Comments and Suggestions on

DRAFT MERC MULTI YEAR TARIFF REGULATIONS, 2024

*Prayas (Energy Group)* *15th April 2024*

# 1 Tariff and true-up processes under the MYT period

For the control period FY26 to FY30, the Commission proposes to discontinue the mid-term review (MTR) process. Tariff determination for all the years in the Control Period will take place in the first year, and the final true-up for the first four years and the provisional true-up for the final year would be completed only in FY30.

The Commission is of the view that utilities have gained experience to project Annual Revenue Requirement (ARR) over the control period in an approach similar to utilities regulated by the Central Electricity Regulatory Commission (CERC). Further, with the levy of fuel surcharge via the monthly levy of Z-FAC and annual levy of OUC, major variation between projections and actuals can also be addressed.

We support the Commission's proposal to fix tariffs and provide cost trajectories for a period of five years. **However, the absence of a mid-term review process could result in several implementation aspects and reduce accountability of licensees, which adversely affects DISCOM and consumer interests.** Without an MTR, the Commission would likely initiate multiple parallel processes towards periodic performance accountability as well. This is especially the case in this control period, which will be characterized by demand uncertainty, an increase in supply options for consumers, an increased share of renewable energy in the supply mix, increased penetration of smart metering, and adoption of storage technologies. The proposed process would also be counterproductive in implementing many provisions as well as realizing the broader objectives of the current regulations.

## 1.1 Compliance to directives

In Draft Regulation 5.2, the petitioner is to submit the compliance status to the Commission's directives in earlier orders during the true-up process. If the true-up takes place at the end of the control period, compliance (even for directives requiring monthly, quarterly, annual actions) would be checked once in five years, reducing the accountability for timely compliance.

## 1.2 Changes in Power Procurement Plans

As per Draft Regulation 19, the DISCOM's power procurement plan must be based on MERC's Framework for Resource Adequacy Regulations, 2024. These regulations (as well as the CEA RA guidelines) require an annual rolling Resource Adequacy (RA) plan. Changes to the RA plan each year will impact the DISCOM's future procurement for the control period and likely result in significant cost changes. The costs would likely exceed the Fuel Adjustment Charge (FAC) levy cap, necessitating additional regulatory proceedings and delayed payments to generators.

## 1.3 Uncertainty in costs due to Capital investment

Capex cost variations are not solely due to delays and cost overruns. For RDSS projects, Component II (system strengthening) grants are provided only if DISCOMs meet the financial sustainability criteria in the Results Evaluation Framework. Otherwise, the grant amount will be treated as a loan, increasing the capex cost in the ARR. This increase would not be covered under FAC or OUC, leading to higher DISCOM indebtedness and consumer carrying cost burden.

## 1.4 Impact on Ability to Borrow, Given Existing Prudential Norms

In November 2022, the Ministry of Power notified additional prudential norms for REC and PFC while lending to DISCOMs. These require the true-up for Year T-2 to be completed before availing a loan in Year T. With the proposed framework of true-ups at the end of the control period would also mean that true-ups take place with 3 or 4 year delays for some years. Thus, no DISCOM in Maharashtra would qualify for PFC/REC loans.

## 1.5 Changes in Tariff Design with Potential Changes in Sales Mix

MERC's Green Open Access Regulations have provided a wide range of alternate supply options for consumers. Additionally, the Grid Interactive RE Regulations enable group net metering and net metering for the first 5 GW of consumers without Grid Support Charges. Further, these draft regulations facilitate the rollout of multiple distribution licensees. These trends and regulatory enablers will result in significant sales variation over the five-year control period, requiring agile tariff and tariff design changes based on emerging trends. An MTR process would enable such adjustments. Without such a process, DISCOM finances could be impacted.

## 1.6 Tariff Uncertainty for Consumers

During the control period, the factors mentioned earlier could lead to significant cost variations, necessitating substantial monthly and annual adjustments through FAC/OUC. However, FAC would not capture several costs, particularly DISCOM capex expense variations. Currently, OUC only accounts for impacts of higher court/tribunal decisions or the Commission's review orders on LDC, generators, transmission, and distribution licensees. Cost claims through this process would be time-consuming and litigious. Delays in OUC-based cost recovery or amounts exceeding the FAC cap would increase consumer carrying costs and affect viability of utilities across the value chain. With such tariff volatility, the five-year tariff fixation would be meaningless, reducing consumer confidence and investor interest.

Given the significant changes expected in the sector during this control period, timely regulatory approvals will be essential. However, an excessive number of processes could seem onerous and reduce the regulatory certainty that is central to the Multi-Year Tariff (MYT) framework. Considering the maturity of the Maharashtra power sector, the following streamlined processes are proposed:

- DISCOMs, GENCOs, TRANSCOs, LDC and STU should file an annual petition covering compliance to directives, performance, costs regarding key trajectories and the status of major capital project changes. GENCOs should also submit compliance with Fuel Utilization

- Plans. DISCOMs should also report sales mix, power procurement costs and changes in RA plans. The Commission should then issue an order on compliance to directives and utility performance. If cost pass-through is warranted, it can be considered in this process.
- Conduct a Mid-Term Review (MTR) process during the control period to revise tariffs/tariff design if necessary and true-up the first two years.
- Alternatively, undertake an annual process solely to reconcile and true-up power purchase and transmission costs, allowing for cost pass-through if required. Capital expenditure, O&M expenses, and other costs based on pre-specified plans/ trajectories and which are controllable can be trued-up at the end of the control period.

# 2 Power procurement related provisions

## 2.1 Clear frameworks for detailed Demand forecast

As per Draft Regulation 6.4, the Distribution Licensees shall project the realistic power purchase requirement considering the provisions of the Maharashtra Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024. Regulation 6 of the Draft RA regulations specifies category-wise load forecasts for the medium and long-term and Regulation 7 details framework for sub-hourly forecasts to be submitted on an annual level. However, draft MYT Regulation 100 provides a framework for sub-category-wise monthly sales forecasts.

There is a need for clear consistent framework for demand forecast under these regulations, and to ensure consistency with RA regulations. It is not desirable that there are multiple forecasts under multiple processes for the same time-period for an area of supply.

It is suggested that:

- detailed demand forecasts as approved in the RA plan (and modifications in subsequent rolling plans) are submitted as part of the demand forecast under these regulations
- any deviations from the RA plan forecasts, if required should be specified in the petition with rationale for the deviation for ERC approval
- changes in the demand projections approved in the tariff proceedings should be incorporated as changes in subsequent rolling plans under RA regulations
- additionally, the ERC should evolve detailed data formats for submission of data and assumptions regarding sub-hourly, monthly, slab-wise demand forecasts.

## 2.2 Public consultation while approving power procurement plan and for tariff adoption under Section 63

The provision ensuring that all future power procurement (short, medium, and long term) shall only be undertaken through competitive bidding has been retained from MERC's MYT Regulations 2019, as per Reg 18.3 of the draft regulations. Ensuring implementation of this provision in letter and spirit is important towards achieving efficiency gains and optimal, cost-effective power procurement.

As per proposed Reg 19, the power procurement plan is to be prepared by the distribution licensee considering the provisions of the MERC (Framework for Resource Adequacy) Regulations, 2024. The approval of such plan is also to be carried out under the MERC (Framework for Resource Adequacy) Regulations, 2024. Given that power procurement costs constitute a major share of cost of supply, and that there are increasing risks and uncertainties associated with power purchase, ensuring transparency and accountability while adopting the power purchase plan is crucial and should be subject to public scrutiny. All power procurement by distribution licensees should only be as per the approved power procurement plan, as far as possible. Any proposal for power purchase that deviates from the power procurement plan should be included and justified in the petition, and also be approved only after a public process.

Draft Reg 21 talks about additional procurement beyond the power procurement plan. Approval of any such additional power purchase petition should necessarily happen based on a public process, since the costs will be passed through, and potentially impact consumers for a long period.

In case of any power purchase undertaken by the Distribution licensee under Section 63, with deviations from the Standard Bidding Guidelines issued by MoP – such bidding should be approved only based on public process.

The first proviso to Reg 20.2 of the draft regulations state that public consultation is not required for the adoption of tariff discovered under Section 63. Given that these tariffs impact the consumer, public regulatory scrutiny should extend to ensuring that competitive tariffs are adopted. Thus, all tariff adoption, including that under Section 63, should be carried out transparently and subject to public consultation.

We request the Commission to:

- Ensure that the approval of power procurement plan is subject to regulatory and public scrutiny
- Mandate that any additional power procurement under draft Reg 21 shall be subject to a public process
- Carry out public consultation for any deviation from standard bidding guidelines for power procurement through Sec 63
- Carry out public consultation for tariff adoption of Sec 63 projects also, towards ensuring adoption of competitive tariffs

### 2.3 Tracking of URS power

In accordance with MoP's Electricity (Late Payment Surcharge and Related Matters) (Amendment) Rules 2024, generators are required to offer power which has been declared but not scheduled (i.e., un-requisitioned surplus (URS) power) in the power exchange, at a price not exceeding 120% of the ERC determined/adopted energy charges plus transmission charges. If a generator fails to do so, the URS power not offered on the power exchange (against the declared capacity) will not be considered for the payment of fixed charges.

