Comments and suggestions on CERC Approach Paper on: Terms and Conditions of Tariff Regulations for Tariff Period 1.4.2024 to 31.3.2029

Ref. No: PEG/2023/37

The Central Electricity Regulatory Commission (CERC) published an approach paper on the 'Terms and Conditions of Tariff Regulations for Tariff Period 1.4.2024 to 31.3.2029', dated 26 May 2023 and asked for comments and inputs from the public.

In the interest of ensuring efficient and simplified sector operations while safeguarding consumer and sector interests and gaining clarity on the approaches proposed, Prayas (Energy Group) has the following inputs and comments:

1. Discouraging Section 62 and benchmarking tariffs

Simplifying the tariff setting process is a key objective of the approach paper. Discouraging new Section 62 projects and encouraging the competitively bid Section 63 route instead would be the easiest way to simplify the tariff setting process, both for generation and transmission projects. If the Commission has to consider new Section 62 projects at all, benchmarking of their tariffs to recent Section 63 projects of comparable capacities and technologies could be explored.

Prayas' analysis of TBCB based ISTS transmission projects (67 projects) shows that their price discovery is on average 34% lower than CEA benchmark cost estimates (a glimpse of the analysis in 3 visualisations can be seen here). This suggests the need for improved cost benchmarking. Further, there are likely to be differences between CEA's estimated cost for RTM projects and estimates from PGCIL's investment board approval data and the final capitalization figure approved by CERC for tariff determination. Thus, CERC should come out with the study report comparing the CEA cost estimates, both for RTM and TBCB projects and the final discovered prices (TBCB) and approved capital costs by CERC for RTM projects. This will help in improving benchmarking.

2. Provision of historic data

Exhaustive stage/unit level operational data from central and some state generators for FY13-FY17 was published along with the draft Tariff Regulations for the previous control period (FY19-FY24). Such data provision is crucial towards ensuring transparency and accountability of operations, while also ensuring effective engagement in the regulatory process. Toward ensuring continuation of this good practice, the Commission should seek stage/unit level operational data and O&M expenses for the last control period and publish it with the draft regulations for FY24-FY29 as well.

For ISTS transmission assets, tariffs are determined for each project/scheme separately irrespective of the ownership. Considering the large number of such schemes in the country and hence the large number of tariff orders issued by CERC every year, there is no consolidated data about the actual ISTS charges levied at national level by each developer. So, we suggest that CERC should publish a consolidated list of all ISTS lines/schemes for each owner and a consolidated table of all ISTS lines (irrespective of ownership) with relevant techno-economic data on its website annually.

3. Preparing business plan for regulated capacity under central generating companies

Central generators, like NTPC and NHPC, are major actors in the sector and have significant regulated capacity. Given that their projects impact power procurement planning across multiple states, it will be useful for central generators to come up with a business/resource plan for every control period, outlining the details of projected capital investments under Section 62 in the time period and providing justification for the same. This becomes very important for new Section 62 thermal and hydro capacity. Since such capacity has long gestation periods and lifetimes, it may become unviable in a rapidly changing electricity sector and impose an unnecessary financial burden on procurers over long periods of time. Such a business plan can then be approved by the CERC following a public process, subject to the Commission being satisfied about the need for such investments and subject to prudence checks. This practice is already followed by many state level utilities and it helps to provide clarity to sector stakeholders, not only about cost and expenses over the coming control period, but also about capacities and projects in the pipeline.

4. Considering tariff approval at the generating company level

Currently, tariff approvals are undertaken for each asset (stage/unit of generating station) under CERC's jurisdiction separately. As on date, under this case by case treatment, only around 40% of NTPC capacity have tariff orders for the last control period (2019-2024), even as it comes to an end. As a step towards simplification of tariff approval, such a process could be carried out for the generating company as a whole, wherein the generator submits a single petition with details of all the plants whose tariff needs to be determined. All the relevant procurers and the broader public can participate in the tariff setting proceedings, following which a single tariff order can be issued for all the plants of the generator. This is the process followed for all state-owned generating companies.

5. Scrutinising of capacity additions including new coal-based replacement capacity

The approach paper discusses the need to augment the country's generation fleet to meet its growing demand, including bringing on board thermal capacity. However, as seen in figure 4 (all India Plant Load Factor (%)) of the approach paper, while the PLF of the thermal fleet has increased post Covid, it is still well below the normative PLF (which for most thermal plants is around 80-85%)[1]. Optimisation of the existing fleet should be considered and implemented before any coal-based or hydro capacity addition is considered, given its increasing unviability and potential for long-duration lock-ins.

