Comments and suggestions on draft GERC MYT Regulations, 2023

Prayas (Energy Group) *9th October 2023*

Gujarat Electricity Regulatory Commission (GERC) published the draft Multi-Year Tariff (MYT) Regulations, 2023 – pursuant to the discussion paper on the MYT Regulations for the fourth control period (FY25-FY29) – and has invited inputs and comments from the public on the draft regulations.

The operative control period from FY25 to FY29 is where Gujarat power sector will see a substantial transformation due to:

— Scaling up of renewable energy deployment in order to meet state-level commitments, in line with national trajectories for renewable procurement.
— The need for grid integration of renewable energy (RE) and reliable supply, which involves various measures across the value chain. Some of these include flexible operation of thermal power plants, tariff incentives, and encouraging sales during low-cost RE availability.
— Distribution companies (DISCOMs) seeing a transformation in their role and witnessing changes in their business model due to open access and captive consumption. Sales migration to these avenues is driven by the falling prices of renewable energy and the availability of open access for consumers with 100 kW load.
— Renewed focus on transmission and distribution (T&D) network planning and operations. This is especially the case with increase in prosumers, the rollout of the RDSS scheme, the implementation of GNA and the designation of Gujarat as a bid area for t-GNA implementation.
— The adoption of communicable metering infrastructure at both the interface and consumer levels, which can enable better energy accounting and service quality monitoring

The tariff regulations of GERC are being revised after seven years where the sector has seen several changes. The draft regulations have introduced several changes that enable better operations and accountability of utilities and are aligned with several rules and policies notified by the central and state government.

We particularly welcome and commend the commission for:

— Providing timelines and guidelines for allocation of assets and cost for the wires and retail business (Regulation 3.3, Annexure V)
— Conducting detailed analysis for revision of rate of return on equity and specifying utility-wise performance parameters for additional RoE.(Regulation 35)
— Stipulating technical validation session as part of the tariff determination process (Regulation 25.1)
— Reduction in return on equity by 0.25% in case of delay in tariff filings by utilities (Regulation 25.11)[1].

[1] TBCB thresholds adopted by other SERCs are available here: https://indiatransmission.org/Commercial/TBCB%20Threshold%20in%20states

— Providing a clear framework for treatment of subsidies in line with MoP Rules (Regulation 28)
— Specifying limit DPR schemes and for stipulating limit non-DPR schemes as a 20% of DPR schemes (Regulation 29.15).
— Requiring submission of a fuel utilisation plan from the generating companies (Regulation 47)
— Clearly stipulating the threshold for TBCB in the regulations at Rs. 100 and for projects 220 kV and above (Regulation 64.2.1).
— Mandating use of advanced tools and models for demand forecasting from the second year of the control period (Regulation 107.3).
— Commissions proposal to develop an online portal for submission, review, approval and monitoring of capital investment schemes. Mandate for online reporting of status of ongoing capex schemes and imposition of penalties in case of non-compliance. (Para 11 of Annexure III)
— Shifting to RoCE approach for assets commissioned w.e.f. new Control Period, while maintaining the existing assets under the RoE approach (Regulation 35 and 36).

Prayas (Energy Group)'s has proposed some suggestions to enhance the commission's progressive initiatives and to prepare for the major changes expected in the sector by 2029. The suggestions are related to demand and supply planning, cost and performance evaluation, aspects of tariff design and the tariff determination process.

Contents

1 Demand and supply planning

1.1 Separate Resource Adequacy Regulations to be notified by GERC

As per the CEA Resource Adequacy Guidelines, the resource adequacy framework should cover:

- Demand assessment and forecasting
- Generation resource and procurement planning
- Monitoring and compliance

Further, the planning period is for ten years on an annual rolling basis. Ideally as GUVNL is responsible for power procurement for all DISCOMs, the plan should be submitted by GUVNL. This would also help optimise demand supply resources across the states, especially given DISCOMs like DGVCL and UGVCL have such different sales mix, demand profiles.

It is suggested that GERC draft separate regulations with a resource adequacy framework in line with the CEA Resource Adequacy Guidelines. This can be similar to the draft Framework for Resource Adequacy Regulations recently published by MPERC[2].

The provisions related to demand forecasting and power procurement planning in the MYT regulations can be in line with the RA guidelines as stated by the Commission and should be harmonious with the RA regulations.

1.2 Demand forecast mandate for up to 10 years, data submission mandate for load surveys

GERC regulations propose short term (monthly plans for the upcoming year) and five year plans for the control period. Given the lead-time requirement for investments and the 10 year annual rolling plan requirement under the RA guidelines, it is suggested that:

- Monthly forecasts should be provided for two years as part of the MYT and MTR filings.
- In addition, ten year demand and supply assessments shall be provided by the licensees with the MYT and MTR petitions.
- Change in sales (especially due to open access and captive) is considered an uncontrollable factor in the draft regulations. However, migration of consumers to open access and captive options would severely affect the financial viability and operational capability of DISCOMs. Therefore, energy wheeled via open access and offsite captive as well as energy consumed

[2] https://mperc.in/uploads/notice/6ba006cd845c254f839825055afe58cb.pdf

by RTPV and onsite captive should be tracked and projected not just on a monthly basis but also for the medium-term (5 year) and long-term (10 year).

— Scenario based analysis as proposed in Regulation 107.2 should not be restricted to just monthly projections but should be extended to medium and long-term projections.
— Impact of time of day (ToD) tariffs on various consumer categories in load shifting should also be captured.
— Impact of banking services provided by DISCOMs to open access and captive consumers should be captured to aid recalibration of banking frameworks and charges and to plan power procurement. While this may not be significant today, with growth in green open access, such demand can be significant by 2029.
— In addition to load duration curves, the Commission has specified the need for a load research study from the second year of the control period. To operationalise this, from the first year of the control period, the Commission should mandate DISCOMs to report hourly consumer demand profiles at least for each year of the control period to aid demand assessment. This can be based on AMI metering of agricultural/ urban feeders/ DTs, SEM data of open access/ off-site captive consumers, AMI metering of HT consumers and eventually smart meter data of LT consumers.

