Views of GRIDCO on CERC Approach Paper for Determination of Tariff Regulations FY 24-29 Period

1. Tariff Determination – General Approach

Tariff design based on first year tariff as the base year with indexation for balance life period shall not be a prudent approach on account of various variables which cannot be forecasted for the entire project life period requiring frequent revisions. Further, it would be very difficult to capture all revisions adequately through indexation because of considering the price index need not be justified due to the impact of inflation on various cost attributes. Therefore, present methodology is quite prudent and realistic and works well within the Tariff framework adhering to the public policy.

Drawback of Approach-1 methodology:

1. Suggested approach will require components to be escalated annually for each project as otherwise it will not correctly gather the rate of interest charges as would vary from year to year over the control period.
2. It will not cater to the contingency towards swapping of loan resulting in benefit to generating company/transmission licensee.
3. It will not cater to O & M expense varying at higher than indexed rate.
4. It will not cater to statutory changes in income-tax rates and other tax rates.
5. The debt market in India is yet to be stabilize, thus the present situation is pre-matured to be considered for implementing such approach, based on first year tariff with indexation for the balance life.

Moreover, the basis and the rate of indexation for each generating station by the Commission would be quite subjective and would bring wide variation as compared to the cost-plus approach as the normative approach would be based on assumptions, which may not match with the ground realities on operation of the plant. Thus, the normative basis for the sake of ease in calculation would definitely be a set back to the Cost-Plus Tariff regime.

The proposal for continuation of present practice for Energy Charges, for both new and existing generating stations based on actual fuel cost and normative performance parameters as currently allowed would be equally applicable for determination of AFC being currently followed in the interest of all the stakeholders.

The existing MYT methodology i.e. **Approach-2** may be continued. The basis of MYT should be for implementation of simple and comprehensive tariff structure which would be well understood by the investor as well as the beneficiaries and the stakeholders. Introducing new concepts in every MYT period will bring about Regulatory Uncertainties over the life of the project. It is therefore submitted that new concepts are quite assumptive and shall not adhere the Cost Reflective Tariff, thereby vitiating the National Electricity Policy and carrying little understanding for the beneficiaries and the stakeholders. Thus, the proposed Approach-1 may not introduced in the greater interest of the sector.

2. Procurement of Equipment and Services

Purchase and sale of power in India are regulated business. The Appropriate Commissions are empowered u/s 62 to determine the tariff as per the Regulations framed under Section 61 of the Electricity Act, 2003 at which the Distribution Companies purchase power from the generators. The cost of generation, transmission and distribution is ultimately borne by the end consumers. Further, Section 62 of the Electricity Act, 2003 specifies that the Appropriate Commission, while specifying the terms and conditions for the determination of tariff shall safeguard consumers' interest and at the same time ensure recovery of the cost of electricity in a reasonable manner. Therefore, it becomes inevitable that the same can only be achieved through award of work and services contracts for developing projects through a transparent process of competitive bidding, duly complying with the policy/guidelines issued by the Government of India from time to time. Further, it is also suggested that E-Reverse Auction may be adopted for better price discovery.

3. Reference Cost for Approval of Capital Cost – Benchmark Cost V/s Investment Approval Cost

Investment approval costs generally address the concerns of the investors and developers and is not intended to optimize the capital cost from the consumers perspective. Therefore, a model / benchmark cost may be notified by the Commission which can be used as a yardstick for the purpose of prudence check. The benchmark cost / model may not replace the price discovery based on International Competitive Bidding (ICB) tendering process. Rather, it may be used for defining boundaries through the variables sheet and may not replicate the micro detailing which normally is the prerogative of project proponent/manufacturer.

While carrying out prudence check, the model will be used to identify outliers (considering the deviations in boundaries in actual case and the model) as possible cases for carrying out further/detailed prudence check and assessing the reasonableness of the capital cost. Based on the principle of 'Management by Exception', this process will lead to saving of resource and time spent on conducting prudence check while admitting the capital cost. Model may be kept dynamic so that changes based on fresh inputs/additions can be made as per needs to reflect market trends. Ultimate comparable cost for prudence check will be the overall cost and not package wise cost. Optional packages may be accounted separately. In no case investment approval, be considered as benchmark cost and the Commission may allow the reasonable capital cost after prudent check.