Further, it is good to note that the merits of operating older, economical stations reliably and efficiently toward addressing growing demand and facilitating integration of growing renewables have been recognised. However, in Section 2.8 (b) of the approach paper, one option for older capacity going forward, is its replacement with more efficient coal-based units.

[1] It is understood that increasing PLF is subject to constraints of when such capacity is and can be deployed, in response to demand variations.

As with any other coal-based capacity additions, such replacements too should be carefully scrutinised since the generator typically bears little or no risk for Section 62 capacity addition (including replacement). Any coal-based capacity that comes online now is likely to be capital intensive (as recognised in the approach paper), and will only increase the cost of generation. Additionally, given the useful life of TPPs, they will remain in the sector and could potentially cause resource lock-ins till 2050 and beyond, leading to fixed cost liability for the procurers and their consumers which may not be warranted.

6. Reflecting risks in the sector

In the interest of attracting investments in the sector, the approach paper significantly focuses on de-risking investments. For instance, in Section 2.4 (3), the approach paper states that a key objective is to provide a push to encourage private investments *"through Assured Returns, Mitigation of Risk Perception, and Regulatory Certainty"*. However, this should not result in a situation of underplaying genuine risks and providing false certainties in an increasingly dynamic sector, where new thermal and hydro investments are indeed risky. Therefore, the focus should be to balance the need for investments while recognising the genuine risks inherent in a dynamic sector.

7. Challenges in considering the Normative approach for tariff setting

7.1. Simplification introduced Is unclear

The first alternative discussed in the approach paper is the normative approach, which aims to device an asset specific normative tariff and eliminate the need for periodic tariff setting. This is done toward simplifying the tariff setting process.

However, there will still be a truing-up process required for the 'AFC excluding O&M component', as per 3.2 (1) (c), for which the Commission has to be approached. Similarly, separate petitions are expected to be filed for seeking approval on additional capital expenditure. Given that, even currently, the Commission is mostly approached for truing up and approval of additional capital expenditure, it is unclear how the suggested approach will simplify the regulatory process related to tariff setting/approval.

7.2. Suggested method for indexation

The tariff indexation specified under section 3.2 (1) (b) is carried out with regard to the previous year (AFC component as computed for the N^{th} year/AFC component as computed for the $N\text{-}1^{th}$ year). However, if the N^{th} or $N\text{-}1^{th}$ year is an outlier, that bias will be unrealistically reflected in the indices of all future years. Instead, it is suggested that the indexation is specified based on the performance of the plant over the last 5 years (say N, N-1, N-2, N-3, N-4) as follows.

4 indices can be computed by considering consecutive years (AFC component as computed for $N\text{-}3^{th}$ year/ AFC component as computed for $N\text{-}4^{th}$ year; AFC component as computed for $N\text{-}2^{th}$ year/ AFC component as computed for $N\text{-}3^{th}$ year; AFC component as computed for $N\text{-}1^{th}$ year/ AFC component as computed for $N\text{-}2^{th}$ year; AFC component as computed for N^{th} year/ AFC component as computed for $N\text{-}1^{th}$ year). The lowest of these 4 should then form the basis of indexation for future years.

7.3. Need for data transparency

It is crucial to note that the simplification proposed under this approach should not be conflated with lesser transparency and data availability. Even if such a simplified method of tariff setting is adopted, generators should be mandated to continue data reporting of operational parameters, expenses, etc. The tariff regulations must, thus, ensure data reporting by the generators happens periodically to ensure transparency in the sector and accountability of operations. Unfortunately, even now generators do not report data pertaining to GCV, price of fuel, blending ratio, etc. on their website even though this is mandated as per the second proviso of Regulation 40 (2) of the CERC MYT Regulations 2019, The Commission should ensure that generators adhere to such regulations.

7.4. Need for periodic revision of tariff regulations

Section 3.2 (1) (g) of the approach paper states that *"For future tariff periods, the AFC of the existing projects, including servicing of additional capitalisation shall continue to be governed as per the CERC Tariff Regulations, 2024"*. Periodic revision of tariff regulations are crucial toward reflecting the fast changing realities of the sector. Toward ensuring that the regulations maintain relevance, their review and required revision at the end of each control period must be retained.

8. Inputs on financial aspects that affect tariff

8.1. Questionable need for providing higher RoE for timely completion of projects

Section 4.2.4 discusses the capital cost of hydro generating stations, and towards expediting construction has considered providing higher return on investments/equity for projects completed in a timely manner. In Section 4.16, it is stated that *"Hydro generating stations except ROR based are already allowed 1% higher RoE, however, not much capacity addition has been witnessed in recent times due to delays so additional RoE in the form of timely completion of projects may also be an option to attract investors"*. Therefore, since experience suggests that even the provision of higher RoE is not sufficient to attract investments or curtail delays, further increasing the RoE is not a feasible solution.