In addition to improving utilisation of surplus power, this amendment to the LPS Rules will have significant impact on the cost recovery of the generators. Despite this, the draft regulations do not address the LPS Rules Amendment 2024. The Commission should amend the State Electricity Grid Code to include the impact of the LPS Rules Amendment 2024, with directions to sector actors in this regard. To avoid regulatory ambiguity, the Commission should also include appropriate regulatory provisions in the MYT regulations to account for the impact of the LPS Rules Amendment 2024 on AFC recovery.

Further, to facilitate the monitoring of such sale of URS power, the Commission should require generators to submit data tracking the treatment of un-requisitioned capacity. A format for such tracking is suggested below:

*Table 1. Proposed format for tracking of URS from each unit*

| For each generating unit: | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Contracted Capacity | Declared Capacity | Scheduled Capacity | Un-requisitioned capacity | Capacity offered for sale | Bid offered | Capacity sold | Remaining capacity |
| | *A* | *B* | *C* | *D=B-C* | *E* | *F* | *G* | *H=D-G* |
| | (MW) | (MW) | (MW) | (MW) | (MW) | *(₹/unit)* | (MW) | (MW) |
| Block 1 | | | | | | | | |
| Block 2 | | | | | | | | |
| …. | | | | | | | | |

*Source: Prayas (Energy Group)*

Such tracking should be reported on the generator's website periodically, say every month, and submitted to the Commission. Additionally, to ensure accountability, the generator should submit certification towards the capacity offered for sale, bid offered, and the capacity sold from the power exchange.

We request the Commission to:

- Introduce regulatory provisions to address impact of MoP LPS Rules Amendment 2024 on generator operations and cost recovery (in the MYT Regulations and in the State Grid Code)

- Mandate generators to publish on their website the necessary information to track capacity declared available, scheduled and offered on the market as suggested in Table 1, and require that such data (with power exchange certification) be submitted to the Commission on a monthly basis

# 3 Removal of cost-plus framework for BESS

Draft Regulation 137 details the cost-plus tariff determination framework for Battery Energy Storage Systems (BESS). There have been multiple recent tenders for BESS (both stand-alone and co-located with RE generators) for price discovery under Section 63, both with SECI as well as DISCOMs, which have resulted in awarding of tenders at competitive rates. The winners for the recent GUVNL auction for 250 MW/500 MWh quoted record low tariffs which demonstrates the applicability of Section 63 with this technology. In the coming decade it is imperative to foster competitive cost reduction, innovation and scaling of BESS. Therefore, innovation in RfPs for competitive bidding under Section 63 (developed via consultations with the wide range of industry stakeholders) and innovation in technology used for BESS will play a critical role.

Section 63 as a framework is better suited for scaling, cost-reduction and innovation required for BESS contracting by DISCOMs. Thus, it is suggested that BESS procurement only takes place through Section 63 in Maharashtra and that Draft Regulation 137 is deleted.

# 4 Return on equity

## 4.1 Need for a better framework to link incentives to ramp rate

Reg 28.4 (a) of the draft regulations discusses RoE linked incentives for the achievement of incremental ramp rate of 0.25% per minute over and above the required 1% ramp rate, subject to a ceiling of 1.25% RoE incentive per year. In the interest of ensuring that the incentive provided is effective, a clear process of achievement, certification and approval of ramp rate is necessary.

Towards this, the second proviso of draft Reg 28.4 (a), which directs MSLDC to formulate the procedure for certification of ramp rate of thermal power plants, is a step in the right direction. However, in the interest of effectiveness and accountability the following considerations and clarifications must be made:

a. **Frequent demonstration of ramping capability:** The certification of ramp rate, according to the procedure to be formulated by MSLDC, should be contingent on the generating station proving the ability to provide reliable and consistent operations at the claimed ramp rate. Regulations under Section 32 of the MERC Grid Code 2020 states the conditions and process for generating units to demonstrate the maximum declared capacity (DC) for a time block and provides for the SLDC to carry out such tests on a random basis, not exceeding once every quarter. However, in line with this, and to especially ensure reliability in achievement of incremental ramp rates when required, the SLDC should have the

provision to carry out more frequent randomized tests for generating units that claim RoE ramp rate incentives, i.e, those claiming ramping capability of 1.25% and above.
RoE incentive should be allowed based on consistently achieving ramp rates (over 1.25%) during the frequent (say, monthly) randomized tests for declared capacity carried out by the SLDC.

b. **Detailed reporting of declared capacity (DC) testing results:** There was a similar provision for ramp rate incentive in MERC MYT Regulations 2019, and MSPGCL claimed a flat 0.25% additional RoE for FY21 and FY22 for all its stations (except Parli 4-5) as part of its MTR petition (petition in MERC Order 227 of 2022). However, since the generator was unable to provide unit wise data, the SLDC could not process the ramp rate certification, and no incentives were allowed. In order to address this, the Commission should mandate adherence to the data reporting required as per the MERC Grid Code 2020.
Details of the demonstration of the DC is required to be captured by the generators in the format prescribed under Format 2 in Annexure 3 of MERC Grid Code 2020. The SLDC is required to verify the same and issue certification of DC declaration (and thus ramp rates) in accordance to Format 3 in Annexure 3 of MERC Grid Code 2020. Reg 5.5 also requires the SLDC to upload the details of the DC demonstration on its website in the prescribed format on a monthly basis.
The same certification process is used to identify misdeclaration of capacity, in addition to identifying achievement of ramp rates over 1.25% for RoE incentives. Misdeclaration of capacity entails penalties which impact the recovery of AFC and therefore consumer tariffs. Therefore, it is essential that details of capacity declaration and its testing be reported as mandated on the SLDC website every month. Allowance of RoE incentive and recovery of AFC should be contingent on such public reporting of DC declaration and testing results.

c. **Disallow incentive in case penalty for misdeclaration of capacity is applicable:** As per Reg 32.3 of MERC Grid Code 2020, the inability to ramp is considered a misdeclaration by the generator and penalty as per the prevailing MYT regulations are applicable. Towards ensuring sustained flexibility and reliability in operations towards meeting system needs, if a generator is subject to such penalty in a year, on account of inability to ramp as required during demonstration of DC, no RoE incentive for ramp rates should be allowed for the year.

Given the significance of such incentive towards plant operations, MSLDC should be mandated to prepare the procedure in a timebound manner, and it should be approved after public consultation.

| We request the Commission to: |
| --- |

- Direct the MSLDC to ensure frequent (say, monthly) randomized demonstration of ramping capability of generating units claiming ramp rates over 1.25%, and allow RoE incentives based on consistent performance during such testing
- Ensure details of declaration of capacity and testing of the same is published on the SLDC website every month, in accordance to the formats prescribed in MERC Grid Code 2020 and allow RoE incentives and AFC recovery subject to such availability
- Disallow RoE incentive if penalty for misdeclaration of capacity has been applicable for the year, on account of inability to achieve required ramp rate during demonstration of DC
- Ensure the submission of MSLDC procedure for certification and achievement of ramp rate is timebound and its approval is subject to public process

### 4.2 Providing targeted incentives for availability during peak hours

Thermal power plants are subject to a normative plant availability factor of 85%, as per draft Reg 46.1. The proposed Reg 28.4 (c) (iii) however, incentivizes availability even over 75% during peak hours. Given that the norm is 85%, availability below the norm should not be incentivized. Thus, no additional RoE should be provided for availability >75% but under 85%.

Further, towards ensuring incentives are provided to encourage generators to effectively support grid operations, the approach suggested in Table 2 can be considered for incentivizing availability during peak hours of different seasons.

*Table 2. Suggested targeting of availability linked RoE incentives during peak hours*

| | Availability > 90% | Availability > 85% |
|---|---|---|
| High-Demand Season | 0.6% | 0.4% |
| Low-Demand Season | 0.4% | 0.2% |

*Source: Prayas (Energy Group)*

Note: High/low demand season and peak/off-peak hours should be defined based on national net load

The objective of the incentive is to encourage thermal generators to be available when they are needed the most. With increasing penetration of renewable sources (particularly solar) and shifting of peak loads towards the solar hours, the greatest need for thermal generation may not coincide with peak load. Therefore, such incentivization should be based on peak hours considered at net load (i.e. the load to be served after considering the load that solar and wind can serve) and not total load. Moreover, providing an incentive based on overall peak load may act as a perverse incentive for plants (high-cost ones in particular) to misdeclare high availability during such periods, since the probability of their getting scheduled in such periods would be very low.

It is also important to note that draft Reg 28.4 c and 28.5 c provide RoE incentives for availability during peak hours for thermal and hydro generation, respectively. However, while this incentive ranges from 0.25% to 0.75% for thermal generation, the range of incentivisation for hydro generation is 1% to 2.25%. The consideration of additional performance-based RoE for hydro generation has been taken in the interest of making it equitable with other generation in the fifth control period, as stated by the Commission in para 4.6.15 of the explanatory memorandum. The reason for the significant difference in availability linked incentive provided for thermal and hydro generation is not clear.