4. Capital Cost for Projects acquired post NCLT Proceedings

It is perceived that the tariff under Section 62 needs to be determined on the cost-plus principle, therefore, the acquisition value should be considered. Further, if the acquisition price is higher than the historical value, the same may be capped at the historical value of such assets, as consumers should not be burdened with premium quoted for the asset. Tariff provisions to be included to address the issue of the cost of debt servicing, including repayment, interest on Working Capital and O&M only during the CIRP process. No RoE, benefits of Other Income, gains out of improved performance be allowed to the generating / transmission companies during this period.

5. **Computation of IDC – Post Scheduled COD**

   It may be noted that the quantum of IDC depends on phasing of fund allocated for the entire project. Any delay during the project construction period has a ripple effect on extending the SCOD. Therefore, the impact of such delay can be handled by timely correcting the course by crashing of activities / parallel work / putting more labour during the project execution through continued project monitoring. Distributing the entire IDC across the project execution life cycle shall not be appropriate as the same shall not be in tandem with the fund utilized. Therefore, the Option-1 i.e. existing mechanism wherein the pro-rata deduction (based on delay not condoned) is done on IDC beyond SCOD may be continued.

6. **Treatment of Liquidated Damages**

   The approach laid down by the Hon'ble APTEL in Judgment in Appeal no. 72 of 2010 for treatment of liquidated damages may be adopted. The utilities may be directed for furnishing Auditor's Certificate with regard to LD collected / to be collected from the vendors. Necessary changes may be made to the additional capitalisation forms so that such information is submitted along with the tariff petition.

7. **Price Variation**

   Any variation in price due to delay in achieving SCOD needs to be accounted for, since, all such costs have price implications. Therefore, for allowing price variation (both positive and negative), the utilities may be mandated to submit the statutory auditor certificate along with the Petition duly certifying the price variation corresponding to delay both before and after SCOD and the same may be allowed on pro-rata basis corresponding to the delay condoned. Any reduction in price should also be considered by the Commission.

8. **Renovation and Modernization (R&M)**

   Regulation 28 of the CERC Tariff Regulations for FY 19-24 provides for 'special allowance' as compensation for meeting the requirement of expenses including renovation and modernization beyond the useful life of the generating station or a unit thereof. The Special Allowance admissible to a generating station has been allowed @ Rs 9.5 lakh per MW per year for the tariff period 2019-24 in the Regulations. With emergence of new technologies, the efficiency of the plants has improved. Therefore, the amount of Special Allowance to be allowed against R&M of the plants need to be revisited in light of the same.

9. Delay towards obtaining Forest Clearance and Servicing Impact of Delay

The Power Plants are required to obtain certain clearances and approvals for setting up their generating units as per appropriate policies / rules / regulations etc. Such clearances and approvals include private land acquisition, Govt. Land allotment, allocation of forest land and forest clearance, conversion of land use pattern to non-agricultural purpose, allocation of land for fuel transport, RoW for power evacuation line, water drawl permission, Environmental Clearance, Defense Clearance etc.

The Commission while framing the CERC Tariff Regulations, 2019, in its Explanatory Memorandum observed that land acquisition and Right of Way issues have been largely outside the control of the project developer. It may be noted that apart from construction of power projects getting all the relevant clearances and approvals from the appropriate authorities are also responsibility of the project developer. The Commission while framing the Regulations for FY 19-24 considered land acquisition and RoW as an uncontrollable factor.

It is very difficult to ascertain whether the approvals and clearances are attributable to the generating company or the transmission licensee in absence of any such confirmation / affidavit from the appropriate authority. Therefore, extending the list of uncontrollable items and gradually bringing in more clearances and approvals under its ambit shall send a wrong signal to the beneficiaries and discourage the developers from putting their efforts for timely completion of projects and shall burden the end consumers. In view of the above, it is suggested that any delay to be condoned by the Commission should be supported by confirmation / affidavit from the appropriate authority with mention of reasons for delay and the forest clearance should not be included under the list of uncontrollable items.