Timely completion of the project is the responsibility of the project proponent, and they should as such be held to this standard rather than providing extra incentives to achieve it. CERC's past Tariff Regulations for FY09-14 and for FY14-19 had provisions to allow a 0.5% additional RoE if a new project was completed in accordance to set timelines. The tariff regulation for FY19-24 have done away with the provision of allowing additional RoE for timely completion of projects. This should be continued, and the Commission could instead consider penalising delayed project completion with lower RoE instead of an incentive for timely completion.

8.2. Considerations while computing RoE

In Section 4.16, toward the computation of Rate of Return on Equity, the approach paper discusses linking the RoR with market interest rates. Linking the RoR with G-Sec rates by adding a modest risk-premium could be considered since Section 62 projects inherently have very low risk.

Further, the methodology considered for such computation historically has been the CAPM method. Market risk premium is a parameter that contributes to the computation of RoR under CAPM. The approach paper defines this as the extra yield that can be earned over the risk-free rate by investing in the stock market and proposes computing this parameter through any method, including the Survey Method. Firstly, as stated earlier, investments in Section 62 projects by generators are much less risky than investing in the stock market and hence the risk premium as calculated from stock market returns is not appropriate for such projects. Secondly, the Survey Method could be subject to biases and errors, and it would be more reliable if transparent and verifiable methods were considered. The Commission should devise a formula to link RoR with G-Sec rates keeping these factors in mind.

In Section 4.16.2, 'Differential RoE', the Commission notes the FoR recommendation for 'differential RoE for Generation and Transmission Businesses with a reduction in RoE for Transmission Business'. Given the low risks for transmission and the high level of savings in TBCB projects vs RTM, we feel that the CERC should implement the FoR recommendation in this matter.

8.3. Ensure penalisation of delays when computing IDC

Toward the computation of IDC, the approach paper in Section 4.4.1, proposes two alternatives in addition to the existing practise of disallowing excess IDC on a pro-rata basis for any uncondoned delay beyond the SCOD, these are as follows:

- Pro-rata IDC may be allowed considering the total implementation period wherein the actual IDC till implementation of the project is pro-rated considering the period up to SCOD and period of delay condoned over total implementation period
- IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay

The former alternative is preferred. However, if the latter alternative is chosen, even if the actual IDC is below the IDC in the Investment Approval and there is a delay in the commissioning of the project, there needs to be some penalty for the delay in project commissioning.

8.4. Consideration of delays in Forest Clearances as an uncontrollable factor

While it is important to reduce bottlenecks to timely project completion, it is also crucial to ensure accountability of the generator to adhere to timelines. If a measure as proposed in Section 4.8 is considered, it should be subject to strict scrutiny of the utility's role in procuring such clearances in a timely manner, and delays in obtaining Forest Clearances should be deemed as an uncontrollable factor only after the Commission is satisfied on a case-to-case basis that the delay is not attributable to the generator.

8.5. Ensure Interest on loans is on project specific basis

In Section 4.14, the approach paper proposes the approval of IoL on the basis of WAROI of the generation/transmission company instead of considering project specific IoL. However, it is preferable to continue to adopt project-specific IoL, because the difference in interest rates across projects is likely due to differences in their respective risks or bankability. Adopting WAROI would mask such differences across projects and lead to an increased cost for the less risky projects while decreasing it for those deemed risky – which is not desirable.

8.6. Extension of life to 35 years must not translate to extension of PPA

Given that it is better reflection of ground realities and actual plant operation, it is a step in the right direction to extend the useful life of these transmission and coal based generation projects to 35 years from the current 25 years, as suggested in Section 4.19.

However, durations of PPAs should not be deemed to be extended along with such extension of life of the plant. Beneficiaries should continue to have a say in whether they want to procure power from the plant during the extended period, and should not by default be saddled with generation from plants on account of their extended lives.

Further, to ensure prudence, the R&M to be undertaken after 25 years, or alternatively the special allowance accepted, should be subject to sufficient scrutiny. For instance, if the plant is mostly run to meet seasonal or daily peaks, and therefore is used sparingly, the justification of such expense may merit review. Similarly, if the plant avails special allowance, then it should be accountable to show corresponding performance improvement.