It is suggested that Regulation 107 be modified to reflect these changes.

1.3 Strengthening power procurement planning processes

Regulation 108 of the draft MYT regulations provides guidelines for power procurement and requires the DISCOMs to prepare month-wise, long-term power procurement plan in capacity and energy terms with a procurement plan for peak/off-peak periods. Towards better planning and coordination, it must be specified that the procurement plan:

— Shall be based on the energy forecasts conducted by the utilities as per Regulation 107.
— Shall clearly stipulate plans for meeting peak, base and intermediate load as well the requirement and procurement plan for Battery based energy storage and other storage options.
— It should be clarified in the regulations that unless approved by the Commission in the power procurement plan prepared as per Regulation 108.6 and 108.8, long-term and medium-term power procurement would be disallowed by the Commission. Similarly, unless approved by the Commission under Regulation 108.9, short term procurement would be disallowed by the Commission. This is to ensure the procurement and investment decisions are undertaken based on the detailed planning exercise before the regulatory commission.
— Regulation 108.9 should be modified to mandate DISCOMs to prepare short-term procurement plans based on week-ahead, fortnight-ahead and seasonal forecasts to optimise costs. With the implementation of t-GNA and each state becoming a separate bid area, the area clearing price for Gujarat state might increase due to congestion. At the same time, DISCOMs will have options for 11 month ahead procurement with power exchanges soon launching these contracts. Significant innovation and cost optimisation measures are possible with short-term trades which should also be detailed by the utilities in their procurement plan. Short term procurement can be efficient with week-ahead, fortnight-ahead, seasonal forecasts rather than be reactive and dependant only on day-ahead trades.

In addition to FDRE tenders[3], innovative, flexible and non-RTC hybrid contracts are already emerging in the RE procurement space[4]. Such non-RTC contracts should also be explored for non-RE procurement based on demand- supply assessment and RA plans.

1.4 Long-term procurement to be based on long-term assessments, modelling

As per regulation 108.7.1 and 108.8, long term procurement should be based on availability of power for each month of the coming year and for a five year term. Long term procurement is typically for 25 years. In the next seven years, there will be significant changes in demand as well as supply options which will affect requirement and availability. Basing long-term procurement options on 5 year availability projections could be risky and lead to resource lock-ins. In this context, it is suggested that, the demand supply projections for long-term procurement at least assess availability and energy requirement for a ten year period. This should also be supplemented by production cost and capacity expansion modelling exercises by the DISCOMs/ GUVNL to ensure power procurement decisions are cost-optimal. Similar to the specification of advance modelling tools for demand forecasting, the Commission should also specify use of such modelling tools for power procurement decisions in the regulations.

It is suggested that Regulation 108.8 be modified to reflect these changes.

1.5 Mandate for Circle-wise capital investment plans for distribution licensees

With decentralised generation options and consumer choice of supplier, it is important that network planning takes place in a disaggregated manner. In addition to scheme-wise details, it is suggested that for DISCOMs, circle-wise, DPR/ scheme-wise capital expenditure and capitalisation data is reported for each year in the capital investment plans. Such detailed reporting is provided in Tamil Nadu. In case of transmission utilities, at least the STU can report zone-wise disaggregation of plans for the control period.

1.6 Comprehensive rather than piece-meal treatment of MDL to reduce implementation challenges and litigation

The draft regulations have made provisions for multiple distribution licensees (MDL) operating in the same area. The provisions in the MYT regulations give clarity on certain aspects. However, what is needed is a comprehensive framework which can address risks and implementation challenges with the rollout. These include frameworks for:

- Reducing uncertainties in demand projections: Challenges with projecting demand growth (for incumbent, new licensees and non-DISCOM sales) in the face of uncertainty. A uniform framework for forecasting and consolidating demand over (weekly, annual, 5 year, 10 year rolling plans) is crucial. Currently, there is no such framework.
- Reducing risk of network duplication and skewed network development: Given the cost plus framework for tariff determination there is a substantial risk of network duplication, under utilisation of assets and siting/planning of networks being skewed towards areas with more commercial and industrial consumers. These have been challenging to monitor for existing

[3] https://www.seci.co.in/whats-new-detail/2462

[4] A few examples for tenders of hybrid contracts:
https://www.seci.co.in/view/publish/tender/details?tenderid=53454349303030303930
https://www.seci.co.in/view/publish/tender/details?tenderid=53454349303030303538
https://www.seci.co.in/view/publish/tender/details?tenderid=53454349303030303437

licensees[5]. Measures to reducing possibilities of overcapitalization and siting based on consumer cherry picking by the licensee need to be put in place. These can range from stricter frameworks for cost past through as well as processes for approval/ monitoring of network rollout in an integrated, cost optimal manner. There could also be considerations of substantially reducing guaranteed return on equity provided in areas with multiple licensees so as to promote competitive operations. RoE could also be lower in areas where cherry picking is a possibility. There might even be a need to mandate submission and approval of detailed disaggregated plans at the sub-division/ feeder level to aid planning and monitoring.

