From,
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Jaipur -302021
13th July 2018

To,
The Secretary,
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chanderlok Building,
36, Janpath, New Delhi-110001 Tel: 23353503.

Dear sir,

The CERC has issued public notice vide no. L-1/236/2018/CERC dated 24.5.18 inviting comments / suggestions on Consultation paper in respect of Terms and Conditions of Tariff for the tariff period commencing from 1st April 19 by 15.7.18

2. Renewable Energy (RE) generation- backing down of thermal power stations : As on 31.3.18, installed Thermal generation, Hydro generation , grid connected wind and solar generation capacity was respectively 222907 MW, 45293 MW, 34046MW and 21651 MW. Thus solar and Wind RE generation capacity has become significant proportion (25%) of the Thermal generation capacity. This proportion is bound to increase in future as cost of generation per unit of solar and wind generation is less than thermal generation and even less than fuel cost of some thermal plant. This increase is welcome from the consideration of beneficial effect on global warming and consequent climate change. However, being in-firm power and availability for part of the day, it is posing problems in grid management. For availing the RE generation, thermal stations are being backed down or fully shut down. Normally, Thermal stations can be backed down up to 30% of its rated capacity without oil support. Below this load, oil support will enhance and fuel cost of generation increases and in case of shutdown, a huge quantity of oil will be required to be burnt during start up. For factoring this in load dispatch, it is suggested that while tariff may be based on normative fuel consumption but generating company should declare following three components based on design / actuals. This will enable system operator to effect economic dispatch (including backing down) from national perspective and decide the thermal generation to be despatched for secondary (or slower ) balancing (effective after and will in turn not affect adversely the generating company:

(i) cut off point of no secondary oil injection and consumption in ml/kwh at various loads in % of rated capacity upto cutoff point; and
(ii) start up fuel consumption; and
(iii) Ramp rate and ramp down rates of thermal generation

3. RE generation – grid balancing (para 10.5(b) , 10.6 to 10.8 ) :- (1)Grid balancing of RE generation with Hydro, pumped storage hydro and gas thermal power station, will require changes in existing scheduling and deviation settlement regulations as brought out at para 5.5.5. For illustration , say solar generation is envisaged in Rajasthan to be balanced with hydro-generation / pumped storage at Tehri Hydro generation in central sector. If scheduled solar generation from 10.00 a.m. to 4.00 p.m. is 1000 MW and tehri hydro is 250 MW (i.e. overall schedule of 1250MW) and if solar generation has picked up to higher level of 1500 MW then

balancing (so as to maintain the same overall schedule) will be Solar generation 1500 MW and tehri hydro (pumping) 250 MW. As ramp rate of solar generation is very high , it has to be balanced instantaneously with hydro generation. As solar generation in Rajasthan and hydro generation at tehri are in different state, existing scheduling mechanism (vide clause 6.5 (18), 23(i) and annexure -1 clause 4(ii) of IEGC), any change in schedule will be effective from 6th time block.(i.e. after 75 to 90 minutes). During this period (lasting more than 5 time blocks), Rajasthan's over injection will be considered as 500 MW (irrespective whether tehri has altered its generation or not). Rajasthan will be subjected to additional charge for deviation under reg 7 of Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014. If Rajasthan does not effect reduction in solar generation and tehri hydro changes its generation to pumping , then they will also be subjected to additional charges for deviation under said regulation. This may lead Tehri hydro not to absorb solar generation and Rajasthan not to accept and back down extra solar generation. This is not desirable as cheaper and clean generation is backed down. This is not conducive to promote RE generation. This illustration is equally applicable for balancing with any other hydro station or gas thermal station not in the state of generation of solar (or wind power).

