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The Secretary
Central Electricity Regulatory Commission
3rd & 4th Floor, Chanderlok Building
36, Janpath
New Delhi – 110 001

Sir,

Comments on Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024 for the tariff period from 1.4.2024 to 31.3.2029

With reference to your communication File No. L-1/268/2022/CERC dated 4 January 2024, we furnish our submissions / suggestions on the above draft Tariff Regulations for your kind consideration in three copies. We shall be grateful if the Hon'ble Commission recognizes our concerns and makes necessary modifications.

We also crave leave to submit at a future date further materials on the subject which may be available to us in the event we are of the opinion that the same would render meaningful assistance to the Hon'ble Commission in the matter.

Yours faithfully,

Executive Director
(Regulatory Affairs & Corporate Services)

Encl.

Comments on Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024

It is respectfully submitted that tariff for a significant part of generation, transmission and distribution assets / functions are determined by Appropriate Commissions under Section 62 of the Electricity Act, 2003. While the State Commissions and the Joint Commissions have completely separate jurisdiction, these Electricity Regulatory Commissions are guided by the Tariff Regulations framed by the Hon'ble Central Electricity Regulatory Commission ("**Hon'ble Commission**") while specifying terms and conditions for determination of tariff under Section 61 of the Electricity Act, 2003 and for determination of tariff under Section 62 of the Electricity Act, 2003. Therefore, the Tariff Regulations framed by the Hon'ble Commission hold immense importance for the entire electricity sector of the nation.

In this context, it is humbly submitted that generating companies / licensees under the superintendence of their respective State Electricity Regulatory Commissions often lack bargaining power / influence which is otherwise available to large Central Public Sector Undertakings, like NTPC Limited etc. The Hon'ble Commission is kindly aware about the ground realities which affect the generating companies, particularly in the matters of fuel supply, fuel quality, sale of un-requisitioned power, part load compensation for all set sizes and vintages for RE integration etc. The Tariff Regulations of the Hon'ble Commission, having an overarching impact on the entire power sector of the Country, may kindly be specified considering the ground realities and for units of various set-sizes and vintages.

CESC Limited is a distribution licensee as well as a generating company under the Electricity Act, 2003. Comments of CESC Limited on the draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024 are placed hereinbelow for kind consideration of the Hon'ble Commission.

(A) Capital Cost and Additional Capitalization beyond original scope- (Regulation 19 and 26)

In the draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024 (hereinafter referred to as "**Draft Regulations**") it has been proposed that capital cost of an existing generation project would also include capital expenditure necessary towards enabling of flexible operations of the generating station at a lower load as well as towards expenditure towards biomass handling equipment and facilities for co-firing. This is a welcome step considering the policy environment existing in the country, wherein various initiatives towards decarbonisation of the electricity sources entails adequate support from the existing thermal generating stations, without compromising on the grid security aspects.

There has been a lot of thrust on increasing the flexibility of operation of thermal generating stations. There has been a slew of recent Regulations, Reports and policy notifications like

i. Ministry of Power – Scheme for Flexibility in Generation and Scheduling of Thermal/Hydro Power Stations through bundling with Renewable Energy and Storage Power;

ii. CERC (Ancillary Services) Regulations, 2022;

iii. Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023;

iv. CEA Report on Flexibilization of coal fired power plant; and

v. Ministry of Power - Electricity (Promoting Renewable Energy Through Green Energy Open Access) Rules, 2022.

The essence of these policy formulations is focused on accommodating increasing share of Renewable Energy into the national grid, stipulating the flexibility requirements for operation of the thermal generating stations, as most of the sources of renewable energies are inherently unstable in nature. To introduce such flexibility in the operation of existing thermal power stations significant investments in control and instrumentation systems are necessary. The Draft Regulations have rightly addressed the concern of the generating companies, by allowing the same under additional capital expenditure beyond original scope and thereby as part of the capital cost, and therefore may please be incorporated in the final Regulations.

Further, the Ministry of Power, Government of India has recently announced the Policy for Biomass Utilization for Power Generation through Co-firing in coal-based power plants that urges thermal plants to blend 5-10% biomass pellets for co-firing along with coal. Biomass pellets have different chemical and physical properties than coal and are usually hygroscopic in nature. This entails different equipment and facilities for handling and storage of such pellets within the plant that involve certain capital expenditures by the generating companies. Incorporation of the capital expenditure for such biomass handling is a necessary and positive amendment in the Draft Regulations which ensures financial viability for the generating company.

(B) Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC)- (Regulation 21)

In the Draft Regulations it has been proposed (Clause 5) that in case the delay in project construction is on account of delay of receipt of clearance from statutory authorities pertaining to forest clearance, NHAI clearance, approval of Railways, acquisition of government land etc., maximum condonation would be allowed till 90% of the delay. It is submitted that such approach of limiting the condonation of delay is extremely prejudicial to the interest of the generating company or licensee, as the delay is attributable to the delay in action on part of statutory authorities but the financial burden of the same is proposed to be borne by the generating companies or licensees who have no control over sanctioning these clearances at all. This would increase the associated risk in the project and the cost of debt for such projects will go up due to such in-built risk. This will also discourage fresh investments in a sector which is vital for economic growth of the nation. Therefore, it is requested that the limit of 90% may please be removed, and condonation of such delay for computation of IDC and IEDC may be allowed in entirety, which is not attributable to the project developer.

(C) Return on Equity - (Regulation 30)

The Hon'ble Commission in the Draft Regulations have proposed to continue with the Return on Equity of 15.50% for existing projects. The same rate has been prevalent historically and has been preserved over the past Tariff Regulations. In this respect it is submitted that there is a necessity of the rate of return to be revised upwards given the need of supporting the growth of a sector vital to support the economy and protect the financial interest of the investors. For determination of the appropriate rate of return for a regulated sector, the CAPM method can be used to estimate the systemic risk in the sector. A detailed submission regarding an appropriate rate of return has been provided through **Annexure A** placed in this submission. It is humbly submitted that the Hon'ble Commission may kindly consider the same accordingly. CAPM model application would also require higher return on equity as detailed in the estimate provided.

