# Discussion Paper

Multi-Year Tariff Regulations

for the Fourth Control Period

Staff Paper


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## Disclaimer

The issues and suggestions presented in this Discussion Paper do not reflect the views of the Gujarat Electricity Regulatory Commission, its Chairperson, or individual Members, and are not binding on the Commission. The discussion paper is circulated with the objective of initiating discussion on various aspects of Multi Year Tariff Determination Process and soliciting inputs of the stakeholders in this regard.

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## List of Abbreviations

| | |
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| AIVPL | AspenPark Infra Vadodara Private Limited |
| A&G | Administrative and General |
| AAD | Advance Against Depreciation |
| ARR | Aggregate Revenue Requirement |
| AT&C Losses | Aggregate Technical and Commercial Losses |
| BAU | Business As Usual |
| CAPM | Capital Asset Pricing Model |
| CEA | Central Electricity Authority |
| CERC | Central Electricity Regulatory Commission |
| CPI | Consumer Price Index |
| DGVCL | Dakshin Gujarat Vij Company Limited |
| DPA | Deendayal Port Authority |
| DSM | Demand Side Management |
| DTA | Domestic Tariff Area |
| EA 2003 | Electricity Act 2003 |
| EE | Energy Efficiency |
| EPS | Electric Power Survey |
| FERV | Foreign Exchange Rate Variation |
| FOR | Forum of Regulators |
| FPPPA | Fuel and Power Purchase Price Adjustment |
| FY | Financial Year |
| GERC | Gujarat Electricity Regulatory Commission (or “the Commission”) |
| GETCO | Gujarat Energy Transmission Company Limited |
| GFA | Gross Fixed Asset |
| GIS | Gas Insulated Sub-station |
| GIFT-PCL | GIFT Power Company Limited |
| GOI | Government of India |
| GSECL | Gujarat State Electricity Corporation Limited |
| GTO | Gate Turn-off Thyristor |
| GUVNL | Gujarat Urja Vikas Nigam Limited |
| IDC | Interest During Construction |
| IEDC | Incidental Expenses During Construction |
| IT | Information Technology |
| IoWC | Interest on Working Capital |
| LD | Liquidated Damages |
| LT-DRAP | Long-term Discom Resource Adequacy Plan |
| MCLR | Marginal Cost of Funds based Lending Rate |
| MERC | Maharashtra Electricity Regulatory Commission |
| MGVCL | Madhya Gujarat Vij Company Limited |
| MoP | Ministry of Power |
| MUL | MPSEZ Utilities Limited |
| MYT | Multi-Year Tariff |
| NAPAF | Normative Annual Plant Availability Factor |
| NAPLF | Normative Annual Plant Load Factor |
| NFA | Net Fixed Asset |

| | |
|---|---|
| NTP | National Tariff Policy |
| O&M | Operation and Maintenance |
| PEUM | Partial End Use Method |
| PGVCL | Paschim Gujarat Vij Company Limited |
| PSERC | Punjab State Electricity Regulatory Commission |
| R&M | Renovation and Modernization |
| RDSS | Revamped Distribution Sector Scheme |
| RERC | Rajasthan Electricity Regulatory Commission |
| RoCE | Return on Capital Employed |
| RoE | Return on Equity |
| RPO | Renewable Purchase Obligation |
| SEZ | Special Economic Zone |
| SERC | State Electricity Regulatory Commission |
| SLDC | State Load Dispatch Centre |
| SLM | Straight Line Method |
| STU | State Transmission Utility |
| STATCOM | Static Synchronous Compensator |
| TPL | Torrent Power Limited |
| UGVCL | Uttar Gujarat Vij Company Limited |
| WAROI | Weighted Average Rate of Interest |
| WACC | Weighted Average Capital Cost |
| WPI | Wholesale Price Index |

# 1. Introduction

## 1.1. Background

### 1.1.1. History of Gujarat Electricity Business

The Gujarat Electricity Board was unbundled and restructured by the Government of Gujarat with effect from 1st April, 2005. The Generation, Transmission and Distribution businesses of the erstwhile Gujarat Electricity Board were transferred to seven successor companies. The seven successor companies are listed below:

**Generation Company: Gujarat State Electricity Corporation Limited (GSECL)**

**Transmission Company: Gujarat Energy Transmission Corporation Limited (GETCO)**

**Distribution Companies:**

**1) Dakshin Gujarat Vij Company Limited (DGVCL)**

**2) Madhya Gujarat Vij Company Limited (MGVCL)**

**3) Uttar Gujarat Vij Company Limited (UGVCL)**

**4) Paschim Gujarat Vij Company Limited (PGVCL)**

**Gujarat Urja Vikas Nigam Limited (GUVNL)**, a holding company of the above named 6 subsidiary companies is responsible for bulk purchase of electricity from various sources and supply to Distribution Companies and, other activities including trading of electricity.

Additionally, Section 31(1) of the Electricity Act, 2003 (EA 2003), requires the State Government to establish a separate State Load Despatch Centre (SLDC). Section 31(2) of the Electricity Act, 2003, provides that the SLDC shall be operated by a Government Company/ Authority/ Corporation constituted under any State Act and until such Company/ Authority/ Corporation is notified by the State Government, the State Transmission Utility (STU) would operate the SLDC. Accordingly, in the State of Gujarat, the STU, viz., GETCO, has so far been operating the SLDC.

Further, there is private sector participation in Generation and Distribution Businesses in the state of Gujarat.

- Torrent Power Limited (TPL), is carrying on the business of Generation and Distribution of

Electricity in the cities of Ahmedabad, Gandhinagar and Surat. The Commission determines tariff for the Distribution Business of TPL in Ahmedabad, Surat and Dahej and for the Generation Business of TPL in Ahmedabad. Besides, the Commission has also granted TPL, two second Licenses for distribution of electricity - first in the area of Dholera Special Investment Region (SIR), District Ahmedabad vide Order dated 21st April, 2018 in Licence Application No. 1 of 2018 and second in the Area of Mandal Becharaji SIR, Villages in the Taluka - Mandal, Detroj and Becharaji, District - Ahmedabad and Mehsana, vide Order dated 14th December, 2021.

- Torrent Energy Limited (TEL) was promoted by Torrent Power Limited (TPL), to generate and distribute power as a Codeveloper of the Dahej Special Economic Zone (DSEZ) area, . notified by the Ministry of Commerce and Industry, Government of India, vide Notification No. 2131(E) dated 20th December, 2006, as a Multi-Product SEZ. The Commission vide its Order dated 17th November,2009, issued Orders for issuance of distribution license to TEL as a second distribution licensee for distribution of electricity in the DSEZ area. Subsequently, TEL got amalgamated in TPL, with effect from the appointed date of 1st April, 2014.

- GIFT Power Company Limited (GIFT PCL), a 100% subsidiary company of Gujarat International Finance Tec-City Company Limited, is a Distribution Licensee for the GIFT City area. The Commission granted the second License for distribution of electricity to GIFT PCL vide Order dated 6th March, 2013 in Licence Application No. 1 of 2012.

- Deendayal Port Authority (DPA) (formerly Kandla Port Trust) is a Distribution Licensee for the Deendayal Port located on the Gulf of Kutch on the north-western coast of India. The License for supply of electricity was granted to DPA by the Chief Commissioner of Kutch under the Indian Electricity Act, 1910. Consequent to the enactment of the Electricity Act, 2003, DPA has become a deemed Distribution Licensee under the EA 2003.

- AspenPark Infra Vadodara Private Limited (AIVPL), is a company incorporated under the Companies Act, 1956. It has developed a sector specific SEZ for High-tech Engineering products and related services at Village Alwa and Pipaliya, Taluka Waghodia, District Vadodara in the State of Gujarat under Section 3 of the SEZ Act, 2005. Aspen has been notified as the developer of the SEZ by the Ministry of Commerce and Industry, Government of India and granted deemed Distribution Licensee status by the Commission.

- MPSEZ Utilities Limited (MUL) (Formerly known as MPSEZ Utilities Private Limited) obtained the status of Distribution Licensee vide Government of India (GOI) notification dated 3rd March, 2010. This was also endorsed by the Gujarat Electricity Regulatory Commission (GERC) vide Order No. GERC/Legal 2010/0609 dated 6th April, 2010 allowing for distribution of electricity in Mundra SEZ area, Kutch.

Therefore, power utilities being regulated by the GERC (or the Commission) ranges from State Government owned power utilities including distribution licensees supplying power to large urban and rural areas, to large private sector private utilities including distribution licenses supplying power in the cities and also small distribution licensees both in the government sector as well as the private sector, supplying power in the SEZs and SIRs. While regulating the tariff of these different utilities / licensees, the Commission may need to consider differentiated approach in certain parameters or factors, while keeping a common overall MYT framework for all.

## 1.2. Enabling provisions of Electricity Act, 2003

The State Electricity Regulatory Commissions have been vested with the responsibility of formulation of Tariff Regulations for Generation, Transmission, Supply and Wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State under Section 86 of the Electricity Act, 2003. Sections 61, and 62 of the EA 2003 provides the terms & conditions and principles for determination of tariff respectively. Relevant provisions of the EA 2003 are as under:

*"**Section 86. (Functions of State Commission): ---** (1) The State Commission shall discharge the following functions, namely:*

*(a) determine the tariff for generation, supply, transmission and wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State:*

*Provided that where open access has been permitted to a category of consumers under section 42, the State Commission shall determine only the wheeling charges and surcharge thereon, if any, for the said category of consumers;*

*….."*

***"Section 61. (Tariff regulations):***

*The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:*

*(a) the principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission*

*licensees;*

*(b) the generation, transmission, distribution and supply of electricity are conducted on commercial principles;*

*(c) the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;*

*(d) safe guarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;*

*(e) the principles rewarding efficiency in performance;*

*(f) multi year tariff principles;*

*(g) that the tariff progressively, reflects the cost of supply of electricity and also, reduces cross-subsidies in the manner specified by the Appropriate Commission;*

*(h) the promotion of co-generation and generation of electricity from renewable sources of energy;*

*(i) the National Electricity Policy and tariff policy:*

*Provided that the terms and conditions for determination of tariff under the Electricity (Supply) Act, 1948, the Electricity Regulatory Commission Act, 1998 and the enactments specified in the Schedule as they stood immediately before the appointed date, shall continue to apply for a period of one year or until the terms and conditions for tariff are specified under this section, whichever is earlier."*

*"**Section 62. (Determination of tariff): ---** (1) The Appropriate Commission shall determine the tariff in accordance with the provisions of this Act for –*

*(a) supply of electricity by a generating company to a distribution licensee:*

*Provided that the Appropriate Commission may, in case of shortage of supply of electricity, fix the minimum and maximum ceiling of tariff for sale or purchase of electricity in pursuance of an agreement, entered into between a generating company and a licensee or between licensees, for a period not exceeding one year to ensure reasonable prices of electricity;*

*(b) transmission of electricity ;*

*(c) wheeling of electricity;*

*(d) retail sale of electricity:*

*Provided that in case of distribution of electricity in the same area by two or more distribution licensees, the Appropriate Commission may, for promoting competition among distribution licensees, fix only maximum ceiling of tariff for retail sale of* *electricity.*

*(2) The Appropriate Commission may require a licensee or a generating company to furnish separate details, as may be specified in respect of generation, transmission and distribution for determination of tariff.*

*(3) The Appropriate Commission shall not, while determining the tariff under this Act, show undue preference to any consumer of electricity but may differentiate according to the consumer's load factor, power factor, voltage, total consumption of electricity during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required.*

*(4) No tariff or part of any tariff may ordinarily be amended, more frequently than once in any financial year, except in respect of any changes expressly permitted under the terms of any fuel surcharge formula as may be specified."*

## 1.3. National Tariff Policy (NTP)

The Ministry of Power, Government of India, in compliance with Section 3 of the EA 2003, notified the Tariff Policy on 6th January, 2006 and revised Tariff Policy on 28th January, 2016. The revised Tariff Policy, inter-alia, sets the goal for ensuring availability of electricity to different categories of consumers at reasonable rates for achieving the objectives of rapid economic development of the country and improving the living standards of the people. It also envisages adequate return on investment for the developer to attract investment in the sector. It further envisages transparency, consistency and predictability in approach for tariff fixation. Section 4 lays down the objectives of this Tariff Policy as under:

*a) Ensure availability of electricity to consumers at reasonable and competitive rates;*

*b) Ensure financial viability of the sector and attract investments;*

*c) Promote transparency, consistency and predictability in regulatory approach across jurisdictions and minimise the perceptions of regulatory risks;*

*d) Promote competition, efficiency in operations and improvement in quality of supply;*

*e) Promote generation of electricity from Renewable sources;*

*f) Promote Hydroelectric Power generation including Pumped Storage Projects (PSP) to provide adequate peaking reserves, reliable grid operation and integration of variable renewable energy sources;*

*g) Evolve a dynamic and robust electricity infrastructure for better consumer services;.*

*h) Facilitate supply of adequate and uninterrupted power to all categories of consumers;*

*i) Ensure creation of adequate capacity including reserves in generation, transmission and distribution in advance, for reliability of supply of electricity to consumers.*

## 1.4. GERC Multi Year Tariff (MYT) Regulations till date

In exercise of powers conferred under Section 181 (2) read with Section 36, Section 39, Section 40, Section 41, Section 51, Section 61, Section 62, Section 63, Section 64, Section 65 and Section 86 of the Electricity Act, 2003 and all other enabling powers in that behalf, and under Section 32 of the Gujarat Electricity Industry Reorganisation and Regulation) Act, 2003 (Gujarat Act No. 24 of 2003) and all powers enabling it in that behalf, the Gujarat Electricity Regulatory Commission has notified the following regulations for tariff determination of power utilities in the state of Gujarat:

- GERC notified the **Gujarat Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2005** on 31st March 2005 for determining the tariff for the Distribution Licensees. GERC also notified **Gujarat Electricity Regulatory Commission (Levy And Collection of Fees and Charges by SLDC) Regulations, 2005** on 30th March 2005.

- On 30th November 2007, GERC notified the **Gujarat Electricity Regulatory Commission (MYT Framework) Regulations, 2007** as an appendix to the **GERC (Terms and Conditions of Tariff)** Regulations for determining the tariff within the MYT framework for all matters for which the Commission has power under the EA 2003. These Regulations were applicable for the First Control Period i.e., FY 2008-09 to FY 2010-11.

- On 22nd March 2011, GERC notified the **Gujarat Electricity Regulatory Commission (MYT Framework) Regulations, 2011** for determining the tariff within the MYT framework for all matters for which the Commission has power under the EA 2003. These Regulations were applicable for the Second Control Period i.e., FY 2011-12 to FY 2015-16.

- On 29th March 2016, the Commission has notified the **Gujarat Electricity Regulatory Commission (MYT) Regulations, 2016** for determination of tariff for the Third Control Period i.e., FY 2016-17 to FY 2020-21. Subsequently, on above regulation the Commission has notified two amendments on 02nd December, 2016 and 18th August, 2018.

- While the Commission had initiated the process of framing the MYT Regulations for Fourth Control Period i.e., FY 2021-22 to FY 2025-26 by issuing public notice dated 10th August, 2021, the process was delayed due to circumstances and reasons beyond the control of the Commission. Considering the delay, the Commission vide its Suo-Motu Order No. 07

of 2020 dated 23rd December, 2020 deferred the 5-year control period for new MYT Regulations for one year, i.e., till 31st March 2022. Due to ongoing pandemic, the process was further delayed due to circumstances and reasons beyond the control of the Commission. The Commission vide its Order in Suo-Motu Petition No. 1995 of 2021 dated 24th September, 2021 deferred the next MYT Control period by one more year, i.e., till 31st March 2023. Subsequently, the Commission once again deferred the next MYT Control period by one more year, i.e., till 31st March 2024, vide its Order in Suo-Motu Petition No. 2140 of 2022.

## 1.5. MYT Principle

The Section 61 of the EA 2003, states that the Appropriate Commission for determining the terms and conditions for the determination of tariff shall be guided, inter-alia, by Multi-Year Tariff principles. The National Tariff Policy has given guidelines on the MYT principles that are considered while framing the MYT Regulations. The broad objectives of any MYT framework are as follows:

- Provide Regulatory Certainty to the investors and consumers by promoting transparency, consistency and predictability of regulatory approach and thereby minimizing the regulatory risk perception for all stakeholders.
- Ensure financial viability of the sector to attract investment and safeguard the interest of the consumers.
- Provide incentivisation framework to reward performance, promote efficiency and competition
- Address the risk sharing mechanism between Utilities and consumers based on controllable and uncontrollable factors.

### 1.5.1. Control Period

The NTP 2016 states as follows:

*“5(h)(1) …….The framework should feature a five-year control period. The initial control period may, however, be of 3 year duration for transmission and distribution if deemed necessary by the Regulatory Commission on account of data uncertainties and other practical considerations. In cases of lack of reliable data, the Commission may state assumptions in MYT for first control period and a fresh control period may*

*be started as and when more reliable data becomes available."*

GERC has published the tariff orders for Multi-Year Aggregate Revenue Requirement (ARR) for FY 2016-17 to FY 2020-21 for all utilities on 31st March 2017. Subsequently, the Commission vide its Suo-Motu Order dated 22nd December, 2020 in Case No. 07 of 2020 in the matter of "Filing of application for determination of ARR and Tariff for FY 2021-22", has decided to determine ARR for FY 2021-22 based on the principles and methodology as provided in the GERC (Multi-Year Tariff) Regulations, 2016 and defer the next MYT Control Period by one year. Subsequently, the Commission vide its Suo-Motu Order dated 24th September, 2021 in Case No. 1995 of 2021 in the matter of "Filing of application for determination of ARR and Tariff for FY 2022-23", has decided to determine the ARR for FY 2022-23 based on the principles and methodology as provided in the GERC (MYT) Regulations, 2016 and defer the next MYT Control Period by one year. Further, the Commission vide its Suo-Motu Order dated 20th October, 2022 in Case No. 2140 of 2022 in the matter of "Filing of application for determination of ARR and Tariff for FY 2023-24", has decided to determine the ARR for FY 2023-24 based on the principles and methodology as provided in the GERC (MYT) Regulations, 2016 and defer the next MYT Control Period by one year. The Commission has published the tariff orders for all utilities for FY 2023-24 on 31st March 2023.

**Considering that three Control Periods have already passed, it is suggested that the next Control Period (i.e., Fourth MYT Control Period) may be of five years and from FY 2024-25 to FY 2028-29.**

**Comments and suggestions are invited from the stakeholders on the possible regulatory options.**

### 1.5.2. Controllable/ Un-Controllable Parameters

All the parameters in the MYT framework are divided into controllable and uncontrollable parameters. The GERC MYT Regulations, 2016 provides as follows:

***"22. Controllable and uncontrollable factors***

*22.1 For the purpose of these Regulations, the term "uncontrollable factors" shall comprise of the following factors, which were beyond the control of the Applicant, and could not be mitigated by the Applicant:*

*(a) Force Majeure events;*

*(b) Change in law, judicial pronouncements and Orders of the Central Government, State Government or Commission;*

*(c) Variation in the price of fuel and/ or price of power purchase according to the FPPPA formula approved by the Commission from time to time;*

*(d) Variation in the number or mix of consumers or quantities of electricity supplied to consumers:*

*Provided that where there is more than one Distribution Licensee within the area of supply of the Applicant, any variation in the number or mix of consumers or in the quantities of electricity supplied to consumers within the area served by two or more such Distribution Licensees, on account of migration from one Distribution Licensee to another, shall be attributable to controllable factors;*

*(e) Transmission Loss;*

*(f) Variation in market interest rates;*

*(g) Taxes and Statutory levies;*

*(h) Taxes on Income;*

*(i) Income from realisation of bad debts written off:*

*Provided that where the Applicant believes, for any variable not specified above, that there is a material variation or expected variation in performance for any financial year on account of uncontrollable factors, such Applicant may apply to the Commission for inclusion of such variable at the Commission's discretion, under this Regulation for such financial year.*

*22.2 Some illustrative variations or expected variations in the performance of the Applicant, which may be attributed by the Commission to controllable factors include, but are not limited to, the following:*

*(a) Variations in capitalisation on account of time and/or cost overruns/ efficiencies in the implementation of a capital expenditure project not attributable to an approved change in scope of such project, change in statutory levies or force majeure events;*

*(b) Variation in Interest and Finance Charges, Return on Equity, and Depreciation on account of variation in capitalisation, as specified in clause (a) above;*

*(c) Variations in technical and commercial losses of Distribution Licensee;*

*(d) Variations in performance parameters;*

*(e) Variations in interest on working capital;*

*(f) Failure to meet the standards specified in the Gujarat Electricity Regulatory Commission (Standard of Performance of Distribution Licensee) Regulations, 2005, except where exempted in accordance with those Regulations;*

*(g) Variations in labour productivity;*

*(h) Variation in Operation &Maintenance expenses;*

*(i) Bad debts written off. "*

It is observed that, GERC MYT Regulations, 2016 covers all the controllable and uncontrollable parameters enlisted by most of the SERCs. However, the delay on account of forest clearances is not mentioned in prevailing provisions.

Further, Central Electricity Regulatory Commission (CERC), while framing the CERC Tariff Regulations, 2019, in its Explanatory Memorandum, observed as follows:

*"2.5.5 The Commission has observed while dealing with tariff petitions, that matters pertaining to acquisition of land or getting right of way, have become one of the main causes of delay in commissioning of projects. In the existing 2014 Tariff Regulations, only force majeure and change in law have been specifically identified as uncontrollable factors. However, the Commission has noticed that, land acquisition and Right of Way issues have been largely outside the control of the project developer and accordingly, the Commission has also been condoning the delay and allowing the associated cost to form part of the capital cost. In the light of these practical issues, the Commission has proposed to include time and cost over-runs on account of land acquisition, as an uncontrollable factor, except where the delay is attributable to the generating company or the transmission licensee…"*

In view of the reasons mentioned above, the delay on account of forest clearances may also be considered as a factor that may be included under the uncontrollable factors provided that such delays are not attributable to the Utilities.

**Comments and suggestions are invited from the stakeholders on inclusion of delay on account of forest clearances as an uncontrollable factor**.

### 1.5.3. Sharing of Gain/Losses on Controllable Parameters

The NTP 2016 states as follows:

*" **8.1 Implementation of Multi-Year Tariff (MYT) framework***

*…..*

*2) The State Commissions should introduce mechanisms for sharing of excess profits and losses with the consumers as part of the overall MYT framework. In the first control period the incentives for the utilities may be asymmetric with the percentage of the excess profits being retained by the utility set at higher levels than the percentage of losses to be borne by the utility. This is necessary to accelerate performance improvement and reduction in* *losses and will be in the long term interest of consumers by way of lower tariffs.*

*….”*

Currently, the Commission has allowed one-third of the gains/losses on account of controllable factors to be passed on to the consumers as rebate/additional charge and the remaining two-third is to be retained/absorbed by the utilities.

Many SERCs such as Rajasthan Electricity Regulatory Commission (RERC), Maharashtra Electricity Regulatory Commission (MERC), Punjab State Regulatory Commission (PSERC), etc. allow at least 40% of the gains to be passed on to the consumers, whereas 100% of the losses are to be borne by the utilities. Some of the ERCs allow sharing of gains but not the losses by the Utilities. CERC allows sharing of 50% of the gains due to variation in norms, however there is no sharing of losses. Given that it’s the Fourth Control Period, changes in proportion of sharing gains and losses may be suggested, including the possibilities of not sharing of any losses with the beneficiaries / consumers.

**Comments and suggestions are sought from the stakeholders on any modification in the sharing mechanism that may be required.**

### 1.5.4. Parametric Performance Review

The MYT framework is finalised based on the parameters under the Utilities’ control. These mainly consist of Financial and Operating parameters for Generation, Transmission, SLDC and Distribution Licensees. The annual targets for these parameters are set at the beginning of the Control Period.

The NTP mentions as follows:

*“5(h)(3) Once the revenue requirements are established at the beginning of the control period, the Regulatory Commission should focus on regulation of outputs and not the input cost elements. At the end of the control period, a comprehensive review of performance may be undertaken.”*

The GERC MYT Regulation, 2016 provides for filing of MYT Petition at the beginning of the Control Period, Mid-Term review of ARR, as well as annual Truing-up of expenses and revenue based on audited accounts by the Commission. The relevant provisions of GERC MYT Regulations, 2016 is reproduced as below:

***“16. Multi-Year Tariff framework***

*……*

*16.2 The Multi-Year Tariff framework shall be based on the following elements, for determination of Aggregate Revenue Requirement and expected revenue from tariff and charges for Generating Company, Transmission Licensee, SLDC, Distribution Wires Business and Retail Supply Business:*

*(i) A detailed Multi-Year Tariff Application comprising the forecast of Aggregate Revenue Requirement for the entire Control Period and expected revenue from existing tariffs for the first year of the Control Period to be submitted by the Applicant:*

*…..*

*Provided further that a Mid-term Review of the Aggregate Revenue Requirement shall be undertaken for the Generating Company, Transmission Licensee, SLDC and Distribution Licensee on an application that shall be filed by the utilities along with the Petition for truing-up for the second year of the Control Period and tariff determination for the fourth year of the Control Period;*

*…..*

*(iii) Truing up of previous year's expenses and revenue by the Commission based on Audited Accounts vis-à-vis the approved forecast and categorisation of variation in performance as those caused by factors within the control of the Applicant (controllable factors) and those caused by factors beyond the control of the Applicant (uncontrollable factors):*

*….*

*(vi) Annual determination of tariff for the Generating Company, Transmission Licensee, SLDC, Distribution Wires Business and Retail Supply Business, for each financial year within the Control Period, based on the approved forecast and results of the truing up exercise.*

Most of the ERCs still continue to follow the approach of annual tariff determination under their respective MYT framework, with a few exceptions. CERC undertakes the truing-up exercise for generating entities and transmission licensees only once in the five-year Control Period. UPERC also follows one time truing-up exercise for generating entities during the MYT Control Period, while undertake annual truing-up for transmission and distribution licensees. MERC follows mid-term review of operational and financial performance vis-à-vis the approved forecast, only after three years of the Control Period by truing-up for first and second years, provisional true-up for third year and allow revised forecasting of ARR, expected revenue from existing tariff, expected revenue gap and proposed tariff for the fourth and fifth year of the Control Period by all the Utilities

– Generation, Transmission, SLDC and Distribution. Presently, GERC carries out annual truing-up exercise for all Utilities. It is proposed to do away with the annual truing-up exercise for the Utilities in a phased manner. One option could be to introduce a mid-term review for Generation, Transmission and SLDC Utilities consisting of truing-up for first two years based on actuals, provisional truing-up for the third year based on provisional figures, and revision of projected figures for fourth and fifth year may be undertaken, while continuing with the annual truing-up for Distribution Utilities. Another option could be to undertake mid-term review for all Utilities. Third option could be to undertake annual or mid-term review for Distribution Utilities and truing-up for other Utilities to be undertaken only at the end of the Control Period.

**Comments and suggestions are invited from the stakeholders regarding introduction of Mid-Term Review, along with truing-up for first 2/3 years of Control Period for the Distribution Licensees and only one-time truing-up in case of Generation, Transmission and SLDC Utilities.**

# 2. Common Financial Parameter

## 2.1. Capital Cost

Capital cost forms the basis of tariff determination and is therefore highly important that it is approved after prudence check. Capital Cost for a project currently include the expenditure incurred or projected to be incurred, Interest During Construction (IDC), Incidental Expenses During Construction (IEDC) and financing charges, any gain or loss on account of Foreign Exchange Rate Variation (FERV) on the loan during construction up to the date of commercial operation of the project, capitalised initial spares and additional capitalisation. All these components are currently approved by the Commission after prudence check such as scrutiny of the reasonableness of the capital expenditure, financing plan, interest during construction, use of efficient technology, cost over-run and time over-run, etc.

### 2.1.1. Capital Investment Plan Approval

The GERC MYT Regulations, 2016 provides for Capital Investment Plan as follows:

> ***"19. Multi-Year Tariff Application***
>
> *…..*
>
> *19.3. The capital investment plan shall show separately, on-going projects that will spill over into the Control Period, and new projects (along with justification) that will commence in the Control Period but may be completed within or beyond the Control Period. The Commission shall consider and approve the capital investment plan for which the Generating Company, Transmission Licensee, SLDC and Distribution Licensee for the Distribution Wires Business and Retail Supply Business, may be required to provide relevant technical and commercial details.*
>
> *….*
>
> ***66. Capital Investment Plan***
>
> *66.1 The Transmission Licensee shall submit a detailed capital investment plan, financing plan and physical targets for each year of the Control Period for meeting the requirement of load growth, improvement in quality of supply, reliability, metering, reduction in congestion, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period:*
>
> *Provided that the Capital Investment Plan shall be submitted for each year of the Control Period:*
>
> *Provided further that the Capital Investment Plan shall be accompanied by such information, particulars and documents as may be required including but not limited to the*

*information such as number of bays, name, configuration and location of grid substations, substation capacity (MVA), transmission line length (ckt-km) showing the need for the proposed investments, alternatives considered, cost/benefit analysis and other aspects that may have a bearing on the transmission charges.*

*66.2 The Capital Investment Plan of the Transmission Licensee shall be consistent with the transmission system plan for the intra-State transmission system.*

*…..*

***78. Capital Investment Plan***

*78.1 The SLDC shall submit a detailed capital investment plan, financing plan and physical targets for each year to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.*

*78.2 The SLDC shall submit the Capital Investment Plan as specified in **Chapter2** of these Regulations.*

*…..*

***88. Capital Investment Plan***

*88.1 The Distribution Licensee shall submit detailed capital investment plan, financing plan and physical targets for each year of the Control Period for meeting the requirement of load growth, reduction in distribution losses, improvement in quality of supply, reliability, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.*

*88.2 The Distribution Licensee shall be required to ensure optimum investments to enhance efficiency, productivity and meet performance standards prescribed by the Commission.*

*…..*

***95. Capital Investment Plan***

*95.1 The Distribution Licensee shall submit a detailed capital investment plan, financing plan and physical targets for each year of the Control Period for meeting the requirement of load growth, reduction in distribution losses, increase in collection efficiency, metering, consumer services, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.*

*95.2 The Distribution Licensee shall be required to ensure optimum investments to enhance efficiency, productivity and meet performance standards prescribed by the Commission.*

*95.3 The Distribution licensee shall submit the Capital Investment Plan as specified in **Chapter2** of these Regulations."*

Further, Ministry of Power, Government of India has published draft Electricity (Amendment) Rules, 2023 incorporating provisions of 'subsidy accounting & payment' and 'Framework for financial sustainability' for comments. The relevant extract of the draft Rule 20 is reproduced as follows:

***"20 (I) Framework for financial Sustainability:***

*….*

*(d) All the prudent cost incurred by the Distribution licensee for creating the assets for development and maintenance of distribution system in accordance with sub-section (1) of section 42 of the Act shall be pass-through;*

*Provided that such pass-through of the cost for the assets created by the distribution licensee shall be subject to following conditions:*

*i) Asset has been created in accordance with the capex roll out plan for the licensee approved by the respective State Commission.*
*ii) Asset has been procured in competitive and transparent manner.*
*iii) Asset are geo-tagged and properly recorded in Fixed Asset Register (FAR) and the details are made available on the website of the Distribution licensee.*

*…"*

Capital Investment Schemes have a significant impact on the overall costs, and hence the revenue requirement and tariff determination process for regulated entities. The need for regulating the Capital Investment Schemes in an unambiguous and transparent manner is critical for providing regulatory certainty, for promoting efficient and optimal utilization of resources.