Most of the approvals and forest clearances are obtained from the Govt. agencies. Therefore, the cost of such delay cannot be loaded on the beneficiaries and the concerned departments cannot be held free from obligations. In case the delay is unpredictable and cannot be controlled by the generator / transmission companies then, the beneficiaries should not suffer for the same. It is suggested that, in view of such helplessness situation of the generator / transmission companies, the Commission may direct them to first obtain all the clearances which are uncontrollable, before proceeding for execution of the projects so that both cost and time overrun can be contained.

10. Additional Capitalisation

Additional capitalisation under CERC Tariff Regulations, 2019 is allowed within the original scope of work executed up to cut-off date (Regulation 24), executed after the cut-off date (Regulation 25), beyond the original scope of work for safety and security, Change in Law, Arbitration Award, Force Majeure, deferred works related to the ash handling system (Regulation 26), Renovation & Modernization. (Regulation 27), revised emission standards (Regulation 29).

It has been proposed in the Approach Paper that an enabling provision may be introduced to existing Regulation 26 for allowing expenses if they are found to be beneficial/essential for continued operations. In this regard, it is suggested that only if the additional capitalization is inevitably required and also can be helpful in reducing the resultant tariff of the power plants, then such cost may be allowed by the Commission after prudence check and due consideration of views/ recommendations / objections / suggestions of all the beneficiaries.

It has been proposed that a special compensation based on the analysis of actual additional capitalisation incurred by the generating stations in the past may be allowed in form of yearly allowance which shall not be subject to any True-up and capitalisation. It may be noted that the developers should strictly abide by the timelines and cut-off date for capitalizing their assets and cannot be allowed over indefinite time period for such works. Allowing normative special compensation in lieu of additional capitalisation shall be a burden on the beneficiaries and shall contribute to increase in tariff. Therefore, the proposed special compensation is scrupulously opposed.

11. GFA/NFA/Modified GFA approach

CERC Tariff Regulations permit depreciation till recovery of 90% of the capital cost and Equity infusion up to 30% of capital cost. The generating company/transmission licensees is allowed full RoE on gross equity infused even when the cumulative depreciation exceeds the debt repayment. This has allowed creation of internal resources. This provision catered capacity augmentation required to meet the peak and energy deficit that the country was facing a decade ago. Now the situation has changed, and the actual peak demand met is above 96% (MW) for FY 22-23 as per the LGBR report. Investors' confidence in the power sector has already been enhanced which is evident from the investments received during last couple of years. Now power from RE sources are gradually dominating the market due to their low-cost clean energy. Unless the cost of thermal and large hydro power is lowered, the costly power from such sources may lose their affordability in near future. Therefore, NFA approach may be adopted and no scope for creation of internal resources be allowed. The prevailing Regulations has not addressed the following:

i. Depreciation is allowed for normative loan repayment as per prevailing Regulations. (Ref: Regulation 32 (2), (3)). After repayment of entire loan amount, depreciation is allowed up to 90% of the capital cost of the asset. So, there is additional margin of 20% for the depreciation for which there is no requirement of loan repayment.
ii. The investor / developer gains out of depreciation after repayment of loan till 90% of the value of the capital cost
iii. The investor / developer gets full RoE on the gross equity value of asset even though the value of asset has reduced due to depreciation over the years.

In view of the above, it is suggested that:

i. The depreciation may be used to repay both the debt and equity component proportionately.
ii. During the repayment of equity component, the RoE may be calculated on the residual net equity and not on the gross equity.
iii. During the repayment of loan component, the interest on loan may be continued to be calculated on the residual loan amount after deduction of cumulative depreciation as per the prevailing Regulations.
In view of above GRIDCO proposes for NFA approach.

In addition to the above explanation on Modified GFA is required for providing suggestions.

12. O&M Expenses

Thermal generating stations operating in the country are combination of both old and new units. The generating stations, which have been commissioned in the last 10 years, shall not require large O&M expenses for running of the plant. Similarly, older plants, which have served their scheduled life, may be given the option of phasing out, instead of incurring high exorbitant costs on Renovation and Modernization followed by large Operation and Maintenance expenses in the subsequent years and moreover with running of the plants at low PLF, becoming less competitive to other Generators. As the O&M expense norms for old and new thermal stations are common, the beneficiaries are forced to bear the additional expenditure in the form of capacity charges, which also results in higher fixed cost. Therefore, separate norms should be devised for allowing O&M expenses for older plants and newer plants. Also, separate norms may be provided for operation of transmission assets located in difficult terrain.