8.7. Servicing impact of delay based on cost disallowance

The rigorous pursuit of approvals from statutory authorities is the responsibility of the project proponent and lapses in such follow up lead to delays on account of inefficiencies, which may impact the consumer. To encourage follow up with authorities and to ensure accountability the approach paper in Section 4.9 suggests three options:

- Even if delay beyond SCOD on account of clearances and approvals are condoned, some part of the cost impact (Say 20%) corresponding to the delay condoned may be disallowed.
- Alternatively, RoE corresponding to cost and time overruns allowed over and above project cost as per investment approval may be allowed at the weighted average rate of interest on loans instead of a fixed RoE.
- The current mechanism of treating time overrun may be continued, considering that utilities are automatically disincentivised if the project gets delayed.

The third option does not encourage accountability from utilities as there is little penalty on them for overruns, and the status quo is likely to remain if it is opted for. The first two options are likely to provide good signals to the generator with regard to follow up and timely completion of projects. Among them, the first option is better suited, since disallowing some part of the cost of even condoned delay will prove a strong deterrent to inefficient action leading to delays.

8.8. Input Price of Integrated mines:

The input price of coal from integrated mines is eventually passed on to consumers. The existing formulation of computing the input price is not consistent with the objectives of offering coal mines for captive use to power plants through allotments and auctions under the Coal Mines (Special Provisions) Act, 2015 and related Rules. If coal from a captive mine were to be more expensive than CIL notified price for the same grade, then it would be better for consumers that the coal is procured from CIL. The reason for allotting captive coal mines 'free' to power companies is so that they could obtain coal at a lower price. The following official communications reinforce this point that the objective of allocating captive mines to power generators was to reduce power tariffs:

- As per 3.2(e) of the directive from the Ministry of Power to CERC, dated 16.4.2015, on supply of electricity by generating companies where the coal is being sourced from coal mines allocated under CMSP, Second Ordinance, 2014: "*The revision of tariff undertaken by the Central Electricity Regulatory Commission as above shall not lead to higher energy charges and total tariff throughout the tenure of Power Purchase Agreement than that which would have been obtained as per terms and conditions of the existing Power Purchase Agreement.*"
- The methodology for fixing floor/reserve price for auction and allotment of coal mines/blocks, prescribed by the Ministry of Coal states, in Clause (3) with regard to coal mines/blocks allotted for specific end-uses, that: "*This would ensure that there is no adverse impact on power tariff.*"
- Additionally, Clause (4) of the methodology, that deals with auctions of coal mines/blocks, also highlights the objective of reducing power tariffs, as it states: *"A ceiling price of CIL notified price for each coal block will be fixed and the bidders will be mandated to quote lower than this ceiling price"* and *"…This method will ensure that the benefit of lower bid price is passed through to the consumers."*

In view of the above, the RoM price of coal for integrated mines should be capped at the CIL notified price for the corresponding grade of coal, to be consistent with the objectives of allotting coal mines for captive consumption. Maharashtra ERC has adopted such a measure in the second amendment to its 2019 MYT Regulations.

8.9. Consideration for normative rate of Interest on Working Capital

CERC's current regulations adopt the normative rate of 1 year SBI MCLR plus 3.50% for IoWC. This is more relaxed than the IoWC norm adopted by GERC (1 year SBI MCLR plus 2.50%) and MERC (1 year SBI MCLR plus 1.50%). As per GERC's discussion paper on multi-year tariff for FY25-29, it proposes allowing IoWC at a rate equal to 1 year SBI MCLR plus 1.50%, in accordance with the practise followed by MERC. Given that central stations have more bankability, the lower normative rate for IoWC (of 1 year SBI MCLR plus 1.50%) should be adopted by the Commission and applicable to central plants as well.

8.10. Positive steps

The approach paper has outlined some positive steps, these include:

- Continuing special allowance (in lieu of R&M) for the rest of the tariff period, if the utility opts for it at the beginning of the tariff period, though this should be subject to the utility demonstrating some performance improvement.
- Consideration of acquisition value during tariff setting of projects acquired post NCLT proceedings
- Disallowing price variation for uncondoned delays, and allowance of pro rata price variation on the basis of audit certificate for condoned delay
- To avoid front loading of tariffs and to reduce resistance to investments a loan tenure of 15 years instead of the current practice of 12 years

9. Inputs on operational parameters that impact tariff

9.1. Availability norms

Section 5.1.1 discusses the Normative Annual Plant Availability Factor (NAPAF). Given the changes in the sector, there is merit in reviewing the existing norms. Availability norms could, for instance, be estimated on the basis of received domestic FSA coal in the past year. There have been significant improvements in domestic coal supply recently, and coal supply is unlikely to be a barrier for availability.