(2) To obviate this and to effect immediate (or within short duration of 3-5 minutes) the balancing of RE generation's variations, it would be appropriate that RE (Solar& wind) generating station(s) and its balancing hydro and gas stations is considered as a virtual island for the purpose of scheduling and deviation settlement. This island can effect inter-island changes in generation schedule , which does not affect schedule of island, by exchange of communication and for such exchanges within the island, criterion of effectiveness from 6th time-block will not apply. However, boosting of generation to return back the RE energy absorbed can be preplanned and change in generation schedule will be for the island and this will be effective after 6th time block. Thus criterion of 6th time block will apply only for injection schedule or drawal schedule of the virtual island from the region.. Mechanism of single authority for scheduling for island and payments for (i) inter-island exchanges and (ii)sharing of deviation charges and additional charges for deviation to be settled by generating stations of the virtual island. Alternatively sr.no.(i) can be the injection payable at agreed settlement rate and return payable at another settlement rate (considering losses and incremental O&M charges) and sr.no.(ii) can be that overdrawal ( or underdrawal) shall be shared by Generating station under injecting (or over injection) in proportion to such under ( or over) injection.

4. Aggregation of hydro capacity (including pumped storage) (para 10.5(b): Consultation paper suggests assigning of the responsibility of operation of the hydro and pumped storage hydro projects at regional levelwith primary objective of balancing. Aggregation of hydro-capacity for balancing is desirable but it will involve redrawing of interstate agreements, PPAs and acceptance of charges by beneficiaries etc. and achieving the same through regulations will raise host of issues. For illustration, Bhakra – Beas hydro generation complex is a multi-state and multi-purpose hydro projects. Generating capacity is based on heavy discharge during few rainy days and on such few days all generating capacity operates at rated capacity. Except for these days, it is feasible to reduce the generation corresponding to solar generation (to conserve water into the reservoir). The schedule of electricity supply from Bhakra – Beas complex is maintained by supplying solar power to them in lieu of conserving hydro power. Hydro generation will be enhanced (by utilizing the conserved water), when there is no or reduced solar generation and extra hydro power is then supplied to Rajasthan. . However as water discharges from generating station is governed by irrigation requirement so this balancing mechanism will work if solar

power injection and extra drawal is balanced daily or at least in a day thereafter as beyond this period storage in downstream barrage may not enable maintaining water discharges as per irrigational requirement. If this balance can not be effected due to low load demand in Rajasthan or grid constraint, then option will be to stop balancing or allow other partner state to utilize extra hydro generation. This will require agreement among partner states for such operation, tariff for utilization of power in excess of partnership share, losses to be considered etc. Such agreed mechanism can not be applied to other hydro project , which may have other constraint. For example it can not be applied for Chambal hydro projects which will involve inter-regional exchange of power as generation at Gandhi Sagar (GS) is drawn by MP and that at Rana Pratap Sagar (RPS) and Jawahar Sagar (JS) Power station is drawn by Rajasthan and any extra drawal / underdrawal will normally constitute inter-regional exchange. Further, upstream power station at GS and down stream power station at RPS , has to effect generation such that water level in RPS is maintained to a level required for the operation of atomic power stations. Similarly storage and retrieval from Tehri hydro will have different mechanism as energy consumption in pumping and heavier incremental O&M will have to be considered. On these account , there may be different set of agreement for each hydro station effecting balancing of RE generation variations. On these accounts, it would be preferable that initially smaller virtual island concept is accomplished through agreements between partners/ beneficiary state of allocated power and then these islands are merged to get desired objective of aggregation. For this enabling provisions can be made in regulations (preferably in IEGC- definition of regional entity, clause 2.4.2 – role of RPC and chapter 6 - scheduling) and RPC can be entrusted the function to strive for such virtual islands. Services of Forum of regulators can also be availed.

5. Balancing with gas based power stations (para 10.6 and 10.7) - Immediate / faster ramp up and ramp down of generation at gas based power station will be feasible only for the capacity in operation in open cycle mode. For combined cycle ramp up / ramp down time is likely to be twice that of combined cycle. Irrespective of this, like hydro, gas thermal does not have margin in capacity and as such for balancing solar generation it can lower its generation but it can not generate beyond its rated capacity to supply extra capacity. In other words its normal generation has to be below rated capacity with some open circuit operation. Also. On these account, balancing with gas thermal will require agreement for loss of such generation ( or payment for deemed generation) , besides losses, incremental O&M, payment for gas if it fall below minimum off take quantity and extra fuel cost if open cycle operation is required. In other words, its aggregation will be on different lines than of that of hydro.