We request the Commission to:

- Remove the proposed incentivization for availability >75% but ≤ 85% during peak hours
- Consider targeted incentives of additional RoE for availability >85% during peak hours across high and low demand seasons as suggested in Table 2
- Ensure definition of peak hours is based on net load
- Clarify the difference in incentives provided for availability during peak hours across thermal and hydro generators

### 4.3 Moving away from SAIDI linked RoE incentives for distribution in the medium term

For the distribution wires business, the performance linked RoE incentive is based on the availability of wires, estimated based on the System Average Interruption Duration Index (SAIDI). The draft regulations clarify that the SAIDI shall be calculated from the automated measurements records through Smart Meters. It is likely that smart meter rollout and ensuring seamless timely two-way communication across Maharashtra will take time. In the interim, it is not clear if there is a minimum percentage of meters across each sub-division for which data can be provided to calculate this index. As this is challenging to ascertain at this time, network availability can be linked to, mean time between feeder outages, DT failure rates as well as mean time between failure of DTs. Thresholds can be linked to circle-wise targets for feeder outages, DT failure rate and MTBFs of DTs. This will be easy to implement as DISCOMs are collecting such data. Targets can also be based on past performance to track and incentivize improvements.

It is suggested that other frequently and easily recorded indicators such as feeder outages, mean time between outages, DT failure rate and mean time between DT failure is used instead of SAIDI to estimate network unavailability. The equity incentives can be based on demonstrated circle-wise improvements. With time and robust implementation of smart metering infrastructure in Maharashtra, SAIDI can be adopted. Before SAIDI adoption, past data based on smart meters should be used to set targets for the future.

### 4.4 RoE for Pumped Storage

Draft Reg 138.7 proposes an 18% base RoE and 1% ramp rate linked additional RoE for pumped storage projects. This is much higher than the RoE proposed for any other type of project, including hydro projects which have a proposed base RoE of 11% and an additional RoE of 4.5%.

Given that PSP is an established technology and that such PSP undertakings are regulated cost plus assets which are relatively low risk, RoE of over 18% is not reflective of on-ground realities and has no basis. The Commission should thus revise the RoE downwards and limit it to a value comparable to existing hydro projects, say in the range of 11-13%.

We request the Commission to set appropriate RoE, in the range of 11-13% for PSP.

## 5 Prudence of interest on long-term loans

As per draft Reg 29.5 the RoI of long-term loans is based on the weighted average rate of interest on the basis of the actual loan portfolio at the beginning of each year. Draft Reg 29.8 and 29.10 do require prudence checks on the charges incurred for obtaining the loans and efforts towards re-financing towards net savings.

While this is a good provision, there is currently no assessment of the prudence in financing/re-financing of long-term loans. Generators, licensees, MSLDC, STU are required to submit details of long term loans as part of the true-up/tariff petition and the requisite data submission. This includes the interest rates for long term loans. However, since the regulations have provisions for refinancing, as proposed in Regulation 29.10, separate reporting of whether such options were availed or not are not part of current formats. This should be separately recorded.

Towards further ensuring prudence, the Commission should contrast the submitted interest rates with the prevalent interest rates (linked to a benchmark rate), and require justification for interest rates that significantly exceed prevalent rates, or changes in interest rates not consistent with changes in prevalent benchmark rates. Such a process should be carried out along with each tariff/true-up process.

We request the Commission to:

- Allow for separate reporting of re-financing options availed by generators, licensees, MSLDC, and STU as part of the tariff/true-up process
- Include regulatory provisions to scrutinise and approve interest rates of long term borrowings (as part of the generator's true-up/tariff petitions) by comparing them with prevalent rates and rate movements

## 6 Improved targeting of availability-linked AFC recovery

As per draft Reg 50.2, capacity charge is recovered separately across high and low demand periods, with differential availability-linked weights across peak and off-peak hours.

While this is a good measure toward encouraging responsive operations of generators in a changing sector, it can be further strengthened. Optimally, plants should be encouraged to be available and generate during periods of high demand for that type of plant, and incentivisation should be tapered for periods of lower demand. The objective of providing greater weightage for availability during high demand seasons/peak hours for TPPs is to encourage availability at times when thermal generation would be most required.

Towards this, it is suggested that the definition of peak/off-peak hours and high/low demand seasons 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 is also consistent with our suggestion in Section 4.2 of this submission regarding RoE incentives for increased availability. MSLDC can be instructed to define peak hours and high demand seasons by considering net-load using past data on a regular basis.

Table 3 elaborates these ideas further with indicative weightages for AFC recovery:

*Table 3. Proposed consideration of availability-linked FC recovery and application of PLF incentive*

| | Peak hours | Off-peak hours |
|---|---|---|
| High-Demand Season | ~2.5X weightage per hour for AFC recovery*<br>→ Rs. 0.5/kWh PLF incentive | ~1.2X weightage per hour for AFC recovery*<br>→ Rs. 0.25/kWh PLF incentive |
| Low-Demand Season | ~1.2X weightage per hour for AFC recovery*<br>→ Rs. 0.25/kWh PLF incentive | ~0.8X weightage per hour for AFC recovery*<br>→ No PLF incentive |

*Source: Prayas (Energy Group)*

Note: High/low demand season and peak/off-peak hours should be defined based on national net load

**For example, if the high-demand season is defined as 3 months and each day is assumed to have 4 peak hours, then the four combinations of high-demand/peak, high-demand/off-peak, low-demand/peak and low-demand/off-peak would correspond to about 4%, 21%, 13% and 63% of the year, respectively. However, the AFC recovery for these periods as per the suggested approach would be about 10%, 25%, 15% and 50% respectively.*

We request the Commission to:

- Reconsider availability-liked AFC recovery in line with the approach suggested in Table 3, and to base it on net load rather than overall load

## 7 Application of PLF incentive

Draft Reg 50.8 retains the PLF incentive provided for generation in excess of the NAPLF during peak and off-peak hours, considered cumulatively across high and low demand seasons.

However, it is important to note that generators are fully compensated for all the costs incurred in generation (such as the cost of coal), and are paid the full AFC (subject to availability) to enable them to earn a good return on equity, service their debt, undertake O&M etc. The draft regulations also provide further incentivisation for high availability during peak hours. Therefore, given merit-order based dispatch, the only purpose of providing a PLF incentive is to encourage generators to procure low-cost coal to improve their chances of getting scheduled, and thus lower the ECR for consumers. Providing a very high PLF incentive defeats this purpose of obtaining low-cost coal to reduce ECR. Since generation above NAPLF (particularly from expensive, typically non-pithead, plants) is only likely to be required during peak net-demand periods, PLF incentive should also be provided on the basis of high/low demand seasons and peak/off-peak hours based on net load, Moreover, given the arguments above, such an incentive – which is over and above all cost recovery and a handsome RoE – should be modest. Such a gradation is suggested in Table 3.

We request the Commission to:

- Consider varying PLF incentives across high/low demand season in addition to peak/off peak hours based on net load, in line with the suggestions in Table 3

## 8 GCV-related data and considerations

Like in MERC's MYT Regulations 2019, GCV 'As Billed' is considered for the calculation of ECR in these proposed regulations, as per draft Reg 50.6. Considering GCV 'As Billed' for ECR calculation is crucial towards ensuring accountability and optimum operation, while safeguarding consumer interests, and retaining this provision is a good measure. The allowed variation between GCV 'As Billed' and GCV 'As Received', however, has been increased from 300 kcal/kg in the 2019 regulations to 650 kcal/kg in the draft. As per the explanatory memorandum, such an increase has been allowed considering GCV loss data for the last five years, as submitted by MSPGCL.

Though, as noted by the Commission in the SOR for MERC's MYT Regulations 2019, the normative GCV loss of 300 kcal/kg was allowed "…,***so that over time, all stakeholders move towards achieving the objective of minimizing this GCV loss****, and the Generating Companies as well as their Beneficiaries pay only for what they are getting"* ***[Emphasis added]***. It is important to note that the extant allowed GCV loss of 300 kcal/kg is also based on submissions by MSPGCL. Thus, over the last control period, not only have generators been unable to minimize GCV loss, there seems to have been an increase in GCV loss. Allowing an increased GCV loss based on historic data does not ensure accountability in operations and does not align with the objective of minimizing the GCV loss over time.

However, it is understood that there are some losses between GCV As Billed and GCV As Received which must be allowed for. In keeping with objectives of ensuring accountability in operations and minimising GCV loss, the Commission should retain the allowable GCV loss of 300 kcal/kg, as introduced in MERC MYT Regulations 2019. To further understand the on-ground extent of GCV loss, the Commission should set up a committee to undertake an in depth assessment of the causes for GCV loss between 'As Billed'/loading and 'As Received'/unloading points, identify means to reduce such loss, and determine the GCV loss which the generator should be held accountable for and that which can be attributed to factors outside the generators control.