Regarding, segregation of Employee cost and other O&M cost, it is suggested that any Pay/Wage Revision impact may be treated separately as the same cannot be predicted in advance. It may be noted that the Commission in past has allowed the pay revision of the employees in excess of the notified trajectory (Ref: Petition No. 392/GT/2020, Order Dated 29.03.2023). Further, the wage revision % cannot be predicted in advance. Therefore, the impact of pay revision should not be allowed on normative basis as the same is neither repetitive nor recurring in nature. However, the Commission shall have the option to consider the same at the time of Truing-Up. It should also be considered that the wage revision impact should be limited to actual expense over and above the normative expense. Further, in case the normative O&M expense is more than the actual expense including wage revision then no additional amount should be allowed in this regard. In view of the same, the wage revision may be allowed on case to case basis after prudent check.

13. Inclusion of Capital Spares

Initial spares and maintenance spares (part of O&M expenses) are already allowed on a normative basis and it’s only the capital spares that are allowed on an actual basis as per the existing Regulations. Regulation 23 of the CERC Tariff

Regulations, 2019 provides ceiling norms for Initial spares to be capitalised as a % of the Plant and Machinery cost. The Hon'ble Commission may revise the same in light of the improved technology and revised requirement of the power plants.

In the Approach Paper it has been suggested that the Capital Spares may be projected on normative basis or low value spares below Rs. 20 Lakh may be made part of normative O&M expenses, while for capital spares with a value in excess of Rs. 20 lakh, shall be reimbursed on a case to case basis. No explanation for considering Rs. 20 Lakh as threshold value has been provided in the Approach Paper. It is submitted that since the capital spares are non-recurring and sporadic in nature and cost of the same cannot be predicted in advance. Therefore, it may only be allowed on actual basis by the Commission after prudence check.

14. Depreciation

The bankability of the power sector especially, the power generation business has improved in comparison to the previous years and has gained momentum with increasing demand of energy for rapid industrialization. So, nowadays loans are available with 15-18 years of repayment period for large capital projects. Foreign Soft Loans with much lower interest rate and long repayment period of 25 years are also available. Therefore, the existing as well as the upcoming Generators may necessitate the option for swapping of loan and reduce their finance costs through low interest rate and increase the repayment tenure. This shall be helpful in reducing front loading of tariff. In view of the same, depreciation rate may be specified considering a loan tenure of 18 years and additional provisions may also be specified for allowing lower rate of depreciation to be charged by the generator in the initial years upon mutual agreement with the beneficiaries.

15. Interest on Loans

It may be noted that the transmission licensee majorly undertakes projects for capacity expansion at various locations and accordingly cost is distributed across various project locations. Such costs are very low in comparison to the generation projects. Therefore, it is a cumbersome task to ascertain one to one co-relation between such transmission assets and loans and requires considerable time and effort. However, this case does not hold good for the generation projects which require substantial capital investment. Therefore, for approval of interest on loans, the weighted average actual rate of interest of the transmission licensee may be considered and for generating company interest on loans may continued to be calculated separately for each asset / project.

16. Return on Equity (RoE) V/s Return on Capital Employed (RoCE)

In RoCE approach, the return on total capital employed is allowed on the basis of weighted average cost of capital (WACC), wherein the cost of debt and equity needs to be estimated for the computation of the WACC. Fluctuation of Interest Rates make benchmarking the cost of debt difficult to predict and there is requirement of annual determination of WACC due to progressive change and reduction in capital employed over the period. Therefore, the current RoE approach may be continued.

17. Rate of Return on Equity

Additional Capitalisation on account of Change in Law and Force Majeure conditions are not in control of the generating / transmission licensees and beneficiaries. Therefore, such additional capitalisation should not be used as a means to make profit by the companies. However, rate of RoE, more than the Interest on Working Capital (IoWC) and less than the RoE of the capital cost of the project i.e. 15.50% in this case, be allowed for such additional capitalisation. Further, the rate of return on the equity contribution may be revisited by the Commission and redetermined under changed market conditions on yearly or bi-yearly basis. RBI lends money to commercial banks or financial institutions in India against government securities at the Repo rate. Changes in Repo Rate affects the flow of money in the market and the same may be considered as a base for redetermination of RoE.