— Reducing risk of stranded assets in power procurement: Power procurement planning for each individual DISCOM in the area of supply would be challenging and so would the process of assessing prudence of power procurement plan and adherence to resource adequacy guidelines. With multiple licensees, such measures could contribute to over-investments leading to NPAs or under-investments leading to losses/load shedding.
— Clarity on measures for metering and energy accounting and loss estimation: Clarity on measures for loss accounting, installation of check meters, procedures for metering and loss apportioning would be beneficial. The requirement of a Distribution System Operator and their role can also be considered.
— Clarity on accountability frameworks for supply and service quality: With multiple licencees providing services to one consumer, mechanisms to fix accountability for quality of supply issues and electricity safety issues is required. For example, in case of interruptions, fixing accountability for line outages, DT failure, generator outages, coal shortage and taking appropriate measures is necessary. This would become a complex exercise in coordination, reporting, recording and taking appropriate action when there are substantial number of parallel licensees operating across the state.
— Clear frameworks for determination of ceiling tariff for the area of supply: GERC has enabling provisions for ceiling tariffs in the MYT regulations but the basis for determination of ceiling tariff is unclear. If the possibility of appropriate ceiling tariff for the area of supply is considered to encourage competition, it is not clear how prudent cost recovery in a cost-plus framework is to be ensured. In addition, tariff design to manage cross subsidy, the basis and methodology for estimation and levy of cross subsidy surcharge, applicability of regulatory asset surcharge and estimation of wheeling charge should be clarified. DISCOMs also have been demanding increasing fixed charges to reflect fixed costs incurred. The framework and the necessity for this, given that separation of wires cost and supply cost takes place on a notional basis should also be clarified.

In this context, it is suggested that the Commission notify separate framework and regulations which are applicable in areas with multiple distribution licensees and that the regulations take cognizance and are harmonious with the MYT regulations.

[5] As the MERC notes in Case 111 of 2019, beyond prudence checks, even gross reporting and violations of license conditions are challenging to monitor. In the order, MERC observes that ***"In spite of being aware that its License area is likely to reduce based on its own application, NUP went on developing its distribution assets in the entire area. It is difficult to understand as to how such act of NUP was in consumers' interest."***

2 *Cost and Performance Evaluation*

2.1 Return on equity linked to crucial performance parameters

While we welcome the additional performance linked RoE for various utilities, we have some suggestions on the performance parameters which can be tracked:

- Distribution: We feel that distribution loss is already a performance parameter where gain and loss sharing is allowed. Thus, it is best if not linked to RoE. Similarly, increase in RoE for smart meter deployment should be based on the benefits of smart metering which are not yet established. However, reliability of DISCOMs is an important concern. In this context, RoE should be provided only if :
    - DT failure rates reduce by atleast 1 percentage point year on year.
    - Feeder level outages reduce by 1 percentage point year on year for urban and industrial feeders and 2 percentage point for rural feeders.

The exact figures can be calibrated based on past performance and future potential.

- Generation: In addition to improvement in ramp rates, operation below technical minimum (as specified in the state gird code) can also be incentivised.

2.2 Subsidy reporting

Regulation 28 which details the framework for subsidy accounting and reporting is welcome. It is suggested that:

- In addition to the quarterly report, subsidy data is also reported in the true-up/annual reconciliation process.
- The government orders with the subsidy details are also provided with the true-up petitions.
- Quarterly and annual reports also provide slab-wise, category-wise details of number of consumers receiving subsidy, along with sales, revenue and subsidy details (promised and paid, pending subsidy from previous years).
- Break-up of subsidy for various charges (say, FPPPA charge) should be separately reported

These details should be specified in the regulation 28. The regulation should stipulate that the quarterly reports will be available on the DISCOM as well as GERC website.

2.3 Clear framework for estimation of agricultural demand

The regulations have detailed frameworks for demand forecasting and true-ups. However, with a substantial section of consumers who are unmetered/ poorly metered, the veracity of energy accounting and improvement of distribution losses is under question. Since the P.K Mishra Committee report in 1999, there have been no efforts undertaken towards estimation of agricultural demand. This is despite Gujarat being among the first states to physically segregate agricultural feeders and in spite of the state making significant progress towards AMI metering of agricultural feeders and DT metering.

The first step towards performance accountability and improvement of DISCOMs is to be set the house straight and to provide trajectories for reduction from re-stated losses. With the commission moving towards performance accountability for AT&C loss, estimation of agricultural demand is of paramount importance. Therefore, it is suggested that the MYT regulations stipulate that:

- A detailed study of agricultural demand be conducted by a working group appointed by the Commission which includes:
  - Year long, month-wise data from sample dedicated agricultural feeders based on AMI/ AMR readings
  - Year long, month-wise data from sample consumers or agricultural DTs where feeder data is unavailable.
  - Provided that the sample size covers at least 3 to 5% of the agricultural consumers/ agricultural feeders and covers all electrical circles where agricultural consumers are present.
- The working group should consist of representatives from the Commission, consultant, consumer groups and academics with the DISCOMs as special invitees.
- The study report should be submitted before the commencement of the second year of the MYT control period.
- The study report should analyse the data to re-estimate the agricultural consumption norm and therefore agricultural demand for all DISCOMs.
- Based on the study report findings, the Commission should re-state the agricultural consumption norm as well as the distribution loss trajectory for the control period.

MERC initiated a similar process in November 2018[6] for assessment of the agricultural consumption norm by March 2020[7]. Bihar ERC has specified similar provisions in their MYT Regulations, 2018[8].

2.4 Regulatory framework for cost approval of smart metering

As smart metering investments are under TOTEX mode rather than capex, it is not clear if the cost evaluation would not take place with capital investment scrutiny and plan in the MYT regulations.

It is suggested that the Commission specify regulations which provides a clear framework for:

- Approval of smart meter roll-out plan in the state
- Annual estimation of costs (under TOTEX mode) for a ten year period along with estimated benefits from the rollout.
- Devise cost passthrough based on evaluation of actual costs and benefits versus estimated costs and benefits.
- The costs should be adjusted with benefits and then shared with consumers on a gain and loss sharing basis.
- The details for cost benefit analysis before and after installation on a circle wise basis should be provided by the DISCOMs based on data formats stipulated by the Commission as part of these regulations.