We request the Commission to:

- Retain the allowable GCV loss of 300 kcal/kg between the loading and unloading point

- Set up a committee to undertake an in depth assessment of the causes for GCV loss between the loading and unloading points

## 9 ECS related cost impact and recovery

MERC MYT Regulations 2019 included the cost impact of ECS and its recovery through an amendment. However, towards 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 environmental norms. Neither operation of the plant, nor construction of the ECS is equivalent to the utilisation of the ECS and adherence to the norms.

Cost recovery of ECS through tariffs should, thus, be based on compliance to the norms. This could be done on the basis of the generator procuring suitable certification from the Maharashtra State Pollution Control Board (MSPCB) for adherence.
Further, the final deadline for compliance with MoEFCC's revised emission norms (31st December 2026 for non-retiring plants and 31st December 2027 for retiring plants) falls within the upcoming control period. Towards protecting timely compliers, the Commission could exclude ECS related supplementary charges for such units/stations from consideration for MoD till the final deadline (31st December 2027). After that, supplementary charges can be included to decide MoD for all plants. In addition, generation from plants that have not installed ECS by the final 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. Operational incentives, such as the PLF incentive, should also not be applicable for such plants until they are able to comply with the norms. The proposed treatment of TPPs after the final deadline for adherence to norms is summarised in Table 4.

*Table 4. Proposed treatment with regard to adherence to revised emission norms post final deadline*

| | If ECS CapEx is not incurred | If ECS CapEx is incurred |
|---|---|---|
| TPP is compliant | N.A. | ECS related costs (FC and VC) should be passed through |
| If TPP is not compliant | Apply notional additional penalty to compute MoD, so as not to give unfair advantage | Disallow PCE related FC and VC; Apply notional additional penalty to compute MoD so as not to give unfair advantage |

*Source: Prayas (Energy Group)*

Further, as per draft Reg 47.3 O&M expenses on account of ECS is admitted on a normative basis, at 2% of the admitted CapEx (excluding IDC) to be escalated annually at 3.71%. It should be explicitly stated that the O&M expenses will be calculated on the basis of CapEx (excluding IDC) of the ECS alone – the current wording of the draft regulation could be misconstrued as the CapEx (excluding IDC) of the entire station. Further, the norm proposed should be the ceiling of O&M

expenses towards ECS, such that, O&M expenses allowed is based on the lower of actuals or the norm proposed.

We request the Commission to:

- Allow ECS cost recovery based on compliance to the norms, which can be linked to MPCB certification for adherence
- Ensure timely compliers are protected by excluding ECS expenses from consideration of MoD till the final deadline
- Penalise non-compliance post the final deadline in accordance with the treatment suggested in Table 4, so as to avoid unfair advantage to non-compliers
- Compute O&M expenses of ECS based on CapEx (excluding IDC) of the ECS alone, and allow the lower of actuals or norms proposed in draft Reg 47.3

# 10 Transparency regarding expenditure on socio-environmental mitigation measures by thermal power plants

It is understood that the thermal power plant operations have significant socio-environmental impact in the areas surrounding the plant. The generator is expected to take some steps and expenses to address and mitigate these impacts in some measure. These costs are part of the O&M costs in the ARR. The Commission should consider such 'socio-environmental costs' as a separate head under OpEx. This treatment is already carried out for water charges, as per draft Reg 47.1 (d). On similar lines, socio-environmental costs should also merit separate consideration under OpEx. This head should include the cost impact on account of expected preventative and remedial steps taken to address environmental and social impacts of thermal projects. This could include measures such as – audit and assessment of utilisation and disposal of fly ash as required in notification dated 31st December 2021, actions towards certification of safety and clean up, follow up on conditions stipulated in the Environmental Clearance, and other measures required under the generating station's consent to operate.

Hence to ensure transparency, the Commission should direct the generator to separately report the projected expenditure towards mandated socio-environmental measures as part of the generator's ARR submissions. These details should be submitted in a disaggregated manner, with cost projections made separately for different mandated measures. At the time of true-up, the generator should report the actual socio-environmental expenses undertaken under each separate measure, as compared to the amount projected at the time of ARR submission. Only the actual amount should be passed through to the consumer, subject to prudence checks. The balance of the projected socio-environmental costs should only be passed through when such expenses are actually carried out towards addressing socio-environmental impact of the generators.

We request the Commission to:

- Mandate generators to submit detailed and separate reporting of socio-environmental costs projected for the control period as a separate head under OpEx
- Allow socio-environmental costs only based on actuals at the time of true up, with balance amount being passed through only when mandated measures are carried out (and therefore expenses are undertaken)

## 11 Cost-Benefit Assessment for usage of washed coal

In Para 8.3.3 of Case 296 of 2019, MERC directs MSPGCL to "*carry out the proper cost benefit analysis of coal beneficiation after receiving the tenders and before going ahead for placing the contracts for coal beneficiation. MSPGCL should try to ensure that the effective landed price of washed coal at thermal Station in terms of Rs/Kcal is lower than the landed price of coal at thermal station in terms of Rs/Kcal*".

However, such comprehensive assessment and validation of lower effective price of washed coal has been missing from generator's tariff petitions in the previous control period, though some stations do procure and use washed coal. The utilisation of coal from CIL is subject to the prices notified by CIL and governed by regulations regarding permitted GCV loss. This transparency in costs is lacking when washed coal is used in thermal power plants, making a stringent analysis of costs and benefits of washed coal necessary. The approval of any procurement costs for washed coal should be contingent on such cost benefit analysis, which should also be published for public scrutiny. The Commission should ensure that generators using washed coal submit a detailed cost benefit analysis and validate reported improvements in GCV through coal beneficiation from each source of washed coal. No associated fuel procurement costs should be allowed until such details have been submitted and scrutinised.

We request the Commission to:

- Mandate that costs associated with procurement and utilisation of washed coal will only be allowed if respective generators submit a detailed cost benefit analysis (CBA) and validate reported improvements in GCV through coal beneficiation from each source of washed coal
- Ensure that the approval of costs relating to washed coal be subject to public consultation

## 12 Study towards assessing decommissioning cost

Given the transition that the sector is undergoing, closure of coal-based assets is going to be increasingly common in future. Closure of coal-based assets is likely to involve costs for physical asset closure and disposal or repurposing, and aspects such as addressing social and environmental impacts. Providing regulatory clarity regarding this aspect in advance of expected closure of assets is crucial, particularly with regard to cost recovery.

Accounting for decommissioning costs is going to have different impact on capacity with different vintages. Accounting for these costs in the case of assets which are near or past the end of their useful life, for instance, will require different considerations than those for plants which have significant balance operational life or are new/yet to be commissioned. The Commission should set up a committee to discuss approaches to deal with the impact of decommissioning costs of thermal capacity with differing vintages under its jurisdiction. The committee should consult stakeholders, including civil society organisations, given that decommissioning costs are linked to remediation and restoration, and likely to impact consumer tariffs. Regulations for cost recovery related to decommissioning can be based on the findings of the committee based on public deliberations.

We request the Commission to:

- Set up a committee to identify approaches to deal with the impact of decommissioning costs on thermal capacity with differing vintages under its jurisdiction, subject to consultation with stakeholders including civil society organisations

## 13 Making additional financial resources available to generators to enable community welfare

In the interest of providing support to communities in the vicinity of thermal power projects, the Commission should consider an additional 'social welfare' allowance, provided for each generating station. While some benefits are provided, they are limited to specific individuals or households, but measures towards support at the community level is lacking. In Maharashtra, there is precedence of such community welfare/local development funds being disbursed for project affected communities of energy projects. For instance, a social benefit grant of Rs. 5 lakhs/year for the first three years is provided to Gram Panchayats of villages affected by solar feeder projects under MSKVY 2.0 scheme. For wind power projects in Maharashtra, project proponents are charged a village panchayat tax, and the revenue thus earned is intended to be utilised by panchayats for community welfare.

Given that thermal projects have a more significant impact on the villages surrounding it, thermal generating companies may also choose to or may need to provide 'social benefit grant' of Rs. 5 lakhs/year for affected villages in the vicinity (say, 10km) of each thermal station. Such social benefit grant paid to affected villages should be over and above all the statutorily mandated measures and expenses for environmental protection and community benefit. In such cases the generator should be allowed to recover these expenses through their ARR, as an additional component of ARR. Considering the example of MSPGCL, the annual social benefit grant amounts to Rs. 8.75 Crore/year (assuming 25 villages each in the vicinity of the seven MSPGCL thermal power projects), which is 0.24% of the O&M expenses of MSPGCL in FY22. Thus, providing such allowance will have negligible impact on operating costs and ARR but will be a significant benefit for communities living near thermal plants.

This allowance could be disbursed to each Gram Panchayat with directions to ensure that it is used for activities such as – infrastructure creation for drinking water supply, sanitation, health, education, skill development, roads, cross drains, electrification including solar power, solid waste management facilities, scientific support and awareness to local farmers to increase yield of crop and fodder, rain water harvesting, soil moisture conservation works, avenue plantation, plantation in community areas, etc.