While, the GERC MYT Regulations, 2016 provide for submission of detailed Capital Investment Plan by the Utilities as a part of MYT Petition, with a view to further regularize and streamline the filing and approval process of Capital Investment Schemes, a need is felt for developing a comprehensive Capital Investment Plan approval process, covering various aspects including threshold limit for prior approval, process of submission for approval, details required for prudence check, defining framework for approval of Schemes, need for approval of completed cost, etc.

It is observed that most of the SERCs have not yet provided separate guidelines and / or Regulations for Capital Investment Scheme approval framework. While few have defined broad guidelines, Maharashtra Electricity Regulatory Commission has notified MERC (Approval of Capital Investment Schemes) Regulations, 2022, which has comprehensively detailed out the process of capex approval for power utilities covered under regulated tariff mechanism. It is proposed to develop a comprehensive Capital Investment Scheme approval framework for the utilities in the State of Gujarat, including following key aspects:

- Categorization of Capital Investment Schemes for Generation, Transmission, SLDC and Distribution Utilities

- Threshold limits for in-principle prior approval separately for Generation, Transmission, SLDC and Distribution Utilities (including those for Parallel License situations)
- Categorization of Schemes not requiring prior-approval from the Commission, including overall monetary limits for as a percentage of total capital investment, etc.
- Process for submission of application for in-principle prior approval – content of application, Detailed Project Report, etc.
- Details required for prudence check - Technical and Financial criteria for in-principle approval of schemes, cost-benefit analysis, utilisation index of the assets, etc. for final approval of completed cost.
- Approval process – In principle, final approval along with ARR and tariff determination and final approval of the completed cost including conditions to be fulfilled for allowing capitalization including geo-tagging, reflection in Fixed Asset Register, etc.
- Other conditions including – Capital Investment Schemes not approved by the Commission, not to be allowed in the ARR, enabling provisions for operationalization of the proposed capital investment approval framework as a continuous process independent of the annual or periodical ARR / MYT Petitions filing process.

**Comments and suggestions are invited from the stakeholders regarding the option of introducing a comprehensive Capital Investment Scheme approval framework for the utilities in the State of Gujarat, to be implemented with effect from the new MYT Control Period.**

### 2.1.2. Debt Equity Ratio - RoE (GFA) vs RoCE (NFA)

The GERC MYT Regulations, 2016 considers a normative debt to equity ratio of 70:30 for a project. The return is provided on the normative equity base i.e., 30% of the project's capital cost or actual equity (in case it is less than 30%) on a perpetual basis over the entire life of the assets. The point to note here is that the asset base for earning return remains constant throughout the life of the project.

The interest on debt is provided as a separate component of the annual fixed cost based on Weighted Average Rate of Interest (WAROI). The WAROI is calculated on the basis of the actual loan portfolio of the project during the year. For allowing repayment of principal component of debt, the current practice is to allow depreciation corresponding to 90% of 70% of capital investment over first 12 years, while the remaining capital is depreciated over the residual life of the asset.

The Return on Capital Employed (RoCE) method involves computation of the return using

Weighted Average Cost of Capital (WACC) applied on an asset base to calculate the total return. It is the most widely used method by regulators across countries in the world, both developed and developing. The ROCE method takes into account several factors such as age of assets, additional capitalization in schemes, varying debt-equity ratio of projects etc. In this method, the WACC is computed by the following formula:

WACC= $(D/V)*K_d + (E/V)*K_e$

Where

D = Normative Debt

E = Normative Equity

V = Total Capital i.e., Sum of Debt & Equity

$K_d$ = Cost of Debt

$K_e$ = Cost of Equity

There are two approaches followed for the interest rate – the cost of debt may be pass though based on the weighted average cost of debt of the entire loan portfolio or it benchmarked based on average cost of debt to businesses in a sector. The latter approach is often used by regulators. The cost of equity is estimated using the CAPM model. In the RoCE approach used worldwide, depreciation is calculated on a straight-line basis over the life of asset. It is not linked to loan repayment unlike in India.

Thus, it can be seen that the two approaches discussed above differ both in the allowed rate of return and capital base for return. While in the RoE approach, the equity base remains same through-out the life of asset, it reduces in RoCE approach by depreciation allowed for the equity portion along with the debt portion.

The cost of equity in RoE approach is set using CAPM model, while the interest rate is allowed separately based on weighted average interest rate of loan portfolio. The RoCE approach uses weighted average cost of capital for allowing return on capital and the interest rate is linked to market.

While GERC MYT Regulations, 2016 like CERC and many other SERCs follow the RoE or GFA based approach, some of the SERCs like DERC and APERC as well as CERC in case of generation assets of NLC India Limited follow RoCE or NFA based approach.

While the Regulatory needs to ensure the return on investment to the investors on the approved capital investments, in a usual course of business, the returns get reduced over the life of asset as they recover the depreciation on year-on-year basis. However, the power sector utilities are allowed RoE on gross equity infused even when the cumulative depreciation exceeds the debt component over the life of assets or until the assets is in use.

The Tariff Regulations based on RoE or GFA Approach (including GERC MYT Regulations, 2016) do not have provisions of reduction of equity after completion of useful life. However, RoCE or NFA approach provides for adjustment of both debt and equity from the depreciation in a proportionate manner from the beginning itself. An asset, which has competed his useful life, recovers around 90% of the invested capital in the form of depreciation by the end of useful life. Therefore, continuing to allow return of existing equity base i.e., 30% of the capital expenditure essentially means allowing return on the investment which they have already recovered.

The argument in favour of the GFA approach is that it is not only essential to encourage the prospective investment in the sector, but also critical to incentivize the utility to keep operating the existing assets which are still in good shape, even if the original useful life is completed. This also provides benefit of reduced fixed cost as there is no or very little debt to be serviced and equity component at historical /cost, which in comparison to current replacement cost is much cheaper. Therefore, there are multiple alternatives which may be considered for implementation including as follows:

- Consider shifting to RoCE (NFA) approach for all assets, i.e., existing as well as assets commissioning in the new Control Period;
- Consider shifting to RoCE (NFA) approach for assets commissioned w.e.f new Control Period and keeping the existing assets under RoE (GFA) approach only;
- For existing assets reduce Equity to salvage value levels or normative equity levels during the new MYT Control Period and RoCE (NFA) approach for assets commissioned w.e.f. new Control Period;

**Considering the pros and cons of the various methodology discussed, comments and views of the stakeholders are requested on these approaches.**

### 2.1.3. Hybrid Approaches for restricting Equity at specified level after completion of Useful Life

There are two more hybrid approaches being followed in some specified cases. The first is being applied by CERC after completion of useful life in case of a generating station or a transmission system including communication system. Proviso to Regulation 18(3) of the CERC (Terms and Conditions of Tariff) Regulations, 2019 provides as follows:

> *"Provided that in case of a generating station or a transmission system including communication system which has completed its useful life as on or after 1.4.2019, if the equity actually deployed as on 1.4.2019 is more than 30% of the capital cost, equity in excess of 30%shall not be taken into account for tariff computation;"*

The CERC in its Statement of Objects and Reasons (SoR) for CERC (Terms and Conditions of Tariff) Regulations, 2019 has stated as follows:

> *"7.1.7 It is observed that many of the generating stations and transmission systems which were commissioned on or before the commencement of tariff period 2004-09, and which have either completed or about to complete their useful life, have a debt-equity ratio of 50:50. The Commission sees strong logic to bring uniformity of the capital structure of all the projects. Therefore, the excess equity of the projects are required to be aligned at par with normative debt:equity ratio.*
>
> *7.1.8 The Commission, after considering all the relevant aspects carefully, has decided that the proposed reduction of equity to the extent of 30% instead of salvage value will be more pragmatic approach, as it takes care of the interest of both the investors and consumers. Accordingly, in case of a generating station or a transmission system which has completed its useful life as on or after 1.4.2019, if the equity actually deployed as on 1.4.2019 is more than 30% of the capital cost, equity in excess of 30% shall not be taken into account for tariff computation and will be deemed to paid from the accumulated depreciation."*

The second approach is being adopted by RERC in its MYT Regulations, 2019, which provide as under:

> "***19. Debt-equity ratio***
>
> *…*
>
> *In case of Generating Station or a transmission system or distribution system, which has completed its useful life as on or after 1.4.2019, the accumulated depreciation as on the completion of the useful life less cumulative repayment of loan shall be utilized for reduction of the equity and depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan and thereafter shall be utilized for reduction of equity."*

Under this hybrid or modified GFA approach, the depreciation recovery in the initial years is utilized for the repayment of the loan and post that it is adjusted towards the equity. Accordingly, at the end of useful life of the asset, the remaining equity component is equivalent to the salvage value of the asset.

Adoption of one of these or any other alternative approach for the assets operational beyond original useful life may be explored, in case of continuation of the existing RoE (GFA) approach.

**Comments and suggestions are invited from the stakeholders regarding the various options.**

### 2.1.4. Post-Tax Vs Pre-Tax Rate of Return Approach

The issue is whether the returns to the investor should be allowed on a post-tax basis or on pre-tax basis. Both the approaches have merits and demerits.

Under the post-tax approach, the Commission has to assess the income tax liability at the time of determination of ARR and tariff, which can be complicated in case of entities that are undertaking other non-core businesses also, irrespective of whether they are regulated or not. Another demerit of the post-tax approach is that there is no inducement for better tax planning. However, in case of post-tax returns, the tax benefits available to the sector are passed on to the consumers.

On the other hand, the pre-tax return approach is aimed at encouraging power sector entities to do better tax planning and does not have the above demerits of post-tax return approach. The income tax liability does not have to be projected in advance, and at the end of the year, does not have to be matched with the actual income tax paid, etc. The issue of estimating the income tax for utilities operating in several States/Businesses will also not arise.

It should also be noted that the erstwhile State Electricity Boards (SEBs) were not liable to pay income tax. However, post EA 2003, most of the erstwhile SEBs have been unbundled and the successor companies engaged in the business of generation, transmission and distribution of electricity are liable to pay income tax.

Under the mechanism of pre-tax returns, the benefits of Section 80 IA applicable to new units are not passed on to the beneficiaries and the tax recovered by utilities in some cases are more than the actual income tax. Under the regulated business, in general, the profit of the utilities should be equal to RoE specified because all other elements of tariff are based on the general premise of pass through of costs subject to achievement of normative performance parameters. Practically, the profit of the utilities is influenced by other factors such as profits of non-core business carried out by the utilities, UI earnings, efficiency gains, incentive earned, difference in the depreciation allowed under tariff and as per Income Tax Act, 1961, income tax holiday allowed in power sector, etc.

Another option could be to consider the income tax rate on normative basis (MAT / Corporate Tax Rate) and utilize it to gross up the base Rate of return on Equity only. However, the income tax on account of incentives and other non-regulated businesses shall not be allowed to be passed on in the tariff. Under the regulated business, when the utilities are allowed specified post tax rate of return on equity in addition to prudently incurred expenses, the recovery of tax on specified Return on Equity by the utilities needs to be allowed based on actual tax paid on Return on Equity on 'no profit' and 'no loss' basis, as tax on Return on Equity is a sort of reimbursement to ensure the recovery of the specified RoE.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

### 2.1.5. Cost of Equity

Section 61(d) of the Electricity Act, 2003, and Paragraph 5.11 (a) of the Tariff Policy 2016 have suggested to strike a balance between safeguarding of consumers' interest and recovery of the cost of electricity in a reasonable manner while laying down broad guiding principles for the determination of the rate of return.

Further, the Forum of Regulators, in its Report on "Analysis of Factors Impacting Retail Tariff And Measures To Address Them" has recommended as follows.

> *"In the entire value chain, transmission business has the lowest risk. The RoE for transmission companies should therefore, be reviewed immediately. RoE for generation and transmission should be linked to the 10 year G Sec rate (average rate for last 5 years) plus risk premium subject to a cap as may be decided by Appropriate Commission. For a Discom, the RoE could be fixed based on the risk premium assessed by the State Commission. Income tax reimbursement should be limited to the RoE component only."*

It is observed that the Forum of Regulators (FOR) has also recommended differential RoE for Generation and Transmission Businesses with a reduction in RoE for Transmission Business.

For computation of expected cost of Equity, capital asset pricing model (CAPM) is the most widely used method. According to this method, the expected cost equity can be calculated as:

$$Ra = Rf + [\beta \times (Rm - Rf)]$$

Where:

Ra = Expected rate of return (Cost of Equity)

Rf = Risk-free rate

β = Beta of the security

Rm = Expected return on market

Further, considering the longer periods of data while computing RoE using the CAPM, provides the reliable results as it averages out the period of higher and lower returns and economic uncertainties. Therefore, data for 10 year period for risk free rate, beta and expected return on market may be considered.

The second approach would be to link the expected rate of return with market interest rates such as G-SEC rates/RBI Repo Rate plus certain spread, which will reflect the appropriate risk levels and be lucrative to the investor for enabling future investments.

**Comments and suggestions are invited from the stakeholders on the approaches for allowing Cost of RoE.**

### 2.1.6. Splitting Cost of Equity (Rate of Return on Equity)

The GERC MYT Regulations 2016 provides one composite rate of return on equity (RoE). However, few SERCs segregated the rate of RoE on equity in two parts – one fixed rate equal to the Base RoE, which is assured to the Utility and other variable rate linked to additional RoE, which is allowed against some identified measurable performance parameters and allowed at the time of truing-up. The objective of this approach is to link part of the RoE to improve operational performance of the Utilities, in order to incentivize better performance from them.

The following table summarizes the approach adopted by some of the SERCs to allow variable rate linked to additional RoE:

*Table 1: Variable Rate of Return on Equity*

| State / ERC | Variable Rate of Return on Equity |
|---|---|
| **CERC** | **Thermal Generating Stations:**<br>• 0.25% for every incremental ramp rate of 0.10% per minute achieved over and above the ramp rate of 1% per minute; Ceiling at 0.50%; |
| **Maharashtra** | **Thermal Generating Stations:**<br>• 0.25% for every incremental ramp rate of 0.10% per minute achieved over and above the ramp rate of 1% per minute; Ceiling at 0.50%;<br>• Mean Time Between Failure (MTBF) >45 days -> 0.50%, MTBF >90 days -> 0.75%, MTBF >120 days -> 1.00%<br>**Transmission:**<br>• Overachievement of Transmission Availability – 0.75% for different slabs up to 1.50%<br>**Wheeling:**<br>• Overachievement of Wires Availability – 0.50% for different slabs up to 1.50%<br>**Retail Supply:**<br>• Up to 1.00% linked to percentage of assessed bills as a percentage of total bills issued in a year<br>• Up to 1.00% if collection efficiency for the year is above 99% |

| State / ERC | Variable Rate of Return on Equity |
|---|---|
| **Madhya Pradesh** | **Thermal Generating Stations:**<br>• 0.25% for every incremental ramp rate of 0.10% per minute achieved over and above the ramp rate of 1% per minute; Ceiling at 0.50%;<br>**Transmission:**<br>• No provision<br>**Distribution**<br>Additional RoE – Up to 2.00%<br>• 0.75% linked to metering of rural domestic consumers<br>• 0.75% for capitalisation more than 95% approved amount<br>• 0.50% for R&M expense more than 95% of approved amount |

Apart from this, CERC (Terms and Conditions of Tariff) Regulations, 2019 provides for a reduced rate of RoE at weighted average rate of interest on actual loan portfolio of the Utility in respect of additional capitalization after cut-off date beyond the original scope, excluding additional capitalization due to Change in Law. Further, CERC and most of the SERCs also penalize the Utilities for non-achievement of certain requirements, summarized as follows:

- In case of a new project, the rate of return on equity shall be reduced by 1.00% for such period as may be decided by the Commission, if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO) or Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the respective RLDC/SLDC;

- in case of existing generating station, as and when any of the requirements under (i) above of this Regulation are found lacking based on the report submitted by the concerned RLDC/SLDC, rate of return on equity shall be reduced by 1.00% for the period for which the deficiency continues;

- in case of a thermal generating station, with effect from 1.4.2020, rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate of 1% per minute.

Further, UPERC in its MYT Regulations for Generation Tariff and Transmission and Distribution Tariff, has provided for penalizing the Utilities at the rate of 0.25% per month for delay in filing of MYT and/or Tariff Petitions.

In line with the above, it is proposed to introduce segregated the rate of RoE on equity in two parts – one fixed rate equal to the Base RoE, which is assured to the Utility and other variable rate linked to additional RoE, which is allowed against some identified measurable performance parameters and allowed at the time of truing-up. The following table lists down illustrative list of some of the parameters which may be considered for variable rate linked to additional RoE and penalty on RoE.

*Table 2: Suggested list of Performance Parameters for differential rate of RoE*

| Utility | Performance Parameters for additional Rate of RoE | Parameters for Penalty on Rate of RoE |
|---|---|---|
| **Generation** | • Ramp Rate<br>• Mean Time between failure<br>• Generation during Peak-Demand | • Delay in filing Petition<br>• Absence of operational RGMO, FGMO, etc. |
| **Transmission** | • Exceeding Transmission Availability within the dead band (where no incentive is provided)<br>• Transmission Loss % Target<br>• No. of disruptions in Transmission Lines / Substations during the year and average duration of such disruptions | • Delay in filing Petition<br>• Absence of data telemetry equipment, etc.<br>• Non-separation of SLDC from Transmission |
| **SLDC** | • Percentage of Approved Capex Utilization<br>• Implementation of Forum of Regulators' recommendations in Capacity Building of Indian Load Despatch Centres (CABIL) | • Non-separation of SLDC from Transmission<br>• Delay in filing Petition |
| **Distribution Wheeling** | • Percentage of Approved Capex Utilization<br>• Percentage Utilization of approved R&M Expenses<br>• Overachievement of Wires Availability<br>• Overachievement of Distribution Loss Targets<br>• Overachievement of Smart Meters deployment targets<br>• Overachievement of targeted independently measurable parameters – SAIFI, SAIDI, MAIDI, MAIFI CAIDI, Transformer Failure Rate, etc. against targets<br>• Overachievement of other identified Performance Parameters mentioned in GERC Supply Code / MoP Rights of Consumer Rules, 2022, whichever is more stringent | • Delay in filing Petition<br>• Non-separation of books of accounts for Wheeling and Retail Supply Business |
| **Distribution Retail Supply** | • Percentage of assessed bills as a percentage of total bills issued in a year | • Delay in filing Petition<br>• Non-separation of books of accounts for Wheeling and |

| Utility | Performance Parameters for additional Rate of RoE | Parameters for Penalty on Rate of RoE |
|---|---|---|
| | • Overachievement of Collection Efficiency Targets<br>• Implementation of ToD based tariff for Residential Consumer categories | Retail Supply Business<br>• Non-submission of detailed sales and demand forecast and power procurement plan in line with CEA's Resource Adequacy Guidelines |

Different Performance Parameters and trajectories may be adopted for different Distribution Licensees based on their actual performance and priority of the area of supply.

**Comments and suggestions are invited from the stakeholders regarding the option of introducing an additional variable rate cost of equity (RoE) and penalty on cost of equity (RoE) and also on the list of parameters for the same.**

## 2.2. Tax on Income

GERC MYT Regulations, 2016 stipulates as under:

*"41. Tax on income*

*41.1 The Commission in its MYT Order shall provisionally approve Income Tax payable for each year of the Control Period, if any, based on the actual income tax paid, including cess and surcharge on the same, if any, as per latest Audited Accounts available for the Applicant, subject to prudence check.*

*41.2 Variation between Income Tax actually paid, including cess and surcharge on the same, if any, and approved, if any, on the income stream of the regulated business of Generating Companies, Transmission Licensees, SLDC and Distribution Licensees shall be reimbursed to/recovered from the Generating Companies, Transmission Licensees, SLDC and Distribution Licensees, based on the documentary evidence submitted at the time of truing up of each year of the Control Period, subject to prudence check.*

*41.3 Under-recovery or over-recovery of any amount from the beneficiaries or the consumers on account of such tax having been passed on to them shall be adjusted every year on the basis of income-tax assessment under the Income-Tax Act, 1961, as certified by the statutory auditors. The Generating Company, or the Transmission Licensee or SLDC or Distribution Licensee, as the case may be, may include this variation in its truing up Petition:*

*Provided that tax on any income stream other than the core business shall not be a pass through component in tariff and tax on such other income shall be borne by the Generating Company or Transmission Licensee or the Distribution Licensee, as the case may be."*

Therefore, the Commission currently follows the approach of allowing the normative tax as per actuals subject to prudence check.

While following the approach of allowing income tax as per actuals, there might be a possibility of burdening the consumers with the income tax pertaining to other income/business, earning on account of efficiency target overachievement and other incentive provided by central / state government in the infrastructure. In order to segregate the income tax pertaining to core business, the utility have to maintain the expenditure pertaining to different stream separately in their books of accounts or has to be certified by a statutory auditor.

However, following the approach of grossing up of RoE based on effective tax rate (as per ITR), it ensures that tax is being allowed only of RoE part and are able to pass on the benefits and concessions available in income tax to the beneficiaries. However, the tax rate at which it should grossed up needs to be deliberated. A guidance can be taken from CERC Approach Paper for 2024 Tariff Regulations in this regard, which stipulates:

> *"4.17……………*
>
> *In view of the above discussion and recent amendments to the Income tax regime, a domestic company shall fall under one of the following brackets, and the maximum tax amount that shall be payable is limited by the tax rates notified for the relevant category. Therefore, Base Rate of RoE may be grossed up as follows:*
>
> *1. At MAT rate (If not opted for Section 115 BAA)*
>
> *2. At effective tax rate (if not opted for Section 115BAA) subject to ceiling of Corporate Tax Rate; or*
>
> *3. At reduced tax rate under Section 115BAA of the Income Tax Act or any other relevant categories notified from time to time subject to ceiling of rate specified in the relevant Finance Act.*
>
> *Further, tax shall be allowed only in cases where the company has actually paid taxes as under no circumstances tax can be allowed to be recovered if the company has not paid any tax for* the year under consideration."

Accordingly, it proposed to introduce a capping on the pass through of tax only up to the effective tax rate (to be computed based on tax paid as a percentage of assessed profits as per Assessment Order issued by the Income Tax Authority) on the average/opening equity balance allowed by the Commission for the financial year or the actual tax paid by the Utility.

Further, it is also observed that CERC Terms and Conditions of Tariff Regulations, 2019 in first proviso to Regulation 30(2) provides for rate of return on equity at weighted average rate of interest on actual loan portfolio for additional capitalization after cut-off date beyond original scope, excluding additional capitalization due to Change in Law events, on which the normal rate of return on equity has continued, but without grossing-up with tax rate. Accordingly, one of the possible approaches could be to consider allowing a cost of equity (RoE) without any income tax as pass-through to the Utilities.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

## 2.3. Interest on loan

GERC MYT Regulations, 2016 provides as under:

*"**38. Interest and finance charges***

*38.1 The loans arrived at in the manner indicated in Regulation 33 on the assets put to use, shall be considered as gross normative loan for calculation of interest on loan:*

*Provided that interest and finance charges on capital works in progress shall be excluded:*

*Provided further that in case of de-capitalisation or retirement or replacement of assets, the loan capital approved as mentioned above, shall be reduced to the extent of outstanding loan component of the original cost of the de-capitalised or retired or replaced assets, based on documentary evidence.*

*38.2 The normative loan outstanding as on April 1, 2016, shall be worked out by deducting the cumulative repayment as admitted by the Commission up to March 31, 2016, from the gross normative loan.*

*38.3 The repayment for the year during the Control Period from FY 2016-17 to FY 2020-21shall be deemed to be equal to the depreciation allowed for that year.*

*38.4 Notwithstanding any moratorium period availed by the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the annual depreciation allowed.*

*38.5 The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee:*

*Provided that at the time of truing up, the weighted average rate of interest calculated on the basis of the actual loan portfolio during the year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee shall be considered as the rate of interest:*

*Provided further that if there is no actual loan for a particular year but normative loan is still* *outstanding, the last available weighted average rate of interest for the actual loan shall be considered:*

*Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, does not have actual loan, then the weighted average rate of interest of the other business of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee regulated by the Commission shall be considered:*

*Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, does not have actual loan, and the other business of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee regulated by the Commission also does not have actual loan, then the weighted average rate of interest of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee as a whole shall be considered:*

*Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee as a whole does not have actual loan, then the Bank Rate plus 200 basis points shall be considered as the rate of interest for the purpose of allowing the interest on the normative loan.*

*38.6 The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest: Provided that at the time of truing up, the normative average loan of the year shall be considered on the basis of the actual asset capitalisation approved by the Commission for the year.*

*38.7 The above interest computation shall exclude interest on loan amount, normative or otherwise, to the extent of capital cost funded by Consumer Contribution, Grants or Deposit Works carried out by Transmission Licensee or SLDC or Distribution Licensee or Generating Company, as the case may be.*

*38.8 The Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, in the ratio of 2:1.*

*38.9 Interest shall be allowed on the amount held as security deposit held in cash from Transmission System Users, Distribution System Users and Retail consumers at the Bank Rate as on 1stApril of the financial year in which the Petition is filed."*

Further, the table below provides the review of treatment of loan in the MYT Regulations of the select ERCs:

**Table 3: Treatment of Loan by various ERCs**

| Parameter | CERC | Gujarat | Maharashtra | Telangana | Rajasthan |
|---|---|---|---|---|---|
| **General Provisions** | •Repayment is considered from the first year of the commercial operation and is equal to the annual depreciation allowed<br>•No moratorium considered | | | | |
| **Rate of Interest** | •Weighted average rate of interest calculated on the basis of the actual loan portfolio during the year | | | | |
| **Rate of Interest (in case of no actual loan)** | • No actual loan for a particular year -> last available weighted average<br>• No actual loan -> weighted average rate of interest of the whole business is considered. | • No actual loan for a particular year -> last available weighted average rate of interest<br>• No actual loan -> rate of interest for other businesses else,<br>• Bank rate + 2% | • No actual loan for a particular year -> last available weighted average rate of interest<br>• No actual loan in past as well -> weighted average rate of interest for other businesses<br>• No actual loan on other business in past as well -> weighted average rate of interest for entity as whole else<br>• Bank rate + 2% | • No actual loan for a particular year -> last available weighted average rate of interest<br>• No actual loan->rate of interest specified in regulation (1 Yr SBI MCLR) | • No actual loan for a particular year -> last available weighted average<br>• No actual loan -> weighted average rate of interest of the whole business is considered. |
| **Refinancing of loan** | • Benefit is shared between beneficiaries and | • Benefit is shared between beneficiaries and | • Benefit is shared between beneficiaries and licensee in ratio of 2:1 | • Benefit is shared between beneficiaries and | • Refinance/ re-structure the actual loan as long |

| | | | | | |
|---|---|---|---|---|---|
| | licensee in ratio of 1:1 | licensee in ratio of 2:1 | • Provided also that the re-financing shall not be subject to any adverse terms and conditions and additional cost. | licensee in ratio of 2:1 | as it results in net savings on interest |

| Parameter | Punjab | Karnataka | Madhya Pradesh | Delhi | Uttarakhand | Himachal Pradesh |
|---|---|---|---|---|---|---|
| **General Provisions** | Allow obligatory taxes on interest, finance charges (including guarantee fee payable to the Gov.) and any exchange rate difference arising from foreign currency borrowings, as finance cost | Repayment for each year of the Control Period shall be deemed to be equal to the depreciation allowed for that year. | Repayment is considered from the first year of the commercial operation.<br>No moratorium period | • Repayment is considered from the first year of the commercial operation.<br>• No moratorium period<br>Rate of Interest shall not exceed approved return on equity. | Normative outstanding loans after deducting cumulative repayment shall be considered<br>Repayment equal to depreciation | Computed on the outstanding loans, duly taking into account the schedule of repayment |

| Parameter | Punjab | Karnataka | Madhya Pradesh | Delhi | Uttarakhand | Himachal Pradesh |
|---|---|---|---|---|---|---|
| **Rate of Interest** | For existing loans, the actual rate of interest paid/payable (other than working capital loans) on loans by the Licensee is considered<br>For new loans, one (1) year State Bank of India (SBI) MCLR as on 1st April of plus a margin determined on the basis of actual rate of interest | Weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year | Weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year | Weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year | WAROI on actual loan portfolio of the previous year after providing appropriate accounting adjustment for interest capitalised. | weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year |
| **Rate of Interest (in case of no actual loan)** | No actual loan for a particular year -> last available weighted average | No actual loan for a particular year -> last available weighted average rate of interest<br>No actual loan on in past as well -> weighted | •No actual loan for a particular year -> last available weighted average<br>•No actual loan -> weighted average rate of interest of the whole business is considered. | Bank rate plus margin specified by the Commission in the business plan<br>Bank rate = MCLR or Other benchmark rate by SBI | No actual loan for a particular year -> last available weighted average rate of interest<br>No actual loan ->weighted average rate of interest of the whole business is considered. | |

| Parameter | Punjab | Karnataka | Madhya Pradesh | Delhi | Uttarakhand | Himachal Pradesh |
|---|---|---|---|---|---|---|
| | | average rate of interest for entity as whole | | | | |
| **Refinancing of loan** | | Shared between the beneficiaries and the generating company, in the ratio of 50:50. | •Benefit is shared between beneficiaries and licensee in ratio of 2:1 | Shared between the beneficiaries and the generating company, in the ratio of 50:50.<br>Net saving computed as the product of total quantum of loan availed and difference of weighted average rate of interest on actual loans versus margin of 1.00% plus (+) SBI MCLR. | •Benefit is shared between beneficiaries and licensee in ratio of 1:2 | - |

As clearly evident from the above table, the treatment of normative loan of majority of the ERCs are more or less similar. It is proposed to continue with the existing approach of considering the addition in line with the normative debt to equity ratio and repayment linked to allowed depreciation for the year.

Further, the interest on loan is computed as WAROI calculated on the basis of the actual loan portfolio during the year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee. However, different licensees have different business risk profile and the above methodology sometime allows the inefficiencies of licensees with high risk profile to be passed on to the consumers. Therefore, it is proposed to continue with the approach of allowing interest on loan as WAROI calculated on the basis of the actual loan portfolio during the year with an upper capping of the interest rate linked to an identified benchmarked long-term debt rate of interest, which may be different for government and private utilities. Further, in case of absence of any actual loan by a utility for the regulated business, it is proposed that the WAROI shall be linked with the benchmarked long-term debt rate of interest, instead of the rate of debt of other business, or past debt.

