as such with the addition of any natural ISTS line, power flows on then existing as well as new intra-state transmission lines will undergo change and as such although intra-state lines might have been planned and created for single state, it may become essential to transmit inter-state power and has to be considered as ISTS line. **Reg. 93(5) may therefore provide that 'any existing or new intrastate line essential to transmit inter-state power based on actual power flows or system studies shall be considered as ISTS line**'.

28. CEA recommendations in respect of impact of part load operation on performance of thermal power stations and consequent variations in norms of unit heat rate, auxiliary consumption and secondary fuel oil consumption has not been considered in the regulation. Plant load factor of thermal generation has gone down upto 54.51% in FY20-21 and post covid it has improved to 58.87% in FY21-22(vide p- 70/316) of CEA's National Electricity Plan vol-1: 2023) but in future RE penetration will increase with the RPO of 24.61% in FY22-23 increased to 41.36% by FY28-29 (vide MOP order dated 22 July 22 and notification dated 20th October, 2023). Consequently, PLF of thermal generation may go down below 54.5% by FY28-29 besides thermal generation lowered to minimum during day on account of solar generation. **With this background, it is necessary to specify norms for low PLF as recommended by CEA** so that coal/ lignite based power plant may not be reluctant to operate at low loads / low PLF.

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