A more detailed framework is available here: https://energy.prayaspune.org/power-perspectives/smart-metering-of-electricity-consumers-in-india-getting-it-right. Such a detailed

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6 https://merc.gov.in/report-details/final-report-on-working-group-for-agricultural-consumption-study/

7 In Case No. 322 of 2019: https://merc.gov.in/Order-detais/322-of-2019/

8 https://berc.co.in/rules-regulations/regulations/individual-regulation/1619-multi-year-distribution-tariff-regulations-2018

framework would provide clarity to DISCOMs and consumers alike on cost impact and benefits of the initiative.

2.5 Need for capital investment regulations, details for reporting on portal

It is suggested that Annexure III provisions, which are currently guidelines be made part of the MYT regulations such that there are detailed regulatory mandates for capital investment planning rather than guidelines. Given the investment in generation and in the wires network expected in the coming years, such clear mandates are necessary. As noted by the Commission in the explanatory memorandum, having regulations for capex approval is also an approach taken by the Maharashtra ERC.

It is suggested that :

- Para 2.9 of the Draft Guidelines for Capital Expenditure Approval Framework be modified to specify that utilities report status of projects along with time and cost overruns and interest during construction incurred and reasons for delay, if any for each project.
- The Commission has also proposed geo-tagging of new assets and existing assets with a specific time-frame. The commission must also specify a penalty for non-compliance in this case, at least for new assets.

2.6 Clarity on thresholds to be provided in regulations

The Commission has taken several progressive steps towards performance accountability and towards efficient operations. However, it is crucial that several of these provisions are clarified and specified in the regulations. This will provide certainty, instil investor confidence and incentive utilities to undertake steps towards better performance efficiency. Therefore, the Commission should:

- Specify the price ceiling for short-term power purchase in the first proviso of Regulation 108.5 at say, 20% higher than the average power purchase cost of the DISCOM. The Commission should also specify that explicit approval of the Commission is needed for purchase if rate is in excess of ceiling.
- Specify the efficiency factor at say, 0.5% (in Regulation 56.1.2) which can be revised based on the study conducted by the Commission. An efficiency factor of zero assumes that the utilities have the same productivity growth rate and input price inflation as other firms in a competitive set-up. This cannot be verified. Further the efficiency factor should be fixed for the five year period.
- Since the year ending 31st March 2023 has passed, the weightage of CPI and WPI in Regulation 56.1.2 can also be stipulated.

2.7 Collection efficiency and its improvement

Reporting AT&C losses as per the CEA guidelines is welcome to ensure standardisation in reporting practice. However, along with this information, the DISCOMs should be mandated to report:

- The extent of dues pending from the previous year which were collected in that year. This will enable a better understanding of performance of the DISCOMs, especially as collection efficiency can exceed 100% (without caps) if such collection was significant.
- Category-wise pending dues

— Age-wise analysis of receivables of the DISCOMs.

2.8 Amendment of the grid code towards flexible operation of generating units

The GERC Grid Code has not been amended or revised in a decade. Before the notification of the MYT regulations, it is crucial that the grid code is also amended. Many of the issues raised by the commission can be undertaken as part of the grid code amendment. These include:

- Specifying a framework for Part load compensation for thermal generating units in line with IEGC to address compensation in case of backing down.
- Specification of technical minimum of 55%, in line with IEGC
- Stipulation of merit order dispatch procedures, similar to MERC Grid Code[9] (Regulation 33 of the MERC regulations)
- Enabling sale of unrequisitioned capacity on day-ahead basis can be enabled. The IEGC, 2023 specifies that generating stations may sell URS as available at 9:45 am in the DAM, unless consent is withheld by the beneficiary or buyer in writing. Similar provision can be stipulated in the state grid code to enable sale of URS power and reduce backed down capacity as envisioned in Rule 9 of the Late Payment Surcharge Rules, 2022.

2.9 Specification of 'must-run' status for all RE

Proviso for Draft Regulation 17.4 states that "*Merit Order Despatch principles shall not apply to purchase of power from Renewable Energy sources up to the RPO specified by the Commission*".

It is not clear if this implies that RE procured beyond RPO can be curtailed or if this provision is guaranteeing must-run status of all RE. It should be clarified that "must-run" status is applicable on all renewable energy capacity irrespective of RPO target. In fact, given the competitive costs, DISCOMs should be encouraged to exceed their RPO targets and invest in load shifting measures, storage technologies to aid RE integration. In fact, not conferring RE with must-run status would be deviating from the Electricity (Promotion of Generation of Electricity from Must-Run Power Plant) Rules, 2021.

2.10 Compliance with Fuel Utilisation Plan (FUP) mandate and requirement for data reporting

Para 47 of the draft MYT regulations requires the generating company to prepare and submit a FUP. The FUP is useful towards tracking contracted coal and alternative sources. The Commission should specify penalties in case the FUP is not submitted as per formats prescribed by the Commission. In addition, the regulations should also require the generator to publish the requisite data on their website on a monthly basis, in accordance to the format required by the Commission.

2.11 Impact of environmental norms

Towards adherence to the revised emission standards and deadlines notified by the Ministry of Environment, Forests and Climate Change, thermal power plants are required to install emission control systems (ECS). The draft MYT regulations have considered this impact, and have included cost compensation measures on account of such installation and operation, which is a step in the right direction.

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[9] https://merc.gov.in/wp-content/uploads/2022/07/Regulation-English.pdf

However, to ensure 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 GPCB for adherence, or the Commission mandating generators to publish emissions data obtained from CEMS (Continuous Emissions Monitoring System) on their website and approving expenditure only after scrutiny of such data for adherence.

Further, 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) applicable to all plants, which falls within the upcoming control period. 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. Supplementary charges can be included to decide MoD for all plants after the final deadline and 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) compilation

Thus, 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.