6. Balancing with thermal generation (para 10.8)- Ramp rate - Hydro and Gas thermal power stations will provide immediate / fast balancing. Coal / lignite thermal generating stations will have slower balancing. However, out of thermal units , high ramp up and ramp down rates will be preferred. Such preference should be reflected through tariff for retrofitting to have high ramp rate. This can be achieved by specifying differential rate of Return on equity for power plant and its retrofitting. E.g. ROE with a specified ramp rate or lower to be bank rate (or MCLR)+400 basis point. While that for retrofitting to have high ramp rate to have additional basis points on ROE with ramp rate subject to verification annually.

7. (1) Storage system(para 36):- comments on the storage system was invited earlier in March 17.Out of generality at that stage, now comments are now sought specifically on:-

(i) storage system as part of generating station; and

(ii) storage system provided as part of transmission system.

(2)Energy storage system is basically a balancing system with storage batteries. It can be broadly of two categories, viz

(i) to have combined schedule of generation & storing system (i.e the energy injection to / retrieval from storage system) leading to narrow deviation from schedule. Such storage system will be operating (i.e. charging + discharging)for part of the day and required for a small fraction (say 5%-10%) of the energy generation; and

(ii) to have combined schedule of generation & storage to be practically flat curve and Such storage system will operate (i.e. charging and discharging) for 24 hours and of the energy storage capacity to be almost 2/3 of daily generation.

(3)Presently storage system is quite costlier compared to tariff of solar and wind RE generation (on account of which it is required) . On this account, energy storage provided by generator or transmission utility will not be economically viable. Storage system of first category may be close to economical viability provided benefits derived by (a) generator ( by way of saving in deviation settlement charges), (b) saving in transmission system cost (due to lower peak to be catered ) and (c) discoms ( due to lower transmission charges due to better load factor on transmission system) is considered. In respect of such storage system as part of generation, these can be built in tariff /deviation settlement mechanism. One mechanism can be recovering from wind and solar generating companies, monthly connectivity charges based on contracted capacity. However, RE energy is mostly supplied to discoms through PPA and such charge will not be absorbed by generators but passed on / loaded to the discom / consumers. Another mechanism can be to lower the absolute error (presently based on installed capacity) of no deviation charges (which at present is 12%) or alter it to absolute deviation of 12% of peak daily schedule. Presently, this will not be feasible as deviation settlement mechanism as specified by SERCs have not been fully operational. Another mechanism can be to incentivise generating companies having absolute deviation from schedule better than 12% during tariff period and charging it to 'regional deviation pool account' created under deviation settlement regulations. Commission can consider making enabling provisions. As regards providing storage system as part of transmission or by Transmission company, it is stated that it will not have economic viability ( based on transmission charges without and with storage ) and may require viability gap funding. Otherwise, it will add to the cost of transmission and hence burden discom / consumers. CERC can advise for such scheme under section 79 (2)(ii) of the electricity Act – promotion of efficiency (of transmission system utilization and efficiency of grid management) and can make enabling provision e,g , in reg. corresponding to reg2(1) -scope of transmission system to include storage system (and elsewhere adding storage system wherever communication system occurs) , 3 definition of storage system, transmission system and useful life, 29(3)-O&M expenses, 38-norms, 39- auxiliary consumption, 33(1A)-charges for storage system and 43 sharing of charges of CERC tariff reg 2014. Fixed charges of battery operated system (of transmission utility) can be based on financial principles as applicable to transmission system with depreciation charges based on capital cost of battery system and inverter considering battery replacement say every 3$^{rd}$ year and inverter every 10$^{th}$ year and working capital to include say 2.5% of capital cost and returned energy 80% and ROE may be specified for 2-3 ramp rates.

8. Cost of Hydro- generation (para 5.5):- Cheaper hydro resources at lower levels have already been exploited. Hydro resources in higher riches is costlier, may encounter geographical faults, adverse climate conditions and adverse geographical conditions leading to transportation constraints leading to time and cost overruns. Even otherwise because of high fixed cost they

have high cost of generation. In view of these being clean energy and perpetual sources and having capability of balancing variations in RE generations due to vagaries of nature ,thse needs to be promoted. Lowering of tariff can be achieved by longer period of term loan (and hence reduction in depreciation rate) and lower rate of interest. Both of these can be achieved by providing interest free long term loan out of clean environmental cess (formerly clean energy cess) of financial institutions to provide longer repayment period and lower interest rates for hydro power plants. CERC can advise central Govt. under section 79 (2)(iii) of the electricity Act.