We request the Commission to:

- Allow thermal gencos to claim payment of social benefit grant of Rs. 5 lakh per year per village in a 10 km radius of each thermal power station, to be disbursed to the respective Gram Panchayat for social welfare oriented activities, (which should be over and above all the statutorily mandated measures and expenses for environmental protection and community benefit) and allow the recovery of this social benefit grant as an additional component of the ARR, subject to actual payments to Gram Panchayats

## 14 Provision of a monthly Fuel Utilisation Plan (FUP)

Proposed Reg 39.6 requires the generator to maintain data of actual performance on fuel utilisation vis-à-vis the approved fuel utilisation plan, along with justification on variation between the two. It also requires the generator to publish such information on the generator’s website every month.

In light of the recent instances of shortages, a comprehensive and effective fuel utilisation plan and adherence to the same becomes crucial towards preventing ad hoc fuel procurement and the resultant spikes in tariff. To ensure adherence to the continuing mandate (as per draft Reg 39.6) and towards accountability and transparency, the Commission should disallow 1% of the variable costs as penalty in the absence of regular monthly publication of actual performance vis-à-vis the FUP on the generator’s website.

Additionally, the Commission should undertake review of the published actual fuel utilisation performances on a quarterly basis and provide directives to the generator towards prudent and improved fuel procurement and utilisation planning.

We request the Commission to:

- Disallow 1% of the VC as a penalty in the absence of regular monthly publication of actual performance vis-à-vis the FUP on the generator's website as required by draft Reg 39.6
- Review actual fuel utilisation performance and provide directives to generators towards improved power procurement and utilisation

## 15 Considerations for operation at technical minimum

CEA (Flexible Operation of Coal based Thermal Power Generating units) Regulations, 2023 notifies a technical minimum of 40%, and has stipulated a phasing plan for all generating stations to adhere to the revised technical minimum. Given that achievement of this phasing plan falls within this control period, it is crucial to account for the impact of such modification on the operation of the thermal power plant.

As a crucial step in this direction, the Commission should direct that when the SLDC requires the generator to run at near technical minimum, i.e. between 40%-50%, it should specify generation in that band for at least 12 consecutive time blocks. This will aid the generator to ensure safe and reliable generation even at lower loading. The Commission should include this operational provision through amendments to the State Electricity Grid Code.

We request the Commission to:

- Mandate that the SLDC should specify operation at technical minimum for at least 12 consecutive time blocks
- Amend the State Electricity Grid Code to include such provision

## 16 Circle wise capital expenditure plans for distribution companies with true-up after 5 years

Draft Regulation 91 and 101 provides detailed specification of the distribution capital investment plan. Over the years MERC and Maharashtra utilities have developed a detailed process for capital planning, reporting, tracking process and regulatory scrutiny.

To ensure improved planning and performance accountability, it is suggested that the Commission approve the network investments based on the detailed capital investment plan for a five year period. The costs arrived at would be fixed for a five year period and will only be trued-up at the end of the control period.

Further, large DISCOMs like MSEDCL have skewed network development due to varying density of consumers, levels of industrialization and urbanization etc. Going forward, there will be significant decentralized embedded generation in the state with open access, captive investments and MSKVY implementation. To ensure adequate and robust network availability, it is suggested that capital investment plans be submitted on a circle-wise basis.

To reduce the skewness and to increase accountability for delays and cost-overruns in capital expenditure, it is suggested that:

- Detailed capital investment plans be specified on a circle-wise basis. Investments required at the utility level can be reported separately but should include details of all works towards addition/ strengthening of networks mentioned in the plan. Network strengthening in areas with poor performance in supply quality indicators or high R&M requirements should be prioritized.
- Capital investment plans should also consider increased network requirements due to open access, captive, grid interactive RE and increased embedded generation. The Commission and the DISCOM can also identify areas in each circle where open access/captive/net metering or billing was constrained due to issues with network capacity and incorporate works to address them.
- The approved plan for 5 years is trued-up at the end of the control period. However, progress of ongoing works should be reported every quarter on the licensee website.
- Mumbai DISCOMs may be exempt from circle-wise reporting.

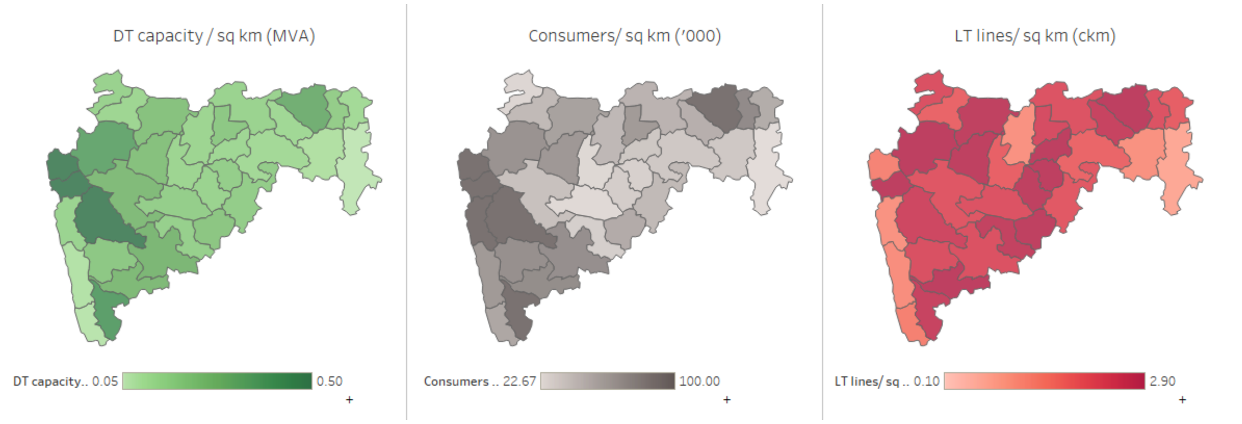
# 17 O&M norms

## 17.1 Circle-wise O&M expenses and increase O&M for bottom 10 circles

Draft Regulation 92 and 102 provide details for operation and maintenance expenses. The norms are provided separately for the distribution and the supply business. Previously, the actual O&M expenses of previous years were increased based on inflation (or inflation minus efficiency factor) to calculate the normative expenses. In the draft regulations, the O&M norms are specified as % of GFA and on a per consumer basis. Thus, with increase in capital investment and consumer growth, O&M would increase. These norms are reduced at an average rate of 1% per annum towards efficiency improvements. The proposed methodology is a significant improvement from the existing methodology for estimation of O&M norms.

It is quite suitable for urban distribution utilities with dense networks, high capital investment and high consumer density. However, like the existing inflation linked methodology, it does not account for skewness in O&M expenses, capital investment and low consumer density in areas within the DISCOM (especially MSEDCL) which affect supply and service quality. Figure 1 shows the skewness in DT capacity, LT lines and consumer density across MSEDCL circles.

*Figure 1- Total DT capacity per square km | LT lines per square km |Number of consumers per square km*




To address the skewness, it is suggested that:

— **O&M expenses be estimated on a circle-wise basis for MSEDCL:** Common and administrative costs should be apportioned on a pro-rata basis. This exercise should be completed and required data should be submitted within six months such that it can be used during the tariff determination process for estimation of costs.

— **Separate O&M norms for ten circles which require the most attention**: For the ten circles with the least network and consumer density and with significant issued of network availability, the O&M norms applicable should be 2% higher than the norm for the rest of MSEDCL.

— **Additional expenses approved for 10 circles non-transferable:** The additional amounts allocated due to 2% higher O&M norm for these 10 circles should be spent in these circles and cannot be used in any other circles.

— **20% R&M in each circle:** Regulations should specify that R&M expenses should account for at least 20% of O&M expenses in each circle.

A circle-wise approach will enable MSEDCL to improve quality of supply across circles and will also be necessary for introduction of multiple distribution licensees in MSEDCL's area of supply.

## 17.2 Gain and Loss sharing of O&M expenses

Operation and Maintenance expenses are crucial to ensure improvements in supply and service quality especially in a vast area of supply like MSEDCLs. If actual O&M expenses are lower than the Commission prescribed norm, it need not be an indication of performance efficiency. It could be an indication of neglect of crucial O&M activities, especially in rural areas.

O&M expenses account for about 8% of MSEDCL's cost to supply but with attention to O&M, consumer service quality can be improved dramatically. For this control period, it is suggested O&M expenses are passed though at actuals up to the approved O&M. Therefore, under-expenditure should not be treated as gains. With improved reporting of supply and service quality data at the circle level, over time, norms and cost sharing mechanisms can be linked to supply and service quality indicators.

It is suggested that:

- O&M expenses be accounted and reported on circle-wise basis.
- The 10 Circles with the least density in terms of network, consumers should have a higher norm.
- O&M expenses should be 100% passthrough to consumers up to the approved norm. Over time, frameworks can be evolved to link O&M performance to quality of supply and service.