2.12 Capping of Input price of integrated mines to the CIL notified price

The input price of coal from integrated mines is eventually passed on to consumers. 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. Maharashtra ERC has recognised this in their second amendment to its 2019 MYT regulations. The Commission should consider capping the RoM price of coal for integrated mines to the CIL notified price for the corresponding grade of coal, to be consistent with the objectives of allotting coal mines for captive consumption under the Coal Mines (Special Provisions) Act, 2015 and related Rules.

2.13 Decommissioning of assets

In addition to cost recovery on projects considered as part of these draft regulations, the cost impact of decommissioning TPPs must be accounted. 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 Central Pollution Control Board 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 GERC may consult the state PCB 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.

3 *Tariff related aspects*

3.1 Consideration of peak/off-peak hours and high/low demand season for availability and PLF

The draft MYT regulations, in Section 57, compute capacity charges across 3 high demand and 9 low demand months, with 4 peak and 20 off-peak hours each day. Considering daily peak and off-peak periods and high/low demand seasons, are useful towards ensuring a responsive/flexible system. The draft regulations provide a higher weightage of AFC recovery during peak hours , as per Para 57.2.

While this is a good measure toward encouraging responsive operations of generators it can be further strengthened. Optimally, plants should be encouraged to be available and generate during periods of high demand, and incentivisation should be tapered for periods of lower demand.

Table 2 suggests an alternate structure for PLF incentives and Availability-based AFC recovery to account for different combinations of peak/off-peak hours and high/low demand seasons:

Table 2. Suggested optimisation for PLF/Availability incentivisation

	Peak hours	Off-peak hours
High Demand Season	Rs. 0.5/kWh PLF incentive 10% of the AFC Recovery for availability	Rs. 0.25/kWh PLF incentive 25% of the AFC Recovery for availability
Low Demand Season	Rs. 0.25/kWh PLF incentive 15% of the AFC Recovery for availability	No PLF incentive 50% of the AFC Recovery for availability

Source: Prayas (Energy Group) compilation

Note: High Demand Season is considered to be a period of three months (92 days) and Low Demand Season is a period of nine months (273 days). Four hours a day are considered as Peak hours, and the remaining twenty hours are considered as Off-peak hours.

The above proposal ensures that more AFC is recovered during high demand periods, and less during low demand periods. 10% of AFC recovery is linked to peak-high-demand hours (which make up just 4.2% of the 8760 hours in the year), thus giving a nearly 2.5-fold weightage to those hours compared to average. Similarly, 50% of AFC recovery is linked to off-peak-low-demand hours (which account for 62.3% of the year), thus giving a weightage of only 0.7 to each such hour, compared to the average. Similarly, 40% of AFC is recovered in the 33.5% of the year that forms the "intermediate demand periods" corresponding to off-peak-high-demand or peak-low-demand – thus giving them a slightly higher than average weightage.

Compared to the proposed weightages in the draft regulations, the above proposal increases the weightage associated with peak hour availability from 20% of fixed cost recovery to 25% of fixed cost recovery allocated to peak hours (which form 16.66% of the year). The proposal also introduces weights for fixed cost recovery during high demand seasons, which is not present in the draft regulations.

Incentives for generation above the normative PLF could also be considered, similar to that offered in CERC 2019 MYT Regulations, which provides incentives for generation above the norm at a different rate for peak and off-peak hours . The Commission could further improve PLF based incentivisation— such that the highest incentivisation (say Rs. 0.50/kWh) could be provided to plants that have generated in excess of the normative PLF during peak hours in the high demand season, and no incentive need be provided for such generation during off peak hours in the low demand season. A lesser incentive (say Rs. 0.25/kWh) could be provided for operation in excess of the normative PLF during both peak hours in low demand season and off peak hours during high demand season. Since the PLF incentive is over and above the cost recovery through ECR and RoE for the generator, the values can be relatively modest.

Toward ensuring availability and generation of thermal power plants when the system most requires it, peak hours and high-demand seasons should be defined based on net load (i.e., after accounting for the must-run capacity such as solar and wind) instead of overall load.

3.2 GCV consideration in ECR calculation

It is good to note that the Commission has moved from considering GCV As Fired to GCV as received for the purposes of ECR computation, as per Para 57.10 of the draft MYT regulations. This addresses some of the slippages in coal quality that were being passed on to the consumer without regulatory scrutiny.

However, since it is proposed that energy charges should be computed on GCV As Received, the grade loss or slippage between GCV As Billed and GCV As Received can be passed through as actuals, burdening the end consumer and minimising accountability on other stakeholders in general, and generators in particular.

This is of particular interest when viewed in line with Para 7 of CIL's model Fuel Supply Agreement (FSA) which governs coal purchase by the generators. It 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. Allowing the pass through of all grade slippage between loading and unloading gives little incentive for generators to ensure quality and minimise loss, though the coal is in their custody from the delivery point.

The total heat content (kcal) of coal at the loading point cannot reduce during transit, except corresponding to some loss of coal quantity during transit— that is already allowed (0.2-0.8%) as per Para 53.7 of the draft MYT regulations. Thus, GCV variation during transit should not be considered beyond the generator's control, and hence should not be passed through to electricity consumers.

Maharashtra ERC has recognised this responsibility of the generator and the undue burden on the consumer, and MERC's 2019 MYT regulations, computes ECR on GCV As Billed (less a maximum of 300 kcal/kg for differences between As Billed and As received, and 85 or 120 kcal/kg for stacking loss)

Towards safeguarding consumer interests and ensuring efficiency in operations, the Commission should revise its tariff regulations on similar lines such that energy charge rate is calculated at GCV as billed (with some allowance for transit and stacking loss).

However, losses between GCV As Billed and GCV As Received can be split into losses on account of methodology[10] and losses on account of transit. Losses on account of transit have already been accounted for in Para 53.7 of the suggested regulations, and should not be allowed beyond the permitted losses.