9. Transmission tariff (para 7.5.4 to 7.5.6 ):-Proposal to separate transmission tariff into transmission access and transmission service makes economic sense. One who book transmission capacity need pay for transmission access irrespective of its use and in addition pay for service used. However, it may happen that revenue from transmission access and transmission service is in excess / deficit of transmission cost as determined by the Commission. In that case excess or deficit determined by transmission company should be passed on by the transmission company and that due to true up be the commission, to the transmission charges for next year.

10. Tariff for integrated thermal and RE power plant (para 7.6.4):- (1)Integrated power plants should be segregated into two categories:-

(i) integrated coal or lignite thermal power plants with nature independent RE projects like bio-mass or bio gas or bio fuel or geo thermal where daily scheduling is not affected by vagaries of nature and as such balancing not required; and

(ii) integrated coal or lignite thermal project with solar or wind power or tidal power plant where daily schedule is affected by vagaries of nature and balancing of RE with thermal will be required.

(2) In case of sr.no.(i), peak generation capacity will be sum of peak generation capacity of both and as such weighted average rate of fixed and variable charges may be based on installed capacity of each. In case of sr.no. (ii), because of balancing of RE generation by thermal plant, peak generation will not be sum of their available capacity and fixed charges can be that of thermal power station and Notional fixed charges equal to 50% of feed-in / bid tariff (on the lines of that payable for (deemed generation for ) backing down of wind generation vide clause 7.6.2 of GOI guidelines for tariff based competitive bidding process for procurement of power from grid connected wind power projects notified vide no. 23/54/2017-R&T dated 8.12.2017) and variable charges may be weighted average based on target generation of both with fuel cost for thermal and 50% of feed in or bid tariff for RE generation. Excess or deficit due to RE generation may be passed on to next years in determination of variable charges.

11. O&M expenses (para 21)- (1)with reference to para 21.4 and 21.7(e), it is stated that O&M expenses of substation is broadly the function of nr. of bays, transformation & reactor, capacitor bank capacity and their rated voltage. This can be considered by specifying O&M expenses based on nr. of bays, transformer+ reactor capacity and capacitor bank capacity like that in RERC tariff regulations.

(2) With reference to para 21.2 and 21.7(a) , it is submitted that consisting of (i) employees cost, (ii)Administrative and general expenses and (iii0 repairs and maintenance. CPI(IW) will capture the wage revision but impact will come gradually. So on long term basis, O&M expenses can be indexed to WPI and CPI but it will not capture immediate impact of wage revision. It will be appropriate to continue on present practice with immediate impact can considered through mid term review based on actuals in the year following the year of wage

revision and with such mid term review, appropriate reduction to be considered in indexing formula based on CPI and WPI.

(3) (para 21.2 and 21.7( e)) - impact of number of units on O&M expenses can be considered by % reduction based on number of units.

(4) (para 21.3 and 21.7( d)):- employees expenses and administrative and general expenses are not likely to be effected with continuous low scheduling. Repair and maintenance expenses may get reduced if scheduling is consistently low but is scheduling is with shutdown, these are likely to increase. In view of these , no changes may be effected.

(5) general: O&M expenses also includes employees expenses which besides pay and allowances include overhead charges like P.F contribution , provisions for gratuity , leave salary, pensions and post retirement benefits. It is observed in some cases while O&M expenses in tariff considers these overheads, genco/trasco / disco, do not make contribution to respective funds. Commissions while truing up allows considering these overheads of O&M expenses to the extent of actually made, but besides violations of statutory provisions, it is deferring the liability and also not serving the interests of employees. Commission should consider deferring such liabilities as violation of their order and impose fine under sec. 146 till such contributions are made.