# 18 Framework for time of day tariffs

## 18.1 Applicability

Draft Regulation 113 specifies the framework for levy of time of day tariffs. We support the proposal to levy ToD tariffs on all consumers with load > 10 KW, including domestic. With the operationalization of these regulations, Maharashtra will be the first state in India to levy ToD tariffs on such a wide ambit of consumers.

To reduce implementation issues,

- **Exempt agriculture**: It must be clarified whether ToD tariffs will be not applicable on agricultural consumers. Since the metering status of such consumers is poor the transaction cost to levy ToD tariffs would be high.
- **Ensure readiness of metering infrastructure**: For consumers with load between 20 kW and 10 kW who do not have meters which are capable of recording slot-wise consumption, a time-bound plan for converting their meters must be submitted by all licensees with the notification of these regulations. Further, the Commission should track progress as per plan such that all such consumers have requisite meters before the commencement of the control period.

## 18.2 Time of day tariff design

In draft Regulation 113.2, MERC has proposed a ToD structure for the next control period. This is in line with the framework prescribed in Rule 8A of the Electricity (Rights of Consumers) Amendment Rules, 2023.

The proposed design provides for:

- 20% rebate from 9 AM to 4 PM, during solar hours and from 12 AM to 6 AM, which have typically been off-peak periods.
- 20% penalty from 4 PM to 8 PM during evening peak
- 10% penalty from 8 PM to 12 AM and from 6 AM to 9 AM.

It is interesting to note that there is no period when only the normal energy charge is levied in this design.

The study commissioned by MERC to assess ToD tariff design was based on load curves till 2021-22.

Within this control period, there will be several major developments which impact demand and supply patterns of MSEDCL. These include increased procurement of variable, seasonal RE, rollout of green open access an increased day time agricultural supply with MSKVY. Going forward the impact of ToD will also vary significantly from DISCOM to DISCOM depending on the sales mix especially with increase in residential cooling demand etc.

Figure 2 shows the seasonal variation in demand for MSEDCL from April 2022 to December 2022. Summer consists of March, April, May while monsoon months are June to October. November to February are the winter months. In the summer, the peak is during the day but during winter, the peak is closer to 11 AM. Further the night-time off-peak periods are sharply lower than the peak. In monsoon, the demand is mostly flat during the day.

*Figure 2: Seasonal variation in demand Jan- Dec 2022*

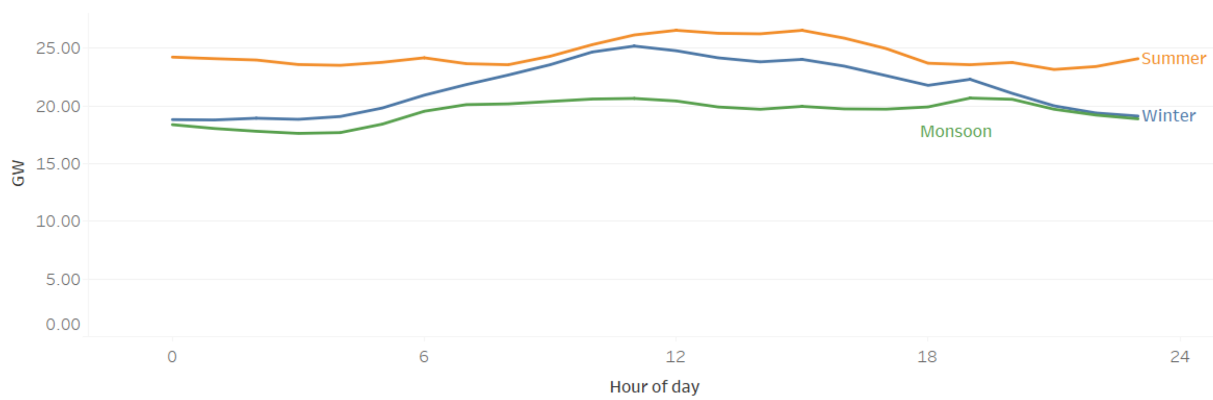
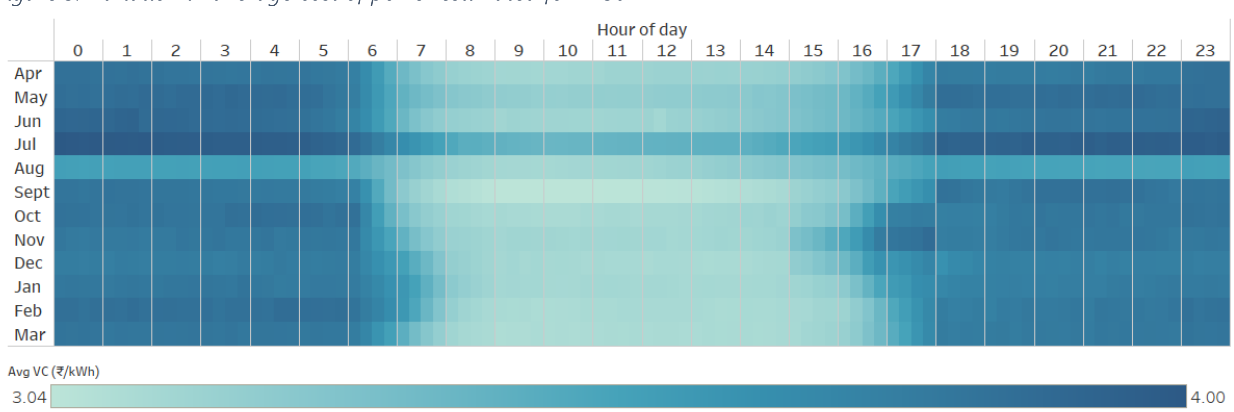



Figure 3 shows the block-wise cost variation in average rate of power purchase for each month in 2030. The demand supply projections for 2030 are from Prayas (Energy Group)'s detailed production cost modelling exercise for Maharashtra[1].

*Figure 3: Variation in average cost of power estimated for FY30*




[1] For more details please see the report: https://energy.prayaspune.org/our-work/research-report/maharashtra-s-electricity-supply-mix-by-2030 . The model used for this study along with data and assumptions is available here: GridPath model used for this study is available at [https://github.com/prayas-energy/gridpath-mh](https://github.com/prayas-energy/gridpath-mh).

The figure clearly shows that the price of power during off-peak periods will be higher than day-time. Further, with the rollout of green open access, many partial open access and captive consumers will avail low cost RE through third party contracts and increase their drawal from the DISCOM during the evening and off-peak night hours (i.e 12 AM to 6 AM). There is no guarantee that this period will continue to be off-peak going forward.

The modelling results show that the variable charges during day time periods (7AM to 4 PM or 9AM to 4PM) was 10% less than the monthly average variable cost in almost all months. In July and August, it was 5% to 7% less. At the margin, the cost difference is much higher indicative of the potential savings from load shifting for MSEDCL.

From the two figures, it is clear that the levy of ToD should vary seasonally and that no rebates should be provided between 12 AM to 6 AM in most months (except perhaps some monsoon months). There is also a clear case for provision of day-time rebates to consumers.

Even with multiple major changes in the coming five years, it is crucial to provide certainty to consumers. Therefore, it is suggested that the regulations provide a framework for charges which includes day-time rebates and morning and evening period penalties. The framework should specify that the tariffs should vary seasonally. The framework can also provide a range for applicable penalties and incentives in each slot which acts as a ceiling and floor to inform consumers and investors of the medium term tariff trajectory.

Given these changes, it is suggested that the MYT regulations provide an enabling framework for ToD tariffs which specifies:

— Seasonal variation in Time of Day Tariffs
— Slots in which incentives/ penalties will be levied (Morning and evening peak penalties, day time rebates)
— Range within which incentives and penalties to be offered in each slot for the control period.

This specification can guide the ToD tariff design to be approved in the tariff determination process for each DISCOM.

## 19 Smart metering

Smart metering initiatives qualify as an opex scheme as per these regulations. As per draft Regulation 92.5, DISCOMs may undertake opex schemes and such schemes would be allowed above normative O&M. For these opex schemes, there will be prudence check by the Commission and the DISCOMs shall submit "detailed justification, cost benefit analysis, and life-cycle cost analysis of such schemes as against capex schemes, and savings in O&M expenses, if any". These measures are sufficient for other opex schemes indicated in Draft Regulation 92.5 but a clearer and more precise regulatory framework would be required for smart meters in the MYT regulations. This is because of:

- **Significant outlay**: The outlay of the scheme is significant at Rs. 26,000 crores for the next ten years in MSEDCL's area of supply alone. This is comparable to the capital cost approved by

MERC for six units of MSPGCL (Koradi 8, 9 ,10, Chandrapur 8,9 and Parli 8) accounting for 3250 MW of capacity for which there was significant regulatory scrutiny by MERC (MERC Case No.59 of 2017).