Further, Return on Equity for emission control system and for additional capital expenditures on account of change in law and force majeure have been proposed to be allowed at SBI MCLR + 350 bps subject to a ceiling of 14%. It is submitted that such a restricted rate of return for new investments is extremely prejudicial to the interest of the developers and a return even lower than the existing ROE rate would substantially discourage any equity investment towards development of the sector. Moreover, in the preceding clauses of the Draft Regulations, the Hon'ble Commission itself has proposed to consider the rate of interest for debt towards installation of emission control systems at weighted average rate of interest for the generating company as a whole, subject to a ceiling of 14%, particularly in the backdrop of northward movement of both the risk and interest cost in recent times. Thus, treatment of the cost of equity capital and that of debt on the same footing is in entirety against the established economic principles and is significantly detrimental to the investors. Thus, such a lower rate of return for new investments must be avoided and the same must be aligned with the ROE rate applicable for existing projects.

It may be underscored given the requirement of investments to cater to power demand post covid economic resurgence and evidence of power shortages in past summers, Renewable investment (with risk of inherent instability) and conventional power plant viability (with its enhanced requirement to provide operational flexibility and fuel procurement) would require gross liability side approach for return. Even for renovation and modernisation, return on equity should be allowed on a gross basis, without adjusting for accumulated depreciation from admitted project cost.

(D) Depreciation for new projects (Regulation 33)

In the Draft Regulations the depreciation for new projects has been proposed to be spread over remaining useful life of the project after completion of 15 years instead of the existing 12 years. Typically, project loans are sanctioned for repayment within 10-12 years. At the same time the Draft Regulations propose to retain the method of computation of interest on loan capital on normative basis with repayment considered on normative basis equal to allowed depreciation. This has an artificial effect of reducing the Capacity Charge of the tariff.

However, adoption of this approach to reduce tariff will be entirely at the expense of the new project developer. The reasons are:

- Depreciation is the only non-cash expenditure for the project owner and the cash flow generated from revenue on this account is typically utilised for actual repayment of project loans.
- The depreciation allowed to be recovered under the extant Tariff Regulations is about 70% in the first 12 years. This is already not sufficient to meet the entire repayment requirement. Thereby the actual cash outflow for repayment requirements eats into the RoE, effectively reducing the realised RoE by a couple of % points from the normative extant RoE of 15.5%.
- Therefore, artificially reducing the depreciation further by stretching the recovery period for the initial block of 70% of capital cost will further reduce the cash flow of the project owner. Since the actual repayment requirement will not change, the enhanced differential cash outflow requirement for repayment will further erode the actual realised RoE.
- On top of the above proposal, the Draft Regulations have proposed to reduce the RoE to 15% from 15.5% for new transmission projects. This will reduce the realised RoE even more for the new projects.

- All the above put together is a serious disincentive for generating companies and licensees and nothing short of an impediment to desirous private investments in future.

Viability of a project depends on periodic cash flows during the life of the project. For assessment of project viability, cash flow estimates over a given life of the project were relied upon. Prolonging the recovery of capital cost by reducing the depreciation rate will adversely affect the cash flow from the project and consequently the reasonable return that the investor of the project had envisaged from such investment. Therefore, changes introduced during the project life will seriously affect the viability of the projects and will hurt further investments in the sector due to regulatory uncertainties. Therefore, it is submitted that the depreciation of new projects should be maintained in line with the existing projects only.

(E) Working Capital (Regulation 34)

The Hon'ble Commission has proposed the rate of interest on working capital @ Reference Rate of Interest as on 01.04.2024, wherein Reference Rate has been defined as MCLR+325 bps, down from the erstwhile MCLR+350 bps. It is humbly submitted in this context that the risk perception of the electricity business has enhanced significantly in light of the increasing uncertainties in the business and higher cost of finance in a high inflation environment. Therefore, it is humbly submitted that the interest rate on working capital may kindly be increased to account for the increased risks and allow the same at @ MCLR + 450-500 bps.

(F) Operation and Maintenance Expenses (Regulation 36)

In the Draft Regulations it has been proposed that any additional O&M expenses on account of force majeure or change in law event would be allowed only at the time of true-up in case such amount exceeds 5% of the normative O&M Expenses. It is submitted that such conditionalities in case of change in law or force majeure circumstances are restrictive in nature. The fulcrum of deciding a force majeure or change in law event is that the generating company or the licensee company has no control over the external environment and consequently, the expenses incurred under such circumstances are beyond their control. Therefore, any consequential impact must be allowed to be recovered at actuals so as to restore the same financial position for the company as if such an event had not occurred. At the same time delayed allowance for recovery of such expenses creates additional burden on the company as the cost of financing such expenses goes up unnecessarily. Therefore, this clause may please be accordingly modified so as to enable the generating companies and licensees to recover such expenses immediately through tariff.

It is proposed that the Hon'ble Commission may kindly modify the regulation to allow the generating company or the licensee to charge an additional amount in tariff to recover the expenses incurred on this count within a period of six months. Appropriate intimation to the Hon'ble Commission of factual position may be made immediately after expiry of this six-month period. At the time of final truing up the Hon'ble Commission may require the company to submit appropriate Auditors' Certificate for verification of the expenses incurred and recovery made for this purpose.

The Hon'ble Commission, guided by Tariff Policy, has so far and in these regulations, held the principle that where norm is applied, the entitlement should be based on norm only and not lower of actual or norm and this principle needs to be continued.