9.2. Incentives

Toward the suggested approach in Section 5.10, separate incentives for specific plants (old pit head/hydro) should not be considered, as such plants are likely to be competitive and will generate in most cases. Any incentive mechanism considered should be applicable to all plants uniformly.

With regard to the incentives themselves, the PLF incentive is primarily required in peak demand periods to incentivise low-cost generation from non-pithead plants by encouraging them to procure low-cost coal so that they are high on the MoD stack. The incentive is over-and-above the cost of procuring coal which is anyway pass-through (and over-and-above the RoE to the developer) – hence it can be modest. The current incentives of Rs. 0.65/kWh in peak hours and Rs. 0.5/kWh in non-peak hours are very high and should be revisited.

On the other hand, higher availability should not be incentivised and existing provisions with regard to availability should continue, with AFC being pro rata reduced for availability below the norm. However, there is value to encouraging plants to be available during peak hours. In order to encourage this, the existing tariff regulations already provide a higher weightage of AFC recovery during peak hours. Going forward, the Commission should consider increasing this weightage and extending this treatment to high demand months/seasons (in addition to peak hours), as coal-based and hydro plants are likely to increasingly be required to supply electricity primarily during peak demand periods.

9.3. Peak/Off-peak tariff

Considering daily peak and off-peak periods, as discussed in Section 5.2, and high/low demand seasons, are useful toward ensuring a responsive/flexible system. Toward further strengthening such flexibility, as mentioned in Section 9.2 of this submission, the weightage of AFC recovery allowed during peak hours could be further increased and a similar seasonal weight for AFC recovery during high demand months should also be considered.

Currently, regulations require peak periods (months and hours) to be declared by the RLDCs. However, since the objective of providing greater weightage for availability during peak is to encourage availability at times that they would be most required, it is suggested that the definition of 'peak periods' itself should be based on net load (i.e., after accounting for the must-run capacity such as solar and wind), rather than overall load. This should be the case since those are the periods when thermal and hydro plants would be most required. SLDCs and RLDCs should be able to easily identify such net peak periods.

Given that central plants supply power across regions, taking into account the differences in peak periods across regions/states becomes necessary. Toward this, SLDCs could submit net-load curves based on which the peak season/hours for each plant could be determined, and according to this, higher weightage for AFC recovery would be applicable.

9.4. Operational norms

In Section 5.4, the approach paper discusses the relaxation of operational norms for inefficient generation. Currently, relaxed norms are allowed based on actual performance for continued inefficient generation. However, as the paper recognises, given the limited resources and fuel to be distributed to ensure demand is met, such relaxation should be reconsidered and efficient generation should be prioritised instead.

Section 5.6 discusses operational norms on account of Emission Control Systems (ECS). Toward ensuring proper operation of ECS, and to justify the intent of the related expenses, the cost of ECS should be reimbursed subject to achieving the purpose of incurring the ECS expenditure, i.e. adherence to the norms. This could be done either on the basis of the generator procuring suitable certification from CPCB or respective SPCB for adherence, or the Commission mandating generators to publish emissions data obtained from CEMS on their website and approving expenditure only after scrutiny of such data for adherence.

The implementation of such ECS will impact the cost of plants and, in turn, affect their position on the MoD stack. Given the varying deadlines for compliance applicable to different plants, the Commission could exclude ECS expenses from consideration for MoD till the final deadline (31st December 2027), which falls within the upcoming control period. After that, supplementary charges can be included to decide MoD for all plants. In addition, generation from plants that have not installed ECS by their applicable deadline should be subject to a notional additional penalty after such deadline while considering MoD so that they do not gain an unfair advantage by being non-compliant to the norms. In addition, PLF incentive should also not be applicable for such plants until they are able to comply with the norms. This is summarised in table 1 of this submission.

9.5. Coal blending

Imports are the costliest source of coal-based generation and their procurement should be strongly scrutinised, particularly since there have been significant improvements in domestic coal supply[2]. Given the improvement of the domestic supply situation, and the existence of other procurement alternatives such as integrated mines, e-auctions and (soon) commercial mines, import of coal should only be considered as a last resort. If at all import blending is considered, as discussed in Section 5.9, the consent of beneficiaries should be obtained before such procurement. Since the impact of such procurement will affect what consumers ultimately pay for electricity, the impact on energy charge rate should be the basis of seeking such consent from beneficiaries instead of the blending %.

[2] See https://pib.gov.in/PressReleasePage.aspx?PRID=1940460

9.6. Part load operations

Section 5.7 of the approach paper discusses compensation of part-load operations. The Commission also published an addendum with regard to consideration of operation below the technical minimum of 55%, and introduced the impact of such operation on the FC and VC of the plant.