Further, the remaining provisions i.e. for the case where there is no actual loan and sharing of gains on account of refinancing, it is proposed to continue with the existing approach.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

## 2.4. Depreciation

### 2.4.1. Depreciation methodology and rate;

Depreciation is a major component of the annual fixed cost. The principles behind the charging of depreciation and the depreciation rates have been debated over the years, including the linkage of depreciation to creation of a reserve fund for replacement of assets versus the linkage of depreciation to providing cash flow for repayment of loans taken by the Utility.

In this context, Clause 5 (c) of the Tariff Policy stipulates:

> *"**The Central Commission may notify the rates of depreciation in respect of generation and transmission assets.** The depreciation rates so notified would also be applicable for distribution with appropriate modification as may be evolved by the Forum of Regulators.*
>
> ***The rates of depreciation so notified would be applicable for the purpose of tariffs as well as accounting. There should be no need for any advance against depreciation.***

*Benefit of reduced tariff after the assets have been fully depreciated should remain available to the consumers."*

GERC MYT Regulations, 2016 stipulates that:

*"39. Depreciation*

*39.1 The value base for the purpose of depreciation shall be the Capital Cost of the asset admitted by the Commission.*

*39.2 The Generation Company or Transmission Licensee or SLDC or Distribution Licensee shall be permitted to recover depreciation on the value of fixed assets used in their respective Business computed in the following manner:*

*(a) The approved original cost of the project/fixed assets shall be the value base for calculation of depreciation;*

*(b) Depreciation shall be computed annually based on the straight line method at the rates specified in the Annexure I to these Regulations:*

*Provided that the remaining depreciable value as on 31stMarch of the year closing after a period of 12 years from date of commercial operation shall be spread over the balance useful life of the assets:*

*Provided further that for a Generating Company or a Transmission Licensee or SLDC or a Distribution Licensee formed as a result of a Transfer Scheme, the depreciation on assets transferred under the Transfer Scheme shall be charged as per rates specified in these Regulations for a period of 12 years from the date of the Transfer Scheme, and thereafter depreciation will be spread over the balance useful life of the assets:*

*Provided also that the depreciation on the assets financed through consumer contribution, deposit work, capital subsidy or grant, shall be considered as per the Annual Accounts:*

*Provided also that the depreciation already charged after the date of the Transfer Scheme, shall not be restated:*

*Provided also that the Generating Company or Transmission Licensee or SLDC or Distribution Licensee, shall submit all such details or documentary evidence, as may be required under these Regulations and as stipulated by the Commission, from time to time, to substantiate the above claims:*

*Provided also that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life;*

*(c) The salvage value of the asset shall be considered at 10 per cent of the allowable capital cost and depreciation shall be allowed upto a maximum of 90 per cent of the allowable capital cost of the asset: Provided that in the case of hydro generating station, the salvage value shall be as provided in the agreement, if any, signed by the developers with the State Government.*

*39.3 Land other than the land held under lease and the land for reservoir in case of hydro generating station shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing depreciable value of the asset.*

*39.4 In case of the existing projects, the balance depreciable value as on April 1, 2016, shall be worked out by deducting the cumulative depreciation as admitted by the Commission up to March 31, 2016, from the gross value of the assets.*

*39.5 In case of projected commercial operation of the asset for part of the year, depreciation shall be calculated based on the average of opening and closing value of asset, approved by the Commission:*

*Provided that depreciation will be re-calculated during truing-up for assets capitalised at the time of Truing Up of each year of the Control Period, based on documentary evidence of asset capitalised by the Applicant, subject to the prudence check of the Commission, such that the depreciation is calculated proportionately from the date of capitalisation."*

GERC MYT Regulations, 2016 has specified the straight-line method for determination of depreciation expenses for the Generation, Transmission, Distribution Wire, and Retail Supply business, and a residual value of 10%. The asset wise depreciation rate for the first 12 years is specified in the Regulation, and the remaining depreciable value of an asset as on 31st March of the year closing after a period of 12 years from date of commercial operation is to be spread over the balance useful life of that asset. Further, the repayment of loan has also been considered on normative basis and has been considered equal to the annual depreciation allowed.

Further, CERC in the Approach Paper for the control period 2024-29 has stated as follows:

*"4.13 ……..*

*Further, Part B of Section 123 of the Companies Act, 2013, with regard to the residual value of any asset specifies as follows.*

*"4. The useful life or residual value of any specific asset, as notified for accounting purposes by a Regulatory Authority constituted under an Act of Parliament or by the Central Government shall be applied in calculating the depreciation to be provided for such asset irrespective of the requirements of this Schedule."*

*Further, Depreciation depends on the following three factors:*

*1. Rate base (gross fixed assets on which the rate of depreciation applied), which includes subsequent additions.*

*2. Method of depreciation – Straight Line Method (SLM) has been followed in all preceding years.*

*3. Depreciable life – As the assets are required to be provided with 90% depreciation over the life. Hence, the rate of depreciation is directly linked to life of the assets.*

*It is observed that while specifying the depreciation rate, the tenure of the loan considered is 12 years, whereas the life of most of the assets is between 25 and 40 years. It is observed that shorter loan duration and higher depreciation in the initial years have resulted in front loading of tariffs. Considering that nowadays loans are available for 15-18 years, the possibility of increasing the loan tenure for the computation of depreciation rates needs to be explored. Excessive front loading of tariffs increases resistance to future investments. For example, external loans have much lower interest rates, therefore, spreading depreciation over longer periods in the case of external loans can be a viable option for reducing costs in the initial years, which shall, however, include FERV factor and other financing cost. Therefore, there is a need to create a balance and align the depreciation rate with the actual loan tenure and life of the assets.*

*In view of the above, a depreciation rate may be specified considering a loan tenure of 15 years instead of the current practice of 12 years. Further, additional provisions may also be specified that allow lower rate of depreciation to be charged by the generator in the initial years if mutually agreed upon with the beneficiary(ies)."*

In view of above, it is agreed that, as per prevailing provisions depreciation are skewed in the initial 12 years, even though the life of most of the assets is in the range from 25 to 40 years. Further, considering the revised loan tenure of 15-18 years, it is prudent to revise the period for accelerated depreciation from 12 years to 15 years. The Tariff Policy stipulates that the depreciation rates specified by the CERC should be adopted for generation and transmission business, and may be adopted for the distribution business also, after suitable modification to be undertaken by the Forum of Regulators. The Tariff Policy also states that the same rate of depreciation should be considered for tariff purposes as well as accounting purposes and that there should be no need of providing Advance Against Depreciation (AAD) while determining the tariff. Accordingly, the depreciation rates shall be revised in line with the revision of normative loan tenure to 15 years.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 2.4.2. Treatment of IT assets

GERC while notifying the GERC MYT Regulations, 2016 had considered the salvage value at 90% for all the asset categories. However, IT equipment such as laptop, communication system etc. have shorter life span and are prone to technology change, thereby leaving almost negligible salvage value.

CERC in their Tariff Regulations 2014 have considered the salvage value as NIL for the IT equipment. Considering the Tariff Policy which stipulates that the depreciation rates specified by the CERC should be adopted for generation and transmission business, and may be adopted for the distribution business also, after suitable modification to be undertaken by the Forum of Regulators. Therefore, it is proposed to consider salvage value as NIL for IT Equipment.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 2.4.3. Restricting Depreciation till Loan Repayment in case we continue with GFA approach

The tariff regulations ensure the return on investment to the investors on the approved capital investments. In a usual course of business, the returns gets reduced over the life of asset as they recover the depreciation on year-on-year basis. However, the power sector utilities are allowed RoE on gross equity infused even when the cumulative depreciation exceeds the debt component over the life of assets or until the assets is in use.

The existing tariff regulations doesn’t have provisions of reduction of equity after competition of useful life and are essentially based on GFA approach as discussed above. However, under the NFA approach and modified GFA approach, the equity gets reduced to the salvage value after competition of useful life.

An asset, which has competed his useful life, recovers around 90% of the invested capital in the form of depreciation by the end of useful life. Therefore, continuing to allow return of existing equity base i.e., 30% of the capital expenditure essentially means allowing return on the investment which they have already recovered. This leads to over recovery to the utilities and burdens the consumers in the form of end user tariffs.

This issue needs to be deliberated from the point of view, whether the return should be allowed on NFA approach, or the depreciation should be allowed till loan repayment is completed.

Therefore, if the Commission continues with the GFA approach, comments and views of the stakeholders are requested on the approach whether depreciation should be allowed till loan repayment only.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 2.5. Normative Rate of Interest on Working Capital

GERC MYT Regulations 2016 stipulates that:

> *"Interest on working capital shall be allowed at a rate equal to the State Bank Base Rate (SBBR)/1 year State Bank of India (SBI) Marginal Cost of Funds Based Lending Rate (MCLR) /any replacement thereof by SBI for the time being in effect applicable for 1 year period, as may be applicable as on 1stApril of the financial year in which the Petition is filed plus 250 basis points:*
>
> *Provided that at the time of truing up for any year, interest on working capital shall be allowed at a rate equal to the weighted average State Bank Base Rate (SBBR) /1 year State Bank of India (SBI) Marginal Cost of Funds Based Lending Rate (MCLR) /any replacement thereof by SBI for the time being in effect applicable for 1 year period, as may be applicable prevailing during the financial year plus 250 basis points."*
>
> *………"*

The following table summarily compares the normative rate of interest on working capital for various ERCs.

*Table 4: Normative Rate of Interest on Working Capital*

| State | Interest Rate for Working Capital |
|---|---|
| **Gujarat** | 1-Y SBI MCLR + 2.50% |
| **CERC** | 1-Y SBI MCLR + 3.50% |
| **Maharashtra** | 1-Y SBI MCLR + 1.50% |
| **Rajasthan** | Average Base Rate prevalent during first six months of the year previous to the relevant year + 3.00% |
| **Punjab** | 1-Y SBI MCLR + 3.50% |
| **Himachal Pradesh** | 1-Y SBI MCLR + 3.00% |
| **Delhi** | Bank rate on 1st April of FY + margin specified in business plan |
| **Uttarakhand** | 1-Y SBI MCLR + 3.50% |
| **Madhya Pradesh** | 1-Y SBI MCLR + 3.50% |
| **Karnataka** | Lower of (i) RBI base rate (latest) +2.50% and (ii) wt. av. rate of interest proposed by the licensee |

,It is observed majority of the SERCs have adopted the CERCs normative rate, i.e., 1-Y SBI MCLR +

3.50%, which is much more relaxed than existing normative rate specified by GERC, i.e. 1-Y SBI MCLR + 2.50%, with an exception of MERC, where the margin specified is 1.50% only. Accordingly, it is proposed to consider allowing the Interest on Working Capital at a rate equal to the one-year marginal cost of lending rate (MCLR) of the State Bank of India issued from time to time as on 1st April of the respective financial year plus 150 basis points.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 2.6. Carrying/Holding cost

Regulation 21.6 (c) of the GERC MYT Regulations, 2016 specifies as follows:

> *"Carrying cost to be allowed on the amount of Revenue Gap or Revenue Surplus for the period from the date on which such gap/surplus has become due, i.e., from the end of the year for which true-up has been done, till the end of the year in which it is addressed, calculated on simple interest basis at the weighted average State Bank Base Rate (SBBR) / I year State Bank of India (SBI) Marginal Cost of Funds Bused Lending Rate (MCLR) / only replacement thereof by SBI for the time being in effect applicable for I year period, as may be applicable for the relevant year, i.e. the year for which Revenue Gap or Revenue Surplus is determined:*
>
> *Provided that carrying cost on the amount of Revenue Gap shall be allowed up to the above limit, subject to prudence check and submission of documentary evidence for having incurred the carrying cost in the years prior to the year in which the revenue gap is addressed."*

In addition, the Clause 3(3)(c) of The Interest Act, 1978, states that it is not in the purview of the court to allow interest on interest. The relevant excerpt of the aforesaid Act is stipulated as under for the ready reference:

> *"3. Power of court to allow interest.*
>
> *(3) Nothing in this section, —*
> a) *shall apply in relation to—*
> *(i) any debt or damages upon which interest is payable as of right, by virtue of any agreement; or*
> *(ii) any debt or damages upon which payment of interest is barred, by virtue of an express agreement;*
> b) *shall affect—*
> *(i) the compensation recoverable for the dishonour of a bill of exchange, promissory note or cheque, as defined in the Negotiable Instruments Act, 1881 (26 of 1881); or*
> *(ii) the provisions of rule 2 of Order II of the First Schedule to the Code of Civil Procedure, 1908 (5 of 1908);*
> c) *shall empower the court to award interest upon interest."*

The main objects of the Electricity Act 2003 is to balance the interest of all the stakeholders. Further, the Commission had always endeavor to balance the interest of the consumers on the one hand and the licensees on the other. Protecting the interest of consumers and rationalisation of electricity tariff are the main objects of the Electricity Act 2003. However, if interest upon interest allowed, it will be against one of the main objects of Electricity Act 2003, i.e., balance the interest of all the stakeholders.

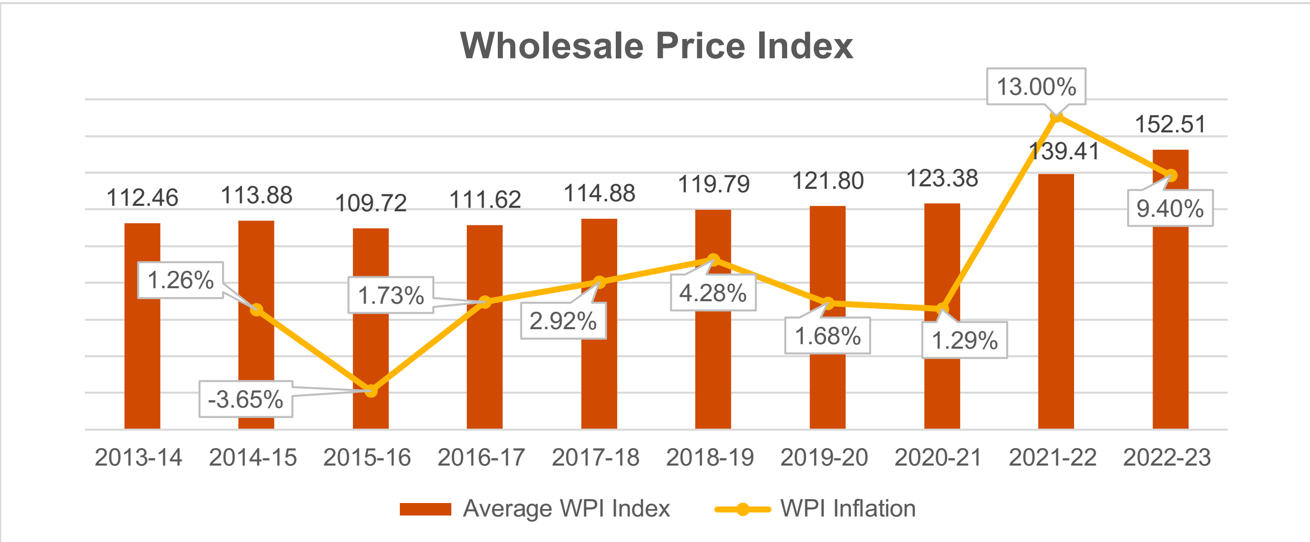
Therefore, the carrying cost/holding cost are worked out by applying the principles of simple interest. If the concept of allowing interest on interest, i.e. compound interest is applied, it would be a never-ending exercise and would create additional burden on the beneficiaries. The Regulation 21.6 (c) of the GERC MYT Regulations, 2016 clearly specifies that carrying cost has to be calculated on simple interest basis. However, in the interest of clarity, it is proposed that the same may be further clarified through specific unambiguous provision and / or with an illustration.

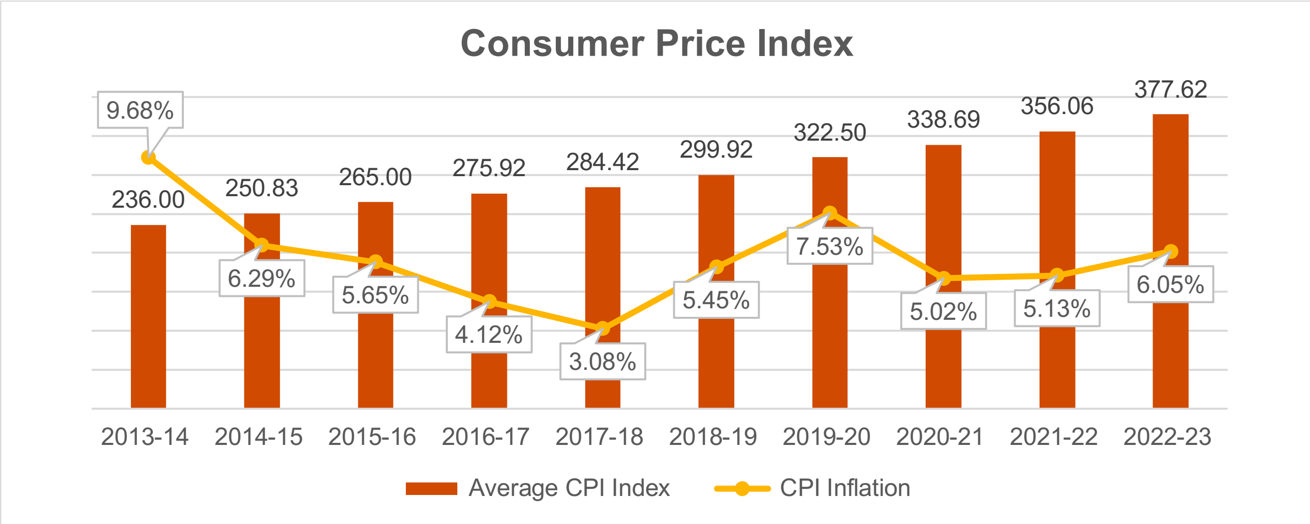
**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 2.7. Escalation Factor

In order to determine the Operation and Maintenance (O&M) expenses for the third control period, the Commission had considered an escalation factor for of 5.72% as specified by Central Electricity Regulatory Commission in its CERC (Terms and Conditions of Tariff) Regulations, 2009. The factor of 5.72% was calculated based on the inflation data up to October 2008. Since the fourth control period shall be starting from FY 2024-25, considering the factor of 5.72% may not be appropriate.

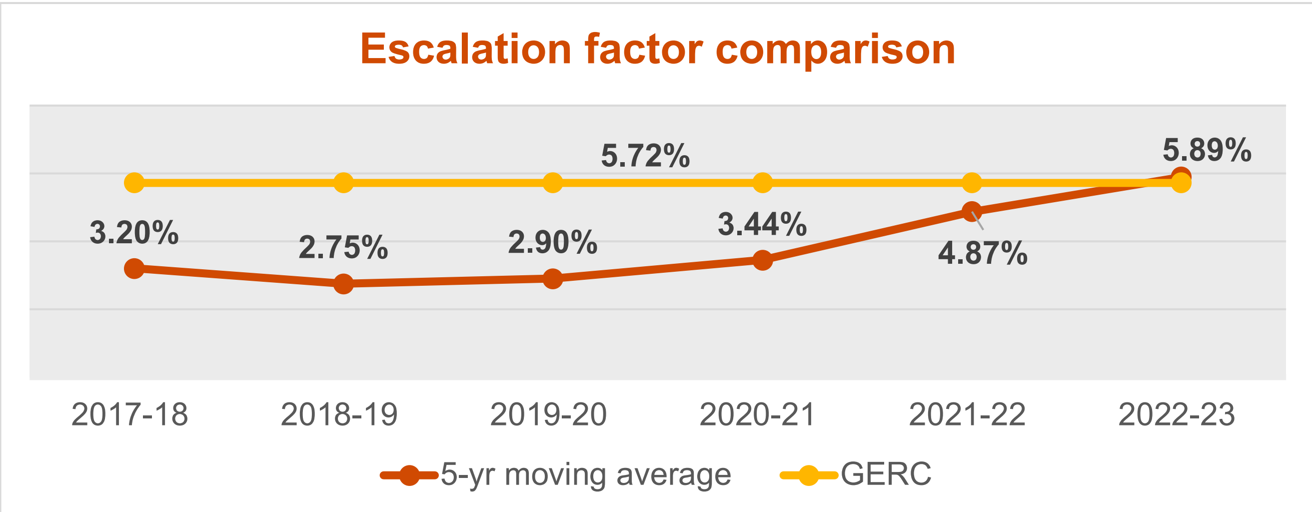
Further, the Wholesale Price Index (WPI) and Consumer Price Index (CPI) have fluctuated in the last few years mainly due to the effects of COVID-19 and global economic changes due to the Russia-Ukraine war. The WPI and CPI inflation for the last 10 years is as follows:






The WPI has fluctuated from 1.29% in FY 2020-21 to 13.00% to FY 2021-22. The CPI has also dipped from 7.53% in FY 2019-20 to 5.02% in FY 2020-21.

Further, the following graph compares the existing escalation rate as per GERC MYT Regulations, 2016 with an escalation factor computed based on a five-year moving average figures of CPI and WPI, which is clearly showing a huge deviation.




Therefore, it is proposed to consider a moving average of last 8 to 10 years' WPI and CPI values for determining the escalation factor for O&M expenses for the Utilities at the beginning of each financial year. The same may be considered to be trued-up based on monthly average actual WPI and CPI values during the true-up of each year of the control period.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

# 3. Generation

## 3.1. Operating Parameters

The operating parameters for Generating Stations include as follows:

- **Thermal Generating stations (Coal/Gas based)-** Normative Annual Plant Availability Factor (NAPAF), Normative Annual Plant Load Factor (NAPLF), Gross Station Heat Rate, Secondary fuel oil consumption, Limestone consumption, Auxiliary Energy Consumption, Transit and Handling Losses

- **Hydro generating stations**- Auxiliary Energy Consumption, Normative Annual Plant Availability Factor (NAPAF).

### 3.1.1. Normative Annual Plant Availability Factor (NAPAF)

GERC MYT Regulations, 2016 prescribes Normative Annual Plant Availability Factor of 85 per cent for full recovery of Annual Fixed Charges for all thermal generating stations, except for GSECL Generating Stations covered under Regulation 53.1. Further, relaxation of 2 per cent is provided in case of shortage of coal and uncertainty of assured coal supply on sustained basis, which shall be reviewed annually.

The NAPAF is determined based on the past years data available and best industry practices. As, the working environment is evolving day by day due to technological advancements, improved O&M practices, lower shutdowns and outages, the PAF has been improving. However, the availability of fuel and it's blending still remains a constraint. Similarly, the changing hydrology, and restrictions imposed on the flow of water, and changes in the pattern of water usage in the case of multipurpose dam projects, has impacted the NAPAF of the hydro generating stations.

In view of the above, NAPAF may be reviewed considering past years' PAF, arrangement of fuel (Coal), other than designated fuel supply agreements, changes in hydrology, etc. based on the following two methodologies:

1) Historical data of state generating plants – last 8 to 10 years may be considered and any anomalies due to force majeure events such as COVID-19 shall be taken care of;

2) CERC/ other SERC benchmarks considering CEA recommendations-

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

### 3.1.2. Other Operating Norms including SHR, Auxiliary Consumption, etc.

Various Regulations of the GERC MYT Regulations, 2016 prescribes norms for generating stations as follows:

- Regulations 53.3 and 53.4 – Gross Station Heat Rate
- Regulation 53.5 – Secondary Fuel Oil Consumption
- Regulation 53.6 – Lime stone Consumption
- Regulation 53.7 – Auxiliary Energy Consumption
- Regulation 53.8 – Transit and Handling Losses

These operating parameters may be reviewed based on the following two methodologies:

1) Historical data of generating plants – last 8 to 10 years may be considered and any anomalies due to force majeure events such as COVID-19 shall be taken care of;
2) CERC/ other SERC benchmarks considering CEA recommendations

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

## 3.2. Life Extension of a Generating Station

Several thermal as well as hydro generating plants of Gujarat have completed their useful life of 25 and 35 respectively and a few shall be completing the same in the next control period. These plant capacities can either be enhanced by installation of new plants or renovating the existing one or uprating them. In order to incentivise the extension of life beyond the useful life of the generating station or units, the Commission has given a provision for Renovation and Modernisation (R&M) expenses and Special Allowance (in lieu of R&M) forming part of the Annual Fixed Cost.

GERC Regulations 2016 state as follows:

> *"**50. Renovation & Modernisation***
>
> *……….*
>
> *50.5 In case of coal-based/lignite fired thermal generating station, the Generating Company, may, at its discretion, avail of a 'special allowance' in accordance with the norms specified in Regulation 50.6, as compensation for meeting the requirement of expenses including Renovation and Modernisation beyond the useful life of the generating station or a unit thereof, and in such an event, revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the special allowance shall be included in the Annual Fixed Cost:*

*Provided that such option shall not be available for a generating station or Unit for which Renovation and Modernization has been undertaken and the expenditure has been admitted by the Commission before the date of effectiveness of these Regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.*

*50.6 The Special Allowance shall be @ Rs. 7.5 lakh/MW/year for the year 2016-17 and thereafter escalated @ 5.72% every year during the Control Period, unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:*

*Provided that in respect of a unit in commercial operation for more than 25 years as on 1.4.2016, this allowance shall be admissible from the year 2016-17:*

*Provided further that the special allowance for the generating station, which, in its discretion, has already availed of a 'special allowance' in accordance with the norms specified in clause (iv) of Regulation 51.6 of Gujarat Electricity Regulatory Commission (Multi-Year Tariff) Regulations, 2011, shall be allowed Special Allowance by escalating the special allowance allowed for the year 2015-16 @ 5.72% every year during the Control Period.*

*50.7 In the event of granting special allowance by the Commission, the expenditure incurred or utilized from special allowance shall be maintained separately by the separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure."*

Further, CEA has also issued guidelines for renovation & modernisation / life extension works of coal/lignite based thermal power stations and hydro power stations.

R&M ensure extension of life of existing plants and saves huge capital expenditure that could have been incurred for commissioning of new plants. Thermal Generating Station also do have the alternative of opting for Special Allowance. However, while the option of R&M assures life extension of the generating station, there is no such condition in case of option of Special Allowance and it can be claimed on year on year basis, without any commitment for future availability. CERC (Terms and Conditions of Tariff) Regulations, 2019 has removed the escalation factor from the provision of Special Allowance. Further, the Approach Paper for Tariff Regulations for 2024-29 Control Period states that appropriate provisions may be provided wherein any utility that has opted for Special Allowance for the first year of the tariff period shall have to continue with the same for the rest of the tariff period.

Therefore, while the option of undertaking R&M instead of fresh capital investment continue to be explored based on a detailed cost-benefit analysis, the alternative of Special Allowance may also be with conditions and restrictions and also without any escalation.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

## 3.2.1. Normative Working Capital

All SERCs use a standard formula as norm for determination of working capital requirement, wherein cost of primary fuel, O&M expenses as well as cost of maintenance spares is allowed, in addition to the Receivables. Regarding inclusion of fuel expenses and one month of O&M expenses as a part of the working capital requirement, these are incurred for a given month are recoverable along with the tariff in the next month, the same needs to be a part of working capital. In addition, exclusion of the same may also have impact on the liquidity position of the utilities.

Further, the working capital norms as per provisions GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 5: Norms of Working Capital for Thermal Generation adopted by SERCs*

| ERC | Fuel Expenses | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|---|
| **Gujarat** | • Cost of Primary fuel:<br>○ 1 Month for Pit head<br>○ 1 ½ Month for Non-Pit head.<br>• Cost of secondary fuel oil for 2 months | 1 month | 1% of Historical Cost (GFA) | 1 month of the fixed charges and energy charges |
| **CERC** | • Cost of Primary fuel:<br>○ 10 days for Pit head<br>○ 20 days for Non-Pit head<br>• 30 days of cost of coal or lignite and limestone<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 45 days of the capacity charges and energy charges |
| **Maharashtra** | • Cost of Primary fuel:<br>○ 15 days for Pit head<br>○ 30 days for Non-Pit head<br>• 30 days of cost of coal or lignite and limestone<br>• Cost of secondary fuel oil for 2 months | 1 month | 1% of opening GFA | 45 days of the fixed charges and energy charges<br><br>Minus<br>Payables for fuel (including oil and secondary fuel oil) to the extent of 30 days |
| **Rajasthan** | • Cost of Primary fuel:<br>○ ½ Month for Pit head<br>○ 1 ½ Month for Non-Pit head<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 1½ months of the fixed and variable charges |

| ERC | Fuel Expenses | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|---|
| **Punjab** | Fuel Cost including cost of limestone / other reagent for 2 months | 1 month | 15% of O&M expenses | 2 months of the fixed and variable charges |
| **Himachal Pradesh** | NA | NA | NA | NA |
| **Delhi** | • Cost of Primary fuel:<br>○ 15 days for Pit head<br>○ 30 days for Non-Pit head<br>• 30 days of cost of coal<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 2 months of capacity and energy charges |
| **Uttarakhand** | NA | NA | NA | NA |
| **Madhya Pradesh** | • Cost of Primary fuel:<br>○ 15 days for Pit head<br>○ 30 days for Non-Pit head<br>• 30 days of cost of coal<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 45 days of the capacity and energy charges |
| **Karnataka** | • Cost of Primary fuel:<br>○ 10 days for Pit head<br>○ 20 days for Non-Pit head<br>• 30 days of cost of coal or lignite and limestone<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 45 days of the capacity and energy charges |

Regarding the primary fuel stock, the norms of other ERCs including CERC have moved to a much more stringent levels, up to 10 and 15 days for pit-head and non-pit head generating stations respectively. Therefore, the existing norms under GERC MYT Regulations, 2016 may need to be reviewed in the light of sectoral benchmarking and also actual inventory maintained by the generating stations in the State.

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed.

For maintenance spares, 20% of total O&M expenses are considered in the states of Rajasthan, Delhi, Madhya Pradesh, Karnataka etc. whereas the states of Maharashtra and Gujarat consider 1% of historical cost of assets. The existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the generating stations.

While majority of the select states consider 45 days of the capacity and energy charges for receivables, only Maharashtra considers 45 days of the fixed charges and energy charges after deducting payables for fuel (including oil and secondary fuel oil) to the extent of 30 days. Therefore, the Commission may review norms for considering the receivables for computing working capital requirement.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

*Table 6: Norms of Working Capital for Gas based Generation adopted by SERCs*

| ERC | Fuel Expenses | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|---|
| **Gujarat** | • Fuel Cost for 1 month<br>• Liquid fuel stock for 15 days | 1 month | 1% of Historical Cost (GFA) | 1 month of the fixed charges and energy charges |
| **CERC** | • Fuel Cost for 30 days<br>• Liquid fuel stock for 15 days | 1 month | 30% of O&M Expense | 45 days of the capacity and energy charges |
| **Maharashtra** | • Fuel Cost for 30 days<br>• Liquid fuel stock for 15 days | 1 month | 1% of opening GFA | 45 days of the fixed charges and energy charges<br><br>Minus<br>Payables for fuel (including oil and secondary fuel oil) to the extent of 30 days |
| **Rajasthan** | • Fuel Cost for ½ Month<br>• Liquid fuel stock for ½ Month | 1 month | 30% of O&M Expense | 1½ months of the fixed charges and variable charges |
| **Punjab** | • Fuel Cost for ½ Month<br>• Liquid fuel stock for ½ Month | 1 month | 30% of O&M expenses | 2 months of the fixed and variable charges |
| **Himachal** | NA | NA | NA | NA |

| ERC | Fuel Expenses | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|---|
| **Pradesh** | | | | |
| **Delhi** | • Fuel Cost for 30 days<br>• Liquid fuel stock for 15 days | 1 month | 30% of O&M expenses | 2 months of the capacity and energy charges |
| **Uttarakhand** | • Fuel Cost for 1 Month<br>• Liquid fuel stock for ½ Month | 1 month | 30% of O&M expenses | 2 months of the fixed and variable charges |
| **Madhya Pradesh** | NA | NA | NA | NA |
| **Karnataka** | • Fuel Cost for 30 days<br>• Liquid fuel stock for 15 days | 1 month | 30% of O&M expenses | 45 days of the capacity and energy charges |

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed.