In the Draft Regulations the rate of escalation of O&M expenses has been proposed at the hybrid inflation rate of 5.89% (CPI : WPI = 60 : 40) worked out on the basis of the last 5 years average. In this context it is humbly submitted that consideration of a 3 year period is much more realistic as it captures the more recent trend of inflation movement. Therefore, a 3 yearly average may kindly be adopted as it would reflect the more recent trend of inflation, which works out to **6.43%**, as illustrated in the table below:

Inflation	2020-21	2021-22	2022-23	3 Year Average
CPI (%)	5.03	5.13	6.06	5.41
WPI (%)	1.29	12.97	9.60	7.95
CPI : WPI (60 : 40) (%)	3.53	8.27	7.48	**6.43**

(G) Wage Revision Impact (Regulation 36)

The Draft Regulations propose that any impact on account of wage revision for Central or State Government companies would be allowed only at the time of true-up. It is submitted that wage revisions for government companies are done based on stipulated guidelines with relevant statutory authorities and for private companies', wage revisions are done with some market-based benchmark references. Wage agreements, even in case of private companies, are statutory in nature. Periodic wage / salary revision for employees is a call of the time for both government and private companies. Therefore, allowance of impact due to wage revision should not be restricted to any amount but allowed at actuals. The companies may be allowed to charge the same through their Capacity Charge in the corresponding year, which would be under the ambit of true-up at the end of the control period. This would effectively mitigate any cash flow impact for the companies and alleviate any necessity of carrying cost / marginal working capital requirements. Further, it is also respectfully submitted that the rationale for differential treatment vis-à-vis private developers has not been clarified and such allowance should not be restricted only to government companies and is required to be extended to private developers as well.

(H) Treatment of Capital Spares (Regulation 36)

Capital spares of value up to INR 20 Lakhs have been proposed to be made a part of existing normative O&M expenditure. It is submitted that for capital spares, the process of allowing on actual basis may be retained. It is a fact that the incidence of capital spare is sporadic and non-recurring. Further, it is submitted that a few of the capital spares need to be kept in the inventory as they have high lead times of procurement and are much more expensive than tools / tackles or other smaller items they are proposed to be clubbed with. Considering that the capital spares support in reliable operation of major plant equipment, the same may be allowed to be treated as additional capitalization and made part of O&M expenses. Therefore, the practice of allowing all capital spare on actual basis may be continued. Maintenance spare can be continued to be a part of O&M expenses.

However, in case the Hon'ble Commission adopts the proposed methodology of inclusion of low value spares under Rs 20 Lakhs to be included under O&M expenses, it is submitted that that such amount must be allowed through increase in the normative O&M expenses as determined by the Hon'ble Commission.

(I) Additional O&M for Transmission Projects (Regulation 36)

In the Draft Regulations additional O&M expenses (to the tune of 5%) incurred for operating transmission lines in hilly regions in the country including North Eastern states has been proposed. It is submitted that there are other transmission projects with special features like river-crossing over wide navigable rivers that are significantly different from standard configuration of transmission lines and actually require higher maintenance expenses on account of riverine configuration including barges and jetties required for such maintenance activities. Therefore, it is prayed that such transmission lines with river-crossing over wide navigable rivers may also be included in the list of special cases and higher O&M norms may be allowed for these cases.

(J) Input Price of coal - Integrated Mine (Regulations 39, 40, 42, 48,53)

In the extant Tariff Regulations, for the mines allocated through auction under Coal Mines (Special Provisions) Act, 2015, there is no provision of inclusion of mining charge charged by the Mine Developer and Operator (MDO) in the ROM cost. Therefore, If a generating company having an auctioned mine, engages an MDO for the purpose of crushing, transportation, handling or washing, the same cannot be recovered under the current and the proposed Draft Regulations.

Ministry of Coal vide its clarification dated 17 January 2015 (Relevant extract furnished through **Attachment**) in “Queries & Responses to Standard Tender Document dated 27 December 2014” had clarified that charges such as transportation cost, crushing cost, washing cost etc. are allowable expenses while calculating the Energy Charge in relation to an auctioned coal mine.

Yet, in the proposed Draft Regulations, the cost of mining charged by the MDO including crushing, transportation, handling or washing charges are not included in ROM cost of coal mined from coal mines allocated through auction under Coal Mines (Special Provisions) Act, 2015. The Hon’ble Commission is requested to include mining charge, charged by the MDO including crushing, transportation, handling or washing charges in the ROM cost of coal mined from such mines. These are real costs incurred by the generating company for mining and transportation of coal. Therefore, suitable changes may be incorporated in Regulation 39 and Regulation 40 of the Draft Regulations before finalisation.

Since Input Price of coal from such mines consists of ROM cost of coal + Additional Charges incurred for crushing, washing, handling and transportation, any additional capital expenditure incurred for relevant infrastructure due to reasons such as complying with directions or orders of any statutory authorities, liabilities due to Change in Law or Force Majeure events etc. needs to be taken into account while calculating input price of coal. It is requested to make appropriate changes in the Regulations to take into account the effects of Additional Capital Expenditure incurred due to Change in Law or Force Majeure events or other similar reasons on the input price of coal from the coal mines allocated through auction under Coal Mines (Special

Provision) Act, 2015. Suitable changes may be incorporated in Regulation 39 and 42 of the Draft Regulations.

Hon’ble Commission is requested to make appropriate changes in the Regulation 48 to allow recovery of mine closure expenses for the coal mines allocated through auction under Coal Mines (Special Provision) Act, 2015 in line with those allocated through the allotment route.

Successful Bidder of a coal mine allocated through auction under Coal Mines (Special Provision) Act, 2015 are required to make payment of “Upfront Amount” and “Fixed Amount” to the relevant authorities. Hon’ble Commission is requested to consider amortization of such payable amount over the life of the mine and make suitable provision in the Regulation for inclusion of the same in the input price of the coal. Other provisions for consideration of captive mine costs and revenue may be allowed to continue.

Further, in line with the ‘Policy for Handling and Disposal of Washery Rejects’ dated 27 May 2021 published by Ministry of Coal, Government of India, the Hon’ble Commission has rightfully exempted integrated mines allocated through auction route from sharing of any such non-tariff income with the beneficiaries.