The treatment proposed in the addendum is appropriate to compensate generators for part load operations. This is subject to the understanding that the proposed compensation to variable cost because of the Net Heat Rate (NHR) deterioration on account of such operation reflects only the cost of increased consumption of primary and secondary fuel due to deterioration of net SHR.

While it is understood that the inclusion of the addendum under the approach paper for tariff regulations assures its applicability to Section 62 plants, it is unclear if similar provisions for operation below the technical minimum of 55% will extend to Section 63 plants. Clarity on this front must be provided by the Commission, after examining plant loading related clauses that exist in Section 63 PPAs, to prevent further bottlenecks at the regulator in the form of Change in Law or other petitions.

9.7. GCV of fuel

As per the current CERC regulations, generators pay for coal based on GCV as billed, however consumer tariffs (ECR) are computed on the basis of GCV as received. There have been considerable slippages between grades between the as billed and as received point, as recognised in Section 5.8, which means consumers do not get the coal they are paying for. Given that consumer tariff is computed on an as received basis, the impact of these slippages have been passed through without sufficient scrutiny.

Further, Para 7 of CIL's model Fuel Supply Agreement (FSA) states,

"7. Transfer of Title to Goods

Once delivery of coal have been effected at the Delivery Point by the Seller, the property/title and risk of Coal so delivered shall stand transferred to the Purchaser in terms of this Agreement. *Thereafter the Seller shall in no way be responsible or liable for the security or safeguard of the Coal so transferred. The Seller shall have no liability, including towards increased freight or transportation costs, as regards missing/diversion of wagons/rakes or road transport en-route, for whatever causes, by Railways, or road transporter or any other agency."* ***[Emphasis added]***

Given this, the coal becomes the generators property at the loading/delivery point and all the risks thereafter are transferred to it. Further, with the introduction of third party sampling through reputed agencies such as CIMFR, there is less cause for disputes regarding GCV as billed. Therefore, GCV slippage during transit should not be a factor beyond the generator's control, and hence should not be passed through to electricity consumers.

Allowing the pass-through of all grade slippage gives little incentive for generators to ensure quality and minimise loss. Toward this, the Commission should revise the extant norms such that ECR is calculated at GCV as billed (with some allowance for transit and stacking loss). The

Maharashtra ERC, through its MYT Regulations for FY19-24, have adopted this approach to ensure more efficient operations and safeguard consumer interest.

9.8. O&M Norms for Special Cases

The paper talks about additional O&M expenses for transmission assets in north-east and hilly regions and has invited comments on how to consider them. The point raised need some consideration as such assets can have more cost and need additional O&M expenses as compared to normal terrain. On the question of the manner in which such cost should be considered, a special O&M expense charge component can be added for such projects. Norm for such expenses can be decided based on actual additional O&M expenses incurred on such projects in the last 5 years (2018-2023) compared to projects in normal terrain. Based on learning in this 5-year period, a norm can be decided for the period of 2029-34.

With increasing frequency of cyclones or other natural disaster across the country, there is a need for disaster-resilient infrastructure and O&M planning (which might increase cost of construction and O&M). Hence, a provision of special O&M allowances can be devised to promote disaster-resilient transmission assets in the country. We suggest that CERC could consider this during this tariff period and it should be applicable to projects on case-to-case basis.

10. Other key issues impacting tariff

10.1. ECS recovery tariff structure

In accordance to the MoEFCC Environment (Protection) Second Amendment Rules, 2022 around 82% of NTPC's capacity falls under category C. This means that this capacity is subject to the laxest deadlines for compliance to the emission norms. Even so, these plants have to be compliant with the non-SOx emissions norms by 31st December 2024, and with the SOx emission norms by 31st December 2026, since the capacity is non-retiring (as per CEA's FGD Status Report for June 2023). Further, the final deadline of compliance is 31st December 2027 (for SOx emission norms from retiring plants), which falls within the control period under consideration. The 2022 amendment to the environmental norms also includes an environmental compensation or penalty for non-compliant generation beyond the plants' respective deadlines.
Section 6.2 seeks comments on the existing mechanism for recovering the cost impact of installation of ECS. Toward ensuring timely compliance and in the interest of preventing regulatory bottlenecks, clarifications on the applicability of the supplementary FC and VC subject to adherence to the norms should be provided well in advance. Post the deadline, the treatment outlined in table 1 could be considered.