The low-risk assets like the transmission assets may be allowed lower RoE in comparison to the thermal and hydro power plants. The power plants which have outlived their lives may be allowed a lower rate of return than the new plants. Also, timely completion of the hydro projects may be incentivized in terms of additional RoE of 0.5% for attracting investments.

18. Rate of Return – Old Thermal Generating Station

Old generating stations have already outlived their lives and repaid their debt obligation. They are getting special allowance for R&M, therefore no additional incentive should be allowed for such generating stations. It may be noted that by allowing such incentive the landed cost of the power shall increase and may make the plant uncompetitive.

19. Interest on Working Capital

It is submitted that the prevailing working capital norms may be retained. As observed in the Approach Paper the PLF of the gas based generating stations has remained around 20%-25% in recent years. It is agreed that that these generating stations will continue to operate at such low PLFs in the next tariff period due to their high cost. Therefore, the working capital requirement of gas based generating stations may be recalibrated considering their actual working capital requirement in the last 3 years.

20. Life of Generating Stations and Transmission System

GRIDCO appreciates the proposal of extending the useful life of coal based thermal generating stations and transmission sub-stations to 35 years. It is a fact that these assets need to operate beyond 25 years with regular operations and maintenance functions to be carried out by the utilities.

The need for higher repair cost allowing a special allowance or provision of R&M may be continued after 25 years after getting consent of all the beneficiaries. It may be mandated that for availing such allowance or R&M the generating companies shall submit the cost benefit analysis, technical feasibility study report. The Commission may allow such expense on case to case basis considering all the reports, analysis and submissions from the beneficiaries.

21. Sharing of Gains

Regulation 62 of the prevailing CERC Tariff Regulations, 2019 provides that non-tariff net income in case of generating station and transmission system from rent of land or buildings, sale of scrap and advertisements shall be shared between the beneficiaries and the generating company or the transmission licensee, as the case may be, in the ratio 50:50.

It may be noted that Non-Tariff Income comprises but not limited to the following:

a. Income from rent of land or buildings;
b. Income from sale of scrap;
c. Income from investments;
d. Income from sale of ash/rejected coal;
e. Interest income on advances to suppliers/contractors;
f. Net Income from supply of electricity by the Generating Company to the housing colonies of its operating staff and supply of electricity by the Generating Company for construction works at the generating Station, after adjusting the expenses incurred for supply of such electricity;
g. Income from rental from staff quarters;
h. Income from rental from contractors;
i. Income from hire charges from contactors and others;
j. Income from advertisements;
k. Income from sale of tender documents;
l. Income from sale of Gypsum (By product of lime stone)

All the above-mentioned sources of Non-Tariff Income are additional income for the generating companies apart from RoE which are not being shared with the beneficiaries. On the other hand, the DISCOMs are sharing the entire Non-Tariff Income with the consumers. It may be noted that the entire cost of setting and running the power plants and transmission assets are borne by the beneficiaries. Therefore, the Commission may consider for sharing the entire non-tariff income of the generating and transmission companies, with the beneficiaries in the ratio 50:50. It shall be helpful in reducing the AFC and making the cost of power affordable to the consumers.

22. Treatment of interest on differential tariff after truing up

GRIDCO supports that the rate of interest on the differential amount of tariff needs to be followed as per the current practice of allowing a simple interest rate as per Regulation 10(7) to be continued for the Tariff block period 2024-29. Further, interest may be allowed to be charged on the differential amount by the utility only until the issuance of the Order, and no interest may be allowed during the recovery in six equal monthly instalments.

23. Peak and Off-Peak Tariff

The concept of peak and off-peak tariff was introduced for thermal generating stations to incentivize peak period availability and availability during peak demand season. Shifting the recovery based on daily peak and off-peak periods shall be a cumbersome exercise and shall involve more precise scheduling and accounting. Most of the consumers of the State belong to domestic category and have limited variation in load. The domestic consumers shall be affected by shifting to recovery based on daily peak and off-peak periods as the cost of the peak power shall more evenly distributed across all the categories of consumers. Therefore, it is suggested that the prevailing practice of declaring high demand and low demand season may be continued in the interest of the consumers at large.