(K) Transit and Handling Loss (Regulation 56)

The Draft Regulations have proposed different norms for transit and handling losses based on the distance and modality of transportation of primary fuel. With the increased procurement needs of e-auction coal as well as supply of coal under FSA from mines not directly connected to existing railway infrastructure, it becomes imperative the same is transported using more than one mode of transport, including but not limited to road transport, riverways transport etc. These modes have different security measures as well as lot sizes that may not be adequately accounted for through a standard single normative loss level. Thus, allowing a higher level of normative transit and handling loss for multi-modal transport is a welcome development that alleviates some concerns of generating companies who procure coal through these modes.

(L) Gross Calorific Value of Primary Fuel (Regulation 60)

It has been mentioned in the first proviso to Regulation 60(1) of the Draft Regulations, that the onus of ensuring recovery of compensation as per the Fuel Supply agreement (hereinafter referred to as "**FSA"**) on account of grade slippage is on the generating station and accordingly it would pass on the benefits of the same to the beneficiaries of the generating station. It is humbly submitted that in terms of FSA between seller and generating station, seller generates credit and debit note and bills the generator depending on whether the analysed grade (at loading end) turns out to be inferior or superior to the declared grade. Therefore, any adjustment in cost of coal on account of grade slippage would only be limited to as per stipulated terms in FSA and the same would be passed on to the consumers / beneficiaries of the generating station. Pass-through of benefit to consumers on account of adjustment beyond the extent mentioned in FSA for coal heat value (i.e. grade slippage from loading end to unloading end), should not be the onus of the generating station.

The Hon'ble Commission is kindly aware that loss of heat value of coal occurs at multiple points before it is actually fired in the boiler. It is an established position, though an unfortunate one, that there is a nation-wide incidence of serious mismatch between the "as billed" and "as received" heat values of coal.

It is pertinent to mention that in the report of Forum of Regulators (FOR) on "Analysis of Factors Impacting Retail Tariff and Measures to Address Them" it is stated that,

"The GCV loss due to grade slippage between "as billed" and "as received" has been in the range of approximately 600 kCal/ kg."

"As per the fuel supply agreement (FSA) between the coal supplier and the generators, the coal supplier does not provide any compensation for surface moisture of coal upto 7% in dry season and 9% in wet season. Full compensation should be provided for the surface moisture as it has no heat value

Thus, Ministry of Power and Ministry of Coal need to find out a solution to the issue of grade slippage and losses due to moisture content….."

Hence, it is a well-acknowledged fact that there might be wide divergence between “as billed” and “as received” heat values.

‘GCV as received’ at the unloading end of a power station is the basis of computation of fuel cost and energy charge of generating stations. IS 436 (Part-I/Section 1) - 1964 dealing with collection, preparation and testing procedure of samples, needs to be considered as basis for derivation of the “as received” GCV and has been stipulated in the Draft Regulations appropriately.

It is a well-acknowledged fact that significant deterioration of heat value of coal occurs due to ingress of moisture. While equilibrated basis of determination of heat value for coal grade declaration and billing neutralises effect of temperature and humidity, the as received heat value at the unloading end is affected by the same. Therefore, moisture correction is required to be made in accordance with relevant Indian Standards (Clause 6.2 of Indian Standard (IS) 1350, (Part-II) - 1970) in order to arrive at the “as received” GCV. Regulations of the Hon’ble Commission may kindly be specified mentioning these Standards as well.

Considering all above, it is a welcome step proposed in the Draft Regulations to allow loss in calorific value of coal between as billed by the supplier and as received at the station at a ceiling level of 600 kCal/kg for non-pit head based generating stations in absence of any third-party sampling agency certified by the Ministry of Coal. It may be underscored that such difference is not merely on account of grade slippage but duly accommodates moisture adjustment due to different basis of reporting as well as effect of moisture ingress on transportation.

However, it is humbly submitted, that such loss in heat content of coal happens due to reasons stated hereinabove, which are not dependent on the source of coal procured. Hence, it is prayed for that, such margin of loss may also be kindly allowed for coal sourced from integrated mines and through import route.

In terms of Regulation 60, if a third-party sampling agency certified by the Ministry of Coal is present, GCV as received should be the basis for computation of energy charges. It is humbly submitted that actual tested heat value at the receiving end shall be the basis for computation of fuel cost and energy charge of the generating station even if the difference in heat value between the billing end and the receiving end is more than 600 kCal/kg. The As Billed Heat value is based on equilibrated basis neutralising effect of temperature and humidity which are not available for As Received Heat Value. Hence, application of moisture correction in terms of Clause 6.2 of Indian Standard (IS) 1350, (Part-II) - 1970 (or later versions) becomes a necessity. Approved Testing Agency (whether by CIL or designated Tester Listing Agency) is therefore to be considered sacrosanct to protect interest of the generators and the beneficiaries, being a transparent mechanism of determination.

It is also an acknowledged fact that loss of heat value happens during storage. A study conducted by the Central Electricity Authority with due consultations with notable experts in the fields, e.g. Central Institute of Mining and Fuel Research ("CIMFR") and Central Power Research Institute ("CPRI"), has recommended a margin of 105-120 kCal/kg for non-pit head stations towards stacking losses of heat value of coal received in power station and stored till firing of boilers. Thus, it may be stated that while it is possible to an extent to control the heat value loss within the station by the generator during storage, it is beyond the control of the generating station to minimize the loss between the as billed and as received heat values. As per the past experience, we believe that the loss of GCV due to storage may be greater than 85 kCal/kg. The loss depends on the Volatile Matter content of the coal and the number of days of storage. Storage of coal is inevitable since procurement of coal is not entirely under the control of the generator and often it is not possible to make the procurement synchronous with the generation plan. The final loss in GCV from coal stockyard to the point of feeding into the boiler, i.e., coal as fired may be higher than 85 kCal/kg if coal has been stored for a longer period of time.