On the other hand, generators should be compensated for losses on account of methodology. The coal supplier determines the price of fuel on GCV As Billed, which is calculated on Equilibrated Moisture Basis (EMB). But actual coal purchase does not occur under standardised conditions, and the coal purchased by the generator is not necessarily of the grade determined under EMB even at the loading point. The actual quality of coal purchased by the generator will be contingent on field conditions at the loading point, .i.e., coal quality assessed at the loading point on Total Moisture Basis (TMB).

Since GCV As Billed on EMB is recorded at the loading end, equilibrated moisture (moisture in the coal sample at standardised conditions) is also captured. If total moisture content in the coal is additionally measured at the loading end, GCV As Purchased on TMB can be calculated as[11]:

GCV (TMB) = GCV (EMB) x [1-Total Moisture]/[1-Equiliberated Moisture] (kcal/kg)

Both GCV As Billed and GCV As Purchased are assessed at the loading point. The only difference between both the parameters is that GCV As Billed is computed as per EMB, whereas GCV As Purchased is determined as per TMB.

With this understanding, the GERC could consider a reasonable allowance in GCV on account of the difference in GCV As Billed (EMB) and GCV As Purchased (TMB), in the computation of the

[10] The difference in coal GCV between what is priced and what is purchased by the generator.
[11] Also discussed in paragraph 65 of Order 279/GT/2014: https://cercind.gov.in/2016/orders/279O.pdf

energy charge rate on the following lines. This is exactly the same as proposed in the draft regulations with the exception of the definition of CVPF which is highlighted.

$$ECR = \frac{\left[\frac{(GHR-(SFCxCVSF))xLPPF}{CVPF}\right]+[SFC\ x\ LPSFi]+[LC\ x\ LPL]+[SRCxLPR]x\ 100}{100-AUX-AUXen} \quad (Rs/kWh)$$

Where, ECR = Energy charge rate, in Rs/kWh sent out;

GHR = Gross Station Heat Rate, in kCal/kWh

SFC = Normative Specific fuel oil consumption, in ml/kWh;

LPPF = Weighted average landed fuel cost of primary fuel, in Rs/kg, Rs/ litre or Rs/cum, as applicable, during the month. (In case of blending of fuel from different sources, the weighted average landed fuel cost of primary fuel shall be arrived in proportion to blending ratio);

CVPF =(a) Weighted average gross calorific value of primary fuel as billed in kcal/kg for coal-based stations, which is arrived at based on CVB – CVLa – CVLb – CVLc where

- ***i.*** *CVB is the weighted average gross calorific value of coal/lignite as billed by supplier in kCal/kg*
- ***ii.*** *CVLa is the loss in calorific value of coal/lignite between "as billed by supplier" and "as purchased by generating station" to account for the difference between EMB and TMB, subject to the maximum loss in calorific value of 10% over the GCV as billed*
- ***iii.*** *CVLb is the equivalent loss in calorific value corresponding to the quantity of coal lost in transit as per Regulation 53.7 and*
- ***iv.*** *CVLc is the loss in calorific value due to stacking subject to the maximum loss of 1% over the GCV as purchased*

(b) Weighted Average Gross calorific value of primary fuel as billed, in kCal/litre or kCal/cum, as applicable for gas and liquid fuel based stations;

(c) In case of blending of fuel from different sources, the weighted average Gross calorific value of primary fuel shall be arrived in proportion to blending ratio:

CVSF = Calorific value of secondary fuel, in kCal/ml;

LPSFi = Weighted Average Landed Fuel Cost of Secondary Fuel in Rs/ml during the month;

LC = Normative limestone consumption in kg/kWh;

LPL = Weighted average landed cost of limestone in Rs/kg;

SRC = Specific reagent consumption on account of revised emission standards (in g/kWh);

LPR = Weighted average landed price of reagent for Emission Control System (in Rs/kg);

AUX = Normative auxiliary energy consumption in percentage;

AUXen = Normative Auxiliary Energy Consumption of Emission Control System as % of gross generation.

3.3 Time of day tariff structure to be codified in MYT regulations in line with MoP Rules

Time of Day tariffs will be a crucial tariff instrument towards managing variability and seasonality of RE resources, reducing system costs and providing consumers with crucial price signals for demand side management in the future. With reduction in metering costs, such tariffs can be levied on a wide pool of consumers as well. It is vital that a revised ToD framework be applicable in Gujarat for the new control period. The Commission should stipulate the following in the regulations to enable this framework:

- ToD tariffs will be applicable on all consumers with load greater than 20 kW by 2025 and 10 kW by 2027.
- The tariffs should incentivise consumption during availability of low-cost solar and wind energy. Thus, rebate in energy charges during solar hours and high wind seasons is encouraged.
- DISCOMs should be compensated for managing power procurement during high demand/ peak/stress/ periods of low power availability. This can be the "shoulder periods" in the morning and evening. Such ToD penalties can be higher during summer, high demand months.
- All rooftop solar consumers with load greater than 5 kW should be subject to ToD tariffs.
- If subsidies/ rebates in energy charges are being provided to consumers with load greater than 20/10 kW, then the subsidies should also vary with time of day so as to provide appropriate price signals.

This framework is also in line with the provisions of the Electricity (Rights of Consumers) Amendment Rules, 2023.

3.4 Detailed data and analysis for innovation in tariff design

With sales migration, the revenue model of DISCOM is also changing as the dependence on revenue from cross-subsidy is low and reducing. If the revenue is reducing, tariff design should keep in mind the projected sales as well as the tariff while estimating cross subsidy. This will ensure a tariff design that is equitable and leads to revenue recovery from consumers. For example, such an analysis can help fix a trajectory for cross subsidy dependence of agricultural consumers. Currently, the consumer contribution in tariffs and subsidy add up to about 50% of the cost of supply.