For maintenance spares, 30% of total O&M expenses are considered in the states of Rajasthan, Punjab, Delhi, Uttarakhand, Karnataka etc. whereas the states of Maharashtra and Gujarat consider 1% of historical cost of assets. The existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the generating stations.

While majority of the select states consider 45 days to 2 months of the capacity and energy charges only Maharashtra considers 45 days of the fixed charges and energy charges after deducting Payables for fuel (including oil and secondary fuel oil) to the extent of 30 days. Therefore, the Commission may review norms for considering the receivables for computing working capital requirement.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

*Table 7: Norms of Working Capital for Hydro Generation adopted by SERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|
| **Gujarat** | 1 month | 1% of Historical Cost (GFA) | 1 Month of fixed cost |
| **CERC** | 1 month | 15% of O&M Expense | 45 days of the fixed cost |
| **Maharashtra** | 1 month | 1% of opening GFA | 45 days of the fixed charges |
| **Rajasthan** | 1 month | 15% of O&M Expense | 1½ Months of the fixed charges |
| **Punjab** | 1 month | 15% of O&M expenses | 2 months of the fixed cost |
| **Himachal Pradesh** | 1 month | 15% of O&M expenses | 2 months of the fixed cost |
| **Delhi** | N/A | N/A | N/A |
| **Uttarakhand** | 1 month | 15% of O&M expenses | 2 months of the fixed charges |
| **Madhya Pradesh** | 1 month | 15% of O&M expenses | 45 days of the fixed cost |
| **Karnataka** | 1 month | 15% of O&M expenses | 45 days of the fixed cost |

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed.

For maintenance spares, 15% of total O&M expenses are considered in the states of Rajasthan, Punjab, Uttarakhand, Madhya Pradesh, Karnataka etc. whereas the states of Maharashtra and Gujarat consider 1% of historical cost of assets. The existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the generating stations.

While majority of the select states consider 45 days to 2 months of the capacity charges only. Therefore, the Commission may review norms for considering the receivables for computing working capital requirement.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

## 3.3. Principles of Tariff recovery

### 3.3.1. Differential Capacity Charges based on availability during Peak Requirement:

GERC MYT Regulations, 2016 has adopted tariff computation approach from the CERC (Terms and Conditions of Tariff) Regulations, 2014. Tariff Policy guidelines specifies for the introduction of differential rates for capacity charges. CERC, in their Tariff Regulations for the Control Period 2019-24 had also introduced the concept of peak and off -peak rates for the thermal generating stations to incentivize the availability during the peak requirement period (detailed provision is reproduced in the Annexure).

Introduction of such differential capacity charges during peak period would motivate higher availability factor and achieving target availability by the generating station, thus making the generating stations available during the hours most required by the beneficiaries. However, constraints may be faced in declaration the high demand and low demand season as the same needs to be notified in advance. Further, the same needs to coincide with the demand and supply forecast.

After issuance of the CERC (Terms and Conditions of Tariff) Regulations, 2019, few of the SERCs adopted the revised CERC approach of differential capacity charges during peak period, while many of them have continued with the old approach mentioned in CERC (Terms and Conditions of Tariff) Regulations, 2014. Further, CERC in its Approach Paper – CERC MYT Regulations for 2024-29 has now proposed deliberations on recovery based on daily peak and off-peak periods also. Accordingly, following few alternatives may be explored.

- To continue with existing methodology based on CERC Tariff Regulations, 2014
- To adopt revised methodology of month-wise peak/off-peak/normal seasons based on CERC Tariff Regulations, 2019
- CERC Approach Paper for 2024 Tariff Regulations has proposed the option of recovery based on daily peak and off-peak periods

**Comments and suggestions are invited from the stakeholders on the possible regulatory options in the matter.**

### 3.3.2. Option of Capacity Charges recovery on Scheduled Generation after completion of useful life

For the generating stations that have completed their useful life from the date of commercial operation, the generating company and the beneficiary shall have an option to arrive at a mutual agreement for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation. However, the beneficiary shall have the first right of refusal and upon its refusal to enter into an arrangement as above, the generating company shall be free to sell the electricity generated from such station in a manner as it deems fit. This is in line with the Regulation 17 of the CERC (Terms and Conditions of Tariff) Regulations, 2019.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options in the matter.**

## 3.4. Incentive

The generating stations shall be incentivized for achieving the targeted NAPAF and NAPLF. The incentives may be introduced based on pro-rata basis for the achieving more than target. Further, the incentives for achieving excess of target during peak periods may be higher than the incentives provided for achieving the targets. CERC Tariff Regulations, 2019 provides for incentive @ 65 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 50 paise/ kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis within each Season (High Demand Season or Low Demand Season, as the case may be).

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

# 4. Transmission

## 4.1. O&M Expenses

O&M expenses for Transmission Licensee can be determined in two ways:

1) By setting O&M norms based on number of bays and transmission line length (in circuit kms) and escalating the same as per inflation for each year of the control period; or

2) By setting norms for Employee, R&M and A&G expenses separately based on historical data and escalating the same as per inflation for each year of the control period.

The GERC MYT Regulations, 2016 provides for Operation and Maintenance expenses for a Transmission Licensee as follows:

*"**68. Calculation of Aggregate Revenue Requirement***

***….***

*68.2 Operation and Maintenance expenses:*

*68.2.1 Existing Transmission Licensee:*

***Gujarat Energy Transmission Company Ltd. (GETCO)***

***Table 14: O&M Expense norms in Rs. Lakh/Bay and Rs. Lakh/cktkm***

| ***Particulars*** | ***FY 2016-17*** | ***FY 2017-18*** | ***FY 2018-19*** | ***FY 2019-20*** | ***FY 2020-21*** |
|---|---|---|---|---|---|
| *O&M Expenses/Bay* | *7.60* | *8.04* | *8.50* | *8.98* | *9.50* |
| *O&M Expenses/ ckt km* | *0.64* | *0.68* | *0.72* | *0.76* | *0.81* |

*Provided that the Transmission Licensee shall submit a certificate from the Chief Electrical Inspector for the number of bays and circuit kilometres of transmission line added during the year at the time of truing up.*

*68.2.2 For New Transmission Licensee:*

*For the New transmission licensees, the year-wise O&M norms shall be determined on case to case basis:*

*Provided that the same shall not be applicable to those new projects, which are awarded on a competitive bidding basis.*

*…."*

Following table shows the practices across different states.

*Table 8: Approach for O&M Expenses by various ERCs*

| Sr. No. | Methodology | States/ CERC | Regulations |
|---|---|---|---|
| 1 | States Using consolidated approach to determine O&M expenses | CERC | Normative O&M expense on basis of number of bays and circuit kilometre for all years of control period, and escalation factor for escalation towards inflation is specified in the MYT Regulations. |
| 2 | | Gujarat | |
| 3 | | Rajasthan | |
| 4 | | Madhya Pradesh | |
| 5 | | Delhi | Normative O&M expense on basis of number of bays and circuit kilometre for all years of control period, Escalation allowed toward inflation based on CPI & WPI |
| 6 | | Maharashtra | |
| 7 | Employee Expenses, A&G, and R&M Expenses calculated separately | Uttarakhand | The O&M expenses for the nth year is calculated as per following formula<br>'EMPn' = [(EMPn-1) x (1+Gn) x (1+CPIinflation)]<br>'A&Gn' = [(A&Gn-1) x (1+WPIinflation)];<br>R&Mn' = K x (GFA n-1 ) x (1+WPIinflation) ;<br>'K' - is a constant (could be expressed in %). Value of K for each year of the control period as specified by the commission |
| 8 | | Himachal Pradesh | The O&M expenses for the nth year is calculated as per following formula:<br>'EMPn' = [(EMPn-1) x (1+Gn) x (CPIinflation)] + Provision(Emp)<br>'A&Gn' = [(A&Gn-1) x (WPIinflation)] + Provision(A&G) ;<br>R&Mn = K x (GFA n-1 ) x (WPIinflation) ;<br>K' - is a constant (could be expressed in %). Value of K for each year of the control period shall be determined by the Commission |
| 9 | | Punjab | Following formula is used to calculate the O&M Expenses:<br>O&Mn = (R&Mn + EMPn + A&Gn) x (1-Xn)<br>(i) R&Mn= K*GFA*WPIn/WPIn-1<br>(ii) EMPn+ A&Gn= (EMPn-1 + A&Gn-1)*(INDEX n/INDEX n-1)<br>INDEXn = 0.50*CPIn + 0.50*WPIn |

The norms set by CERC may be difficult to adopt as it has too many voltage-wise norms for sub-station bays and transformers, and this may not work for the SERCs. But the same may be reviewed as an option. The O&M expenses may be derived on the basis of the average of the Trued-Up values (without efficiency gain / loss, if any) or based on audited accounts for the last five (5) financial years, subject to prudence check by the Commission. This average figure may be considered as O&M expenses for the middle year and may be escalated with year on year basis with suitable escalation factor based on CPI and WPI of the respective financial years. Further, one-time expenses such as expense due to change in accounting policy, arrears paid due to Pay Commissions, etc., and the expenses beyond the control of the Transmission Licensee such as salary arrears,, terminal benefits, etc., in employee cost, may be allowed by the Commission over and above normative O&M expenses after prudence check. The O&M expenses for the nth year of the Control Period shall be approved based on the formula given below:

**$O\&M_n = (R\&M_n + EMP_n + A\&G_n) \times (1 - X_n)$ + Terminal Liabilities and other one-time expenses**

Where,

**$R\&M_n$** $= K \times GFA_{n-1} \times (Indx_n / Indx_{n-1})$

**$EMP_n$** $= (EMP_{n-1}) \times (1+G_n) \times (Indx_n / Indx_{n-1})$

**$A\&G_n$** $= (A\&G_{n-1}) \times (Indx_n / Indx_{n-1})$

**'K'** is a constant (expressed in %). Value of K for each Year of the Control Period shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking of repair and maintenance expenses, approved repair and maintenance expenses vis-à-vis GFA approved by the Commission in past and any other factor considered appropriate by the Commission;

**$INDX_n$** – Inflation factor to be used for indexing may be a combination of the Consumer Price Index (CPI) and the Wholesale Price Index (WPI) for immediately preceding year before the base year;

**EMPn** – Employee expenses of the Transmission Licensee for the nth Year;

**$A\&G_n$** – Administrative and General expenses of the Transmission Licensee for the nth Year;

**$R\&M_n$** – Repair and Maintenance expenses of the Transmission Licensee for the nth Year;

**$GFA_{n-1}$** – Gross Fixed Asset of the Transmission Licensee for the n-1th Year;

**Gn** is a growth factor for the nth Year. Value of $G_n$ shall be determined by the Commission in the MYT tariff order for meeting the additional manpower requirement based on Licensee's filings, benchmarking, approved cost by the Commission in past and any other factor that the Commission feels appropriate.

**$X_n$** is an efficiency factor for nth Year. Value of $X_n$ shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking, approved cost by the Commission in past and any other factor the Commission feels appropriate;

For the purpose of estimation, the same $INDX_n/INDX_{n-1}$ value may be used for all years in MYT by the Commission. However, the Commission may consider the actual values in the $INDX_n/INDX_{n-1}$ during the true up of the O&M expenses for the respective years of the Control Period.

Terminal Liabilities may be approved as per actual submitted by the Distribution Licensee along with documentary evidence and other documents as desired by the Commission.

The Transmission Licensee, in addition to the above details shall also submit the detailed break-up of the Legal/Litigation Expenses for the previous Years along with the details and documentary evidence of incurring such expenses. The Commission may approve the legal expenses based on the necessary documentary evidence submitted by the Transmission Licensee. The Commission may also carry out due prudence check of legal expenses at the time of truing up.

Further, based on the detailed submissions by the Transmission Licensee, the Commission may consider allowing certain specified expenses on actual basis beyond normative O&M expenses, which are not part of the historical O&M expenses and thus couldn't have been included in the norms. However, in such cases the Commission will also appropriately incorporate the efficiency gains on account of such expenses either in the O&M expenses formulae or other performance parameters. Initially, the efficiency factor, Xn may be considered as 1, which may be subsequently determined based on a separate detailed study at the time of mid-term review of the MYT Control Period.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 4.2. Norms of working capital for Transmission Licensee

GERC MYT Tariff Regulations, 2016 stipulate the following norms of working capital for Transmission Licensee:

> *"**40 Interest on Working Capital***
>
> ***…***
>
> *40.2 Transmission:*
>
> *(i) The Transmission Licensee shall be allowed interest on the estimated level of working capital for the financial year, computed as follows:*
>
> *(i) Operation and maintenance expenses for one month; plus*
>
> *(ii) Maintenance spares at one (1) per cent of the historical cost; plus*
>
> *(iii) Receivables equivalent to one (1) month of transmission charges calculated on target availability level;*
>
> *minus*
>
> *(iv) Amount, if any, held as security deposits except the security deposits held in the form of Bank Guarantee from Transmission System Users:*
>
> *….."*

Further, the working capital norms as per provisions of GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 9: Norms of Working Capital for Transmission Business adopted by ERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| **Gujarat** | 1 month | 1% of Historical Cost (GFA) | 1 month of transmission charges calculated on annual target availability level for transmission licensee<br>Minus<br>Security Deposits from Users other than those in the form of Bank Guarantees |
| **Maharashtra** | 1 month | 1% of opening GFA | 1½ month of the expected revenue from transmission charges at approved tariff for the ensuing year<br>Minus<br>Amount held as security deposits in cash from transmission system users |
| **Rajasthan** | 1 month | 15% of O&M expenses | 1½ month of transmission charges calculated on annual target availability level for transmission licensee<br>Minus<br>Security Deposits from Users other than those in the form of Bank Guarantees<br>(same for transmission and SLDC) |
| **Punjab** | 1 month | 15% of O&M expenses | 2 months of Receivables calculated on normative target availability<br>(same for transmission and SLDC) |
| **Himachal Pradesh** | 1 month | 15% of O&M expenses for one month | 2 months Receivables towards annual transmission charges |
| **Delhi** | 1 month | 15% of O&M expenses | 2 months Receivables towards transmission tariff calculated on NATAF |
| **Uttarakhand** | 1 month | 15% of O&M expenses | 2 months Receivables |
| **Madhya Pradesh** | 1 month | 15% of O&M expenses | 45 days Receivables towards transmission tariff calculated on target availability level |
| **Karnataka** | 1 month | 1% of opening GFA | 2 months Receivables towards transmission charges calculated on target availability level |

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed.

For maintenance spares, 15% of total O&M expenses are considered in the states of Rajasthan, MP, HP, Punjab, etc. whereas the states of Maharashtra and Karnataka consider 1% of historical cost of assets. The existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the transmission licensees.

Considering the billing and recovery efficiency, as well as the current state of the STU, maintaining the receivables equivalent to 1 month of the Annual Fixed Cost should be sufficient for Transmission licensees to maintain their liquidity.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are sought from the stakeholders on continuation of methodology used for determining working capital requirement for Transmission utility.**

## 4.3. Transmission Loss

The Commission conducted a review of regulations adopted by various other SERCs. The regulations are as follows:

*Table 10: Treatment of Transmission Loss by ERCs*

| State | Treatment of Transmission Loss |
|---|---|
| **Maharashtra** | Commission to stipulate Transmission loss trajectory while approving MYT Order |
| **Rajasthan** | The transmission losses to be borne by the users of the transmission system in kind, as percentage of energy transmitted |
| **Punjab** | any gain / loss sharing with the Transmission Licensee on account of overachievement/under- achievement of the Transmission Loss trajectory specified by the Commission, shall be capped to the Return on Equity earned by the Transmission Licensee. |
| **Madhya Pradesh** | Trajectory specified by the Commission based on actual transmission loss of Previous years. Auxiliary consumption on AC sub-substation shall be considered as part of Transmission loss. |
| **Uttarakhand** | As determined by SLDC and approved by the Commission |
| **Himachal Pradesh** | The energy losses in the transmission system of the transmission licensee, as determined by the State Load Despatch Centre. |
| **Karnataka** | Commission to approve Transmission loss Range filed by licensee while approving MYT Order. |
| **Telangana** | Losses below the approved range = Earn incentive and added to the ARR. Losses beyond the approved range = Results in penalty and such penalty shall be deducted from the ARR. Max Penalty < 10% RoE |

If the transmission losses are shared among transmission system users, the transmission utility may not be motivated to reduce these losses. Based on the standards followed in various states, it is proposed to introduce a transmission loss range in the MYT order and any losses falling below this range shall be divided among the Transmission System Users. In order to ensure accountability and to incentivize efficient transmission practices, it is recommended that any losses beyond the established range be evaluated as a penalty to the transmission utility. This penalty should be deducted from the Annual Revenue Requirement (ARR), up to a specified percentage of the rate of RoE.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

## 4.4. Income from Other Business

The GERC MYT Tariff Regulations, 2016 states as follows:

> ***"70. Income from Other Business***
>
> *Where the Transmission Licensee is engaged in any Other Business, an amount equal to two-third of the revenues from such Other Business after deduction of all direct and indirect costs attributed to such Other Business shall be deducted from the Aggregate Revenue Requirement in calculating the annual transmission charges of the Transmission Licensee:*
>
> *Provided that the Transmission Licensee shall follow a reasonable basis for allocation of all joint and common costs between the Transmission Business and the Other Business and shall submit the Allocation Statement, duly audited and certified by the Statutory Auditor, to the Commission along with his application for determination of tariff:*
>
> *Provided further that where the sum total of the direct and indirect costs of such Other Business exceeds the revenues from such Other Business, no amount shall be allowed to be added to the Aggregate Revenue Requirement of the Transmission Licensee on account of such Other Business."*

Further, the provisions GERC MYT Regulations, 2016 have also been compared with the corresponding provisions of other States, which is summarized as follows:

*Table 11: Provisions for Income from Other business for Transmission Licensees adopted by ERCs*

| ERC | Provisions |
|---|---|
| **Gujarat**<br>**Maharashtra** | • Two-third of Revenue net of direct and indirect costs attributed to Other Business deducted from ARR<br>• If the Cost of such other business exceeds Revenue from such other business, , no amount to be added to ARR on account of such business<br>• Licensee to submit audited and certified allocation statement for allocation of all joint and common costs between the Transmission Business and the Other Business |
| **Rajasthan** | • Revenue from other business shall be treated as income to the extent authorized by the Commission |

| ERC | Provisions |
| --- | --- |
| **Punjab** | • License may engage in any other business, with prior intimation to the Commission<br>• Considered as NTI |
| **Himachal Pradesh** | • The income from such business will be calculated in accordance with the Himachal Pradesh Electricity Regulatory Commission (Treatment of Income of Other Businesses of Transmission Licensees and Distribution Licensees) Regulations, 2005 and shall be deducted from the aggregate revenue requirement in calculating the revenue requirement of the transmission licensee |
| **Delhi** | • The net income after tax from Other Business shall be adjusted in the ARR.<br>• Loss on account of other business shall not be considered |
| **Uttarakhand** | • The net income after tax from Other Business shall be adjusted in the ARR |
| **Madhya Pradesh** | • Considered as Non-Tariff Income |
| **Karnataka** | • Income from Other Business shall be adjusted in the ARR |

In order to promote maximum utilization of resources and gain additional income for the Transmission Licensee, separate Regulations may be notified for dealing with Income from Other Business.

**Comments and suggestions are sought from the stakeholders on notifying separate regulations for Income from other business for Transmission utility.**

## 4.5. Development of Intra-State Transmission projects under TBCB

National Electricity Policy, 2005 encourages private investment and their partnership in power sector including in Transmission sector to meet the need of rapidly growing sector. Clause 5.3.10 and 5.8.9 of the said policy is relevant which is reproduced as below:-

> *"5.3.10 Special mechanisms would be created to encourage private investment in transmission sector so that sufficient investments are made for achieving the objective of demand to be fully met by 2012.*
>
> *….*
>
> *5.8.9 Role of private participation in generation, transmission and distribution would become increasingly critical in view of the rapidly growing investment needs to develop workable and successful models for public private partnership. This would also enable leveraging private investment with the public sector finances. Mechanisms for continuous dialogue with industry for streamlining procedures for encouraging private participation in power sector need to be put in place."*

The Tariff Policy notified on 28th January, 2016 inter-alia states that –

*"5.3 The tariff of all new generation and transmission projects of company owned or controlled by the Central Government shall continue to be determined on the basis of competitive bidding as per the Tariff Policy notified on 6thJanuary, 2006 unless otherwise specified by the Central Government on case to case basis.*

*Further, intra-state transmission projects shall be developed by State Government through competitive bidding process for projects costing above a threshold limit which shall be decided by the SERCs."*

Recently, Hon'ble Supreme Court through its judgement dated 23rd November 2022 in the Civil Appeal No. 1933 of 2022 directed that-

*"130. ………."We are cognizant of the fact that in matters dealing with electricity regulation, the regulatory commissions and the transmission utilities are usually bogged down by factors such as technological uncertainty, requirement of heavy investment and issues of right of way. The ad-hoc functioning of the transmission utilities is also attributable to the lacunae in the regulations guiding the exercise of their functions. The Electricity Act 2003 was enacted with the objective of providing the States with sufficient flexibility to regulate the intra-state electricity system and simultaneously provided the regulatory commissions with the power to determine tariffs. Though the Government, both at the Centre and in the States, have framed statutory policies and guidelines regulating the electricity sector, we have noticed that the Regulatory Commissions have not framed the necessary regulations to put into effect the principles prescribed under the Act.*

*131. We direct all State Regulatory Commissions to frame Regulations under Section 181 of the Act on the terms and conditions for determination of tariff within three months from the date of this judgment. While framing these guidelines on determination of tariff, the Appropriate Commission shall be guided by the principles prescribed in Section 61, which also includes the NEP and NTP. Where the Appropriate Commission(s) has already framed regulations, they shall be amended to include provisions on the criteria for choosing the modalities to determine the tariff, in case they have not been already included. The Commissions while being guided by the principles contained in Section 61 shall effectuate a balance that would create a sustainable model of electricity regulation in the States. The Regulatory Commission shall curate to the specific needs of the State while framing these regulations. Further, the regulations framed must be in consonance with the objective of the Electricity Act 2003, which is to enhance the investment of private stakeholders in the electricity regulatory sector so as to create a sustainable and effective system of tariff determination that is cost efficient so that such benefits percolate to the end consumers."*

In view to above, GERC vide its Order in Suo Moto Petition No. 2171 of 2023, dated 07.03.2023 has notified Threshold limit of Rs. 100 Crore (excluding land cost) for all new and augmentation of Intra-State Transmission projects developed through Tariff Based Competitive Bidding (TBCB).

Further, it is observed that SERCs like Maharashtra, Bihar and Himachal Pradesh have complied with the above-mentioned Hon'ble Supreme Court's judgment for fixing the said threshold limit for development of Intra-State Transmission projects under Tariff Based Competitive Bidding, through amending their respective MYT Regulations. Accordingly, it is proposed to incorporate the threshold limit in the capital expenditure approval guideline, for further clarity in the matter.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

## 4.6. Incentive

GERC MYT Regulations, 2016 provides for computation of incentive based on Annual Transmission Charges on achieving higher transmission availability over target availability. It is proposed to link the incentive to the RoE component in the form of a higher rate of return instead of the entire Annual Transmission Charges of the Transmission Licensee.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

# 5. SLDC

## 5.1. Incorporating SLDC as a separate Entity from Transmission Licensee

Section 31 (1) and 31(2) of the Electricity Act, 2003, state as follows:

> *"**Section 31. (Constitution of State Load Despatch Centres):** --- (1) The State Government shall establish a Centre to be known as the State Load Despatch Centre for the purposes of exercising the powers and discharging the functions under this Part.*
>
> *(2) The State Load Despatch Centre shall be operated by a Government company or any authority or corporation established or constituted by or under any State Act, as may be notified by the State Government:*
>
> *Provided that until a Government company or any authority or corporation is notified by the State Government, the State Transmission Utility shall operate the State Load Despatch Centre:*
>
> *Provided further that no State Load Despatch Centre shall engage in the business of trading in electricity."*

The above sections require the State Government to establish a separate State Load Dispatch Centre (SLDC) and provides that the SLDC shall be operated by a Government company / authority / corporation constituted under any State Act and until such company / authority / corporation is notified by the State Government, the State Transmission Utility (STU) would operate the SLDC. Accordingly, in the State of Gujarat, the STU, viz., Gujarat Energy Transmission Corporation Limited (GETCO), has so far been operating the SLDC. Accordingly, separation of SLDC as an entity from the STU is recommended. Till the same is done, there may be some dis-incentivization on the rate of RoE component of the Transmission Licensee and SLDC.

**Comments and suggestions are invited from the stakeholders on the above option.**

## 5.2. Capital Investment Plan

According to the GERC MYT Regulations, 2016, the Regulations regarding the Capital Investment Plan states as follows:

> *"78.1 The SLDC shall submit a detailed capital investment plan, financing plan and physical targets for each year to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period."*

As per the MERC MYT Tariff Regulations, 2019, the Regulations regarding the Capital Investment Plan states as follows:

*"**74 Capital Investment Plan***

*…*

*74.2 The Capital Investment Plan shall be a least cost plan for undertaking investments and shall cover all capital expenditure projects of a value exceeding Rs. Ten Crore or such other amount as may be stipulated by the Commission from time to time and shall be in such form as may be stipulated by the Commission from time to time:*

*Provided that the limit shall be Rs. One crore for Deemed Distribution Licensees.*

*74.3 The Capital Investment Plan shall be accompanied by such information, particulars and documents as may be required including but not limited to the information such as number of distribution sub-stations, consumer sub-stations, transformation capacity in MVA and details of distribution transformers of different capacities, HT:LT ratio as well as distribution line length showing the need for the proposed investments, alternatives considered, cost-benefit analysis and other aspects that may have a bearing on the Wheeling Charges:*

*Provided that the Distribution Licensee shall submit separate details of Capital Investment being undertaken in each Distribution Franchisee area within its Licence area.*

*74.4 The Commission shall consider the Capital Investment Plan along with the Multi-Year Aggregate Revenue Requirement for the entire Control Period submitted by the Distribution Licensee taking into consideration the prudence of the proposed expenditure and estimated impact on Wheeling Charges.*

*74.5 The Distribution Licensee shall submit, along with the Petition for determination of Wheeling Charges, or along with the Petition for Mid-term Performance Review, as the case may be, details showing the progress of capital expenditure projects, together with such other information, particulars or documents as the Commission may require to assess such progress."*

It is proposed that GERC introduces this investment plan in MYT Regulations for the next control period.

According to the CABIL report published in December 2018, the SLDCs get a large amount of money approved for projects but they don't utilize it in the control period that it was approved for. It is proposed that the SLDCs utilize the capital approved with in the period. In case of not meeting a certain threshold percentage of capex approval, SLDC may be penalised through reduction in the rate of RoE component.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

## 5.3. Norms of Working Capital for SLDC Business

The GERC MYT Tariff Regulations, 2016 stipulate the following norms of working capital for Transmission Licensee:

*"**40 Interest on Working Capital***

***…***

*40.3 SLDC:*

*(a) The SLDC shall be allowed interest on the estimated level of working capital for the financial year, computed as follows:*

*(i) Operation and maintenance expenses for one month; plus*

*(ii) Maintenance spares at one (1) per cent of the historical cost; plus*

*(iii) Receivables equivalent to 15 days of the expected revenue from SLDC Charges;*

*Provided that at the time of truing up for any year, the working capital requirement shall be re-calculated on the basis of the values of components of working capital approved by the Commission in the truing up;*

*….."*

Further, the working capital norms as per provisions GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 12:Norms of Working Capital for SLDC Business adopted by ERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| **Gujarat** | 1 month | 1% of Historical Cost (GFA) | 15 days of Receivables of the expected revenue from SLDC charges |
| **Maharashtra** | 1 month | Nil | 1½ month of the expected revenue from levy of annual fixed charges approved by the Commission |
| **Rajasthan** | 1 month | 15% of O&M expenses | 1½ month of transmission charges calculated on annual target availability level for transmission licensee<br>Minus<br>Security Deposits from Users other than those in the form of Bank Guarantees<br>(same for transmission and SLDC) |
| **Punjab** | 1 month | 15% of O&M expenses | 2 months of Receivables calculated on normative target availability |

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| | | | (same for transmission and SLDC) |
| **Himachal Pradesh** | 1 month | 15% of O&M expenses for one month | 2 months Receivables towards SLDC Charges |
| **Delhi** | NA | NA | NA |
| **Uttarakhand** | 1 month | 15% of O&M expenses | 2 months Receivables |
| **Madhya Pradesh** | NA | NA | NA |
| **Karnataka** | NA | NA | NA |

The above comparison shows that GERC's existing working capital norms are already quite stringent as compared to other ERCs.

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed. Further, existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the generating stations.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

# 6. Distribution

## 6.1. Common Points

### 6.1.1. Separation of Accounts of Distribution Licensee

Section 62 of the Electricity Act, 2003 requires determination of tariff for wheeling of electricity and retail sale of electricity separately by the SERCs. Further, in case of open access is allowed under Section 42 of the Electricity Act, 2003, the SERCs determines wheeling charges and surcharge (cross-subsidy surcharge and additional surcharge), whereas captive consumers under Section 9 of the Electricity Act, 2003, are required to pay wheeling charges for availing open access and are exempted from payment of surcharge (cross-subsidy surcharge and additional surcharge).

The Tariff Policy, 2016 stipulates the following regarding benefits of introducing competition into the market wherever there is no natural monopoly:

> *"5.9 The real benefits of competition would be available only with the emergence of appropriate market conditions. Shortages of power supply will need to be overcome. Multiple players will enhance the quality of service through competition. All efforts will need to be made to bring power industry to this situation as early as possible in the overall interests of consumers. Transmission and distribution, i.e. the wires business is internationally recognized as having the characteristics of a natural monopoly where there are inherent difficulties in going beyond regulated returns on the basis of scrutiny of costs."*

As the distribution wires business is a natural monopoly, separating it from the retail supply of electricity is a pre-requisite to introduce completion in the retail supply market.