(M)Plant Availability Factor for peak and off-peak period (Regulation 62)

The proposed Draft Regulations have rightfully removed the distinction between high demand season and low demand season. It is essential as a uniform low and high demand season for the entire country may not be reflective of the true demand patterns and may lead to administrative overhead for the load despatch centres. Consideration of overall plant availability factor on a cumulative basis for peak and off-peak periods also alleviates any risk of under-recovery of Capacity Charge due to shortfall on account of planned and/or scheduled outages, that otherwise was being restricted due to existence of a high and low demand seasons. Thus, the proposed amendment may please be considered for finalization.

(N) Incentive for generating stations (Regulation 62)

The proposed Draft Regulations have rightly increased the incentive applicable for generations more than the normative PLF to 75 Paise/Unit from the existing 65 Paise/unit. This is a welcome step as this would ensure higher despatch during peak demand periods and reward the concerned companies able to meet the demand at the same time.

Furthermore, an additional incentivization scheme for primary response (Average Monthly Frequency Response Performance - incentive up to 1% of the Annual Fixed Cost) is also a significantly affirmative step towards promotion of participation of generating companies in maintaining grid stability. This is vital given the increasing Renewable Energy penetration and should be included in the final Tariff Regulations.

(O) Blending of primary alternate fuel (Regulation 64)

The proposed Draft Regulations have done away with the requirement of prior permission from the beneficiary as well as restriction on the percentage increase in Energy Charge Rate in case of blending of coal. As determination of such percentage increase is often difficult to gauge considering the dynamic pricing of import of coal, it is imperative that such conditionality is rightly removed. Further, blending of import coal is primarily done through mandate / policy guidelines of the Ministry of Power, to alleviate power shortage scenarios and limiting such decision making based on cost economics alone would be both detrimental for the system as well as meeting of electricity demand. Further, the proposed clause of prior consultation with the beneficiary for blending beyond the normative ratio (6%) is also an affirmative directive, as it helps mitigate any concerns of respective stakeholder accordingly.

(P) Norms for operation of Thermal Generating Stations (Regulation 70)

I. Plant Availability Factor and Plant Load Factor (Regulation 70(A))

In the Draft Regulations normative operating parameters viz. Normative Plant Availability Factor (NAPAF) and Normative Plant Load Factor (NAPLF) have been specified. It is encouraging to see that vintage thermal generating stations, i.e., stations that have completed 30 years of operation from COD have been allowed a lower relaxed norm of 80%. This is a pragmatic view taken by the Hon'ble Commission and encourages older stations to participate in the electricity supply for the country.

However, availability of thermal generation stations is being considerably affected by coal shortage, integration of renewable plants, introduction of ancillary services market. Increasing Renewable Energy penetration in the grid would also lead to flexible despatch of thermal stations to meet the demand patterns, which in turn affects the plant load factors. Therefore, it is requested that the overall normative PLF and PAF may be considered for a mid-term review by the Hon'ble Commission considering the aggressive increase in renewable capacity addition coupled with a significant addition of renewable energy sources targeted within the control period.

II. Gross Station Heat Rate and Auxiliary Consumption (Regulation 70(C) and 70(E))

Given the need for renewable integration and vintage, there should not be any case for reducing Norm for Gross Station Heat for stations which achieved COD on or before 1.4.2009 and the value should not be reduced from 2430 kCal/kwh as existing but should be enhanced. Similarly for stations which achieved COD after 1.4.2009, it is imperative that margin over Design Heat Rate should be increased from 1.05 to at least 1.065 as existing prior to 2009-10. The variation in compensation should be appropriately given for different set sizes and although the approach paper proposed to provide the same, it is not elaborated. It is submitted that Heat Rate degradation only compensates the loss from the base operating conditions but level of loading and vintage needs to be factored in arriving at the base value. Compensation should also be provided for normative cost allowed and not on the basis of actual or normative, whichever is lower. Accordingly, irrespective of actual Heat Rate being lower or higher than the normative Heat Rate, the compensation of degradation should consider normative heat rate and the degradation factor needs to be applied on the normative heat rate only. Similarly, for auxiliary energy consumption and specific oil rate, degradation factors should be applied on the normative parameter, and not lower of normative or actual.

III. Norms for consumption of reagent (Regulation 70(F))

For Wet Limestone based Flue Gas De-sulphurisation (FGD) system and CFBC based generating station (furnace injection), the norm for reagent consumption depends on the sulphur content of the coal. While working out the norm for specific limestone consumption, the Draft Regulations provide for considering the weighted average GCV of coal in kCal/kg on ‘GCV as Received’ basis, computed in accordance with Regulation 60 of the Draft Regulations. However, it doesn't take into account the loss in heat value of coal due to storage of coal at the power stations (stacking loss).

It is submitted that in terms of Regulation 64(3)(a) and 64(3)(b) of the Draft Regulations, Energy Charge and Supplementary Energy Charge on account of emission control system is computed after accounting for reduction in heat value of coal on account of stacking loss at generating stations. Since, the limestone consumption will be required to reduce the sulphur content of coal used in the boilers after suffering this stacking loss, it is imperative that the normative determination of specific limestone consumption shall also be based on such coal, instead of the coal ‘As received’ at the power stations (as computed under Regulation 60). Therefore, it is submitted that similar reduction in heat value is also required to be considered while computing reagent consumption norm for Wet Limestone based FGD system and CFBC based generating station (furnace injection). We understand that the Draft Regulations (70(F)) may have inadvertently referred to Regulation 60 instead of Regulation 64(3). Further, such reduction in heat value may be considered in line with our comments for Regulation 60 of the Draft Regulations.