Similarly, it is necessary to evaluate the extent to which fixed charges can be increased without adversely impacting consumers or furthering sales migration. In this context, it is suggested that the DISCOMs are mandated to report category-wise, slab-wise, connected load, number of consumers, sales, prevailing tariffs (fixed, variable and FPPA) as well as the ABR at the time of making the application and with every true-up petition. The commission should also analyse this information while determining future tariff design.

3.5 FPPPA Estimation

GERC has undertaken significant innovations in FPPPA but has not revised the methodology for estimation of FPPPA in a decade. As the Commission already has an existing FPPPA framework it need not adopt the framework prescribed by the Ministry of Power. However, while considering a revised framework, some suggestions to change in the FPPA framework are given below:

- In Regulation 115. 1 (m), variation in inter-state transmission charges should only be considered, not intra-state transmission charges. This is because intra-state tariff determination coincides with the tariff process for DISCOMs.
- In Regulation 115. 1 (m) it is not clear if the FPPPA as a percentage of the billed amount or whether the 5% threshold in Regulation 115. 1 (g) for automatic passthrough is 5% of the billed revenue or the category-wise ABR. This should be clarified. Treatment of categories where the revenue includes subsidies or where there are exemptions from levy of FPPPA should also be clarified.
- Since fuel costs form a substantial part of total costs, vetting of periodic filings by the Commission is essential not just during true-up as specified in Regulation 115. 1 (h). In fact, explicit approval should be necessary from the Commission each time the amount for recovery exceeds a pre-specified threshold/cap for recovery in a month. This is particularly critical if the price increase is substantial and could lead to tariff shock in subsequent months.
- It should be clarified that any cost impact due to decisions of courts or tribunals should be recovered only after explicit regulatory approval is awarded for recovery of the cost. Further, such costs should be reported separately and clearly in each FPPPA filing by the DISCOM.
- The carrying cost for carry-forward in case of under-recovery (Reg 115.1 (f)) and over-recovery ((Reg 115.1 (i)) should be similar. Right now, there is a stark variation. This would penalise DISCOMs for variation in sales beyond their control.
- In case of negative FPPA, the amount should be deposited into an FPPPA stabilization fund which can be used to offset positive FPPPA in other months and reduce tariff volatility and impact on consumers. In order to ensure transparency in reporting of utilisation of such a fund, details of the fund and changes to the fund should be separately reported in FPPPA filings of the DISCOMs. This approach is currently being followed in Maharashtra, where there is significant benefit for consumers. It is suggested that this provision is also added in Regulation 115.1.

3.6 Consideration of prevailing market rate for evaluation of competitive bidding

Regulation 108.1.2 states that "*Provided that in case either no competitive bids are received or the bids received are higher than the prevailing market rates or on any other sufficient reason, then the Distribution Licensee may procure medium-term or long-term power under Section 62 of the Act, subject to fulfilling the conditions specified in Regulation 108.1.3 to 108.1.9 of these Regulations.*"

Within this control period, it is likely that a derivatives market for electricity is launched by the MCX. It is crucial that the regulations stipulate that prices from electricity futures or any transferable electricity derivative market contract would not be used as the reference price of the prevailing market price. Due to the low liquidity in the DAM segment and the potential speculative nature of bidding, the prices discovered in that market would not serve as an appropriate benchmark in regulatory processes. This clarification for reference price should also be provided in the case of ceiling tariffs for short-term power procurement.

4 *Tariff determination process in the MYT period*

4.1 Multi-Year Tariff and Annual Reconciliation of uncontrollable costs for DISCOMs

As per proposed regulations 16.3.4 to 16.3.7, tariff/fee determination for Generation, Transmission and SLDC utilities takes place for five years of the Control Period right before the first year of the control period. This is followed by a Mid-Term Review, where there is true-up for the first two years and revised forecasts for the coming 2 years. However, for distribution companies, tariff and true-up processes are proposed to be initiated for each year of the control period.

We strongly feel that an annual true-up process for distribution companies weakens the objective of the multi-year tariff process which seeks to provide tariff certainty as well as cost and performance trajectories over a medium-term. Annual revision via true-ups imply that medium-term cost and performance benchmarks have no meaning and that tariff and tariff design is revised each year. Provision of clarity in regulatory frameworks and certainty in charges is of paramount importance towards a consumer-centric and investor-friendly power sector. Trajectories for tariffs and charges also provide important incentives for adherence to performance trajectories. In this context, it is suggested that:

— DISCOMs have tariffs announced for a five year period at the start of the control period. This will provide certainty in tariff structure, tariff trajectories and tariff design.
— In addition, the tariffs for all LT consumers with consumption less than 300 units should be linked to inflation so as to prevent such consumers from facing undue tariff shock. This can be codified in the regulations for the control period.
— The mid-term review process should be conducted for DISCOMs as for other utilities to evaluate performance parameters, controllable costs, revenue trajectories etc. Tariffs and tariff design can also be revised in this process.
— True-ups for DISCOMs are to take place at the start of the control period, during MTR and at the beginning of the next control period.
— Most uncontrollable costs are to be recovered via FPPPA recovery as specified in the GERC regulations. Thus, moving from annual to true-up during MTR would not impact DISCOMs substantially. In comparison, the gains to consumers in terms of performance accountability for controllable costs and tariff certainty are significant.
— At the end of each year there should be public reporting of DISCOM performance, sales, revenue and audited accounts which will highlight trends and any major challenges for the utility.

4.2 Consultation for Technical Validation Session (TVS)

The Commission has the provision to conduct a TVS prior to the admission of a tariff petition, as per Para 25.1 of the draft MYT regulations. A TVS is an effective tool towards early identification of data gaps and errors, and facilitating more meaningful regulatory engagement. Towards strengthening this provision, and ensuring a diligent and rigorous TVS, the Commission should ensure that some sector experts and consumer representatives are also part of the TVS exercise and that such an exercise is conducted for all important tariff processes.