Regulation 87 of the GERC MYT Regulations, 2016 provides that the Wheeling Charges of the Distribution Licensee shall be determined by the Commission on the basis of segregated accounts of Distribution Wires Business. However, till audited and certified separate accounts for Distribution Wires Business and Retail Supply Business are not available, it provides for an 'Allocation Matrix' for segregation of expenses between the Wire Business and Retail Supply Business of the Distribution Licensee. Further, it is also stated that the wheeling charges of the Distribution Licensee shall be determined by the Commission on the basis of segregated accounts of Distribution Wires Business, once the Regulations for submission of Regulatory Accounts are notified.

It is observed that despite the continued emphasis of the Commission on separation of the accounting of wires related costs and supply related costs, which is required to move towards greater competition in the retail supply business, as well as determination of true wheeling charges, there is little or no initiative by the Distribution Licensees for segregation of expenses between the Wire Business and Retail Supply Business. One of the possible reasons for this lack of initiative may be due to the fact that the Commission has been providing the 'Allocation Matrix' in its MYT Regulations and not insisting on the time-bound segregation of accounts of Distribution Licensee between Wires Business and Retail Supply Business.

Therefore, while proposing to continue with an 'Allocation Matrix' for the new Control Period, so as to avoid a void, following time-bound action is proposed:

a) Commission to issue guidelines for segregation of accounts of Distribution Licensee between Wires Business and Retail Supply Business in next 6 months;

b) Distribution Licensees to undertake the preparatory work for segregate their accounts of Wires Business and Retail Supply Business in next 6 months;

c) Distribution Licensees to submit their respective audited and certified separate accounts for Distribution Wires Business and Retail Supply Business from the next financial year onwards, i.e. year 2 of the new MYT Control Period, which shall become the basis for determination of wheeling and retail supply ARRs and hence the determination of wheeling charges;

d) Distribution Licensees not able to provide audited and certified separate accounts for Distribution Wires Business and Retail Supply Business, shall continue to segregate the expenses of Distribution Business based on the 'Allocation Matrix' provided in the MYT Regulations. However, in such case, the rate of return on Equity shall be reduced to the base rate / reduced by 1.00% from the normal rate of return of Equity.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.1.2. O&M Expenses

While specifying the normative O&M expenses for the distribution wires business, one of the aspects to be considered is whether the normative O&M expenses should be specified in a consolidated manner or separately, as Employee expenses, A&G expenses, and Repair & Maintenance expenses. Both options have their merits and de-merits. If the O&M expenses are specified in a consolidated manner, the utility has the flexibility to manage its expenditure through own resources (which will increase the employee expenses) or through outsourcing (which will increase the A&G expenses), as appropriate. However, under this dispensation, the variation in the individual heads of Employee expenses, A&G expenses, and Repair & Maintenance expenses are difficult to track, and there are occasions when the Commission may wish to consider these separately, due to specific treatment to be given for pay revision, etc. Therefore, based on past experiences and after reviewing the best practices across states, it is proposed that O&M expenses shall be continued to be considered separately.

Regulation 86.2 of the GERC MYT Regulations, 2016 provides that the O&M expenses shall be derived on the basis of the average of the actual O&M expenses for the three (3) years ending March 31, 2015, which shall be considered as O&M expenses for FY 2013-14. Thereafter, this base O&M expenses shall be escalated by 5.72% per annum to arrive at the O&M expenses for the respective years.

It is observed that the existing practice takes into account only the historical O&M expenses of the utility and the year-on-year escalation factor. There is no consideration of increase in no. of employees, network expansion or increase in GFA base, compliance of new age regulations to meet Standards of Performance, Rights of Consumer Rules, etc. Further, the escalation of O&M expense at fixed rate of 5.72%, doesn't account for any efficiency factors to promote economic O&M practices and new technology adoption by the Distribution Licensee.

Accordingly, based on the review of best practices adopted by other SERCs and also Central Electricity Authority's 'Report on Benchmarking of O&M Practices & O&M Expenses of Distribution Utilities', published in 2022, it is proposed to adopt the following approach for allowing O&M expenses.

The O&M expenses may be derived on the basis of the average of the Trued-Up values (without efficiency gain / loss, if any) or based on audited accounts for the last five (5) financial years, subject to prudence check by the Commission. This average figure may be considered as O&M expenses for the middle year and may be escalated with year on year basis with suitable escalation factor based on CPI and WPI of the respective financial years. Further, one-time expenses such as expense due to change in accounting policy, arrears paid due to Pay Commissions, etc., and the expenses beyond the control of the Distribution Licensee such as salary arrears, terminal benefits, etc., in employee cost, may be allowed by the Commission over and above normative O&M expenses after prudence check. The O&M expenses for the nth year of the Control Period shall be approved based on the formula given below:

$$\mathbf{O\&M_n = (R\&M_n + EMP_n + A\&G_n) \times (1 - X_n) + \text{Terminal Liabilities and other one-time expenses}}$$

Where,

$\mathbf{R\&M_n} = K \times GFA_{n-1} \times (Indx_n / Indx_{n-1})$

$\mathbf{EMP_n} = (EMP_{n-1}) \times (1+G_n) \times (Indx_n / Indx_{n-1})$

$\mathbf{A\&G_n} = (A\&G_{n-1}) \times (Indx_n / Indx_{n-1})$

**'K'** is a constant (expressed in %). Value of K for each Year of the Control Period shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking of repair and maintenance expenses, approved repair and maintenance expenses vis-à-vis GFA approved by the Commission in past and any other factor considered appropriate by the Commission;

**$INDX_n$** – Inflation factor to be used for indexing may be a combination of the Consumer Price Index (CPI) and the Wholesale Price Index (WPI) for immediately preceding year before the base year;

**EMPn** – Employee expenses of the Distribution Licensee for the nth Year;

**$A\&G_n$** – Administrative and General expenses of the Distribution Licensee for the nth Year;

**$R\&M_n$** – Repair and Maintenance expenses of the Distribution Licensee for the nth Year;

**$GFA_{n-1}$** – Gross Fixed Asset of the Distribution Licensee for the n-1th Year;

**Gn** is a growth factor for the nth Year. Value of $G_n$ shall be determined by the Commission in the MYT tariff order for meeting the additional manpower requirement based on Licensee's filings, benchmarking, approved cost by the Commission in past and any other factor that the Commission feels appropriate.

**$X_n$** is an efficiency factor for nth Year. Value of $X_n$ shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking, approved cost by the Commission in past and any other factor the Commission feels appropriate;

For the purpose of estimation, the same $INDX_n/INDX_{n-1}$ value may be used for all years in MYT by the Commission. However, the Commission may consider the actual values in the $INDX_n/INDX_{n-1}$ during the true up of the O&M expenses for the respective years of the Control Period.

Terminal Liabilities may be approved as per actual submitted by the Distribution Licensee along with documentary evidence and other documents as desired by the Commission.

The Distribution Licensee, in addition to the above details shall also submit the detailed break-up of the Legal/Litigation Expenses for the previous Years along with the details and documentary evidence of incurring such expenses. The Commission may approve the legal expenses based on the necessary documentary evidence submitted by the Distribution Licensee. The Commission may also carry out due prudence check of legal expenses at the time of truing up.

Further, based on the detailed submissions by the Distribution Licensee, the Commission may consider allowing certain specified expenses like smart meters, etc. on actual basis beyond normative O&M expenses, which are not part of the historical O&M expenses and thus couldn't have been included in the norms. However, in such cases the Commission will also appropriately incorporate the efficiency gains on account of such expenses either in the O&M expenses formulae or other performance parameters. Initially, the efficiency factor, Xn may be considered as 1, which may be subsequently determined based on a separate detailed study at the time of mid-term review of the MYT Control Period.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 6.2. Distribution Wire Business

### 6.2.1. Wheeling Losses - Distribution Loss vs. AT&C loss

Electricity losses in a distribution system occur mainly on two accounts:

- **Technical Losses:** The cumulative energy consumed by all the elements in a power system (line, transformer, etc.) due to energy dissipated on account of resistance to power flow is classified as "**technical losses**".
- **Commercial Losses:** Losses that occur on account of non-performing and under-performing meters, wrong application of multiplying factors, defects in CT and PT circuitry, meters not read, pilferage by manipulating or by-passing of meters, theft by direct tapping, etc., correspond to energy consumed but not metered or billed and are hence, categorised as "c**ommercial losses**".

The combined "Technical" and "Commercial" losses in the electricity distribution business is termed as **Distribution loss**.

In addition to the above, there is also a loss in revenue collected due to collection inefficiency or non-realisation of billed amount. The aggregate of distribution loss and revenue loss due to non-realisation (collection inefficiency) is termed as "**AT&C loss**" (Aggregate Technical and Commercial loss). Therefore, AT&C loss of the distribution licensee is the combination of technical losses, commercial losses and collection inefficiency.

Since the beginning of the reform process, distribution loss reduction has been one of the primary benchmarks for measuring the performance of a distribution utility. The SERCs have either adopted distribution losses reduction or AT&C loss reduction approach as a performance benchmark.

Distribution loss reduction is a widely used approach at the national and international level to measure the performance of the distribution licensee. Distribution loss is simple to compute as it takes into account the energy input and energy billed to the consumers, thereby taking into consideration the technical losses and unaccounted energy due to theft and misuse. However, in many cases, the actual distribution losses are estimated to be higher than the reported losses, on account of the assessment of un-metered agricultural consumption. Thus, distribution loss method has certain limitations, particularly in case of significant un-metered consumption.

On the other hand, AT&C loss method covers the whole basket of losses of the distribution system and includes technical losses, billing inefficiency, theft, and collection inefficiency. If units sold, units billed and units collected can be computed accurately, then AT&C loss method would be the best indicator of measuring the efficiency of the distribution licensee. However, computation of AT&C losses leads to creation of complexities as it combines technical and commercial parameters, i.e., energy input in units and amount collected in Rupees. Some other issues in AT&C loss computation are as follows:

- Units realised have to be derived based on units billed and collection efficiency
- Units billed may not be measured accurately due to un-metered consumption, thus having the same drawback as distribution loss method
- Revenue collected may include the past arrears
- Amount collected against other charges may not be separately accounted for
- If AT&C loss computation is attempted on cash basis alone (total amount collected/total amount spent), it can lead to distorted results.

Considering the high commercial losses in the Indian power system, the Tariff Policy framed under Section 3 of Electricity Act 2003 has favoured the adoption of the AT&C loss method, as reproduced below:

> *"5(a) The State Commission may consider 'distribution margin' as basis for allowing returns in distribution business at an appropriate time. The Forum of Regulators should evolve a comprehensive approach on "distribution margin" within one year.* ***The considerations while preparing such an approach would, inter-alia, include issues such as reduction in Aggregate Technical and Commercial losses****, improving the standards of performance and reduction in cost of supply."* ***(Emphasis added)***

However, till date, only few SERCs like Delhi Electricity Regulatory Commission have adopted the AT&C loss approach for approving the ARR and tariff of distribution licensees. Relevant extract of DERC (Business Plan) Regulation, 2023 is as bellow:

> ***"26. TARGET FOR COLLECTION EFFICIENCY:***
>
> *(1) The targets for Collection Efficiency for FY 2023-24 to FY 2025-26 of the Distribution Licensee shall be 99.80%.*

*(2) The financial impact on account of Collection Efficiency target shall be computed as per the formula specified in Regulation 163 of the DERC (Terms and Conditions for Determination of Tariff) Regulations, 2017 as amended from time to time for the Distribution Licensee.*

*(3) The financial impact on account of over-achievement in terms of Regulation 164 of the DERC (Terms and Conditions for Determination of Tariff) Regulations, 2017 as amended from time to time, for the Distribution Licensee, from the target of 99.80% to 100% shall be shared equally between Consumers and the Distribution Licensees.*

*Provided that there shall be no penalty for Collection Efficiency if the same is in range of 99.50% to 99.80%."*

The Orissa Electricity Regulatory Commission has considered AT&C Loss trajectory for tariff determination, in line with its Vesting Orders issued w.r.t sale of erstwhile Distribution Utilities under Section 20 of the Electricity Act, 2003 and for vesting of Utilities to the intending purchasers under Section 21 of the Electricity Act, 2003.Relevant extract of OERC MYT Regulation, 2022 is as under:

*"3.14.1. The Commission shall consider the* ***AT&C loss reduction trajectory for tariff determination as provided in Annexure III of these Regulations as per the terms of the Vesting Orders. The Distribution Licensees would be entitled to retain any additional gains resulting from its meeting and surpassing the AT&C loss targets****. This would be over and above the return on equity allowed by the Commission as part of these Regulations and shall not be adjusted as other income or in any way appropriated through any truing up process or future Aggregate Revenue Requirement process."*

Further, it is not prudent to burden consumers who are paying bill on time for the licensees' inability to collect the billed amounts from certain consumers. Further, the inclusion of collection inefficiency by determining the tariffs on the basis of AT&C loss will result in further increase in the consumers' tariff, if collection efficiency is less than 100%. Considering this aspect and in view of issues discussed above, **it is proposed to continue with Distribution Loss approach for approving the ARR and tariff of Distribution Licensees in the State, with the trajectory of distribution loss being stipulated in the multi-year tariff order rather than being specified in the Regulations.**

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.2.2. Norms of Working Capital for Distribution Wires Business

All SERCs use a standard formula as norm for determination of working capital requirement, wherein O&M expenses as well as cost of maintenance spares is allowed, in addition to the receivables less

Security Deposit held by the Utility in cash. Regarding inclusion of one month of O&M expenses as a part of the working capital requirement, as O&M expenses incurred for a given month are recoverable along with the tariff in the next month, the same needs to be a part of working capital. In addition, exclusion of the same may also have impact on the liquidity position of the utilities.

Further, the working capital norms as per provisions GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 13: Norms of Working Capital for Distribution Wires Business adopted by SERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| **Gujarat** | 1 month | 1% of Historical Cost (GFA) | 1 month of the expected revenue from charges for use of Distribution Wires<br>Minus<br>Security Deposits other than those in the form of Bank Guarantees |
| **Maharashtra** | 1 month | 1% of opening GFA | 1½ month of the expected revenue from charges for use of Distribution Wires<br>Minus<br>Amount held as security deposits in cash from Distribution System Users |
| **Rajasthan** | 1 month | 15% of O&M expenses | 1½ month of billing of consumers<br>Minus<br>Security Deposits from Distribution System Users other than those in the form of Bank Guarantees<br>(same for wheeling and retail supply) |
| **Punjab** | 1 month | 15% of O&M expenses | 2 months of the expected revenue from charges for use of Distribution Wires<br>Minus<br>Security Deposits from Distribution System Users |
| **Himachal Pradesh** | 1 month | 15% of O&M expenses for one month (excluding provisions, arrears, terminal benefits) | 2 months of the Wheeling Charges<br>Minus<br>Security Deposits from Distribution System Users |
| **Delhi** | NA | NA | 2 months of Wheeling Charges |
| **Uttarakhand** | 1 month | 15% of O&M expenses | 2 months of the expected revenue from sale of electricity<br>Plus<br>Capital required to fiancé such shortfall in collection of current dues as may be allowed by the Commission<br>Minus<br>One month of power purchase cost based on annual power procurement plan |

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| **Madhya Pradesh** | 1 month | 1% of opening GFA | Nil |
| **Karnataka** | 1 month | 1% of opening GFA | 2 months of average revenue |

The above comparison shows that GERC's existing working capital norms are already quite stringent as compared to other ERCs.

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed. Further, the existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the Distribution Licensees.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.2.3. Reliability of Supply

National Tariff Policy (NTP), 2016 stipulates that the SERCs shall devise a specific trajectory so that 24 hours supply of adequate and uninterrupted power can be ensured to all categories of consumers by FY 2021-22 or earlier depending upon the prevailing situation in the State.

Further, Rule 10 of Electricity (Rights of Consumers) Rules, 2020 specifies that the distribution licensee shall supply 24x7 power to all consumers, with exception some categories of consumers like agriculture. Further, following guidelines has been issued in this regard:

> *"(2) The **distribution licensee shall put in place a mechanism, preferably with automated tools** to the extent possible, for monitoring and restoring outages.*
>
> *(3) In view of the increasing pollution level particularly in the metros and the cities with a population 100,000 and above, **the distribution licensee shall ensure 24x7 uninterrupted power supply to all the consumers, so that there is no requirement of running the diesel generator sets and accordingly, the State Commission shall give trajectory of system average interruption frequency index and system average interruption duration index for such cities**.*

*(4) The* ***State Commission may consider the customer average interruption duration index, customer average interruption frequency index and momentary average interruption frequency index as additional indicators of reliability of supply and the minimum interruption time for calculation of additional reliability indicators shall be as specified by the State Commission and in case the interruption time is not specified by the State Commission****, three minutes shall be considered as interruption time for calculating the additional reliability indicators.*

*(5) The* ***State Commission shall have an online mechanism for reviewing and monitoring of reliability indices of distribution licensees*** *and such Commission may consider a separate reliability charge for the distribution company, if they require funds for investment in the infrastructure for ensuring the reliability of supply to the consumers." {Emphasis added}*

MERC in its MYT Regulation, 2019 had defined target wires availability, and introduced incentive mechanism linked additional RoE for overachievement of Target availability.

In view of above, its proposed to specify trajectory for the Reliability Index (such as SAIDI, SAIFI, CAIDI, CAIFI and MAFIFI) for Distribution Licensee and further device an incentive mechanism linked to wire availability and reliable supply, which is to be derived on the basis of the interruption in the power availability.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.2.4. Pre-Payment / Smart Metering

The Ministry of Power (MoP), Government of India, has launched Revamped Distribution Sector Scheme (RDSS) for the period from FY 2021-22 to FY 2025-26. Part A, Component I of the scheme covers prepaid/smart metering for consumers and system metering at Distribution Transformer at feeder level with Communication feature etc. Under scheme MoP has sanctioned 16,481,871 number of smart prepaid consumer meters to be installed in Gujarat.

Further, regarding Pre-paid metering Clause 5 of Electricity (Rights of Consumers) Rules, 2020 specifies as follows:

*"Metering – (1)* ***No connection shall be given without a meter and such meter shall be the smart prepayment meter or pre-payment meter****. Any exception to the smart meter or prepayment meter shall have to be duly approved by the Commission. The Commission, while doing so, shall record proper justification for allowing the deviation from installation of the smart pre-payment meter or prepayment meter."*

In view of above, it is proposed to specify the category-wise trajectory for smart pre-paid metering, at time of approval of Tariff in MYT Order. Based on achievement of Target, Distribution licensee may be incentivized or penalised.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.2.5. R&M Expenses

R&M expenses are incurred towards the day-to-day upkeep of the distribution network and form an integral part of the efforts towards reliable and quality power supply as also in the reduction of losses in the distribution system.

In order to encourage distribution licensee to perform adequate R&M activity in their area, MPERC in MPERC MYT Regulation, 2021, allows additional Return on Equity based on R&M expense incurred during the Financial Year. Under this mechanism additional RoE is allowed to the distribution licensee for achieving 95% of approved R&M Expenses. Accordingly, similar incentive mechanism is proposed to adopt in next control period to encourage licensee to opt for efficient operating techniques.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 6.3. Distribution (Retail Supply Business)

### 6.3.1. Sales and Demand Forecast

Electricity sales forecast is an indispensable part of ARR projection, since it assists distribution licensee in anticipating revenue inflow, formulate capital investment planning as well as economic power purchase planning. Therefore, in order to ensure economic operation of distribution licensee, there is a need of reliable sales forecast methodology and tolls. At the same time, it is also important to note that the very nature of business is such that uncontrollable factors like weather, growth in consumer load/number on account of Government policies, economic conditions of supply area, open-access consumers, etc. could significantly affect the demand forecasts.

GERC MYT Regulations, 2016 provides for submission of category / sub-category / slab-wise sales forecast based on the past data and reasonable assumptions regarding the future. Further, GERC has also framed guidelines for procurement of power by the Distribution Licensees in 2013, which provides as follows:

> *"3. Every year by 31st January, the Distribution licensees shall submit power procurement plan for 5 years which will include:*
>
> *a. Peak load and energy forecasts of their respective license areas for each of the successive 10 years. The peak load and energy forecasts shall be made for the overall Area of Supply.*

*b. Anticipated power supply position for each of the successive five years along with the projections for additional requirement of procurement of power, if any.*

*c. Hourly load duration projection for each of the successive 5 years."*

Recently in April 2023, the Central Electricity Authority (CEA) has published draft "Guidelines for Medium and Long Term Power Demand Forecast", with an objective to serve as a guiding document for power utilities to bring uniformity in their power demand forecast approach. The draft guidelines are summarized as follows:

- Forecast to be prepared for medium term (1 to 5 years) and long term (at least for next 10 years), which should be reviewed and updated on yearly basis;
- Apart from forecast at Discom and yearly levels, attempts should be made for granular forecast to facilitate power infrastructure planning
    - Spatial - zonal/circle/district/sub-station/transformer level
    - Time – month-wise/day-wise/hour-wise/time-block wise
- Forecast should be carried out for at least three scenarios – Optimistic scenario, Business As Usual (BAU) scenario & Pessimistic scenario, duly taking into consideration the extreme weather parameters, business cycle, impact of emerging aspects, etc. Advanced statistical tools like Multivariate Regression Analysis should also be used for this purpose.
- The power demand forecast should be done under the unrestricted scenario which essentially is reflective of the case when all the unserved demand currently not served by the utilities due to various supply side barriers such as generation & network constraints (resulting in planned load shedding and unplanned outages) is also included.
- Forecasting method should aim at analysing past consumption data of each category separately and factoring in impacts of emerging aspects to arrive at appropriate future growth trends. CEA has suggested use of Partial End Use Method (PEUM), which is used for carrying out Electric Power Survey (EPS) exercises.
- The forecasting results obtained should be validated through at least one different method, say Econometric Method.

Most of the SERCs, in their MYT Regulations, require the Distribution Licensee to submit its yearly (in some cases monthly) sales forecast in MU terms for the MYT control period, based on past data and reasonable assumptions and have not specified any approach or methodology for the same. However, in the wake of its Guidelines for procurement of power by the Distribution Licensees and also above-mentioned CEA guidelines, the it is proposed to introduce a comprehensive approach for Sales (MU) and Demand (MW) forecasts based on load research studies, advance statistical methods including PEUM and econometric methods, and exploring use of various IT tools, including Artificial Intelligence and Machine Learning (AI/ML) to improve accuracy in forecasting and planning, in the new MYT Regulations.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 6.3.2. Power Procurement Guidelines

Various provisions of the Electricity Act, 2003 provides for regulating purchase of electricity by the distribution licensee. Sections 42 and 43 of the Electricity Act, 2003 cast a duty upon the Distribution Licensee to ensure electricity supply to the consumers within its license area on request. Section 86 (1) (b) of the Electricity Act, 2003, envisages the SERC to regulate the electricity purchase and procurement process of distribution licensees including the price at which electricity shall be procured from various sources.

Power purchase cost accounts for approximately 70%-80% of the total cost of the retail supply business and therefore, the power procurement plan is amongst the most vital aspect of distribution retail supply plan. Therefore, the SERC need to ensure transparent, economic and optimal procurement of power by the Distribution Licensee for sale to its consumers. GERC MYT Regulations, 2016 provides for power procurement as follows:

> *"19.4 The Distribution Licensee shall project the power purchase requirement based on the Merit Order Despatch principles of all Generating Stations considered for power purchase, the Quantum of Renewable Purchase Obligation (RPO) under Regulation 4 of Gujarat Electricity Regulatory Commission (Procurement of Energy from Renewable Sources) (First Amendment) Regulations, 2014 and the target set, if any, for Energy Efficiency (EE) and Demand Side Management (DSM) schemes.*
>
> *….*
>
> *94.5.1 The Distribution Licensee shall be allowed to recover the cost of power generated by the Generation Business or purchased from approved sources for supply to consumers based on the power procurement plan of the Distribution Licensee, approved by the Commission."*

Further, GERC has also framed guidelines for procurement of power by the Distribution Licensees in 2013, which provides as follows:

> *"4. Distribution Licensees shall have long-term / medium-term tie up to meet load requirement of at least 75% duration of the fifth year. In case of any shortfall to meet load requirement of 75% of duration of the fifth year through long-term / medium term arrangement, the Distribution Licensee shall initiate the process of long-term procurement of power.*

*5. Distribution Licensees shall have long-term / medium-term tie up to meet load requirement of at least 85% of duration of the third year. In case of any shortfall to meet load requirement of 85% of duration of the third year through long-term / medium-term arrangement, the Distribution Licensee shall initiate the process of medium-term procurement of power.*

*6. The Distribution Licensee shall normally endeavour to procure power through competitive bidding. In case of any proposal for procurement of power through MoU route, the Distribution Licensee shall obtain prior approval of the GERC.*

*7. In case of procurement of power through competitive bidding, the Distribution Licensees shall initiate the process for long-term / medium-term power procurement in accordance with the Ministry of Power's 'Guidelines for Determination of Tariff by Bidding Process for Procurement of Power by Distribution Licensees' notified by the Ministry of Power on 19/01/2005 and in force from time to time…*

*….*

*13. Where the Distribution Licensee is to procure power on a short-term basis or there is a shortfall due to any reason whatsoever, or failure in the supply of electricity from any approved source of supply during the year, for any reason whatsoever, the licensee may enter into a short-term arrangement or agreement for procurement of power through power exchanges or through a transparent process of open tendering and competitive bidding.*

*14. In case of procurement of power through competitive bidding, the Distribution Licensees shall initiate the process for short-term power procurement in accordance with the Ministry of Power's 'Guidelines for Short-Term Procurement of Power by Distribution Licensees through Tariff based bidding process' notified by the Ministry of Power on 15/05/2012 and in force from time to time….*

*….*

*17. The GERC may permit any Distribution Licensee to make purchase of power without requiring that such purchase be subject to Competitive/Open Process in the event of an unforeseen and an exceptional situation. However, the Distribution Licensee shall not, thereby, be exempted from demonstrating the need and the reason for departure from a competitive process together with the economic justification for the purchase, the means, whereby, in the absence of competition, the Distribution Licensee proposes to secure the best possible terms and such other information as the GERC may require."*

Resource Adequacy has attained a center stage in the power procurement planning. The Electricity (Amendment) Rules, 2022 notified by the Ministry of Power, Government of India, provided that the

Central Government, in consultation with Central Electricity Authority will issue Resource Adequacy Guidelines for assessment of resource adequacy during the generation planning stage (one year or beyond) as well as during the operational planning stage (up to one year). It also provided that the SERC shall frame regulations on resource adequacy, based on which the distribution licensees shall formulate the resource adequacy plan and seek approval of the SERC. Recently, the Ministry of Power, Government of India, in consultation with the Central Electricity Authority, has issued the 'Guidelines for Resource Adequacy Planning Framework for India' aiming to establish a Resource Adequacy framework for power procurement by distribution licensees, ensuring a reliable operation of the power system across all timeframes, by laying down the optimal capacity mix required to meet the projected demand at minimum cost.

In the said Guidelines, it is stated that the Distribution Licensees shall prepare its Long-term Discom Resource Adequacy Plan (LT-DRAP) for a 10 year horizon [Long-term Distribution Licensee Resource Adequacy Plan (LT-DRAP)], on an annual rolling basis, to meet their own peak and electrical energy requirement, which shall be vetted by CEA. The Distribution Licensees shall take inputs if required from the Long-term Discom Resource Adequacy Plan (LT-NRAP), Planning Reserve Margin (PRM), capacity credits, etc., while formulating their LT-DRAP and submit their plans to CEA by the month of September for the period starting from the month of April in the subsequent year. After being vetted by CEA, the plan LT-DRAP along with details for meeting the RAR of national peak for the utility may be submitted to SERC/JERC by the month of November for the period starting from the month of April in the subsequent year for their approval. The Guidelines also provides that the CERC in consultation with the Forum of Regulators (FOR) may come out with model regulations for implementing the resource adequacy process in the States/UTs and the distribution utilities.

The Resource Adequacies studies by the Distribution Licensees would require inputs regarding long-term demand projections, demand pattern, load growth estimates, RE generation profile, technical specification of base load generating stations (ramp rates, minimum technical load, heat rate, start-up cost, time, etc.), generation capacities (existing and planned), various costs parameters (capital cost, variable cost, O&M costs, start-up and shut-down costs, reserve offers) of the generators, historical forced outage rates and planned maintenance rates of generation capacities, tie line details and transmission expansion plans, RPO / HPO / Energy Storage obligation targets, spinning reserve and planning reserve margins, etc. Resource Adequacy would not only ensure quality, uninterrupted and cost effective power supply to consumers, but also facilitate optimal generation capacity development and utilization. It will also enable integration of variable RE generation, ensure system reliability and grid security.

Considering the amended Electricity Amendment Rules, 2022, and the Guidelines for Resource Adequacy Planning Framework issued by the Ministry of Power, it is proposed that the new MYT

Regulations to provide for developing Resource Adequacy Plan by the Distribution Licensees to determine the target generation capacities for meeting the forecasted energy demand over a specified future period.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.3.3. Fuel and Power Purchase Price Adjustment (FPPPA)

The Commission in its Order in Case No. 1309/2013 and 1313/2013 vide dated 29.10.2013, has revised the formula for Fuel Price and Power Purchase Price Adjustment (FPPPA) to recover the difference between actual power purchase cost and base power purchase cost approved by the Commission as follows:

**FPPPA = [(PPCA-PPCB)]/ [100-Loss in %]**

Where

**'PPCA'** is the average power purchase cost per unit of delivered energy (including transmission cost), computed based on the operational parameters approved by the Commission or principles laid down in the power purchase agreements in Rs./kWh for all the generation sources as approved by the Commission while determining ARR and who have supplied power in the given quarter and transmission charges as approved by the Commission for transmission network calculated as total power purchase cost billed in Rs. Million divided by the total quantum of power purchase in Million Units made during the quarter.

**'PPCB'** is the approved average base power purchase cost per unit of delivered energy (including transmission cost) for all the generating stations considered by the Commission for supplying power to the company in Rs./kWh and transmission charges as approved by the Commission calculated as the total power purchase cost approved by the Commission in Rs. Million divided by the total quantum of power purchase in Million Units considered by the Commission.

**'Loss in %'** is the weighted average of the approved level of Transmission and Distribution losses (%) for the four DISCOMs / GUVNL and TPL applicable for a particular quarter or actual weighted average in Transmission and Distribution losses (%) for four DISCOMs / GUVNL and TPL of the previous year for which true-up have been done by the Commission, whichever is lower.

The Commission in aforesaid Order has directed the Licensee to approach the Commission for the prior approval for any increase in FPPPA beyond ten paise per kWh in a quarter, along with computation of FPPPA charge. The Commission has also directed that the FPPPA calculations shall be submitted to the Commission within one month from the end of the relevant quarter and same has to be published in the Licensee's website.