(Q) Sharing of Gains (Regulation 81 and 82)

In the Draft Regulations, gains on account of improved performance pertaining to normative station heat rate, auxiliary consumption, specific oil rate and towards interest saved through restructuring/ refinancing of existing loans have been proposed to be shared in the ratio of 1:1 with the beneficiaries. In this context, it is submitted that given that normative parameters are already stipulated, the licensee or the company undertakes stringent operational systems and processes that lead to such gains. These are attributable to enhanced focus and control by the companies, while the beneficiary has no active participation in realizing the same. Therefore, the proposed 1:1 gain share may please be aligned to be more reflective of the effort to reward outcomes and hence be modified to a ratio 2:1 in favour of the generator.

(R) Procurement through competitive bidding (Regulation 100)

The provision for procurement of equipment or services for developing projects through a transparent competitive bidding process, is a prudent approach considering the market dynamics driving efficiency and allowing for the lowest cost discovery for the same. The Draft Regulations have proposed for procurement through other methods under general financial rules under exceptional circumstances. However, to avoid future conflict regarding definition of exceptional circumstances or procurement in general, it is requested that an enabling provision for exemption of such mandate may please be provided for equipment or services of less than INR two (2) crores (a paltry amount considering the entire capital cost). This would provide for required flexibility to the utilities to handle emergency situations. Alternatively, it is suggested that the Hon’ble Commission may also specify the major contracts for which competitive bidding is mandatory and for the rest, it would be optional.

(S) Rate of Interest for Carrying Cost

In the Draft Regulations the rate of interest towards carrying cost in case of receivable by the licensee / generating company has been proposed to be allowed at SBI

MCLR+100 bps while in case of refund (in case of excess tariff determination by more than 10% or in case of truing up of excess capital cost) the rate has been proposed to be 1.20 times the SBI MCLR+100 bps. It is humbly submitted that such skewed treatment of carrying cost, i.e., at a lower rate in case of receivable while a higher rate in case of refundable scenario is detrimental and prejudicial for the companies. It is a settled principle of law that equitable treatment must be adhered to for similar circumstances. Therefore, it is submitted that such a multiplier of interest rate in case of refund may please be made the same as the rate applicable in case of recovery.

Moreover, rate of interest for carrying cost has been proposed at a rate substantially lower than interest rate applicable for interest on working capital. It is respectfully submitted that such differential treatment will be prejudicial for the stakeholders.

It is also submitted that to capture the true essence of “time value of money”, carrying cost needs to be allowed at compound interest rate and not on simple interest rate. Shortfall in recovery is met through borrowing and the financial institutions charge the generators on the basis of compound interest rate. Denying carrying cost at compound interest rate will be detrimental for the sector as a whole.

(T) Part Load Compensation

The Draft Regulations did not provide any compensation mechanism for part load operation. It has been stated in the Explanatory Memorandum that CERC, in accordance with IEGC, 2023 will specify a fresh compensation mechanism based on CEA’s recommendation separately through Regulations / Order. In the Draft Regulations, though the norms have been made stringent compared to the extant Tariff Regulations, compensation mechanism for part load operation has not been introduced. However, without analyzing the compensation mechanism for part load operation it is difficult to comment on the newly prescribed norms. It is prayed that considering the CEA recommendations, the compensation mechanism for part load operations may also be provided in the Tariff Regulations.

It is also prayed that the degradation factor applicable for compensation should be applied on normative parameters and not on the basis of actual or normative, whichever is lower as suggested by Tariff Policy and followed by the Hon’ble Commission consistently in these Regulations.

ANNEXURE - A

Rate of Return on Equity

For determination of the appropriate rate of return for a regulated sector, the CAPM method can be used to estimate the systemic risk in the sector. For such exercise, it may be prudent to study the companies in the benchmark indices for the Power and Utilities sector. Their stock returns reflect the systemic risk in the business. The same systemic risk may be applied to a regulated entity to estimate the requisite normative return on equity for the businesses.

The formula for computing the return on equity based on CAPM is as under:

$\mathbf{R_e = R_f + \beta_e \times (R_m - R_f)}$

Where:

R_f = risk-free rate (that can be earned by investing in a risk free security, e.g., a Government of India (GOI) bond)

β_e = equity beta (most electricity/energy regulators calculate beta using a group of companies comparable to the target utility)

$R_m - R_f$ (Market Risk Premium [**MRP**]) = equity market risk premium (the extra yield that can be earned over the risk-free rate by investing in the stock market)

β_e is an indicator of the systemic risk, which reflects the volatility of stock with respect to the market index. However, in addition to reflecting the nature of operations within an industry and the efficiency of the company in such operations, returns on a particular stock also vary according to the capital structure of the company. In this respect, $Beta_{asset}$ (β_a - Unlevered Beta) is estimated to measure the return on equity for a company, by eliminating the effect of capital structure. β_a is used to estimate the expected return on equity for a stock assuming it has zero debt.

In the context of determination of MRP, it is submitted that, while determining the market rate, a 30 year period has been adopted, in order to capture the rationalised trend of market dynamics.

The CAPM model may be illustrated through the following examples -

The listed companies present across the value chain of the electricity sector constituting the BSE (Power) index may be considered as the true representative of the Power sector. Accordingly, for assessment of cost of equity, the stocks considered for determination of BSE (Power) index have been considered.

$Beta_{quity}$ (β_e), Debt / Equity Ratio and Tax rate for each of the companies have been obtained from www.morningstar.in website, as presently available.

Tax rate (T_a) for the regulated entity has been considered at MAT rate (25.168%). The same has been applied for companies in the sample where the actual tax rate is not available.

Market return has been worked out on the basis of yearly average of BSE S&P Sensex movement over the last 30 years (1995-2024), which works out to **14.1%**.

Value of β_a for all the companies has been considered as the sector representative beta value and has been used to derive from the β_e for the regulated entity by applying the following formula :

$$\beta_a = \beta_e / [1+(1\text{-Tax rate}) \text{ X } (D / E)],$$

where, D / E is the Debt-to-Equity ratio.