- **Substantial consumer impact**: Installation of smart meters will be at consumer premises. With such a direct interface with consumers, it is crucial that accountability and monitoring mechanisms are well detailed so as to not further erode consumer trust deficit.
- **Unprecedented large-scale rollout:** The roll-out will cover over 20 million consumers across Maharashtra, which would be among the largest rollouts in the country. Such deployment at scale in a short period of time needs to be monitored carefully for implementation issues.
- **Accountability of AMISPs as per SLAs:** Smart meter contracts were awarded via competitive bidding as per the standard bidding guidelines issued by the Ministry of Power. The appointed Advanced Metering Infrastructure Service Providers (AMISPs) are accountable for multiple Service Level Agreements (SLAs) as per the contract. If SLAs are not met, penalties can be levied upto 20% of the AMISP service charge. These SLAs include regulatory of performance of scheduled tasks, AMISP system availability and for remote actions performed by the system.

Thus, for smart meters cost passthrough, the Commission should specify that:

- The smart meter rollout plan (for the next five years) for each circle should be provided to the Commission for approval through a public process before the roll-out is initiated.
- The metering plan submitted by the AMISP, additional requirements as well as monthly progress reports submitted by the AMISP (regarding installation of meters, SLA performance reports etc) should be submitted to the Commission. An aggregate annual report based on the AMISP reports should be shared on the ERC website.
- **The claimed/ targeted benefits from smart metering need to clearly established through baseline studies. The Commission should specify a rigorous methodology for assessing the realisation of claimed benefits. Regulatory scrutiny of realised benefits should take place through a public process given the scale of investments and potential tariff impact.**
- The cost passthrough will be contingent on meeting the target benefits and only on the basis of the performance of the smart meters (this should include all performance parameters of the program).

## 20 Energy Efficiency Schemes

Regulation 103 gives the necessary impetus towards Energy Efficiency Schemes (EE) by DISCOMs for the upcoming control period. A comprehensive list of potential measures are listed which the DISCOMs can implement. In addition, DISCOMs are also to set targets by providing a trajectory for consumption reduction and energy savings for the control period.  DISCOMs are also to submit a cost-effectiveness framework and actual performance vis-à-vis the trajectory during true-ups. This framework is comprehensive in terms of holding DISCOMs accountable for adoption and implementation of energy efficiency schemes which have received less attention in the past.

Presently, the draft regulations specify that EE schemes can be undertaken as Capex or Opex measures. This specifies the mechanism or cost passthrough for DISCOMs.

In order to enable and empower DISCOMs to undertaken EE schemes, the Commission can specify that at least 0.5% of the ARR each year must be allocation to Energy Efficiency Schemes. Such a stipulation should ensure scaling of efforts as well as continued investment. Even with the specification, detailed scrutiny of the capex and opex investment must be undertaken. Timely directives should be issued by the Commission to ensure that the expenditure on these fronts is at least 0.5% of the ARR.

It is suggested that:

- 0.5% of ARR each year should be allocated for energy efficiency schemes.
- A detailed list of schemes which qualify under the stipulation should be specified.
- Like any other scheme, cost-benefit analysis should be evaluated and cost prudence checked.

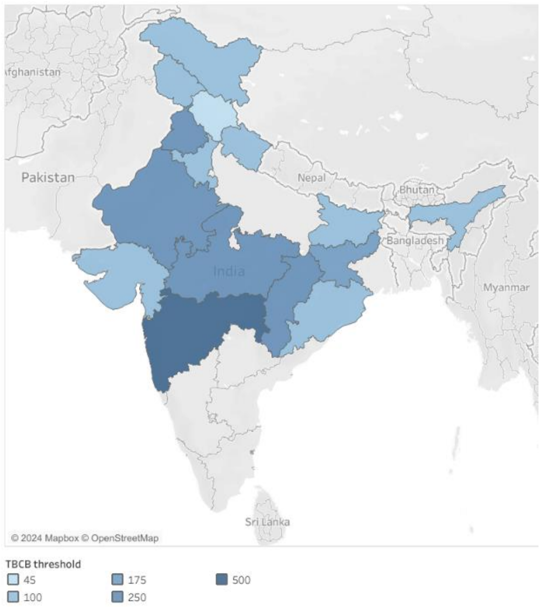
## 21 Tariff based competitive bidding for transmission

As per Annexure IV of the draft regulations, the threshold limit for Intra-State Transmission Systems to be developed through Tariff Based Competitive Bidding is Rs. 500 crores. Analysis of thresholds in 15 states shows that Maharashtra has a highest threshold at Rs. 500 crores. This is also summarized in Figure 5.

- Maharashtra has a highest threshold at Rs. 500 crores.
- In 7 states it is as low as Rs. 100 crores. Himachal Pradesh, a state with hilly terrain has set the threshold at Rs. 45 crores.
- A detailed comparison of existing TBCB thresholds in several states can be seen here[2].

[2] https://indiatransmission.org/Commercial/TBCB%20Threshold%20in%20states

*Figure 4: TBCB Thresholds across states (Rs. Crores)*




Analysis of over 70 ISTS projects showed that tariffs discovered under the TBCB route were about 36% less than if the projects were developed under the Regulated Tariff Mechanism (RTM) (estimated cost as communicated by the Cost Committee constituted by National Committee on Transmission (NCT) and methodology for calculation of tariff as per CERC norms). With such substantial savings, it is imperative that Maharashtra reduce the threshold for TBCB from Rs. 500 crores to Rs. 100 crores.

| |
|---|
| It is suggested that MERC reduce the threshold for TBCB from Rs. 500 crores to Rs. 100 crores. |

## 22 Tariff framework for Multiple Distribution Licensee

The MYT process proposes a framework for certain tariff aspects for multiple distribution licensees in Maharashtra. The tariff framework seems to be designed for the existing parallel licensees in Mumbai.

The introduction of new supply licensees requires a clear and comprehensive framework which addresses issues related to capital investment, network rollout, metering, energy accounting, accountability for reliability and supply and service quality. This is especially the case if the introduction is in MSEDCL's area of supply which has wide variation in network density, sales mix and load.

The framework in these regulations proposes the levy of uniform demand charges and wheeling charges for licensees within an area of supply. If the area of supply of new distribution licensees are overlapping and co-terminus to that of the existing distribution licensee, even one as large as MSEDCL, then the proposed framework could evolve to be effective over time. However, as per the Distribution of Electricity Licence (Additional Requirements of Capital Adequacy, Creditworthiness and Code of Conduct) (Amendment) Rules, 2022, "the area falling within either a Municipal Corporation as defined in article 243Q of the Constitution or three adjoining revenue districts, or a smaller area as may be notified by the Appropriate Government shall be the minimum area of supply." This implies that multiple distribution licensees can operate in areas that are a subset of MSEDCL's distribution area.

Therefore, in MSEDCL's case, introduction of new supply licensees should only take place after there is:

1. **Complete accounting segregation of the Distribution Wires Business and Retail Supply Business:** Notional separation based on the allocation matrix would lead to mis-reporting of costs and affect uniform wheeling charge determination.
2. **Clear accounting of costs (for wires and supply business) for each district (for all circles, divisions and sub-divisions):** This would essentially require asset mapping, allocation of long-term power procurement costs and administrative costs at the circle level. Where districts and circles are not co-terminus and in case of Municipal Corporations, mapping at the sub-division level would also be required.
3. **Changes in MSEDCL's governance and management structures:** This is towards more decentralised management for network planning, operations, maintenance.
4. **MSEDCL files district level ARRs for tariff determination before the Commission:** The proposed framework is essentially implying geography-wise segregation of MSEDCL for tariff determination. Ideally, the process for regulatory scrutiny of MSEDCL's geography-wise ARR filings should be well established before other licensees are introduced.

**Without a comprehensive and a detailed exercise for circle-wise allocation of costs, the roll-out may not result in a level playing field for the incumbent and subsequent licensees and may offer gaming possibilities of transferring costs from one supply area to the other and cherry picking.** The objective of furthering fair competition which would benefit consumers may not be achieved with this approach. Further such an approach is also fraught with likely litigation. In addition, there could be challenges related to metering, skewness in network rollout favouring areas with HT consumers, challenges related to identifying issues with network and supply availability, etc.

Therefore, it is suggested that:

— Proposed framework be introduced only for existing parallel licensees in Mumbai.

— For new supply licensees in Mumbai and the rest of Maharashtra, a separate comprehensive regulation be notified addressing all issued related to the roll-out in a comprehensive manner.

— No licensee should be granted for operating in MSEDCL's area of supply until MSEDCL ensures complete accounting segregation of wires and retail supply business for each district and municipal corporation.

- Commission can issue appropriate directions and set up a committee to address implementation challenges that arise whilst completing this requirement in a timely manner

In addition, there are comments on specific aspects of the framework for tariffs for multiple licensees which are discussed below:

### 22.1 Resource Adequacy and power procurement planning for multiple distribution licensees

According to Regulation 19.1 and Part C of the draft regulations, all DISCOMs are required to prepare a procurement plan "to serve the demand for electricity in its area of supply." With multiple distribution licensees operating in a single supply area, this requirement suggests a duplication of procurement efforts to address the total demand. The draft regulations do not specify any mechanisms or guidelines for demand projections and supply planning in the context of multiple distribution licensees. This lack of a coordinated framework could result in inefficient procurement, suboptimal utilization of resources, and higher costs passed on to consumers. A clear regulatory approach is needed to align the resource adequacy and power procurement planning across multiple licensees within a common supply area.