Further, the recently notified Electricity (Amendment) Rules, 2022 by the Ministry of Power, Government of India, provide as follows:

> *"14.* ***Timely recovery of power purchase costs by distribution licensee.-****The Appropriate Commission shall within ninety days of publication of these rules, specify a price adjustment formula for recovery of the costs, arising on account of the variation in the price of fuel, or power purchase costs and the impact in the cost due to such variation shall be automatically passed through in the consumer tariff, on a monthly basis, using this formula and such monthly automatic adjustment shall be trued up on annual basis by the Appropriate Commission:*
>
> *Provided that till such a methodology and formula is specified by the Appropriate Commission, the methodology and formula specified in the Schedule – II annexed to these rules shall be applicable:*
>
> *Provided further that the existing methodology and the formula specified by the Appropriate Commission shall suitably be amended in accordance with these rules, to implement the automatic pass through of fuel and power purchase adjustment surcharge, on a monthly basis:*
>
> *Provided also that in case the distribution licensee fails to compute and charge fuel and power purchase adjustment surcharge within the time line, specified by the Appropriate Commission, except in case of any force majeure condition, its right for recovery of costs on account of fuel and power purchase adjustment surcharge shall be forfeited and in such cases, the right to recovery the fuel and power purchase adjustment surcharge determined during true-up shall also be forfeited and the true up of fuel and power purchase adjustment surcharge by the Appropriate Commission, for any financial Year, shall be completed by 30th June of the next financial year."*

In the wake of the abovesaid MoP Rules, it is proposed to include the said approach and the formula (mentioned in Annexure), in its new MYT Regulations.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.3.4. Norms of Working Capital for Distribution Retail Supply Business

All SERCs use a standard formula as norm for determination of working capital requirement, wherein O&M expenses as well as cost of maintenance spares is allowed, in addition to the receivables less Security Deposit held by the Utility in cash. Regarding inclusion of one month of O&M expenses as a part of the working capital requirement, as O&M expenses incurred for a given month are recoverable along with the tariff in the next month, the same needs to be a part of working capital. In addition, exclusion of the same may also have impact on the liquidity position of the utilities.

The GERC MYT Regulations, 2016 provides for computation of normative working capital requirement for the retail supply business as follows:

*"(i) Operation and maintenance expenses for one month; plus*

*(ii) Maintenance spares at one (1) per cent of the historical cost; plus*

*(iii) Receivables equivalent to one (1) month of the expected revenue from sale of electricity at the prevailing tariffs;*

*minus*

*Amount held as security deposits under clause (a) and clause (b) of sub-section (1) of Section 47 of the Act from consumers except the security deposits held in the form of Bank Guarantees:*

*……"*

Further, the working capital norms as per provisions GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 14: Norms of Working Capital for Distribution Retail Supply Business adopted by SERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| Gujarat | 1 month | 1% of Historical Cost (GFA) | 1 month of the expected revenue from sale of electricity at the prevailing tariffs<br>Minus<br>Security Deposits other than those in the form of Bank Guarantees |
| Maharashtra | 1 month | 1% of opening GFA | 1½ month of the expected revenue from sale of electricity at approved tariff for ensuing year including revenue from CSS and Additional Surcharge<br>Minus<br>• Amount held as security deposits in cash<br>One month of power purchase cost based on power procurement plan, including transmission and SLDC charges |
| Rajasthan | 1 month | 15% of O&M expenses | 1½ month of billing of consumers<br>Minus<br>Security Deposits from Distribution System Users other than those in the form of Bank Guarantees<br>(same for wheeling and retail supply) |
| Punjab | 1 month | 15% of O&M expenses | 2 months of the expected revenue from sale of electricity<br>Minus<br>• Security Deposits<br>One month of power procurement cost including associated cost |
| Himachal Pradesh | 1 month | 15% of O&M expenses for one month (excluding | 2 months of revenue from sale of electricity<br>Minus |

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| | | provisions, arrears, terminal benefits) | • Security Deposits from Distribution System Users; and<br>Power purchase Cost for one month |
| Delhi | NA | NA | 2 months of ARR of retail supply business<br>Minus<br>• 1 month net power purchase expenses<br>1 month transmission charges |
| Uttarakhand | 1 month | 15% of O&M expenses | • 2 months of the expected revenue from sale of electricity<br>Plus<br>• Capital required to fiancé such shortfall in collection of current dues as may be allowed by the Commission<br>Minus<br>One month of power purchase cost based on annual power procurement plan |
| Madhya Pradesh | 1 month | 1% of opening GFA | 2 months of Receivables<br>Minus<br>• 1 month of power purchase cost;<br>• consumer security deposit; and<br>• any amount paid by prepaid consumers |
| Karnataka | 1 month | 1% of opening GFA | 2 months of average revenue |

Comparing with the corresponding norms of other SERCs, it is observed that the GERC's existing working capital norms are already quite stringent with receivables considered for one month only, whereas in other SERCs it is either 45 days or 2 months. Therefore, it is proposed to continue with the provision of Receivables for 1 month net of consumer security deposits (in cash). Further, it is also proposed to deduct the revenue received from pre-paid consumers, as it is received in advance by the Utilities. Regarding other components of the normative working capital requirement, it is observed that in most of the ERCs, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed. Further, the existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the Distribution Licensees.

Regarding the margin above the benchmark rate, the same may be considered for further revision. Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.3.5. Bad debts written off

Regarding Bad debts written off, Regulation 94.9 of GERC MYT Regulation, 2016 specifies as follows:

> *"94.9 Bad debts written off:*
>
> *94.9.1 The Commission may allow bad debts written off as a pass through in the Aggregate Revenue Requirement, based on the trend of write off of bad debts in the previous years, subject to prudence check:*
>
> *Provided that the Commission shall true up the bad debts written off in the Aggregate Revenue Requirement, based on the actual write off of bad debts excluding DPC waived off, if any, during the year, subject to prudence check:*
>
> *Provided further that if subsequent to the write off of a particular bad debt, revenue is realised from such bad debt, the same shall be included as an uncontrollable item under the Non-Tariff Income of the year in which such revenue is realised."*

From above it can be observed that, existing provision doesn't specify any celling on allowable bad debts written off as a pass through in the Aggregate Revenue Requirement. In order to safeguard the interest of honestly paying consumers it is proposed to cap the Bad debts written off during a Financial Year.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

**Annexure**

## 1. CERC (Terms and Conditions of Tariff) Regulations, 2019

**42. Computation and Payment of Capacity Charge for Thermal Generating Stations:**

(1) The fixed cost of a thermal generating station shall be computed on annual basis based on the norms specified under these regulations and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station. The capacity charge shall be recovered under two segments of the year, i.e. High Demand Season (period of three months) and Low Demand Season (period of remaining nine months), and within each season in two parts viz., Capacity Charge for Peak Hours of the month and Capacity Charge for Off- Peak Hours of the month as follows:

Capacity Charge for the Year ($CC_y$) = Sum of Capacity Charge for three months of High Demand Season + Sum of Capacity Charge for nine months of Low Demand Season

(2) The Capacity Charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:

Capacity Charge for the Month (CCm) = Capacity Charge for Peak Hours of the Month (CCp) + Capacity Charge for Off-Peak Hours of the Month (CCop)

Where,

**<u>High Demand Season:</u>**

$CC_{p1}$= (0.20 $x$ AFC) $x$ ( $\frac{1}{12}$ ) x ( $\frac{\text{PAFMp}}{NAPAF}$) subject to ceiling of (0.20 $x$ AFC) $x$ ( $\frac{1}{12}$ )

$CC_{p2}$ = {(0.20 $x$AFC) $x$ ( $\frac{1}{6}$ ) x ( $\frac{\text{PAFMp2}}{NAPAF}$) subject to ceiling of (0.20 $x$ AFC) $x$ ( $\frac{1}{6}$ )} – $CC_{p1}$

$CC_{p3}$ = {(0.20 $x$AFC) $x$ ( $\frac{1}{4}$ ) x ( $\frac{\text{PAFMp}}{NAPAF}$) subject to ceiling of (0.20 $x$ AFC) $x$ ( $\frac{1}{4}$ )} – ($CC_{p1}$ + $CC_{p2}$)

$CC_{op1}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{12}$ ) x ( $\frac{\text{PAFMop1}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{12}$ )}

$CC_{op2} = \{(0.80\ x AFC)\ x\ (\frac{1}{6})\ \ x\ (\frac{PAFMop2}{NAPAF})$ subject to ceiling of $(0.80\ x\ AFC)\ x\ (\frac{1}{6})\} - CC_{op1}$

$CC_{op3} = \{(0.80\ x AFC)\ x\ (\frac{1}{12})\ \ x\ (\frac{PAFMop3}{NAPAF})$ subject to ceiling of $(0.80\ x\ AFC)\ x\ (\frac{1}{4})\} - (CC_{op1} + CC_{op2})$

**Low Demand Season:**

$CC_{p1} = (0.20\ x\ AFC)\ x\ (\frac{1}{12})\ \ x\ (\frac{PAFMp1}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{12})$

$CC_{p2} = \{(0.20\ x AFC)\ x\ (\frac{1}{6})\ \ x\ (\frac{PAFMp2}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{6})\} - CC_{p1}$

$CC_{p3} = \{(0.20\ x AFC)\ x\ (\frac{1}{4})\ \ x\ (\frac{PAFMp3}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{4})\} - (CC_{p1} + CC_{p2})$

$CC_{p4} = \{(0.20\ x AFC)\ x\ (\frac{1}{3})\ \ x\ (\frac{PAFMp4}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{3})\} - (CC_{p1} + CC_{p2} + CC_{p3})$

$CC_{p5} = \{(0.20\ x AFC)\ x\ (\frac{5}{12})\ \ x\ (\frac{PAFMp5}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{5}{12})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4})$

$CC_{p6} = \{(0.20\ x AFC)\ x\ (\frac{1}{2})\ \ x\ (\frac{PAFMp}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{2})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5})$

$CC_{p7} = \{(0.20\ x AFC)\ x\ (\frac{7}{12})\ \ x\ (\frac{PAFMp7}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{7}{12})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6})$

$CC_{p8} = \{(0.20\ x AFC)\ x\ (\frac{2}{3})\ \ x\ (\frac{PAFMp8}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{2}{3})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7})$

$CC_{p9} = \{(0.20\ x AFC)\ x\ (\frac{3}{4})\ \ x\ (\frac{PAFMp}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{3}{4})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7} + CC_{p7})$

$CC_{op1}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{12}$ ) x ( $\frac{\text{PAFMop1}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{12}$ )}

$CC_{op2}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{6}$ ) x ( $\frac{\text{PAFMop2}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{6}$ )} – $CC_{op1}$

$CC_{op3}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{12}$ ) x ( $\frac{\text{PAFMop3}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{4}$ )} – ($CC_{op1}$ + $CC_{op2}$)

$CC_{op4}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{3}$ ) x ( $\frac{\text{PAFMop4}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{3}$ )} – ($CC_{op1}$ + $CC_{op2}$ + $CC_{op3}$)

$CC_{op5}$ = {(0.80 $x$AFC) $x$ ( $\frac{5}{12}$ ) x ( $\frac{\text{PAFMop5}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{5}{12}$ )} – ($CC_{op1}$ + $CC_{op2}$ + $CC_{op3}$ + $CC_{op4}$)

$CC_{op6}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{2}$ ) x ( $\frac{\text{PAFMop6}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{2}$ )} – ($CC_{op1}$ + $CC_{op2}$ + $CC_{op3}$ + $CC_{op4}$ + $CC_{op5}$)

CCop7 = {(0.80 $x$AFC) $x$ ( $\frac{7}{12}$ ) x ( $\frac{\text{PAFMop7}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{7}{12}$ )} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6)

CCop8 = {(0.80 $x$AFC) $x$ ( $\frac{2}{3}$ ) x ( $\frac{\text{PAFMop8}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{2}{3}$ )} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7)

CCop9 = {(0.80 $x$AFC) $x$ ( $\frac{3}{4}$ ) x ( $\frac{\text{PAFMop9}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{3}{4}$ )} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7 + CCop8)

Provided that in case of generating station or unit thereof under shutdown due to Renovation and Modernisation, the generating company shall be allowed to recover O&M expenses and interest on loan only.

Where,

$CC_m$= Capacity Charge for the Month;

$CC_p$= Capacity Charge for the Peak Hours of the Month;

$CC_{op}$= Capacity Charge for the Off-Peak Hours of the Month;

$CC_{pn}$= Capacity Charge for the Peak Hours of nth Month in a specific Season;

$CC_{opn}$= Capacity Charge for the Off-Peak of nth Month in a specific Season;

AFC = Annual Fixed Cost;

$PAFM_{pn}$ = Plant Availability Factor achieved during Peak Hours upto the end of nth Month in a Season;

$PAFM_{opn}$ = Plant Availability Factor achieved during Off-Peak Hours upto the end of nth Month in a Season;

NAPAF= Normative Annual Plant Availability Factor.

(3) Normative Plant Availability Factor for "Peak" and "Off-Peak" Hours in a month shall be equivalent to the NAPAF specified in Clause (A) of Regulation 49 of these regulations. The number of hours of "Peak" and "Off-Peak" periods during a day shall be four and twenty respectively. The hours of Peak and Off-Peak periods during a day shall be declared by the concerned RLDC at least a week in advance. The High Demand Season (period of three months, consecutive or otherwise) and Low Demand Season (period of remaining nine months, consecutive or otherwise) in a region shall be declared by the concerned RLDC, at least six months in advance: Provided that RLDC, after duly considering the comments of the concerned stakeholders, shall declare Peak Hours and High Demand Season in such a way as to coincide with the majority of the Peak Hours and High Demand Season of the region to the maximum extent possible:

Provided further that in respect of a generating station having beneficiaries across different regions, the High Demand Season and the Peak Hours shall correspond to the High Demand Season and Peak Hours of the region in which majority of its beneficiaries, in terms of percentage of allocation of share, are located.

(4) Any under-recovery or over-recovery of Capacity Charge as a result of underachievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of a Season (High Demand Season or Low Demand Season, as the case may be) shall not be adjusted with under-achievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of the other Season:

Provided that within a Season, the shortfall in recovery of Capacity Charge for cumulative Off-Peak Hours derived based on NAPAF, shall be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Peak Hours in that Season:

Provided further that within a Season, the shortfall in recovery of Capacity Charge for cumulative Peak Hours derived based on NAPAF, shall not be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Off-Peak Hours in that Season.

(5) The Plant Availability Factor achieved for a Month (PAFM) shall be computed in accordance with the following formula:

$$PAFM = 1000\ x \sum_{i=1}^{n} \frac{\mathrm{DCi}}{[\mathrm{N\ x\ IC\ x\ (100 - Aux)}]}\ x\ 100\ \%$$

Where,

AUX = Normative auxiliary energy consumption in percentage.

DCi = Average declared capacity (in ex-bus MW), for the $i^{th}$ day of the period i.e. the month or the year as the case may be, as certified by the concerned load dispatch centre after the day is over.

IC = Installed Capacity (in MW) of the generating station

N = Number of days during the period

Note: DCi and IC shall exclude the capacity of generating units not declared under commercial operation. In case of a change in IC during the concerned period, its average value shall be taken.

(6) In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 50 paise/ kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis within each Season (High Demand Season or Low Demand Season, as the case may be), as specified in Clause (B) of Regulation 49 of these regulations.

(7) The provisions under Clauses (1) to (6) of this Regulation shall come into force with effect from 1.4.2020. Till that date, the capacity charge for a thermal generating station determined under these regulations shall be recovered in accordance with the provisions contained in Clauses (1) to (4) of Regulation 30 of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014, subject to the condition that the NAPAF and NAPLF shall be taken as specified under these regulations.

## 2. MoP's FPPAS Formula

Ministry of Power, Government of India, in Rule 14 of the Electricity (Amendment) Rules, 2022, notified on 29th December, 2022 has specified the methodology and formula for computation of FPPAS the of the ibid methodology, provides as under:-

"1. Computation of fuel and power purchase adjustment surcharge:

(1) For these rules "Fuel and Power Purchase Adjustment Surcharge" (FPPAS) means the increase in cost of power, supplied to consumers, due to change in Fuel cost, power purchase cost and transmission charges with reference to cost of supply approved by the State Commission

(2) Fuel and power purchase adjustment surcharge shall be calculated and billed to consumers, automatically, without going through regulatory approval process, on a monthly basis, according to the formula, prescribed by the respective the State Commission, subject to true up, on an annual basis, as decided by the State Commission:

Provided that the automatic pass through shall be adjusted for monthly billing in accordance with these rules.

(3) Fuel and Power Purchase Adjustment Surcharge shall be computed and charged by the distribution licensee, in (n+2)th month, on the basis of actual variation, in cost of fuel and power purchase and Interstate Transmission Charges for the power procured during the nth month. For example, the fuel and power purchase adjustment surcharge on account of changes in tariff for power supplied during the month of April of any financial year shall be computed and billed in the month of June of the same financial year:

Provided that in case the distribution licensee fails to compute and charge fuel and power purchase adjustment surcharge within this time line, except in case of any force majeure condition, its right for recovery of costs on account of fuel and power purchase adjustment surcharge shall be forfeited and in such cases, the right to recovery the fuel and power purchase adjustment surcharge determined during true-up shall also be forfeited.

(4) The distribution licensee may decide, fuel and power purchase adjustment surcharge or a part thereof, to be carried forward to the subsequent month in order to avoid any tariff shock to consumers, but the carry forward of fuel and power purchase adjustment surcharge shall not exceed a maximum duration of two months and such carry forward shall only be applicable, if the total fuel and power purchase adjustment surcharge for a Billing Month, including any carry forward of fuel and power purchase adjustment surcharge over the previous month exceeds twenty per cent of variable component of approved tariff.

(5) The carry forward shall be recovered within one year or before the next tariff cycle whichever is earlier and the money recovered through fuel and power purchase adjustment surcharge shall first be accounted towards the oldest carry forward portion of the fuel and power purchase adjustment surcharge followed by the subsequent month.

(6) In case of carry forward of fuel and power purchase adjustment surcharge, the carrying cost at the rate of State Bank of India Marginal cost of Funds-based lending Rate plus one hundred and fifty basis points shall be allowed till the same is recovered through tariff and this carrying cost shall be trued up in the year under consideration.

(7) Depending upon quantum of fuel and power purchase adjustment surcharge, the automatic pass through shall be adjusted in such a manner that,

(i) If fuel and power purchase adjustment surcharge≤5%, 100% cost recoverable of computed fuel and power purchase adjustment surcharge by distribution licensee shall be levied automatically using the formula.

(ii) If fuel and power purchase adjustment surcharge>5%, 5% fuel and power purchase adjustment surcharge shall be recoverable automatically as per 6(i) above. 90% of the balance fuel and power purchase adjustment surcharge shall be recoverable automatically using the formula and the differential claim shall be recoverable after approval by the State Commission during true up.

(8) The revenue recovered on account of pass through fuel and power purchase adjustment surcharge by the distribution licensee, shall be trued up later for the year under consideration and the true up for any financial Year shall be completed by 30th June of the next financial year.

(9) In case of excess revenue recovered for the year against the fuel and power purchase adjustment surcharge, the same shall be recovered from the licensee at the

time of true up along with its carrying cost to be charged at 1.20 times of the carrying cost rate approved by the State Commission and the under recovery of fuel and power purchase adjustment surcharge shall be allowed during true up, to be billed along with the automatic Fuel and Power Purchase Adjustment Surcharge amount.

Explanation:-For example in the month of July, the automatic pass through component for the power supplied in May and additional Fuel and Power Purchase Adjustment Surcharge, if any, recoverable after true up for the month of April in the previous financial year, shall be billed.

(10) The distribution licensee shall submit such details, in the stipulated formats, of the variation between expenses incurred and the fuel and power purchase adjustment surcharge recovered, and the detailed computations and supporting documents, as required by the State Commission, during true up of the normal tariff.

(11) To ensure smooth implementation of the fuel and power purchase adjustment surcharge mechanism and its recovery, the distribution licensee shall ensure that the licensee billing system is updated to take this into account and a unified billing system shall be implemented to ensure that there is a uniform billing system irrespective of the billing and metering vendor through interoperability or use of open source software as available.

(12) The licensee shall publish all details including the fuel and power purchase adjustment surcharge formula, calculation of monthly fuel and power purchase adjustment surcharge and recovery of fuel and power purchase adjustment surcharge (separately for automatic and approved portions) on its website and archive the same through a dedicated web address.

3. Computation of Fuel and Power Purchase Adjustment Surcharge:

(4) Formula:

$$\text{Monthly FPPAS for nth Month } (\%) = \frac{(\text{A} - \text{B}) * \text{C} + (\text{D} - \text{E})}{\{\text{Z} * (1 - \text{Distribution losses in}\%/100)\} * \text{ABR}}$$

Where,

Nth month means the month in which billing of fuel and power purchase adjustment surcharge component is done. This fuel and power purchase adjustment surcharge is due to changes in tariff for the power supplied in (n-2)th month

A is Total units procured in (n-2)th Month (in kWh) from all Sources including Long-term, Medium –term and Short-term Power purchases(To be taken from the bills issued to distribution licensees)

B is bulk sale of power from all Sources in (n-2)th Month. (in kWh) = (to be taken from provisional accounts to be issued by State Load Dispatch Centre by the 10th day of each month).

C is incremental Average Power Purchase Cost= Actual average Power Purchase Cost (PPC) from all Sources in (n-2) month (Rs./ kWh) ( computed) - Projected average Power Purchase Cost (PPC) from all Sources (Rs./ kWh)- (from tariff order)

D = Actual inter-state and intra-state Transmission Charges in the (n-2)th Month, (From the bills by Transcos to Discom) (in Rs)

E = Base Cost of Transmission Charges for (n-2)th Month. = (Approved Transmission Charges/12) (in Rs)

Z = [{Actual Power purchased from all the sources outside the State in (n-2)th Month. (in kWh)* (1 – Interstate transmission losses in % /100 ) + Power purchased from all the sources within the State(in kWh)}*(1 – Intra state Transmission losses in %) – B]/100 in kWh

ABR = Average Billing Rate for the year (to be taken from the Tariff Order in Rs/kWh) Distribution Losses (in %) = Target Distribution Losses (from Tariff Order) Inter-state transmission Losses (in %) = As per Tariff Order

(5) The Power Purchase Cost shall exclude any charges on account of Deviation Settlement Mechanism.

(6) Other charges which include Ancillary Services and Security Constrained Economic Despatch shall not be included in Fuel and Power Purchase Adjustment Surcharge and adjusted though the true-up approved by the State Commission.

# Discussion Paper

Multi-Year Tariff Regulations

for the Fourth Control Period

Staff Paper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**Disclaimer**

The issues and suggestions presented in this Discussion Paper do not reflect the views of the Gujarat Electricity Regulatory Commission, its Chairperson, or individual Members, and are not binding on the Commission. The discussion paper is circulated with the objective of initiating discussion on various aspects of Multi Year Tariff Determination Process and soliciting inputs of the stakeholders in this regard.

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## List of Abbreviations

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| AIVPL | AspenPark Infra Vadodara Private Limited |
| A&G | Administrative and General |
| AAD | Advance Against Depreciation |
| ARR | Aggregate Revenue Requirement |
| AT&C Losses | Aggregate Technical and Commercial Losses |
| BAU | Business As Usual |
| CAPM | Capital Asset Pricing Model |
| CEA | Central Electricity Authority |
| CERC | Central Electricity Regulatory Commission |
| CPI | Consumer Price Index |
| DGVCL | Dakshin Gujarat Vij Company Limited |
| DPA | Deendayal Port Authority |
| DSM | Demand Side Management |
| DTA | Domestic Tariff Area |
| EA 2003 | Electricity Act 2003 |
| EE | Energy Efficiency |
| EPS | Electric Power Survey |
| FERV | Foreign Exchange Rate Variation |
| FOR | Forum of Regulators |
| FPPPA | Fuel and Power Purchase Price Adjustment |
| FY | Financial Year |
| GERC | Gujarat Electricity Regulatory Commission (or “the Commission”) |
| GETCO | Gujarat Energy Transmission Company Limited |
| GFA | Gross Fixed Asset |
| GIS | Gas Insulated Sub-station |
| GIFT-PCL | GIFT Power Company Limited |
| GOI | Government of India |
| GSECL | Gujarat State Electricity Corporation Limited |
| GTO | Gate Turn-off Thyristor |
| GUVNL | Gujarat Urja Vikas Nigam Limited |
| IDC | Interest During Construction |
| IEDC | Incidental Expenses During Construction |
| IT | Information Technology |
| IoWC | Interest on Working Capital |
| LD | Liquidated Damages |
| LT-DRAP | Long-term Discom Resource Adequacy Plan |
| MCLR | Marginal Cost of Funds based Lending Rate |
| MERC | Maharashtra Electricity Regulatory Commission |
| MGVCL | Madhya Gujarat Vij Company Limited |
| MoP | Ministry of Power |
| MUL | MPSEZ Utilities Limited |
| MYT | Multi-Year Tariff |
| NAPAF | Normative Annual Plant Availability Factor |
| NAPLF | Normative Annual Plant Load Factor |
| NFA | Net Fixed Asset |

| | |
|---|---|
| NTP | National Tariff Policy |
| O&M | Operation and Maintenance |
| PEUM | Partial End Use Method |
| PGVCL | Paschim Gujarat Vij Company Limited |
| PSERC | Punjab State Electricity Regulatory Commission |
| R&M | Renovation and Modernization |
| RDSS | Revamped Distribution Sector Scheme |
| RERC | Rajasthan Electricity Regulatory Commission |
| RoCE | Return on Capital Employed |
| RoE | Return on Equity |
| RPO | Renewable Purchase Obligation |
| SEZ | Special Economic Zone |
| SERC | State Electricity Regulatory Commission |
| SLDC | State Load Dispatch Centre |
| SLM | Straight Line Method |
| STU | State Transmission Utility |
| STATCOM | Static Synchronous Compensator |
| TPL | Torrent Power Limited |
| UGVCL | Uttar Gujarat Vij Company Limited |
| WAROI | Weighted Average Rate of Interest |
| WACC | Weighted Average Capital Cost |
| WPI | Wholesale Price Index |

# 1. Introduction

## 1.1. Background

### 1.1.1. History of Gujarat Electricity Business

The Gujarat Electricity Board was unbundled and restructured by the Government of Gujarat with effect from 1st April, 2005. The Generation, Transmission and Distribution businesses of the erstwhile Gujarat Electricity Board were transferred to seven successor companies. The seven successor companies are listed below:

**Generation Company: Gujarat State Electricity Corporation Limited (GSECL)**

**Transmission Company: Gujarat Energy Transmission Corporation Limited (GETCO)**

**Distribution Companies: 1) Dakshin Gujarat Vij Company Limited (DGVCL)**

**2) Madhya Gujarat Vij Company Limited (MGVCL)**

**3) Uttar Gujarat Vij Company Limited (UGVCL)**

**4) Paschim Gujarat Vij Company Limited (PGVCL)**

**Gujarat Urja Vikas Nigam Limited (GUVNL)**, a holding company of the above named 6 subsidiary companies is responsible for bulk purchase of electricity from various sources and supply to Distribution Companies and, other activities including trading of electricity.

Additionally, Section 31(1) of the Electricity Act, 2003 (EA 2003), requires the State Government to establish a separate State Load Despatch Centre (SLDC). Section 31(2) of the Electricity Act, 2003, provides that the SLDC shall be operated by a Government Company/ Authority/ Corporation constituted under any State Act and until such Company/ Authority/ Corporation is notified by the State Government, the State Transmission Utility (STU) would operate the SLDC. Accordingly, in the State of Gujarat, the STU, viz., GETCO, has so far been operating the SLDC.

Further, there is private sector participation in Generation and Distribution Businesses in the state of Gujarat.

- Torrent Power Limited (TPL), is carrying on the business of Generation and Distribution of

Electricity in the cities of Ahmedabad, Gandhinagar and Surat. The Commission determines tariff for the Distribution Business of TPL in Ahmedabad, Surat and Dahej and for the Generation Business of TPL in Ahmedabad. Besides, the Commission has also granted TPL, two second Licenses for distribution of electricity - first in the area of Dholera Special Investment Region (SIR), District Ahmedabad vide Order dated 21st April, 2018 in Licence Application No. 1 of 2018 and second in the Area of Mandal Becharaji SIR, Villages in the Taluka - Mandal, Detroj and Becharaji, District - Ahmedabad and Mehsana, vide Order dated 14th December, 2021.

- Torrent Energy Limited (TEL) was promoted by Torrent Power Limited (TPL), to generate and distribute power as a Codeveloper of the Dahej Special Economic Zone (DSEZ) area, . notified by the Ministry of Commerce and Industry, Government of India, vide Notification No. 2131(E) dated 20th December, 2006, as a Multi-Product SEZ. The Commission vide its Order dated 17th November,2009, issued Orders for issuance of distribution license to TEL as a second distribution licensee for distribution of electricity in the DSEZ area. Subsequently, TEL got amalgamated in TPL, with effect from the appointed date of 1st April, 2014.

- GIFT Power Company Limited (GIFT PCL), a 100% subsidiary company of Gujarat International Finance Tec-City Company Limited, is a Distribution Licensee for the GIFT City area. The Commission granted the second License for distribution of electricity to GIFT PCL vide Order dated 6th March, 2013 in Licence Application No. 1 of 2012.

- Deendayal Port Authority (DPA) (formerly Kandla Port Trust) is a Distribution Licensee for the Deendayal Port located on the Gulf of Kutch on the north-western coast of India. The License for supply of electricity was granted to DPA by the Chief Commissioner of Kutch under the Indian Electricity Act, 1910. Consequent to the enactment of the Electricity Act, 2003, DPA has become a deemed Distribution Licensee under the EA 2003.

- AspenPark Infra Vadodara Private Limited (AIVPL), is a company incorporated under the Companies Act, 1956. It has developed a sector specific SEZ for High-tech Engineering products and related services at Village Alwa and Pipaliya, Taluka Waghodia, District Vadodara in the State of Gujarat under Section 3 of the SEZ Act, 2005. Aspen has been notified as the developer of the SEZ by the Ministry of Commerce and Industry, Government of India and granted deemed Distribution Licensee status by the Commission.

- MPSEZ Utilities Limited (MUL) (Formerly known as MPSEZ Utilities Private Limited) obtained the status of Distribution Licensee vide Government of India (GOI) notification dated 3rd March, 2010. This was also endorsed by the Gujarat Electricity Regulatory Commission (GERC) vide Order No. GERC/Legal 2010/0609 dated 6th April, 2010 allowing for distribution of electricity in Mundra SEZ area, Kutch.

Therefore, power utilities being regulated by the GERC (or the Commission) ranges from State Government owned power utilities including distribution licensees supplying power to large urban and rural areas, to large private sector private utilities including distribution licenses supplying power in the cities and also small distribution licensees both in the government sector as well as the private sector, supplying power in the SEZs and SIRs. While regulating the tariff of these different utilities / licensees, the Commission may need to consider differentiated approach in certain parameters or factors, while keeping a common overall MYT framework for all.