12- Merit Order Operation (para 40):- Determining of merit order by normative fuel charges does not lead to economic operation ( not from utility but from national perspective ) where backing down results in higher fuel cost /kwh due to higher fuel consumption with back down, startup fuel consumption and take or pay obligation or where one or more power plants in operation has single part tariff. Merit order should not there be be on fuel charges but should be based on financial implication of every unit of backing down of the generating station, as this will take into account extra cost to discom due to oil support with reduced load, extra cost of fuel due to take / pay obligation or startup / shutdown, impact of transmission charges, cost of likely RPO default and deviation charges.

13. Petitions for tariff determination (para 41.4):- To reduce number of petitions in transmission sector, only single petition per organization may be considered for all assets existing at the end of second quarter of previous year in a region and for interregional transmission. For new assets one petition be considered per organization per region .for all assets created during each half of the year. All petitions to be based on actual expenses duly certified by statutory auditor.

14. Depreciation (para 10.5 (a)) (1) For moderating upfront cost due to depreciation considering elongation of useful life and loan repayment period for hydro power generation projects should not be considered without proper study. Useful life of the hydro project will be dependent on silting and thereby filling of upstream dam up to minimum draw down level. life can be extended beyond this period only by desilting which will raise O&M charges. Similarly Loan repayment period is relevant to new projects and is dependent on policies of Financial institutions. Without financial institutions changing their policy, extending this period will not promote hydro generation.

(2) Loan repayment period (para 14) :- Sanction of Loans by financial institutions (FIs) requires meeting debt service coverage ratio to assure FIs for payment of interest and repayment of loan. Cash flow from interest charges , depreciation and post tax return on equity divided by interest and repayment liability constitute debt servicing coverage ratio. On this account, depreciation rates can not be reduced drastically unless FIs provides longer repayment period. Otherwise, lowering the depreciation rates may lead to cash flow crunch and genco / Transco’s

capability to service debt and therefore to avail loans for the project. As such enhancing the life or lowering of depreciation rates need correspond to repayment period normally offered by FIs.

(3) General : depreciation beyond 12 years: Presently normative equity is kept constant at 30% and debt at 70%. Debt is deemed to be paid by depreciation provided at higher rate of during first 12 years. to enable repayment of debt. For rest of the useful life depreciation is provided for 20% of capital cost (10% being salvage value). In this mechanism, at the end of the project life, an generator will have equity of 30% and surpluses of , 20% from depreciation, salvage value of project (which is considered as 10% but is usually more than 10%) and earning on surpluses created by depreciation. Thus at the end of project life, equity + surpluses will not be less than 200% of equity. It was earlier conceived that generating company / transmission licensee / distribution licensee will continue in business and this will provide surpluses so generated for the creation of new assets. But in many cases generating companies and transmission and distribution licensees , have not envisaged expansion and they will be having huge surpluses. Further in present scenario, new assets can be created by raising fresh debt so there is no need to keep surpluses to this extent and depreciation can be limited to loan amount as % of capital cost.

(4) General : Single rate of depreciation It has been observed that for a power plant, depreciation is mainly on account of power plant machinery, step up substation and dedicated transmission line. Other items have little contribution, it will therefore save time , and labour if single depreciation rate is considered for power plant [ including pumping station, water pipe line, transmission lines , substation, building, etc excluding land (at zero depn rate) and temporary works (100% depreciation) ] instead of separate rate of depreciation considered for individual items. The same can be considered for a substation. Only when such assets are created outside a ower plant or substation , separate depreciation rates should apply.

(5) Para wise comments on para 14.6 are as under:

(a) well maintained power plants in all probability might have effected repayment of debt or operated for 12 years of useful life, Any enhancement of life will have marginal effect on depreciation charge / tariff.

(d) This should apply to new assets. For old assets, it may lead to retrospective adjustment of depreciation , profit of loss account , etc and will not be desirable

(e) For old assets it may not affect annual depreciation charges.For new assets it should be based on study. For transmission lines and substations can have longer life than presently specified but within their life span due to expansion of the system, they loss their significance

15 Differential AFC(para 37.20 and 37.21). Intent appears to be that generating stations should have better availability during peak demand period (of 4 months ) during the year. As peak period season varies from state to state in the region, it will be difficult to specify such periods of 8 and 4 months, Further 80% of AFC recovery in 12 months mean average 6.67 % of AFC recovery every month. additional 20% Additional recovery means AFC during 4 month (.e. average 5% per month above off peak recovery i.e. average 10.67% per month). This may result in ratio of peak and off peak as 175% which is too high and may result in neglecting availability of unit during off peak period. With this comments on points mentioned in para 37.21 are as under:-

(a) For ration of peak period AFC/month to offpeak period AFC/month of 125% , as suggested, off peak period recovery of AFC should be 61.5% in 8 months and peak period recovery of AFC as 38.5% in 4 months.