Calculation of Expected Rate of Return for the listed Power companies in BSE Power Index based on Capital Asset Pricing Model (CAPM) Analysis

Sr. No.	Name of the Company	Beta Equity (β_e)	D/E	Tax Rate (T_a) [1]	Beta Asset (β_a)
1	ABB India Limited	1.04	0.01	24.7%	1.03
2	Adani Green Energy Ltd.	1.36	5.66	33.6%	0.29

Sr. No.	Name of the Company	Beta Equity (β_e)	D/E	Tax Rate (T_a) [1]	Beta Asset (β_a)
3	Adani Power Ltd.	1.13	0.62	25.3%	0.77
4	Adani Energy Solutions Ltd.	2.04	2.83	33.7%	0.71
5	BHEL	1.68	0.00	5.5%	1.68
6	CG Power	2.44	0.01	21.2%	2.42
7	JSW Energy Limited	1.01	1.14	23.7%	0.54
8	NHPC	0.62	0.68	9.8%	0.38
9	NTPC	0.88	1.25	26.6%	0.46
10	Power Grid	0.56	1.23	14.0%	0.27
11	Siemens Ltd.	0.88	0.01	25.7%	0.87
12	Suzlon	1.38	0.02	0.5%	1.35
13	Tata Power	1.35	1.22	27.6%	0.72
	Average				**0.88**

Now, β_e is calculated with a normative debt to equity ratio of 70:30, with a Tax Rate of 25.168%. This yields β_e as follows:

$$\beta_e = \beta_a \times [1+(1-\text{Tax rate}) \times (D/E)]$$

$$\text{So, } \beta_e = 0.88 \times [1+(1-25.168\%) \times (70/30)] = 2.43$$

Beta	β_e	2.43
Risk Free Rate	R_f	7.3%
Market Return	R_m	14.1%
Market Risk Premium	$(R_m - R_f)$	6.8%
Expected Rate of Return	R_e	**23.8%**

As evident from the above exercise, the cost of equity works out to about 24% for the power sector. A similar exercise has been done for the Utilities sector as outlined below.

Listed companies of the electricity sector constituting the BSE (Utility) index, which may be considered as the true representative of the Utilities sector. Accordingly, for assessment of cost of equity, the stocks considered for determination of BSE (Utility) index have been considered.

Calculation of Expected Rate of Return for the listed Power companies in BSE Utilities Index based on Capital Asset Pricing Model (CAPM) Analysis

Sr. No.	Name of the Company	Beta Equity (B_e)	D/E	Tax Rate (T_a) [1]	Beta Asset (B_a)
1	Adani Energy Solutions Ltd.	2.04	2.83	33.7%	0.71
2	Adani Green Energy	1.36	5.66	33.6%	0.29
3	Adani Power Limited	1.13	0.62	25.3%	0.77
4	Antony Waste Handling Cell Ltd	0.72	0.56	24.7%	0.51
5	CESC Ltd	1.41	0.92	18.6%	0.81
6	Gujarat Industries Power Co. Ltd	0.95	0.17	23.5%	0.84
7	Orient Green Power Company Ltd	0.87	0.88	25.2%	0.52
8	Inox Green Energy Services Ltd	1.06	0.06	25.2%	1.01
9	Jaiprakash Power Ventures Ltd	1.66	0.36	42.3%	1.37
10	JSW Energy Ltd	1.01	1.14	23.7%	0.54
11	KPI Green Energy Ltd	1.12	1.89	18.4%	0.44
12	NAVA Ltd	1.19	0.22	3.9%	0.98
13	NHPC Ltd	0.62	0.68	9.8%	0.38
14	NLC India Ltd	1.04	1.15	33.1%	0.59

Sr. No.	Name of the Company	Beta Equity (B_e)	D/E	Tax Rate (T_a) [1]	Beta Asset (B_a)
15	NTPC Ltd	0.88	1.25	26.6%	0.46
16	Power Grid Corporation of India Ltd	0.56	1.23	14.0%	0.27
17	PTC India Ltd.	1.22	0.82	25.4%	0.76
18	Reliance Infrastructure Ltd	1.43	1.23	18.2%	0.71
19	Reliance Power Ltd	2.59	0.89	25.2%	1.55
20	RattanIndia Power Ltd	0.90	0.00	25.2%	0.90
21	SJVN Ltd	0.62	1.15	25.1%	0.33
22	Tata Power Company Ltd	1.35	1.22	27.6%	0.72
23	Torrent Power Ltd	0.69	0.80	27.3%	0.44
24	Waaree Renewable Technologies Ltd	0.80	0.26	27.6%	0.67
25	Va Tech Wabag Ltd	1.91	0.09	31.9%	1.80
	Average				**0.74**

Now, β_e is calculated with a normative debt to equity ratio of 70:30, with a Tax Rate of 25.168%. This yields β_e as follows:

$$\beta_e = \beta_a \times [1+(1-\text{Tax rate}) \times (D / E)]$$

$$\text{So, } \beta_e = 0.74 \times [1+(1-25.168\%) \times (70/30)] = 2.02$$

Beta	β_e	2.02
Risk Free Rate	R_f	7.3%
Market Return	R_m	14.1%
Market Risk Premium	$(R_m - R_f)$	6.8%
Expected Rate of Return	R_E	**21.0%**

The above exercise shows that the return on equity allowed on a normative basis should be not less than 21%.

Therefore, for the generation sector, RoE should be provided in the range of 21% to 24% considering the risk involved in the sector. The companies should be financially sustainable in this rising power demand scenario. Therefore, adequate return should be provided to attract investment in the power sector in preference to other sectors, which is also a stated policy of the Government of India, as pronounced in the Tariff Policy.

For additional capitalisation, investment related to emission control system and for investment in new projects, it is similar to infusion of capital, hence, RoE equivalent to existing projects should be made applicable both for additional capitalisation and for the new projects.

RoE should not be linked to the G-SEC rates/MCLR/RBI Base Rate, as the risk profile involved with the cost of equity is not equivalent to the cost of debt, hence CAPM based approach should be adopted for determination of RoE, as suggested.