## 1.2. Enabling provisions of Electricity Act, 2003

The State Electricity Regulatory Commissions have been vested with the responsibility of formulation of Tariff Regulations for Generation, Transmission, Supply and Wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State under Section 86 of the Electricity Act, 2003. Sections 61, and 62 of the EA 2003 provides the terms & conditions and principles for determination of tariff respectively. Relevant provisions of the EA 2003 are as under:

*"**Section 86. (Functions of State Commission): ---** (1) The State Commission shall discharge the following functions, namely:*

*(a) determine the tariff for generation, supply, transmission and wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State:*

*Provided that where open access has been permitted to a category of consumers under section 42, the State Commission shall determine only the wheeling charges and surcharge thereon, if any, for the said category of consumers;*

*….."*

***"Section 61. (Tariff regulations):***

*The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:*

*(a) the principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission*

*licensees;*

*(b) the generation, transmission, distribution and supply of electricity are conducted on commercial principles;*

*(c) the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;*

*(d) safe guarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;*

*(e) the principles rewarding efficiency in performance;*

*(f) multi year tariff principles;*

*(g) that the tariff progressively, reflects the cost of supply of electricity and also, reduces cross-subsidies in the manner specified by the Appropriate Commission;*

*(h) the promotion of co-generation and generation of electricity from renewable sources of energy;*

*(i) the National Electricity Policy and tariff policy:*

*Provided that the terms and conditions for determination of tariff under the Electricity (Supply) Act, 1948, the Electricity Regulatory Commission Act, 1998 and the enactments specified in the Schedule as they stood immediately before the appointed date, shall continue to apply for a period of one year or until the terms and conditions for tariff are specified under this section, whichever is earlier."*

*"**Section 62. (Determination of tariff): ---** (1) The Appropriate Commission shall determine the tariff in accordance with the provisions of this Act for –*

*(a) supply of electricity by a generating company to a distribution licensee:*

*Provided that the Appropriate Commission may, in case of shortage of supply of electricity, fix the minimum and maximum ceiling of tariff for sale or purchase of electricity in pursuance of an agreement, entered into between a generating company and a licensee or between licensees, for a period not exceeding one year to ensure reasonable prices of electricity;*

*(b) transmission of electricity ;*

*(c) wheeling of electricity;*

*(d) retail sale of electricity:*

*Provided that in case of distribution of electricity in the same area by two or more distribution licensees, the Appropriate Commission may, for promoting competition among distribution licensees, fix only maximum ceiling of tariff for retail sale of* *electricity.*

*(2) The Appropriate Commission may require a licensee or a generating company to furnish separate details, as may be specified in respect of generation, transmission and distribution for determination of tariff.*

*(3) The Appropriate Commission shall not, while determining the tariff under this Act, show undue preference to any consumer of electricity but may differentiate according to the consumer's load factor, power factor, voltage, total consumption of electricity during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required.*

*(4) No tariff or part of any tariff may ordinarily be amended, more frequently than once in any financial year, except in respect of any changes expressly permitted under the terms of any fuel surcharge formula as may be specified."*

## 1.3. National Tariff Policy (NTP)

The Ministry of Power, Government of India, in compliance with Section 3 of the EA 2003, notified the Tariff Policy on 6th January, 2006 and revised Tariff Policy on 28th January, 2016. The revised Tariff Policy, inter-alia, sets the goal for ensuring availability of electricity to different categories of consumers at reasonable rates for achieving the objectives of rapid economic development of the country and improving the living standards of the people. It also envisages adequate return on investment for the developer to attract investment in the sector. It further envisages transparency, consistency and predictability in approach for tariff fixation. Section 4 lays down the objectives of this Tariff Policy as under:

*a) Ensure availability of electricity to consumers at reasonable and competitive rates;*

*b) Ensure financial viability of the sector and attract investments;*

*c) Promote transparency, consistency and predictability in regulatory approach across jurisdictions and minimise the perceptions of regulatory risks;*

*d) Promote competition, efficiency in operations and improvement in quality of supply;*

*e) Promote generation of electricity from Renewable sources;*

*f) Promote Hydroelectric Power generation including Pumped Storage Projects (PSP) to provide adequate peaking reserves, reliable grid operation and integration of variable renewable energy sources;*

*g) Evolve a dynamic and robust electricity infrastructure for better consumer services;.*

*h) Facilitate supply of adequate and uninterrupted power to all categories of consumers;*

*i) Ensure creation of adequate capacity including reserves in generation, transmission and distribution in advance, for reliability of supply of electricity to consumers.*

## 1.4. GERC Multi Year Tariff (MYT) Regulations till date

In exercise of powers conferred under Section 181 (2) read with Section 36, Section 39, Section 40, Section 41, Section 51, Section 61, Section 62, Section 63, Section 64, Section 65 and Section 86 of the Electricity Act, 2003 and all other enabling powers in that behalf, and under Section 32 of the Gujarat Electricity Industry Reorganisation and Regulation) Act, 2003 (Gujarat Act No. 24 of 2003) and all powers enabling it in that behalf, the Gujarat Electricity Regulatory Commission has notified the following regulations for tariff determination of power utilities in the state of Gujarat:

- GERC notified the **Gujarat Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2005** on 31st March 2005 for determining the tariff for the Distribution Licensees. GERC also notified **Gujarat Electricity Regulatory Commission (Levy And Collection of Fees and Charges by SLDC) Regulations, 2005** on 30th March 2005.

- On 30th November 2007, GERC notified the **Gujarat Electricity Regulatory Commission (MYT Framework) Regulations, 2007** as an appendix to the **GERC (Terms and Conditions of Tariff)** Regulations for determining the tariff within the MYT framework for all matters for which the Commission has power under the EA 2003. These Regulations were applicable for the First Control Period i.e., FY 2008-09 to FY 2010-11.

- On 22nd March 2011, GERC notified the **Gujarat Electricity Regulatory Commission (MYT Framework) Regulations, 2011** for determining the tariff within the MYT framework for all matters for which the Commission has power under the EA 2003. These Regulations were applicable for the Second Control Period i.e., FY 2011-12 to FY 2015-16.

- On 29th March 2016, the Commission has notified the **Gujarat Electricity Regulatory Commission (MYT) Regulations, 2016** for determination of tariff for the Third Control Period i.e., FY 2016-17 to FY 2020-21. Subsequently, on above regulation the Commission has notified two amendments on 02nd December, 2016 and 18th August, 2018.

- While the Commission had initiated the process of framing the MYT Regulations for Fourth Control Period i.e., FY 2021-22 to FY 2025-26 by issuing public notice dated 10th August, 2021, the process was delayed due to circumstances and reasons beyond the control of the Commission. Considering the delay, the Commission vide its Suo-Motu Order No. 07

of 2020 dated 23rd December, 2020 deferred the 5-year control period for new MYT Regulations for one year, i.e., till 31st March 2022. Due to ongoing pandemic, the process was further delayed due to circumstances and reasons beyond the control of the Commission. The Commission vide its Order in Suo-Motu Petition No. 1995 of 2021 dated 24th September, 2021 deferred the next MYT Control period by one more year, i.e., till 31st March 2023. Subsequently, the Commission once again deferred the next MYT Control period by one more year, i.e., till 31st March 2024, vide its Order in Suo-Motu Petition No. 2140 of 2022.

## 1.5. MYT Principle

The Section 61 of the EA 2003, states that the Appropriate Commission for determining the terms and conditions for the determination of tariff shall be guided, inter-alia, by Multi-Year Tariff principles. The National Tariff Policy has given guidelines on the MYT principles that are considered while framing the MYT Regulations. The broad objectives of any MYT framework are as follows:

- Provide Regulatory Certainty to the investors and consumers by promoting transparency, consistency and predictability of regulatory approach and thereby minimizing the regulatory risk perception for all stakeholders.
- Ensure financial viability of the sector to attract investment and safeguard the interest of the consumers.
- Provide incentivisation framework to reward performance, promote efficiency and competition
- Address the risk sharing mechanism between Utilities and consumers based on controllable and uncontrollable factors.

### 1.5.1. Control Period

The NTP 2016 states as follows:

*"5(h)(1) …….The framework should feature a five-year control period. The initial control period may, however, be of 3 year duration for transmission and distribution if deemed necessary by the Regulatory Commission on account of data uncertainties and other practical considerations. In cases of lack of reliable data, the Commission may state assumptions in MYT for first control period and a fresh control period may*

*be started as and when more reliable data becomes available."*

GERC has published the tariff orders for Multi-Year Aggregate Revenue Requirement (ARR) for FY 2016-17 to FY 2020-21 for all utilities on 31st March 2017. Subsequently, the Commission vide its Suo-Motu Order dated 22nd December, 2020 in Case No. 07 of 2020 in the matter of "Filing of application for determination of ARR and Tariff for FY 2021-22", has decided to determine ARR for FY 2021-22 based on the principles and methodology as provided in the GERC (Multi-Year Tariff) Regulations, 2016 and defer the next MYT Control Period by one year. Subsequently, the Commission vide its Suo-Motu Order dated 24th September, 2021 in Case No. 1995 of 2021 in the matter of "Filing of application for determination of ARR and Tariff for FY 2022-23", has decided to determine the ARR for FY 2022-23 based on the principles and methodology as provided in the GERC (MYT) Regulations, 2016 and defer the next MYT Control Period by one year. Further, the Commission vide its Suo-Motu Order dated 20th October, 2022 in Case No. 2140 of 2022 in the matter of "Filing of application for determination of ARR and Tariff for FY 2023-24", has decided to determine the ARR for FY 2023-24 based on the principles and methodology as provided in the GERC (MYT) Regulations, 2016 and defer the next MYT Control Period by one year. The Commission has published the tariff orders for all utilities for FY 2023-24 on 31st March 2023.

**Considering that three Control Periods have already passed, it is suggested that the next Control Period (i.e., Fourth MYT Control Period) may be of five years and from FY 2024-25 to FY 2028-29.**

**Comments and suggestions are invited from the stakeholders on the possible regulatory options.**

## 1.5.2. Controllable/ Un-Controllable Parameters

All the parameters in the MYT framework are divided into controllable and uncontrollable parameters. The GERC MYT Regulations, 2016 provides as follows:

***"22. Controllable and uncontrollable factors***

*22.1 For the purpose of these Regulations, the term "uncontrollable factors" shall comprise of the following factors, which were beyond the control of the Applicant, and could not be mitigated by the Applicant:*

*(a) Force Majeure events;*

*(b) Change in law, judicial pronouncements and Orders of the Central Government, State Government or Commission;*

*(c) Variation in the price of fuel and/ or price of power purchase according to the FPPPA formula approved by the Commission from time to time;*

*(d) Variation in the number or mix of consumers or quantities of electricity supplied to consumers:*

*Provided that where there is more than one Distribution Licensee within the area of supply of the Applicant, any variation in the number or mix of consumers or in the quantities of electricity supplied to consumers within the area served by two or more such Distribution Licensees, on account of migration from one Distribution Licensee to another, shall be attributable to controllable factors;*

*(e) Transmission Loss;*

*(f) Variation in market interest rates;*

*(g) Taxes and Statutory levies;*

*(h) Taxes on Income;*

*(i) Income from realisation of bad debts written off:*

*Provided that where the Applicant believes, for any variable not specified above, that there is a material variation or expected variation in performance for any financial year on account of uncontrollable factors, such Applicant may apply to the Commission for inclusion of such variable at the Commission's discretion, under this Regulation for such financial year.*

*22.2 Some illustrative variations or expected variations in the performance of the Applicant, which may be attributed by the Commission to controllable factors include, but are not limited to, the following:*

*(a) Variations in capitalisation on account of time and/or cost overruns/ efficiencies in the implementation of a capital expenditure project not attributable to an approved change in scope of such project, change in statutory levies or force majeure events;*

*(b) Variation in Interest and Finance Charges, Return on Equity, and Depreciation on account of variation in capitalisation, as specified in clause (a) above;*

*(c) Variations in technical and commercial losses of Distribution Licensee;*

*(d) Variations in performance parameters;*

*(e) Variations in interest on working capital;*

*(f) Failure to meet the standards specified in the Gujarat Electricity Regulatory Commission (Standard of Performance of Distribution Licensee) Regulations, 2005, except where exempted in accordance with those Regulations;*

*(g) Variations in labour productivity;*

*(h) Variation in Operation &Maintenance expenses;*

*(i) Bad debts written off. "*

It is observed that, GERC MYT Regulations, 2016 covers all the controllable and uncontrollable parameters enlisted by most of the SERCs. However, the delay on account of forest clearances is not mentioned in prevailing provisions.

Further, Central Electricity Regulatory Commission (CERC), while framing the CERC Tariff Regulations, 2019, in its Explanatory Memorandum, observed as follows:

> *"2.5.5 The Commission has observed while dealing with tariff petitions, that matters pertaining to acquisition of land or getting right of way, have become one of the main causes of delay in commissioning of projects. In the existing 2014 Tariff Regulations, only force majeure and change in law have been specifically identified as uncontrollable factors. However, the Commission has noticed that, land acquisition and Right of Way issues have been largely outside the control of the project developer and accordingly, the Commission has also been condoning the delay and allowing the associated cost to form part of the capital cost. In the light of these practical issues, the Commission has proposed to include time and cost over-runs on account of land acquisition, as an uncontrollable factor, except where the delay is attributable to the generating company or the transmission licensee…"*

In view of the reasons mentioned above, the delay on account of forest clearances may also be considered as a factor that may be included under the uncontrollable factors provided that such delays are not attributable to the Utilities.

**Comments and suggestions are invited from the stakeholders on inclusion of delay on account of forest clearances as an uncontrollable factor**.

### 1.5.3. Sharing of Gain/Losses on Controllable Parameters

The NTP 2016 states as follows:

> *" **8.1 Implementation of Multi-Year Tariff (MYT) framework***
>
> *…..*
>
> *2) The State Commissions should introduce mechanisms for sharing of excess profits and losses with the consumers as part of the overall MYT framework. In the first control period the incentives for the utilities may be asymmetric with the percentage of the excess profits being retained by the utility set at higher levels than the percentage of losses to be borne by the utility. This is necessary to accelerate performance improvement and reduction in*

*losses and will be in the long term interest of consumers by way of lower tariffs.*

*…."*

Currently, the Commission has allowed one-third of the gains/losses on account of controllable factors to be passed on to the consumers as rebate/additional charge and the remaining two-third is to be retained/absorbed by the utilities.

Many SERCs such as Rajasthan Electricity Regulatory Commission (RERC), Maharashtra Electricity Regulatory Commission (MERC), Punjab State Regulatory Commission (PSERC), etc. allow at least 40% of the gains to be passed on to the consumers, whereas 100% of the losses are to be borne by the utilities. Some of the ERCs allow sharing of gains but not the losses by the Utilities. CERC allows sharing of 50% of the gains due to variation in norms, however there is no sharing of losses. Given that it's the Fourth Control Period, changes in proportion of sharing gains and losses may be suggested, including the possibilities of not sharing of any losses with the beneficiaries / consumers.

**Comments and suggestions are sought from the stakeholders on any modification in the sharing mechanism that may be required.**

### 1.5.4. Parametric Performance Review

The MYT framework is finalised based on the parameters under the Utilities' control. These mainly consist of Financial and Operating parameters for Generation, Transmission, SLDC and Distribution Licensees. The annual targets for these parameters are set at the beginning of the Control Period.

The NTP mentions as follows:

*"5(h)(3) Once the revenue requirements are established at the beginning of the control period, the Regulatory Commission should focus on regulation of outputs and not the input cost elements. At the end of the control period, a comprehensive review of performance may be undertaken."*

The GERC MYT Regulation, 2016 provides for filing of MYT Petition at the beginning of the Control Period, Mid-Term review of ARR, as well as annual Truing-up of expenses and revenue based on audited accounts by the Commission. The relevant provisions of GERC MYT Regulations, 2016 is reproduced as below:

***"16. Multi-Year Tariff framework***

*……*

*16.2 The Multi-Year Tariff framework shall be based on the following elements, for determination of Aggregate Revenue Requirement and expected revenue from tariff and charges for Generating Company, Transmission Licensee, SLDC, Distribution Wires Business and Retail Supply Business:*

*(i) A detailed Multi-Year Tariff Application comprising the forecast of Aggregate Revenue Requirement for the entire Control Period and expected revenue from existing tariffs for the first year of the Control Period to be submitted by the Applicant:*

*…..*

*Provided further that a Mid-term Review of the Aggregate Revenue Requirement shall be undertaken for the Generating Company, Transmission Licensee, SLDC and Distribution Licensee on an application that shall be filed by the utilities along with the Petition for truing-up for the second year of the Control Period and tariff determination for the fourth year of the Control Period;*

*…..*

*(iii) Truing up of previous year's expenses and revenue by the Commission based on Audited Accounts vis-à-vis the approved forecast and categorisation of variation in performance as those caused by factors within the control of the Applicant (controllable factors) and those caused by factors beyond the control of the Applicant (uncontrollable factors):*

*….*

*(vi) Annual determination of tariff for the Generating Company, Transmission Licensee, SLDC, Distribution Wires Business and Retail Supply Business, for each financial year within the Control Period, based on the approved forecast and results of the truing up exercise.*

Most of the ERCs still continue to follow the approach of annual tariff determination under their respective MYT framework, with a few exceptions. CERC undertakes the truing-up exercise for generating entities and transmission licensees only once in the five-year Control Period. UPERC also follows one time truing-up exercise for generating entities during the MYT Control Period, while undertake annual truing-up for transmission and distribution licensees. MERC follows mid-term review of operational and financial performance vis-à-vis the approved forecast, only after three years of the Control Period by truing-up for first and second years, provisional true-up for third year and allow revised forecasting of ARR, expected revenue from existing tariff, expected revenue gap and proposed tariff for the fourth and fifth year of the Control Period by all the Utilities

– Generation, Transmission, SLDC and Distribution. Presently, GERC carries out annual truing-up exercise for all Utilities. It is proposed to do away with the annual truing-up exercise for the Utilities in a phased manner. One option could be to introduce a mid-term review for Generation, Transmission and SLDC Utilities consisting of truing-up for first two years based on actuals, provisional truing-up for the third year based on provisional figures, and revision of projected figures for fourth and fifth year may be undertaken, while continuing with the annual truing-up for Distribution Utilities. Another option could be to undertake mid-term review for all Utilities. Third option could be to undertake annual or mid-term review for Distribution Utilities and truing-up for other Utilities to be undertaken only at the end of the Control Period.

**Comments and suggestions are invited from the stakeholders regarding introduction of Mid-Term Review, along with truing-up for first 2/3 years of Control Period for the Distribution Licensees and only one-time truing-up in case of Generation, Transmission and SLDC Utilities.**

# 2. Common Financial Parameter

## 2.1. Capital Cost

Capital cost forms the basis of tariff determination and is therefore highly important that it is approved after prudence check. Capital Cost for a project currently include the expenditure incurred or projected to be incurred, Interest During Construction (IDC), Incidental Expenses During Construction (IEDC) and financing charges, any gain or loss on account of Foreign Exchange Rate Variation (FERV) on the loan during construction up to the date of commercial operation of the project, capitalised initial spares and additional capitalisation. All these components are currently approved by the Commission after prudence check such as scrutiny of the reasonableness of the capital expenditure, financing plan, interest during construction, use of efficient technology, cost over-run and time over-run, etc.

### 2.1.1. Capital Investment Plan Approval

The GERC MYT Regulations, 2016 provides for Capital Investment Plan as follows:

> ***"19. Multi-Year Tariff Application***
>
> *…..*
>
> *19.3. The capital investment plan shall show separately, on-going projects that will spill over into the Control Period, and new projects (along with justification) that will commence in the Control Period but may be completed within or beyond the Control Period. The Commission shall consider and approve the capital investment plan for which the Generating Company, Transmission Licensee, SLDC and Distribution Licensee for the Distribution Wires Business and Retail Supply Business, may be required to provide relevant technical and commercial details.*
>
> *….*
>
> ***66. Capital Investment Plan***
>
> *66.1 The Transmission Licensee shall submit a detailed capital investment plan, financing plan and physical targets for each year of the Control Period for meeting the requirement of load growth, improvement in quality of supply, reliability, metering, reduction in congestion, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period:*
>
> *Provided that the Capital Investment Plan shall be submitted for each year of the Control Period:*
>
> *Provided further that the Capital Investment Plan shall be accompanied by such information, particulars and documents as may be required including but not limited to the*

*information such as number of bays, name, configuration and location of grid substations, substation capacity (MVA), transmission line length (ckt-km) showing the need for the proposed investments, alternatives considered, cost/benefit analysis and other aspects that may have a bearing on the transmission charges.*

*66.2 The Capital Investment Plan of the Transmission Licensee shall be consistent with the transmission system plan for the intra-State transmission system.*

*…..*

***78. Capital Investment Plan***

*78.1 The SLDC shall submit a detailed capital investment plan, financing plan and physical targets for each year to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.*

*78.2 The SLDC shall submit the Capital Investment Plan as specified in* ***Chapter2*** *of these Regulations.*

*…..*

***88. Capital Investment Plan***

*88.1 The Distribution Licensee shall submit detailed capital investment plan, financing plan and physical targets for each year of the Control Period for meeting the requirement of load growth, reduction in distribution losses, improvement in quality of supply, reliability, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.*

*88.2 The Distribution Licensee shall be required to ensure optimum investments to enhance efficiency, productivity and meet performance standards prescribed by the Commission.*

*…..*

***95. Capital Investment Plan***

*95.1 The Distribution Licensee shall submit a detailed capital investment plan, financing plan and physical targets for each year of the Control Period for meeting the requirement of load growth, reduction in distribution losses, increase in collection efficiency, metering, consumer services, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period.*

*95.2 The Distribution Licensee shall be required to ensure optimum investments to enhance efficiency, productivity and meet performance standards prescribed by the Commission.*

*95.3 The Distribution licensee shall submit the Capital Investment Plan as specified in* ***Chapter2*** *of these Regulations.”*

Further, Ministry of Power, Government of India has published draft Electricity (Amendment) Rules, 2023 incorporating provisions of ‘subsidy accounting & payment’ and ‘Framework for financial sustainability’ for comments. The relevant extract of the draft Rule 20 is reproduced as follows:

***"20 (I) Framework for financial Sustainability:***

*….*

*(d) All the prudent cost incurred by the Distribution licensee for creating the assets for development and maintenance of distribution system in accordance with sub-section (1) of section 42 of the Act shall be pass-through;*

*Provided that such pass-through of the cost for the assets created by the distribution licensee shall be subject to following conditions:*

*i) Asset has been created in accordance with the capex roll out plan for the licensee approved by the respective State Commission.*

*ii) Asset has been procured in competitive and transparent manner.*

*iii) Asset are geo-tagged and properly recorded in Fixed Asset Register (FAR) and the details are made available on the website of the Distribution licensee.*

*…"*

Capital Investment Schemes have a significant impact on the overall costs, and hence the revenue requirement and tariff determination process for regulated entities. The need for regulating the Capital Investment Schemes in an unambiguous and transparent manner is critical for providing regulatory certainty, for promoting efficient and optimal utilization of resources.

While, the GERC MYT Regulations, 2016 provide for submission of detailed Capital Investment Plan by the Utilities as a part of MYT Petition, with a view to further regularize and streamline the filing and approval process of Capital Investment Schemes, a need is felt for developing a comprehensive Capital Investment Plan approval process, covering various aspects including threshold limit for prior approval, process of submission for approval, details required for prudence check, defining framework for approval of Schemes, need for approval of completed cost, etc.

It is observed that most of the SERCs have not yet provided separate guidelines and / or Regulations for Capital Investment Scheme approval framework. While few have defined broad guidelines, Maharashtra Electricity Regulatory Commission has notified MERC (Approval of Capital Investment Schemes) Regulations, 2022, which has comprehensively detailed out the process of capex approval for power utilities covered under regulated tariff mechanism. It is proposed to develop a comprehensive Capital Investment Scheme approval framework for the utilities in the State of Gujarat, including following key aspects:

- Categorization of Capital Investment Schemes for Generation, Transmission, SLDC and Distribution Utilities

- Threshold limits for in-principle prior approval separately for Generation, Transmission, SLDC and Distribution Utilities (including those for Parallel License situations)
- Categorization of Schemes not requiring prior-approval from the Commission, including overall monetary limits for as a percentage of total capital investment, etc.
- Process for submission of application for in-principle prior approval – content of application, Detailed Project Report, etc.
- Details required for prudence check - Technical and Financial criteria for in-principle approval of schemes, cost-benefit analysis, utilisation index of the assets, etc. for final approval of completed cost.
- Approval process – In principle, final approval along with ARR and tariff determination and final approval of the completed cost including conditions to be fulfilled for allowing capitalization including geo-tagging, reflection in Fixed Asset Register, etc.
- Other conditions including – Capital Investment Schemes not approved by the Commission, not to be allowed in the ARR, enabling provisions for operationalization of the proposed capital investment approval framework as a continuous process independent of the annual or periodical ARR / MYT Petitions filing process.

**Comments and suggestions are invited from the stakeholders regarding the option of introducing a comprehensive Capital Investment Scheme approval framework for the utilities in the State of Gujarat, to be implemented with effect from the new MYT Control Period.**

### 2.1.2. Debt Equity Ratio - RoE (GFA) vs RoCE (NFA)

The GERC MYT Regulations, 2016 considers a normative debt to equity ratio of 70:30 for a project. The return is provided on the normative equity base i.e., 30% of the project's capital cost or actual equity (in case it is less than 30%) on a perpetual basis over the entire life of the assets. The point to note here is that the asset base for earning return remains constant throughout the life of the project.

The interest on debt is provided as a separate component of the annual fixed cost based on Weighted Average Rate of Interest (WAROI). The WAROI is calculated on the basis of the actual loan portfolio of the project during the year. For allowing repayment of principal component of debt, the current practice is to allow depreciation corresponding to 90% of 70% of capital investment over first 12 years, while the remaining capital is depreciated over the residual life of the asset.

The Return on Capital Employed (RoCE) method involves computation of the return using

Weighted Average Cost of Capital (WACC) applied on an asset base to calculate the total return. It is the most widely used method by regulators across countries in the world, both developed and developing. The ROCE method takes into account several factors such as age of assets, additional capitalization in schemes, varying debt-equity ratio of projects etc. In this method, the WACC is computed by the following formula:

$$WACC = (D/V)*K_d + (E/V)*K_e$$

Where

D = Normative Debt

E = Normative Equity

V = Total Capital i.e., Sum of Debt & Equity

$K_d$ = Cost of Debt

$K_e$ = Cost of Equity

There are two approaches followed for the interest rate – the cost of debt may be pass though based on the weighted average cost of debt of the entire loan portfolio or it benchmarked based on average cost of debt to businesses in a sector. The latter approach is often used by regulators. The cost of equity is estimated using the CAPM model. In the RoCE approach used worldwide, depreciation is calculated on a straight-line basis over the life of asset. It is not linked to loan repayment unlike in India.

Thus, it can be seen that the two approaches discussed above differ both in the allowed rate of return and capital base for return. While in the RoE approach, the equity base remains same through-out the life of asset, it reduces in RoCE approach by depreciation allowed for the equity portion along with the debt portion.

The cost of equity in RoE approach is set using CAPM model, while the interest rate is allowed separately based on weighted average interest rate of loan portfolio. The RoCE approach uses weighted average cost of capital for allowing return on capital and the interest rate is linked to market.

While GERC MYT Regulations, 2016 like CERC and many other SERCs follow the RoE or GFA based approach, some of the SERCs like DERC and APERC as well as CERC in case of generation assets of NLC India Limited follow RoCE or NFA based approach.

While the Regulatory needs to ensure the return on investment to the investors on the approved capital investments, in a usual course of business, the returns get reduced over the life of asset as they recover the depreciation on year-on-year basis. However, the power sector utilities are allowed RoE on gross equity infused even when the cumulative depreciation exceeds the debt component over the life of assets or until the assets is in use.

The Tariff Regulations based on RoE or GFA Approach (including GERC MYT Regulations, 2016) do not have provisions of reduction of equity after completion of useful life. However, RoCE or NFA approach provides for adjustment of both debt and equity from the depreciation in a proportionate manner from the beginning itself. An asset, which has competed his useful life, recovers around 90% of the invested capital in the form of depreciation by the end of useful life. Therefore, continuing to allow return of existing equity base i.e., 30% of the capital expenditure essentially means allowing return on the investment which they have already recovered.

The argument in favour of the GFA approach is that it is not only essential to encourage the prospective investment in the sector, but also critical to incentivize the utility to keep operating the existing assets which are still in good shape, even if the original useful life is completed. This also provides benefit of reduced fixed cost as there is no or very little debt to be serviced and equity component at historical /cost, which in comparison to current replacement cost is much cheaper. Therefore, there are multiple alternatives which may be considered for implementation including as follows:

- Consider shifting to RoCE (NFA) approach for all assets, i.e., existing as well as assets commissioning in the new Control Period;
- Consider shifting to RoCE (NFA) approach for assets commissioned w.e.f new Control Period and keeping the existing assets under RoE (GFA) approach only;
- For existing assets reduce Equity to salvage value levels or normative equity levels during the new MYT Control Period and RoCE (NFA) approach for assets commissioned w.e.f. new Control Period;

**Considering the pros and cons of the various methodology discussed, comments and views of the stakeholders are requested on these approaches.**

### 2.1.3. Hybrid Approaches for restricting Equity at specified level after completion of Useful Life

There are two more hybrid approaches being followed in some specified cases. The first is being applied by CERC after completion of useful life in case of a generating station or a transmission system including communication system. Proviso to Regulation 18(3) of the CERC (Terms and Conditions of Tariff) Regulations, 2019 provides as follows:

> *"Provided that in case of a generating station or a transmission system including communication system which has completed its useful life as on or after 1.4.2019, if the equity actually deployed as on 1.4.2019 is more than 30% of the capital cost, equity in excess of 30%shall not be taken into account for tariff computation;"*

The CERC in its Statement of Objects and Reasons (SoR) for CERC (Terms and Conditions of Tariff) Regulations, 2019 has stated as follows:

> *"7.1.7 It is observed that many of the generating stations and transmission systems which were commissioned on or before the commencement of tariff period 2004-09, and which have either completed or about to complete their useful life, have a debt-equity ratio of 50:50. The Commission sees strong logic to bring uniformity of the capital structure of all the projects. Therefore, the excess equity of the projects are required to be aligned at par with normative debt:equity ratio.*
>
> *7.1.8 The Commission, after considering all the relevant aspects carefully, has decided that the proposed reduction of equity to the extent of 30% instead of salvage value will be more pragmatic approach, as it takes care of the interest of both the investors and consumers. Accordingly, in case of a generating station or a transmission system which has completed its useful life as on or after 1.4.2019, if the equity actually deployed as on 1.4.2019 is more than 30% of the capital cost, equity in excess of 30% shall not be taken into account for tariff computation and will be deemed to paid from the accumulated depreciation."*

The second approach is being adopted by RERC in its MYT Regulations, 2019, which provide as under:

> "***19. Debt-equity ratio***
>
> *…*
>
> *In case of Generating Station or a transmission system or distribution system, which has completed its useful life as on or after 1.4.2019, the accumulated depreciation as on the completion of the useful life less cumulative repayment of loan shall be utilized for reduction of the equity and depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan and thereafter shall be utilized for reduction of equity."*

Under this hybrid or modified GFA approach, the depreciation recovery in the initial years is utilized for the repayment of the loan and post that it is adjusted towards the equity. Accordingly, at the end of useful life of the asset, the remaining equity component is equivalent to the salvage value of the asset.