Table 1. Proposed treatment for noncompliant generation post deadlines

	If PCE CapEx is incurred	If PCE CapEx is not incurred
If the TPP is compliant	PCE related costs to be passed through; supplementary VC not to be part of MoD until final deadline	N.A.
If the TPP is not compliant	Disallow PCE related FC, and apply notional additional penalty to affect their MoD position after plant deadline	Apply notional additional penalty to affect their MoD position after plant deadline

Source: Prayas (Energy Group)

10.2. Decommissioning of assets

In addition to cost recovery of projects decommissioned before the end of their useful life, the cost impact of decommissioning TPPs in general must be accounted for as part of these regulations. Given the transition that the sector is undergoing, closure of coal-based assets is going to be increasingly common. Thus, ensuring there is due process in place for such closures, taking into account the socio-economic and environmental impacts of the same, beforehand is crucial toward preventing regulatory ambiguity and bottlenecks.

The CPCB has already come up with draft guidelines for decommissioning of TPPs in 2021. To ensure that no counterproductive guidelines are provided and toward ensuring coordinated action, the CERC may consult CPCB towards accounting for TPP closures, including the case of plant decommissioning before the completion of its useful life, and account for costs of such decommissioning.

10.3. Simplification of tariff formats

Central cost plus projects play a key role in the power sector, and impact multiple sector stakeholders including the consumer. In the interest of optimality and prudence of their operation, transparency is crucial. Submission of updated and thorough data by these generators, thus, cannot be considered an overhead, and must be ensured at regular intervals.

10.4. Need of Reg 17 (2)

Since this regulation pertains to generators who have completed 25 years of operation, and given that the typical PPA duration is 25 years, it is likely that most such TPPs will not be bound by such contracts with the beneficiaries, unless they have chosen to renew the terms of the agreement. Further, Clause 1 of the regulation provides leeway for both the generator and the beneficiary to exit or continue contracting/supplying power as they see fit. In case the PPA has already lapsed, the beneficiary can choose to not contract power from the generator, and the generator will have to sell the electricity generated through alternative means anyway.

10.5. Committee for Transmission reconductoring

CEA has come out with a paper on Reconductoring of Transmission Lines in ISTS. CEA's initiative to identify implementation modalities for reconductoring the transmission lines in the ISTS network is very timely and extremely important given the expected growth in transmission capacity in the coming years. According to Powergrid, the sectoral outlook for transmission includes investment of ₹ 1,90,000 cr in ISTS, ₹ 1,96,000 cr in InSTS and ~ ₹ 20,000 cr for cross border integration by 2030. This translates to roughly ₹ 60,000 cr/year, each year for the next seven years. The paper covers planning of reconductoring, approval and mode of implementation.

CERC has also identified the need to augment the existing transmission network in the present approach paper as well. Considering the modalities involved in implementation of reconductoring, CEA/FoR should form a working group or a committee with representation from CTU, CERC, Industry, STUs, SERCs and other sector experts to prepare a detailed report on reconductoring, outlining the potential for reconductoring, cost benefit analysis, prioritisation for reconductoring, policy and regulatory issues involved and way ahead towards institutionalising it.

The role of CERC in this regard is particularly important as it has a vital role in cost recovery mechanism (additional capitalisation, cost implications in case of delay in approval of forest or other clearances, considering reconductoring under either R&M (special allowance in lieu of R&M) or technical up-gradation (issue of unrecovered depreciation), early decommissioning and assumed deletions) and aspects related to transmission license. As part of the tariff regulations, CERC should bring in clarity as to how tariff setting would be done for reconductoring projects.

It can begin with a review of past and ongoing reconductoring projects, some of which are noted below:

1. Reconductoring of Dulhasti-Ratle LILO tap Point of Dulhasti -Kishenpur 400 kV line (approx. 13 km) implemented through twin moose conductor with Quad moose conductor in matching time frame of Pakaldul HEP generation.
2. Hiranagar - Kathua 132 kV D/C line, 152 km (Reconductoring)

Source: NRPC

3. Farakka-Malda Transmission Line (India's first 400 kV D/C Twin Invar Reconductoring project)

Source: Sterlite

4. Reconductoring of Rangpo-Gangtok 132 kV D/C line
5. Reconductoring of Melriat (GIS) – Zuangtui 132 kV ASCR Panther S/C
6. Reconductoring of Aizwal – Luangmual 132 kV ASCR S/C line
7. Similar lines in NE Region Expansion Scheme - XX

Source: CTU

8. Live-line reconductoring project, upgrading the Naganathapura to Malgudi 66 kV transmission line in Bengaluru for Karnataka Power Transmission Corporation Ltd.

Source: Sterlite

This itself can bring to light the larger challenges and opportunities in reconductoring and the extent to which current system can be modernised through reconductoring. Also, the study can help in understanding the time and cost-benefit aspects of reconductoring.