It is submitted that for determination of the rate of return, judicious assessment of the existing market scenarios needs to be considered. Risks associated with financing are directly attributable to higher returns and the same may be considered. It may be brought to the attention of the Hon'ble Commission that the current market scenario for thermal projects has significantly become riskier owing to the multiple changes that the environment is undergoing, including policy level initiatives to high level of RE integration in the system. Although demand has picked up in the country post Covid-19, PLFs of the thermal generators continue to remain lower. In spite of higher RE capacity addition, it is submitted that thermal power still accounts for over 70% of the electricity supplied. Therefore, considering the criticality of thermal stations providing reliable supply of electricity, it is extremely important that the investors are adequately compensated for the associated risks they are undertaking. Hence, the same risk-reward principle may be followed for ascertaining the rate of return.

Attachment

Auction of Schedule II Coal Mines

Queries & Responses

To

Standard Tender Document

Dated December 27, 2014

Part IV (Power Sector specific queries)

Nominated Authority
Ministry of Coal
Government of India
New Delhi

January 17, 2015

S. No.	Query	Response
9	**Clause 3.10.2 The aggregate of (i) the Price Offer pursuant to which the Successful Bidder has received the Vesting Order; and (ii) the aforementioned amount of INR 100/Tonne, will be used for computation of energy charge for the purposes of determination of tariff for electricity.** 1. Whether there will be a cap on Energy Charge (including transportation) for the existing PPAs?Clarity on cap on energy charge (throughout the tenure of the existing PPAs) for already contracted generation capacities as stated in Clause 2.4.2 (f) of the Approach Paper is extremely essential to ensure that tariff does not go up. 2. What about statutory levies and other permissible component of energy charge (including transportation)? There are multiple components of the energy charge (esc/ non esc - energy & transportation charge). It is requested that the an illustration for a Case-1 project may kindly be provided taking into account the existing provision of energy charge typically included in such PPAs and how would this new provision related to coal bidding be used for new energy charge formulation with treatment for each sub component (such as ROM Price; processing charges & other within the mine cost; taxes & levies; and transportation cost) explained adequately. 3. Kindly clarify as how transportation component shall be dealt with in case of already contracted capacities as the escalation for transportation component is different than that of fuel charge? Can it be revised upward or considering cap on energy charge it can also only be revised downward? As transportation charge constitute a very significant portion of energy charge. It is extremely essential to put a cap on the same as well in case of already contracted PPAs to ensure that power tariffs do not go up. If the transportation charge in existing PPA is higher than the transportation charge with the Coal Mine, the same should be readjusted to lower amount but overall transportation charge in the existing PPAs should be capped.4. Other statutory taxes, duties and levies are payable in addition to the price offer and INR/Tonne. Hence, this clause is to be accordingly modified. The same has been provided for in Cl.2.4.2 (f) of the Approach Paper for Auctioning of Coal Mines. 5. The consideration on how the energy charges under existing PPA will be impacted due to allotment of captive coal under auction will be a critical factor for participation in the auctions. Hence, the following scenarios on how the PPA tariff will be impacted may kindly be clarified:Let us say, the actual cost based on final price offer from the mine allotted under auction works out to be as follows:Coal Cost – Rs. 0.50/unit; Transportation Cost – Rs. 0.40/unitFor the above mine, how the existing PPA tariff under following four scenarios will be revised shall please be clarified.a. Scenario 1: PPA Tariff: Coal Cost – Rs. 0.60/unit; Transportation cost – Rs. 0.20/unitb. Scenario 2: PPA Tariff: Coal Cost – Rs. 0.60/unit; Transportation cost – Rs. 0.50/unitc. Scenario 3: PPA Tariff: Coal Cost – Rs. 0.40/unit; Transportation cost – Rs. 0.20/unitd. Scenario 4: PPA Tariff: Coal Cost – Rs. 0.40/unit; Transportation cost – Rs. 0.50/unit 6. The bidder has to pay Reserve price of Rs.100/Ton as well as 10% of Intrinsic value /compounded annuitized reserve price over mine life. In addition to above various taxes and duties like Excise duty, VAT, Clean Energy cess, Stowing Excise duty and Royalty etc. are to be paid in percentage of CIL notified price instead of Bid price per ton of coal.In case of typical CIL notified price, these taxes and duties will result in app. 30 paise per kWh in the tariff. This is in contradiction to the stated intent of the Government that the power tariff should remain as low as possible. To keep the power tariff to minimum, it is suggested that royalty, taxes & duties payable should be linked to the Bid Price/ton of coal produced instead of CIL notified price. 7. Following conditions of tender documents are not in line with current Policy and Regulations;a. As per Tender documents escalation under cost plus PPA will be allowed as per Standard Bidding Document, however as per Electricity Act and Tariff Regulation cost plus PPAs are always pass through. We believe like Case 2 PPAs cost plus plants or capacity tied up under cost plus should not be allowed to bid.b. In the current Provision of SBD, there is no separate cost element of Transportation cost for captive power plants as these was premised based on captive power plants are very closed to Mine and cost of transportation cost is to be considered as part of mining cost.	Energy charge shall be determined in accordance with the Methodology for fixing Floor/ Reserve Price for auction/ allotment of coal blocks published via notification No. 13016/9/2014-CA-III dated Dec 26, 2014 by Ministry of Coal. The same may be accessed at the website of Ministry of Coal. The said Methodology mentions that the Appropriate Commission shall, while reviewing/determining the energy charge, factor in other allowable expenses and permissible components of such energy charge and ensure that it does not lead to higher energy charge throughout the tenure of the PPA. It is expected that the Appropriate Commission, while discharging this responsibility, shall use appropriate benchmarks in terms of transportation costs for the relevant mode(s) of transportation and CIL's costs for washing and crushing charges etc. to prevent undue gain to the Successful Bidder on these counts.