4.3 Clarity on public consultation process

Given its impact on consumers and in order to ensure transparency and accountability in utility operations, all tariff processes, including the MTR, should be subject to public consultation and public hearings. This should be clear stipulated in Regulation 16.4.

In addition, it is suggested that public hearings at least for distribution companies be held at the headquarters of each DISCOM to increase participation.

The first proviso of Regulation 108.1.4 states that, "*public consultation shall not be required for adoption of tariff discovered through competitive bidding under Section 63 of the Act*:"

Tariff adoption is often after a bidding process where there could have been deviations from the bidding guidelines. The tariff adoption process is the only avenue where consumers can participate in understanding and assessing the procurement process. The Commission has the right to adopt or disallow tariff based on adherence of specified guidelines and commission regulations. It is suggested that consumers are allowed to participate in this process to aid transparency and accountability in the procurement process. If onerous, several matters can also be clubbed together.

4.4 Sharing of petition on website

We welcome the proposed Regulation 25.4 which states that the petitioner shall provide text searchable documents / downloadable spreadsheets and a web-link for the complete petition on its website. However, it should be clearly stipulated that:

- The queries raised during the technical validation session as well as the data provided to the commission will also be available on the website.
- All petitions henceforth issued by the petitioners should be on their website and should not be taken down/ made unavailable once the process is completed. Past petition data is a useful resource to examine historical trends but is often unavailable. With technology changes, storage of information is not technically difficult or cost-prohibitive and must be encouraged. For example, all petitions of Rajasthan utilities are available on their websites from 2014-15, which helps understand the sector better.
- Any document which has bearing on tariff and performance should not be confidential in nature as it impacts consumers. Th documents should be submitted to the Commission and the commission can determine future course in line with Regulation 78 of the GERC Conduct of Business Regulations, which is applicable on all proceedings before the Commission.
- Along with the petition, there is also an executive summary shared by the petitioner on their website with the major proposals and trends highlighted.

Therefore, the following edits (in bold) are suggested to the relevant provisos

Provided further that the Petitioner shall also provide on its internet website, in text-searchable format or in downloadable spreadsheet format and showing detailed computations, the petition filed before the Commission along with all regulatory filings, information, particulars and documents in the manner stipulated by the Commission:
Provided also that the web link to the complete petition, including its formats and any additional information sought and provided during the technical validation session, shall be easily

accessible, archived for downloading and be prominently displayed on the Petitioner's internet website:
Provided that such information shall be available on the website of the petitioner in a publicly accessible manner for the entire control period.
Provided that the petitioner also shares an executive summary of the petition covering major proposals and important information provided in the petition.
~~*Provided also that the Petitioner may be exempted by the Commission from providing any such information, particulars or documents as are confidential in nature.*~~

5 *Processes for finalising MYT regulations*

5.1 Historic data provision

In the explanatory memorandum of the draft MYT regulations, the Commission has analysed ten years of performance data especially with respect on interest rates and return on equity in order to inform the framework in the regulations. Provision of such data is a useful practice to frame appropriate regulations for performance evaluation. It also provides stakeholders with clarity on the approach of the Commission, help sector actors assess the functioning and challenges of the utilities better, which will enable deeper engagement in the regulatory process. CERC required generators and transmission companies under its jurisdiction to publish such data as part of its tariff determination process for the Central MYT Regulations of 2019[12] (https://cercind.gov.in/2017/orders/L.pdf). It is suggested that such time-series data for crucial performance parameters for the transmission, generation and distribution utilities be published along with the Statement of Reasons accompanying the regulations. The time-series historical data can include information on sales mix, year on year in tariff and power purchase cost, changes in O&M, T&D losses, major capital works undertaken for DISCOMs. For generators, it can include trends in availability, PLF, SHR etc and for transmission lines, it should include trends in costs, delays in projects and trends in availability, loading and losses.

5.2 Data formats for tariff process:

In regulations 16.3.4, 16.3.5, 16.8, 17.2, 20.2, 25.1 and 25.4, the Commission mentions specification of formats for the licensees and generating companies to furnish information in for the tariff determination and true-up process. It is suggested that the formats be shared by the commission and finalised based on stakeholder comments within three months of the notification of the regulations. Specification of the formats, before the effective date of the control period, provides clarity and certainty to the stakeholders. For example, in addition to the existing formats, to make the MYT process more effective, the formats should also specify detailed information on:

- Consumer Category-wise subsidy accounting and annual reconciliation of category-wise booked and paid subsidies as well as pending payments
- Actual working capital borrowings from DISCOMs to provide a clear picture of financial strain faced by DISCOMs
- Annual average availability and PLF across contracted capacity by DISCOMs to assess the extent of backing down in past years

[12] The detailed data submitted by the stakeholders is also published on CERC's website: https://cercind.gov.in/O&M_Data.html

- Data on short-term transactions from DEEP, TAM, G-TAM, I-DAM and RTM contracts with details of each transaction given separately.
- Extent of actual energy (conventional and RE) wheeled for open access and off-site captive consumption and extent of on-site captive consumption on an annual basis.
- Category-wise status of metering (including % of consumers where meter is AMI, pre-paid, capable of energy accounting in ToD slots etc.)
- Month-wise Hours of supply based on feeder data (such information was shared in data gaps as part of the petition)
- Detailed information of project/ scheme specific, general loans and working capital with details on loan amounts, tenure of loan, moratorium period and interest rates across utilities.

Some such formats suggested for such data capture can be found in this 2018 publication: (https://energy.prayaspune.org/our-work/research-report/bricks-without-clay-crucial-data-formats-required-for-effective-tariff-processes).

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