© Alternative can be recovery of AFC per month @ 7.95% of AFC upto 80% PAF. However, during peak 4 month's period, additional AFC/month shall be 0.1% for each 1% PLF above 80% with maximum of 95%.

16. Working capital requirement (para 20.3(b)):- Depletion of coal stock to precariously low level has been observed number of times. It will therefore be appropriate to have working capital requirement for fuel stock at the beginning of the month + receipts during the month subject to ceiling norm of 30 +30=60 days for coal, 15+30=45 days for mine mouth power stations. Tariff determination may be on norms but bills to be adjusted in every month based on previous month's opening stock plus receipts during the month and it is finally determined during true up.

17. Working capital requirement (para 20.3(c)):-Maintenance spares are considered as 15% of annual O@7M expenses which is prima facia high. Maintenance spares can be broadly classified as (i) those required monthly for operation of plant and (ii) those required for annual maintenance. Former like fuel stocks are received during the month and consumed during the month. Their cost may be conceived to be in proportion to monthly O&M expenses. While annual maintenance spares are arranged 3-4 months prior to annual maintenance and consumed in annual maintenance . considering these average stock may correspond to 6 month's consumption. From these considerations , considering O&M spares stock as 15% of annual O&M is high and may be limited to 15% of O&M spares for 6 months.

18. Surge and dips with change in norms (para 37.16) :- Norms are based on actuals so dips in revenue of genco will only be reduction in high profits derived due to norms. Such dips will not lead to operational loss. Revese will be the case with surge. There is no regulatory uncertainty as such norms are based on the principle of previous publication and anu change represents the fair value of the expenses. As such revised norms should apply both to existing as well as new power plants.

19. Return on equity (para 18) :- Initially the 16% return on equity was considered as Interest rate + 5% when average interest rates were around 11%. With rate of interest going down, it was brought down but still it is higher as per above principle. Following this approach, with bench mark rate of 10 year GOI bonds being 7.5%, ROE should be 12.5% for all new and old generation , transmission and distribution assets as cost of borrowing is the same for all. Additional incentive of 0.5% to be considered for transmission projects completed within prescribed time line and without cost overrun. For thermal projects, because of adequate capacity already built incentive is no more required. storage type hydro projects (including pumped storage) and gas based projects may have higher ROE as they can balance RE generation. With above backgrounfd comments on various points is as under:-

(a) Rate of return on equity should be brought down to 500 basis point above bench mark rate of 10 year GOI bonds

(b) Should be the same for all projects as cost of borrowing is the same.

(c) Additional incentive only for storage type hydro projects.

(d) The differential ROE will be harsher

(e) Should be switched over to pre tax return. ROE in term of paisa / kwh to be indicated in tariff order. Income tax (grossed up as per applicable rate) to be pass through quarterly based of CA certificate with its component per unit of sale.

(f) Normally there be no differential return based on unit size, length of line and size of substation. Higher return may be considered for first few higher unit size, higher substation size and higher length / voltage of line tried first time in India being established almost concurrently (i.e. in 2-3 years span).

(g) Dalay in project will result in cost over run and that beyond ceiling capital cost has to be mutually agreed with ROE.

20. . Allocation of Surplus capacity (CC less ACC) – (para 10.3). The proposal may become unworkable, if there are no taker for entire surplus capacity or very little capacity is bid by scrupulous bidder at exorbitantly high tariff. Thus, original discom as well as generating companies will not be comfortable with such cases. Alternative will be that discom may have right of refusal of very high bid rate (say > 110% of his tariff) and generating company to refuse applicability of very Low bid rate (say < 90% of tariff) for the applicability of this proposition and in that case, their obligation for full or part of the capacity will be the PPA tariff. No recall of capacity be permitted during the year out of the contracted capacity.