### 22.2 Retail Supply Margin fixation and uniform incentives

For the Retail Supply Business, where the scope for Gross Fixed Assets (GFA) addition is limited, the Commission has proposed a Supply Margin of Rs. 0.05 per unit in lieu of Return on Equity. This margin is estimated based on data from MSEDCL and Mumbai DISCOMs for FY23. However, with the reading of draft Regulation 112.3 and Regulation 28.8, it is unclear whether this Rs. 0.05 per unit should be claimed based on sales or power procured. It is also not clear whether supply margins will be determined based on actual performance as reported in the true-up process or based on approved projections.

### 22.3 Uniform demand charges and under-recovery of costs

The draft regulations proposed uniform demand charges in an area of supply. Existing DISCOMs are committed to increasing demand charges such that they gradually are more reflective of fixed costs incurred by the DISCOM. With sales migration, energy costs might reduce. However, uniform demand charges would mean under-recovery of fixed cost for some DISCOMs and perhaps recovery of revenue more than fixed cost for others. DISCOMs with under-recovery of costs would be unable to ensure timely payments to generators, affecting its ability to supply power. There is no mechanism to ensure compensation of revenue loss to meet incurred costs. Draft Regulation 112 (3) (d), is restricted only to sale to the cross subsidy requirement of pre-specified consumer categories. The loss of revenue of MSEDCL is related to costs rather than cross subsidy requirement. Since the demand charges for HT categories are higher, such a mechanism may not be enough to compensate for fixed costs payments across categories due to sales attrition. In 2022, the petitions for multiple distribution licensees applied for districts accounting for 40% of

MSEDCL's HT sales implying that the impact of MSEDCLs ability to pay generators for contracted capacity will be seriously affected.

### 22.4 Ceiling tariff to be ineffective in controlling tariffs in current framework

As per the proposed regulations, consumer category-wise or uniform ceiling rate for Energy Charge will be determined by MERC. The provisos in draft regulation 112.3 (e) and (f) allow for DISCOMs to levy applicable fuel surcharge over and above the ceiling tariff. It also allows DISCOMs to undertake additional power procurement during the year if required. This implies that DISCOMs can charge tariffs 20% in excess of the ceiling tariff, and even higher tariffs with regulatory approval. This defeats the purpose of the ceiling tariff.

### 22.5 True-up and performance accountability for multiple distribution licensees

As per draft regulation 112.3 (e) multiple distribution licensees subject to ceiling tariff are not subject to true-up. Quarterly submissions on rebates, subsidy provision and post-facto FAC approval as specified in the draft regulations, are insufficient to track performance of multiple distribution licensees. It should be clarified that licensees are expected to file a petition with performance and cost with detailed reporting of performance, sales, collection efficiency and cost. This should be used to determine the ceiling tariff for the next control period. However, any additional costs over and above costs approved in the MYT order (other than $Z_{fac}$) will be disallowed by the Commission. However, this also implies that any surplus due to over-projection of sales, undercapitalisation (as compared to approved plans) or over-recovery of revenue will be retained by the licensee.

### 22.6 Estimation of Average Cost of Supply and cumulative revenue gaps

Draft regulation 110.3 states that the retail supply tariff for different consumer categories should be based on ACOS where ACOS is calculated using ARR as well as "unrecovered revenue gaps of previous years to the extent proposed to be recovered". Regulation 6.6 clarifies that all licensees should file petitions with unrecovered revenue gaps from previous years which are "proposed to be recovered". Thus, multiple distribution licensees with ceiling tariffs can file and report revenue gaps "proposed to be recovered" and this can be used to estimate ACOS. Such an estimate would complicate estimation of cross-subsidy, especially if there is no regulatory scrutiny or approval required for revenue gaps proposed to be recovered.

In case of MSEDCL, it is not clear how the cumulative revenue gap will be apportioned between areas with multiple licensees and areas without, especially when grant of additional distribution licensee can take place in different areas over an undefined time period.

Draft regulation 112.3 (c) which states that the ceiling tariff should be such that the revenue gap created should not be more than 10% (or % specified by the ERC) of the ARR by considering the approved sales forecast of the licensee. It is not clear if this refers to the approved annual revenue gap or cumulative revenue gap.

### 22.7 Tariff support for certain consumer categories

As per draft Regulation 112.3 (d), energy charges for certain consumer categories (which require lower tariff) shall be fixed by the Commission and the licensee is to levy the same tariff to such a consumer category. It is not clear whether $Z_{fac}$ will be levied on these consumers. Further, the proviso to this regulation states that:

*"Provided further that in case any Distribution Licensee not able to maintain such proportion of sales of such consumer categories then it shall pay for quantum of such lower proportion 'at the rate of prevalent cross-subsidy for such consumer category (i.e. difference of Average Billing Rate and Average Cost of Supply of licensee with higher proportion of sale of such consumer category)' for such consumer category to other parallel Distribution Licensee who has higher proportion of such sales on monthly basis."*

From this proviso, it is unclear:

— Whether the ABR used to estimate the prevalent cross-subsidy will be based on ceiling tariffs or the actual tariffs charged to each consumer category. This is relevant as Draft Regulation 112.3(e) allows licensees to charge less than the ceiling tariff.
— Whether the ABR or ACoS used to estimate the cross-subsidy will be based on actual costs/sales or projected costs/sales. It is also unclear if the ACoS will include "unrecovered revenue gaps of previous years to the extent proposed to be recovered."
— Whether there will be regulatory oversight to ensure the amounts are estimated and paid in a timely manner each month. If so, what the mechanism for regulatory approval will be.
— Whether there is a clear mechanism for dispute resolution in such matters.

### 22.8 Lack of clarity in definitions

In addition, terms such as parallel distribution licensees, parallel licensee, incumbent licensee, subsequent licensee are not defined. Further the role of the incumbent licensee or the subsequent licensees is not defined. Draft regulation 112.2 mentions that the Commission shall determine 'Ceiling Tariff' "within three years from the date of operationalisation of the second distribution licensee." If there are already two distribution licensees in the proposed area of supply, would this specification lead to more confusion?

The lack of clarity in the operationalisation of the network roll-out, energy accounting, ceiling tariff makes it a risky proposition for all consumers in the incumbent licensee's area of supply and also for new distribution licensees. This could lead to non-competitive increase in tariffs without accountability for performance, cherry picking of consumers as well as increased litigation.

### 22.9 Ensuring spirit of competition and avoiding true-up

In the spirit of multiple supply licensees and adopting a ceiling tariff approach, the Commission must ensure that any supply licensee subject to ceiling tariff shall not be allowed any cost plus treatment and hence, true-up recovery.

## 23 Tariff determination process

Given the flux in the sector, consumers and stakeholders in the sector will have to face tariff and cost uncertainty. In this context, regulatory process and decision making should take place through transparent public processes to ensure legitimacy of institutional processes and decisions. Such processes can also provide valuable insights on impacts and implications of various changes which can inform mid-course correction at a time when flexible, responsive planning is key.

To ensure public processes are part of tariff determination the MYT regulations can be amended to:

- **Ensure Technical Validation Sessions**: The third proviso of draft Regulation 13.3 states that the Commission may conduct Technical Validation Sessions (TVS) prior to the admission of tariff petitions. It is suggested that Technical Validation Sessions are treated as indispensible to the tariff determination process as important information and insights can be derived from clarifications and additional data provided by the companies and licensees. Thus, the draft regulation should say that the Commission **shall** conduct TVS prior to the admission of tariff petitions in the presence of consumer representatives.
- **Mandate public hearings in multiple locations in the state**: Currently, the draft regulations stipulate that the petitioner and the Commission can invite comments and submissions from the public on the petition submitted. In the spirit of participation, the Commission should also ensure that the MYT regulations for the upcoming control period specifies public hearings in multiple locations in the state for the tariff determination process for the distribution licensees and public hearings for the determination of tariffs for all other generating companies and licensees in the state.

## 24 Need for extensive stakeholder consultations given the importance of the proposals

There are several new proposals in this draft regulation which could potentially shape the course of the electricity sector reforms in Maharashtra. This could also have potential path-breaking implications for national level reforms. These include Time of Day tariff design, the framework for smart meter cost passthrough, framework for tariffs for licensees in Mumbai and other such licensees and higher incentive-linked ROE for licensees etc. Several stakeholders and consumers across the state will be affected by these changes.

Therefore, we request the Commission to:

- Conduct a technical validation session with all utilities and some sector experts to understand implementation challenges better and address them in the regulations
- Hold a public hearing (in a manner similar to CERC) before finalizing the regulations.

— Publish submissions from all stakeholders on the ERC website to ensure different perspectives are shared with all stakeholders. This will supplement the summary provided in the SoR with the regulations and provide clarity to all concerned.