The working group can also look at other issues related to reconductoring. These could include but not limited to

1. Defining scope of reconductoring: The CEA paper defines reconductoring as "reconductoring is a process of stringing of new conductors on existing towers using the same RoW to increase the thermal capacity of transmission lines. However, this may require modification or replacement of some towers in cases where load bearing capacity of tower is not sufficient. The scheme may also require replacement of terminal bay equipment with high rating equipment commensurate with rating of new conductors."

   Thus, reconductoring of lines may need further actions likes strengthening of towers or increasing the transformation capacity at the end of a line or AC-DC convertors in case an AC line is converted to a DC line. Hence, a clear definition of reconductoring and its scope should be devised.
2. Reconductoring cost benefit analysis could also build scenarios for integrating large scale storage at some specific locations.

3. Project selection criteria: As noted in the CEA paper, 'As per Section 38 (2) of the Electricity Act, 2003, the Central Transmission Utility (CTU) is responsible for development of an efficient and coordinated inter-state transmission system (ISTS). Accordingly, the CTU, in consultation with stakeholders and after system studies, draws proposal for new elements in ISTS or augmentation including reconductoring'.

   However, the CEA paper has not provided any details on a potential framework or relevant criteria based on which any project/element will be selected for reconductoring. As per our understanding, following projects should be considered in priority for reconductoring by CTU if they are:
   - Near its end of useful life
   - Critical for grid and upgradation of power capacity is recommended (by CTU or Grid operator) for such transmission project
   - Near load or generation centres and facing congestion issues
   - Facing Right of way issues.

Criteria such as those noted below should be part of a clear framework for assessing the viability of reconductoring and for selecting a project for reconductoring:

a. Expected Increase in Power flow in future
   - Line near generation or resource potential sites or load area
b. Criticality of line
   - Repeated instances of frequent outages or dependency of grid on the line (contingency or congestion issued faced due to outage of line)
   - Availability of alternate power routing options during construction time if live-line reconductoring not possible.
c. Time and cost evaluation
   - Time and cost needed to build a new line
   - Time and cost to reconductor
d. Useful life remaining for the existing line
   - Line, tower, associated equipment
e. Capacity increment due to reconductoring if applicable
   - Due to material change and possible conversion from AC to DC if feasible and desired
f. Other Possible Benefits
   - Reduced litigations or environmental/ clearance issues
   - Can this improve two-way power flow from same line?
   - Changing single ckt line to double ckt line
   - Improved grid reliability

11. Parameters to consider

11.1. Treatment of hydro

The approach paper lays significant focus on hydro generation to meet future demand growth in the country. It even proposes taking up hydro projects which have been facing delays during construction for early completion. The role of hydro as an environmentally friendly option and its contribution to India's NDC of achieving 50% non- fossil fuel based installed capacity by 2030 is also highlighted.

However, going forward, hydro is more likely to play a supporting role to RE as opposed to being a major source of generation itself. While it may not have environmentally detrimental fallouts like emissions, there are several socio-environmental challenges associated with the development of large hydro projects, which make them risky investments. The associated hydrological risks must be accounted for and shared, for hydro generation projects and PSP. Further, toward ensuring and encouraging efficient operations, the inordinate delays in construction of hydro projects should be reviewed and scrutinised. Attempts at de-risking investments toward attracting investments in hydro should not come at the cost of requisite clearances and safeguards.

11.2. Consideration of storage options

Storage is likely to play a key role in the sector in the coming years, in light of the rapidly growing intermittent RE and the need to ensure grid stability. As per the CEA's updated optimal mix study for 2030, 41.65 GW of Battery Energy Storage Systems (BESS) are likely to exist by 2030 in addition to 18.98 GW of PSP systems. However, the approach paper does not deal with BESS at all though it is likely to play a greater role in the coming years than PSP.

Given that the cost of setting up and utilising such storage – whether BESS or PSP - will be passed on to the consumer and will impact consumer tariffs, storage options and the treatment of their cost impacts should be included in CERC's tariff regulations. In addition, CERC should look into concept of integrated transmission scheme (which includes transmission assets and storage system) while devising tariff framework for storage systems.

The mechanism for computation and recovery of capital expenditure, and by extension their tariffs, should be clearly detailed in the Commission's tariff regulations, to avoid ad hoc and case by case treatment when storage capacity picks up. These should treat both BESS and PSP similarly since they provide similar services to the electricity system.

We request the Commission to accept this submission on record and to allow us to make additional submissions in this matter, if any. We further request the Commission to allow us to make an oral submission during a public hearing, if one is scheduled.

Prayas (Energy Group), Pune

Date: 31st July 2023

Place: Pune