21. Tariff for sale of power by merchant power plants to discoms (page 9.3 ad 9.4):- The proposal is regarding determination of tariff for the capacity of merchant power plants remaining unutilized after Long & medium term supply under PPAc at negotiated tariff or tariff adopted under section 63 of the Electricity Act. Tariffs in such cases can be project specific tariff for entire capacity as other wise for part of the quantity, allocation of each item like capital cost, debt, equity, interest charges, depreciation, O&M etc will arise. Tariff is to consider incremental O&M only and may be based on variable cost as per norms and fixed cost based on depreciated cost determined from the prudent capital cost of the project as on commissioning date less normative depreciation, interest on debt, ROE without any incentive, part (say of O&M expenses representing incremental O&M (say R&M equal to 1/3$^{rd}$ of O&M) and target PLF as per CERC tariff regulations, This may be the ceiling tariff subject to discount as may be mutually agreed based on latest bid price. Fixed charges to be payable as per contracted capacity and variable charges as per schedule.

22. Bench marking of Capital cost (para 11, 37.6, 37.14, 37.15):-(1) Benchmarking of capital cost will not be feasible as per discussiobs at para 37.4 and 37.5. Allowing of compensation towards increase in cost due to uncontrollable events is required to place developer to the same economic position had the uncontrollable event not occurred (vide para 11.9) but for purchaser (hence ultimately consumers) it is not so, as his cost of power purchase enhances and in the meanwhile electricity at lower rate may be available from other sources. The alternative is that cutoff date principle to determine capital cost may be replaced by ceiling capital cost or upward cutoff for capital cost. A project report or tariff petition (for in-principle approval) need indicate cost of generation as per appropriate commission's norms (i.e. CERC norms) with its sensitivity to +ve variation in capital cost. Based on the these, ceiling of capital cost may be agreed by beneficiaries. If capital cost due to cost over run or time over-run or force majeure or any other uncontrollable events, envisaged to exceed the ceiling so agreed, between parties to PPA, it should be brought to the notice of beneficiaries and revised ceiling with other financial parameters to be agreed between beneficiaries and developer or else project be abandoned with compensation payable as per PPA.

(2) In respect cost beyond cut off capital cost, Allowing ROE as specified for approved project cost and ROE equal to risk free rate of interest will only give marginal reduction in ROE and will not address concern of discoms of higher purchase price.In the present scenario of surplus availability of generation capacity, incentive for early completion does not have economic sense. Delay in completion will certainly lead to capital cot increase and ceiling of capital cost to be negotiated will be enough deterrant.

(3) Benchmarking of capital cost will have disadvantage that after benchmarking , no or little data will be available for subsequent bench marking. Further benchmarking may miss some

important item or to account for abrupt changes in cost due to market conditions and taxes and it may then become difficult to determine capital cost. Bench marking of capital cost has disadvatake that if too liberal ( in initial capital cost or its indexing) it would be adverse to disconm and is too tight then to genco. In former case, consumer will be suffer & in latter case, project may not come up. In view of this project specific capital cost approach may be continued and range of capital cost per MW may be fixed (for example Rs. 6.63 crores per MW ± 5% ) within which there be lesser scrutiny and beyond which there may be rigorous scrutiny.

(4) Additional capitalisation (vide para 37.14 and 37.15).or capital cost beyond cut off (at any stage of the project life) or for life extension need be through revised DPRs , except for these due to change in law. These should have techno economic justification and consent of beneficiaries obtained. For additional capitlisation for life expectancy or to meet environment norms or additional requirement , life may be considered as balance life (as per regulations or with life extension) and component of tariff due to additional capitalization to be separately worked out and merged in annual tariff for the purpose of billing.

(5) It appears that deferred investment has been considered up to cut off date based on likely accrual liabilities (vide para 11.6(i) . This should not be considered. Only the works in progress and pending payments (for completed works ) upto COD and within ceiling capital cost need be considered on actual payments (and not on accrued liability basis).

(6) Normative AFC(para 37.17(e)): Tariff determination based on normative AFC may be oversimplification and with all parameters of tariff not reflected in simplification, it may ultimately lead to higher cost to consumer.

Yours

Shanti Prasad ,
Ex-chairman / RERC.