24. Operational Norms

It is evident from the figure that the Central Generating Stations that used to operate at around 80%-85% PLF prior to FY 2013-14 have now been operating at part load and much below the target PLF due to the need for higher RE integration. However, for determination of norms of low load operations a study on the impact of the power plants operating in low load may be conducted and such analysis may be made available for views / suggestions of the beneficiaries. The normative availability of the new plants may be fixed at 90% in view of technical advancement and improved performance.

25. Compensation for Part-Load Operations

From the Approach Paper, it is observed that an Expert Committee has been constituted for evaluation of compensation of operational performance for determination of gains and losses. The report from the Committee may be made available and norms may be fixed in consultation with all the stakeholders.

26. Gross Calorific Value (GCV) of Fuel

GCV of fuel is the primary determinant of the power cost which is considered for the computation of the Energy Charge, payable by the Distribution Companies/Power Utilities to the Generating Companies. The ratio of SHR and GCV gives the quantity of coal used per unit of electricity generated. Therefore, GCV being used for the computation of energy input becomes important as any increase/reduction in GCV decreases/increases the admissible coal consumption affecting the cost of power.

Energy Charge constituting about 60-70% of the total cost of generation tariff has major impact on cost to end consumers. In order to balance the interest of both the generating companies as well as the beneficiaries, the measurement of GCV of coal used for generation needs to be scientifically accurate as the true representative of the coal consumption is required.

The “GCV As Billed” is indicative of total energy content dispatched by the suppliers and normally paid for by the recipient stations. The "GCV As Received" is expected to be same as “GCV As Billed”. "GCV As Fired" is computed at the time of actual use of coal in the generating unit for power generation.

In the entire value chain from mine end to generating station end, the grade of GCV presumed to be same and if any grade slippage occurs, the beneficiaries have no control over the same and the additional cost due to reduction in GCV of coal is being borne by them.

Since the cost of slippage in grade of coal between the loading point and the site of generating station is ultimately passed on to the beneficiaries, this issue needs to be looked at in terms of risk allocation to the generator. The generators need to be given target for reducing the GCV loss from the mine to boiler.

It is only the generator who is billed for coal and should ensure the Quality and Quantity of Coal. The Commission has already fixed norms for allowing slippage in GCV due to storage of coal at the generating station. In similar lines, CEA may be requested to conduct a study and estimate normative loss between “GCV As Billed” and "GCV As Received" for non-pit head plants. Such normative value may be adopted for calculating the GCV of coal received at thermal generating station. In this case, the OERC Regulation 3 (ff) may be referred where “GCV as Received” coal is found by considering “GCV As Billed” and allowing an adjustment for total moisture as per the formula given as under:

$$\frac{GCV \times (1-TM)}{(1-IM)}$$

where: GCV = Gross Calorific Value of coal

TM = Total Moisture

IM = Inherent Moisture

Further, for pit head plants “GCV As Billed” should be considered as "GCV As Received" as the distance between the coal mine and the plant is very less.

27. Blending of Coal

Regulation 43 of CERC Tariff Regulations, 2019 specifies that, where the energy charge rate based on weighted average price of fuel upon use of alternative source of fuel supply exceeds 10% of base energy charge rate as approved by the Commission for that year or exceeds 5% of energy charge rate for the previous month, whichever is lower shall be considered for which prior consultation with beneficiary shall be made at least three days in advance.

The proposal of linking the consent of beneficiaries with % blending of imported coal instead of an increase in ECR shall lead to rise in ECR abruptly without any upper limit. Such increase in ECR cannot be passed on to the consumers frequently which otherwise will be a tariff shock. Further, low-cost coal is also available in the market and the coal scarcity scenario is less likely to happen. It is requested that the current provision of linking the consent of beneficiaries to increase in ECR for blending of coal may be continued.

28. Above all, GRIDCO reserves its right to add further submissions/views or as and when required by the Hon'ble CERC.