Adoption of one of these or any other alternative approach for the assets operational beyond original useful life may be explored, in case of continuation of the existing RoE (GFA) approach.

**Comments and suggestions are invited from the stakeholders regarding the various options.**

### 2.1.4. Post-Tax Vs Pre-Tax Rate of Return Approach

The issue is whether the returns to the investor should be allowed on a post-tax basis or on pre-tax basis. Both the approaches have merits and demerits.

Under the post-tax approach, the Commission has to assess the income tax liability at the time of determination of ARR and tariff, which can be complicated in case of entities that are undertaking other non-core businesses also, irrespective of whether they are regulated or not. Another demerit of the post-tax approach is that there is no inducement for better tax planning. However, in case of post-tax returns, the tax benefits available to the sector are passed on to the consumers.

On the other hand, the pre-tax return approach is aimed at encouraging power sector entities to do better tax planning and does not have the above demerits of post-tax return approach. The income tax liability does not have to be projected in advance, and at the end of the year, does not have to be matched with the actual income tax paid, etc. The issue of estimating the income tax for utilities operating in several States/Businesses will also not arise.

It should also be noted that the erstwhile State Electricity Boards (SEBs) were not liable to pay income tax. However, post EA 2003, most of the erstwhile SEBs have been unbundled and the successor companies engaged in the business of generation, transmission and distribution of electricity are liable to pay income tax.

Under the mechanism of pre-tax returns, the benefits of Section 80 IA applicable to new units are not passed on to the beneficiaries and the tax recovered by utilities in some cases are more than the actual income tax. Under the regulated business, in general, the profit of the utilities should be equal to RoE specified because all other elements of tariff are based on the general premise of pass through of costs subject to achievement of normative performance parameters. Practically, the profit of the utilities is influenced by other factors such as profits of non-core business carried out by the utilities, UI earnings, efficiency gains, incentive earned, difference in the depreciation allowed under tariff and as per Income Tax Act, 1961, income tax holiday allowed in power sector, etc.

Another option could be to consider the income tax rate on normative basis (MAT / Corporate Tax Rate) and utilize it to gross up the base Rate of return on Equity only. However, the income tax on account of incentives and other non-regulated businesses shall not be allowed to be passed on in the tariff. Under the regulated business, when the utilities are allowed specified post tax rate of return on equity in addition to prudently incurred expenses, the recovery of tax on specified Return on Equity by the utilities needs to be allowed based on actual tax paid on Return on Equity on 'no profit' and 'no loss' basis, as tax on Return on Equity is a sort of reimbursement to ensure the recovery of the specified RoE.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

### 2.1.5. Cost of Equity

Section 61(d) of the Electricity Act, 2003, and Paragraph 5.11 (a) of the Tariff Policy 2016 have suggested to strike a balance between safeguarding of consumers' interest and recovery of the cost of electricity in a reasonable manner while laying down broad guiding principles for the determination of the rate of return.

Further, the Forum of Regulators, in its Report on "Analysis of Factors Impacting Retail Tariff And Measures To Address Them" has recommended as follows.

> *"In the entire value chain, transmission business has the lowest risk. The RoE for transmission companies should therefore, be reviewed immediately. RoE for generation and transmission should be linked to the 10 year G Sec rate (average rate for last 5 years) plus risk premium subject to a cap as may be decided by Appropriate Commission. For a Discom, the RoE could be fixed based on the risk premium assessed by the State Commission. Income tax reimbursement should be limited to the RoE component only."*

It is observed that the Forum of Regulators (FOR) has also recommended differential RoE for Generation and Transmission Businesses with a reduction in RoE for Transmission Business.

For computation of expected cost of Equity, capital asset pricing model (CAPM) is the most widely used method. According to this method, the expected cost equity can be calculated as:

$$Ra = Rf + [\beta \times (Rm - Rf)]$$

Where:

Ra = Expected rate of return (Cost of Equity)

Rf = Risk-free rate

β = Beta of the security

Rm = Expected return on market

Further, considering the longer periods of data while computing RoE using the CAPM, provides the reliable results as it averages out the period of higher and lower returns and economic uncertainties. Therefore, data for 10 year period for risk free rate, beta and expected return on market may be considered.

The second approach would be to link the expected rate of return with market interest rates such as G-SEC rates/RBI Repo Rate plus certain spread, which will reflect the appropriate risk levels and be lucrative to the investor for enabling future investments.

**Comments and suggestions are invited from the stakeholders on the approaches for allowing Cost of RoE.**

### 2.1.6. Splitting Cost of Equity (Rate of Return on Equity)

The GERC MYT Regulations 2016 provides one composite rate of return on equity (RoE). However, few SERCs segregated the rate of RoE on equity in two parts – one fixed rate equal to the Base RoE, which is assured to the Utility and other variable rate linked to additional RoE, which is allowed against some identified measurable performance parameters and allowed at the time of truing-up. The objective of this approach is to link part of the RoE to improve operational performance of the Utilities, in order to incentivize better performance from them.

The following table summarizes the approach adopted by some of the SERCs to allow variable rate linked to additional RoE:

*Table 1: Variable Rate of Return on Equity*

| State / ERC | Variable Rate of Return on Equity |
|---|---|
| **CERC** | **Thermal Generating Stations:**<br>• 0.25% for every incremental ramp rate of 0.10% per minute achieved over and above the ramp rate of 1% per minute; Ceiling at 0.50%; |
| **Maharashtra** | **Thermal Generating Stations:**<br>• 0.25% for every incremental ramp rate of 0.10% per minute achieved over and above the ramp rate of 1% per minute; Ceiling at 0.50%;<br>• Mean Time Between Failure (MTBF) >45 days -> 0.50%, MTBF >90 days -> 0.75%, MTBF >120 days -> 1.00%<br>**Transmission:**<br>• Overachievement of Transmission Availability – 0.75% for different slabs up to 1.50%<br>**Wheeling:**<br>• Overachievement of Wires Availability – 0.50% for different slabs up to 1.50%<br>**Retail Supply:**<br>• Up to 1.00% linked to percentage of assessed bills as a percentage of total bills issued in a year<br>• Up to 1.00% if collection efficiency for the year is above 99% |

| State / ERC | Variable Rate of Return on Equity |
|---|---|
| **Madhya Pradesh** | **Thermal Generating Stations:**<br>• 0.25% for every incremental ramp rate of 0.10% per minute achieved over and above the ramp rate of 1% per minute; Ceiling at 0.50%;<br>**Transmission:**<br>• No provision<br>**Distribution**<br>Additional RoE – Up to 2.00%<br>• 0.75% linked to metering of rural domestic consumers<br>• 0.75% for capitalisation more than 95% approved amount<br>• 0.50% for R&M expense more than 95% of approved amount |

Apart from this, CERC (Terms and Conditions of Tariff) Regulations, 2019 provides for a reduced rate of RoE at weighted average rate of interest on actual loan portfolio of the Utility in respect of additional capitalization after cut-off date beyond the original scope, excluding additional capitalization due to Change in Law. Further, CERC and most of the SERCs also penalize the Utilities for non-achievement of certain requirements, summarized as follows:

- In case of a new project, the rate of return on equity shall be reduced by 1.00% for such period as may be decided by the Commission, if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO) or Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the respective RLDC/SLDC;

- in case of existing generating station, as and when any of the requirements under (i) above of this Regulation are found lacking based on the report submitted by the concerned RLDC/SLDC, rate of return on equity shall be reduced by 1.00% for the period for which the deficiency continues;

- in case of a thermal generating station, with effect from 1.4.2020, rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate of 1% per minute.

Further, UPERC in its MYT Regulations for Generation Tariff and Transmission and Distribution Tariff, has provided for penalizing the Utilities at the rate of 0.25% per month for delay in filing of MYT and/or Tariff Petitions.

In line with the above, it is proposed to introduce segregated the rate of RoE on equity in two parts – one fixed rate equal to the Base RoE, which is assured to the Utility and other variable rate linked to additional RoE, which is allowed against some identified measurable performance parameters and allowed at the time of truing-up. The following table lists down illustrative list of some of the parameters which may be considered for variable rate linked to additional RoE and penalty on RoE.

*Table 2: Suggested list of Performance Parameters for differential rate of RoE*

| Utility | Performance Parameters for additional Rate of RoE | Parameters for Penalty on Rate of RoE |
|---|---|---|
| **Generation** | • Ramp Rate<br>• Mean Time between failure<br>• Generation during Peak-Demand | • Delay in filing Petition<br>• Absence of operational RGMO, FGMO, etc. |
| **Transmission** | • Exceeding Transmission Availability within the dead band (where no incentive is provided)<br>• Transmission Loss % Target<br>• No. of disruptions in Transmission Lines / Substations during the year and average duration of such disruptions | • Delay in filing Petition<br>• Absence of data telemetry equipment, etc.<br>• Non-separation of SLDC from Transmission |
| **SLDC** | • Percentage of Approved Capex Utilization<br>• Implementation of Forum of Regulators' recommendations in Capacity Building of Indian Load Despatch Centres (CABIL) | • Non-separation of SLDC from Transmission<br>• Delay in filing Petition |
| **Distribution Wheeling** | • Percentage of Approved Capex Utilization<br>• Percentage Utilization of approved R&M Expenses<br>• Overachievement of Wires Availability<br>• Overachievement of Distribution Loss Targets<br>• Overachievement of Smart Meters deployment targets<br>• Overachievement of targeted independently measurable parameters – SAIFI, SAIDI, MAIDI, MAIFI CAIDI, Transformer Failure Rate, etc. against targets<br>• Overachievement of other identified Performance Parameters mentioned in GERC Supply Code / MoP Rights of Consumer Rules, 2022, whichever is more stringent | • Delay in filing Petition<br>• Non-separation of books of accounts for Wheeling and Retail Supply Business |
| **Distribution Retail Supply** | • Percentage of assessed bills as a percentage of total bills issued in a year | • Delay in filing Petition<br>• Non-separation of books of accounts for Wheeling and |

| Utility | Performance Parameters for additional Rate of RoE | Parameters for Penalty on Rate of RoE |
|---|---|---|
| | • Overachievement of Collection Efficiency Targets<br>• Implementation of ToD based tariff for Residential Consumer categories | Retail Supply Business<br>• Non-submission of detailed sales and demand forecast and power procurement plan in line with CEA's Resource Adequacy Guidelines |

Different Performance Parameters and trajectories may be adopted for different Distribution Licensees based on their actual performance and priority of the area of supply.

**Comments and suggestions are invited from the stakeholders regarding the option of introducing an additional variable rate cost of equity (RoE) and penalty on cost of equity (RoE) and also on the list of parameters for the same.**

## 2.2. Tax on Income

GERC MYT Regulations, 2016 stipulates as under:

*"41. Tax on income*

*41.1 The Commission in its MYT Order shall provisionally approve Income Tax payable for each year of the Control Period, if any, based on the actual income tax paid, including cess and surcharge on the same, if any, as per latest Audited Accounts available for the Applicant, subject to prudence check.*

*41.2 Variation between Income Tax actually paid, including cess and surcharge on the same, if any, and approved, if any, on the income stream of the regulated business of Generating Companies, Transmission Licensees, SLDC and Distribution Licensees shall be reimbursed to/recovered from the Generating Companies, Transmission Licensees, SLDC and Distribution Licensees, based on the documentary evidence submitted at the time of truing up of each year of the Control Period, subject to prudence check.*

*41.3 Under-recovery or over-recovery of any amount from the beneficiaries or the consumers on account of such tax having been passed on to them shall be adjusted every year on the basis of income-tax assessment under the Income-Tax Act, 1961, as certified by the statutory auditors. The Generating Company, or the Transmission Licensee or SLDC or Distribution Licensee, as the case may be, may include this variation in its truing up Petition:*

*Provided that tax on any income stream other than the core business shall not be a pass through component in tariff and tax on such other income shall be borne by the Generating Company or Transmission Licensee or the Distribution Licensee, as the case may be."*

Therefore, the Commission currently follows the approach of allowing the normative tax as per actuals subject to prudence check.

While following the approach of allowing income tax as per actuals, there might be a possibility of burdening the consumers with the income tax pertaining to other income/business, earning on account of efficiency target overachievement and other incentive provided by central / state government in the infrastructure. In order to segregate the income tax pertaining to core business, the utility have to maintain the expenditure pertaining to different stream separately in their books of accounts or has to be certified by a statutory auditor.

However, following the approach of grossing up of RoE based on effective tax rate (as per ITR), it ensures that tax is being allowed only of RoE part and are able to pass on the benefits and concessions available in income tax to the beneficiaries. However, the tax rate at which it should grossed up needs to be deliberated. A guidance can be taken from CERC Approach Paper for 2024 Tariff Regulations in this regard, which stipulates:

> *"4.17……………*
>
> *In view of the above discussion and recent amendments to the Income tax regime, a domestic company shall fall under one of the following brackets, and the maximum tax amount that shall be payable is limited by the tax rates notified for the relevant category. Therefore, Base Rate of RoE may be grossed up as follows:*
>
> *1. At MAT rate (If not opted for Section 115 BAA)*
>
> *2. At effective tax rate (if not opted for Section 115BAA) subject to ceiling of Corporate Tax Rate; or*
>
> *3. At reduced tax rate under Section 115BAA of the Income Tax Act or any other relevant categories notified from time to time subject to ceiling of rate specified in the relevant Finance Act.*
>
> *Further, tax shall be allowed only in cases where the company has actually paid taxes as under no circumstances tax can be allowed to be recovered if the company has not paid any tax for* the year under consideration."

Accordingly, it proposed to introduce a capping on the pass through of tax only up to the effective tax rate (to be computed based on tax paid as a percentage of assessed profits as per Assessment Order issued by the Income Tax Authority) on the average/opening equity balance allowed by the Commission for the financial year or the actual tax paid by the Utility.

Further, it is also observed that CERC Terms and Conditions of Tariff Regulations, 2019 in first proviso to Regulation 30(2) provides for rate of return on equity at weighted average rate of interest on actual loan portfolio for additional capitalization after cut-off date beyond original scope, excluding additional capitalization due to Change in Law events, on which the normal rate of return on equity has continued, but without grossing-up with tax rate. Accordingly, one of the possible approaches could be to consider allowing a cost of equity (RoE) without any income tax as pass-through to the Utilities.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

## 2.3. Interest on loan

GERC MYT Regulations, 2016 provides as under:

*"**38. Interest and finance charges***

*38.1 The loans arrived at in the manner indicated in Regulation 33 on the assets put to use, shall be considered as gross normative loan for calculation of interest on loan:*

*Provided that interest and finance charges on capital works in progress shall be excluded:*

*Provided further that in case of de-capitalisation or retirement or replacement of assets, the loan capital approved as mentioned above, shall be reduced to the extent of outstanding loan component of the original cost of the de-capitalised or retired or replaced assets, based on documentary evidence.*

*38.2 The normative loan outstanding as on April 1, 2016, shall be worked out by deducting the cumulative repayment as admitted by the Commission up to March 31, 2016, from the gross normative loan.*

*38.3 The repayment for the year during the Control Period from FY 2016-17 to FY 2020-21shall be deemed to be equal to the depreciation allowed for that year.*

*38.4 Notwithstanding any moratorium period availed by the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the annual depreciation allowed.*

*38.5 The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee:*

*Provided that at the time of truing up, the weighted average rate of interest calculated on the basis of the actual loan portfolio during the year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee shall be considered as the rate of interest:*

*Provided further that if there is no actual loan for a particular year but normative loan is still* *outstanding, the last available weighted average rate of interest for the actual loan shall be considered:*

*Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, does not have actual loan, then the weighted average rate of interest of the other business of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee regulated by the Commission shall be considered:*

*Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, does not have actual loan, and the other business of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee regulated by the Commission also does not have actual loan, then the weighted average rate of interest of the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee as a whole shall be considered:*

*Provided also that if the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee as a whole does not have actual loan, then the Bank Rate plus 200 basis points shall be considered as the rate of interest for the purpose of allowing the interest on the normative loan.*

*38.6 The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest: Provided that at the time of truing up, the normative average loan of the year shall be considered on the basis of the actual asset capitalisation approved by the Commission for the year.*

*38.7 The above interest computation shall exclude interest on loan amount, normative or otherwise, to the extent of capital cost funded by Consumer Contribution, Grants or Deposit Works carried out by Transmission Licensee or SLDC or Distribution Licensee or Generating Company, as the case may be.*

*38.8 The Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee, as the case may be, in the ratio of 2:1.*

*38.9 Interest shall be allowed on the amount held as security deposit held in cash from Transmission System Users, Distribution System Users and Retail consumers at the Bank Rate as on 1stApril of the financial year in which the Petition is filed."*

Further, the table below provides the review of treatment of loan in the MYT Regulations of the select ERCs:

**Table 3: Treatment of Loan by various ERCs**

| Parameter | CERC | Gujarat | Maharashtra | Telangana | Rajasthan |
|---|---|---|---|---|---|
| **General Provisions** | •Repayment is considered from the first year of the commercial operation and is equal to the annual depreciation allowed<br>•No moratorium considered | | | | |
| **Rate of Interest** | •Weighted average rate of interest calculated on the basis of the actual loan portfolio during the year | | | | |
| **Rate of Interest (in case of no actual loan)** | • No actual loan for a particular year -> last available weighted average<br>• No actual loan -> weighted average rate of interest of the whole business is considered. | • No actual loan for a particular year -> last available weighted average rate of interest<br>• No actual loan -> rate of interest for other businesses else,<br>• Bank rate + 2% | • No actual loan for a particular year -> last available weighted average rate of interest<br>• No actual loan in past as well -> weighted average rate of interest for other businesses<br>• No actual loan on other business in past as well -> weighted average rate of interest for entity as whole else<br>• Bank rate + 2% | • No actual loan for a particular year -> last available weighted average rate of interest<br>• No actual loan->rate of interest specified in regulation (1 Yr SBI MCLR) | • No actual loan for a particular year -> last available weighted average<br>• No actual loan -> weighted average rate of interest of the whole business is considered. |
| **Refinancing of loan** | • Benefit is shared between beneficiaries and | • Benefit is shared between beneficiaries and | • Benefit is shared between beneficiaries and licensee in ratio of 2:1 | • Benefit is shared between beneficiaries and | • Refinance/ re-structure the actual loan as long |

| | | | | | |
|---|---|---|---|---|---|
| | licensee in ratio of 1:1 | licensee in ratio of 2:1 | • Provided also that the re-financing shall not be subject to any adverse terms and conditions and additional cost. | licensee in ratio of 2:1 | as it results in net savings on interest |

| Parameter | Punjab | Karnataka | Madhya Pradesh | Delhi | Uttarakhand | Himachal Pradesh |
|---|---|---|---|---|---|---|
| **General Provisions** | Allow obligatory taxes on interest, finance charges (including guarantee fee payable to the Gov.) and any exchange rate difference arising from foreign currency borrowings, as finance cost | Repayment for each year of the Control Period shall be deemed to be equal to the depreciation allowed for that year. | Repayment is considered from the first year of the commercial operation.<br>No moratorium period | • Repayment is considered from the first year of the commercial operation.<br>• No moratorium period<br>Rate of Interest shall not exceed approved return on equity. | Normative outstanding loans after deducting cumulative repayment shall be considered<br>Repayment equal to depreciation | Computed on the outstanding loans,<br>duly taking into account the schedule of repayment |

| Parameter | Punjab | Karnataka | Madhya Pradesh | Delhi | Uttarakhand | Himachal Pradesh |
|---|---|---|---|---|---|---|
| **Rate of Interest** | For existing loans, the actual rate of interest paid/payable (other than working capital loans) on loans by the Licensee is considered<br>For new loans, one (1) year State Bank of India (SBI) MCLR as on 1st April of plus a margin determined on the basis of actual rate of interest | Weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year | Weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year | Weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year | WAROI on actual loan portfolio of the previous year after providing appropriate accounting adjustment for interest capitalised. | weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year |
| **Rate of Interest (in case of no actual loan)** | No actual loan for a particular year -> last available weighted average | No actual loan for a particular year -> last available weighted average rate of interest<br>No actual loan on in past as well -> weighted | •No actual loan for a particular year -> last available weighted average<br>•No actual loan -> weighted average rate of interest of the whole business is considered. | Bank rate plus margin specified by the Commission in the business plan<br>Bank rate = MCLR or Other benchmark rate by SBI | No actual loan for a particular year -> last available weighted average rate of interest<br>No actual loan ->weighted average rate of interest of the whole business is considered. | |

| Parameter | Punjab | Karnataka | Madhya Pradesh | Delhi | Uttarakhand | Himachal Pradesh |
|---|---|---|---|---|---|---|
| | | average rate of interest for entity as whole | | | | |
| **Refinancing of loan** | | Shared between the beneficiaries and the generating company, in the ratio of 50:50. | •Benefit is shared between beneficiaries and licensee in ratio of 2:1 | Shared between the beneficiaries and the generating company, in the ratio of 50:50.<br>Net saving computed as the product of total quantum of loan availed and difference of weighted average rate of interest on actual loans versus margin of 1.00% plus (+) SBI MCLR. | •Benefit is shared between beneficiaries and licensee in ratio of 1:2 | - |

As clearly evident from the above table, the treatment of normative loan of majority of the ERCs are more or less similar. It is proposed to continue with the existing approach of considering the addition in line with the normative debt to equity ratio and repayment linked to allowed depreciation for the year.

Further, the interest on loan is computed as WAROI calculated on the basis of the actual loan portfolio during the year applicable to the Generating Company or the Transmission Licensee or SLDC or the Distribution Licensee. However, different licensees have different business risk profile and the above methodology sometime allows the inefficiencies of licensees with high risk profile to be passed on to the consumers. Therefore, it is proposed to continue with the approach of allowing interest on loan as WAROI calculated on the basis of the actual loan portfolio during the year with an upper capping of the interest rate linked to an identified benchmarked long-term debt rate of interest, which may be different for government and private utilities. Further, in case of absence of any actual loan by a utility for the regulated business, it is proposed that the WAROI shall be linked with the benchmarked long-term debt rate of interest, instead of the rate of debt of other business, or past debt.

Further, the remaining provisions i.e. for the case where there is no actual loan and sharing of gains on account of refinancing, it is proposed to continue with the existing approach.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

## 2.4. Depreciation

### 2.4.1. Depreciation methodology and rate;

Depreciation is a major component of the annual fixed cost. The principles behind the charging of depreciation and the depreciation rates have been debated over the years, including the linkage of depreciation to creation of a reserve fund for replacement of assets versus the linkage of depreciation to providing cash flow for repayment of loans taken by the Utility.

In this context, Clause 5 (c) of the Tariff Policy stipulates:

> *"**The Central Commission may notify the rates of depreciation in respect of generation and transmission assets.** The depreciation rates so notified would also be applicable for distribution with appropriate modification as may be evolved by the Forum of Regulators.*
>
> ***The rates of depreciation so notified would be applicable for the purpose of tariffs as well as accounting. There should be no need for any advance against depreciation.***

*Benefit of reduced tariff after the assets have been fully depreciated should remain available to the consumers."*

GERC MYT Regulations, 2016 stipulates that:

*"39. Depreciation*

*39.1 The value base for the purpose of depreciation shall be the Capital Cost of the asset admitted by the Commission.*

*39.2 The Generation Company or Transmission Licensee or SLDC or Distribution Licensee shall be permitted to recover depreciation on the value of fixed assets used in their respective Business computed in the following manner:*

*(a) The approved original cost of the project/fixed assets shall be the value base for calculation of depreciation;*

*(b) Depreciation shall be computed annually based on the straight line method at the rates specified in the Annexure I to these Regulations:*

*Provided that the remaining depreciable value as on 31stMarch of the year closing after a period of 12 years from date of commercial operation shall be spread over the balance useful life of the assets:*

*Provided further that for a Generating Company or a Transmission Licensee or SLDC or a Distribution Licensee formed as a result of a Transfer Scheme, the depreciation on assets transferred under the Transfer Scheme shall be charged as per rates specified in these Regulations for a period of 12 years from the date of the Transfer Scheme, and thereafter depreciation will be spread over the balance useful life of the assets:*

*Provided also that the depreciation on the assets financed through consumer contribution, deposit work, capital subsidy or grant, shall be considered as per the Annual Accounts:*

*Provided also that the depreciation already charged after the date of the Transfer Scheme, shall not be restated:*

*Provided also that the Generating Company or Transmission Licensee or SLDC or Distribution Licensee, shall submit all such details or documentary evidence, as may be required under these Regulations and as stipulated by the Commission, from time to time, to substantiate the above claims:*

*Provided also that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life;*

*(c) The salvage value of the asset shall be considered at 10 per cent of the allowable capital cost and depreciation shall be allowed upto a maximum of 90 per cent of the allowable capital cost of the asset: Provided that in the case of hydro generating station, the salvage value shall be as provided in the agreement, if any, signed by the developers with the State Government.*

*39.3 Land other than the land held under lease and the land for reservoir in case of hydro generating station shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing depreciable value of the asset.*

*39.4 In case of the existing projects, the balance depreciable value as on April 1, 2016, shall be worked out by deducting the cumulative depreciation as admitted by the Commission up to March 31, 2016, from the gross value of the assets.*

*39.5 In case of projected commercial operation of the asset for part of the year, depreciation shall be calculated based on the average of opening and closing value of asset, approved by the Commission:*

*Provided that depreciation will be re-calculated during truing-up for assets capitalised at the time of Truing Up of each year of the Control Period, based on documentary evidence of asset capitalised by the Applicant, subject to the prudence check of the Commission, such that the depreciation is calculated proportionately from the date of capitalisation."*

GERC MYT Regulations, 2016 has specified the straight-line method for determination of depreciation expenses for the Generation, Transmission, Distribution Wire, and Retail Supply business, and a residual value of 10%. The asset wise depreciation rate for the first 12 years is specified in the Regulation, and the remaining depreciable value of an asset as on 31st March of the year closing after a period of 12 years from date of commercial operation is to be spread over the balance useful life of that asset. Further, the repayment of loan has also been considered on normative basis and has been considered equal to the annual depreciation allowed.

Further, CERC in the Approach Paper for the control period 2024-29 has stated as follows:

*"4.13 ……..*

*Further, Part B of Section 123 of the Companies Act, 2013, with regard to the residual value of any asset specifies as follows.*

> *"4. The useful life or residual value of any specific asset, as notified for accounting purposes by a Regulatory Authority constituted under an Act of Parliament or by the Central Government shall be applied in calculating the depreciation to be provided for such asset irrespective of the requirements of this Schedule."*
>
> *Further, Depreciation depends on the following three factors:*
>
> *1. Rate base (gross fixed assets on which the rate of depreciation applied), which includes subsequent additions.*
>
> *2. Method of depreciation – Straight Line Method (SLM) has been followed in all preceding years.*
>
> *3. Depreciable life – As the assets are required to be provided with 90% depreciation over the life. Hence, the rate of depreciation is directly linked to life of the assets.*
>
> *It is observed that while specifying the depreciation rate, the tenure of the loan considered is 12 years, whereas the life of most of the assets is between 25 and 40 years. It is observed that shorter loan duration and higher depreciation in the initial years have resulted in front loading of tariffs. Considering that nowadays loans are available for 15-18 years, the possibility of increasing the loan tenure for the computation of depreciation rates needs to be explored. Excessive front loading of tariffs increases resistance to future investments. For example, external loans have much lower interest rates, therefore, spreading depreciation over longer periods in the case of external loans can be a viable option for reducing costs in the initial years, which shall, however, include FERV factor and other financing cost. Therefore, there is a need to create a balance and align the depreciation rate with the actual loan tenure and life of the assets.*
>
> *In view of the above, a depreciation rate may be specified considering a loan tenure of 15 years instead of the current practice of 12 years. Further, additional provisions may also be specified that allow lower rate of depreciation to be charged by the generator in the initial years if mutually agreed upon with the beneficiary(ies)."*

In view of above, it is agreed that, as per prevailing provisions depreciation are skewed in the initial 12 years, even though the life of most of the assets is in the range from 25 to 40 years. Further, considering the revised loan tenure of 15-18 years, it is prudent to revise the period for accelerated depreciation from 12 years to 15 years. The Tariff Policy stipulates that the depreciation rates specified by the CERC should be adopted for generation and transmission business, and may be adopted for the distribution business also, after suitable modification to be undertaken by the Forum of Regulators. The Tariff Policy also states that the same rate of depreciation should be considered for tariff purposes as well as accounting purposes and that there should be no need of providing Advance Against Depreciation (AAD) while determining the tariff. Accordingly, the depreciation rates shall be revised in line with the revision of normative loan tenure to 15 years.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 2.4.2. Treatment of IT assets

GERC while notifying the GERC MYT Regulations, 2016 had considered the salvage value at 90% for all the asset categories. However, IT equipment such as laptop, communication system etc. have shorter life span and are prone to technology change, thereby leaving almost negligible salvage value.

CERC in their Tariff Regulations 2014 have considered the salvage value as NIL for the IT equipment. Considering the Tariff Policy which stipulates that the depreciation rates specified by the CERC should be adopted for generation and transmission business, and may be adopted for the distribution business also, after suitable modification to be undertaken by the Forum of Regulators. Therefore, it is proposed to consider salvage value as NIL for IT Equipment.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 2.4.3. Restricting Depreciation till Loan Repayment in case we continue with GFA approach

The tariff regulations ensure the return on investment to the investors on the approved capital investments. In a usual course of business, the returns gets reduced over the life of asset as they recover the depreciation on year-on-year basis. However, the power sector utilities are allowed RoE on gross equity infused even when the cumulative depreciation exceeds the debt component over the life of assets or until the assets is in use.

The existing tariff regulations doesn't have provisions of reduction of equity after competition of useful life and are essentially based on GFA approach as discussed above. However, under the NFA approach and modified GFA approach, the equity gets reduced to the salvage value after competition of useful life.

An asset, which has competed his useful life, recovers around 90% of the invested capital in the form of depreciation by the end of useful life. Therefore, continuing to allow return of existing equity base i.e., 30% of the capital expenditure essentially means allowing return on the investment which they have already recovered. This leads to over recovery to the utilities and burdens the consumers in the form of end user tariffs.

This issue needs to be deliberated from the point of view, whether the return should be allowed on NFA approach, or the depreciation should be allowed till loan repayment is completed.

Therefore, if the Commission continues with the GFA approach, comments and views of the stakeholders are requested on the approach whether depreciation should be allowed till loan repayment only.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 2.5. Normative Rate of Interest on Working Capital

GERC MYT Regulations 2016 stipulates that:

> *"Interest on working capital shall be allowed at a rate equal to the State Bank Base Rate (SBBR)/1 year State Bank of India (SBI) Marginal Cost of Funds Based Lending Rate (MCLR) /any replacement thereof by SBI for the time being in effect applicable for 1 year period, as may be applicable as on 1stApril of the financial year in which the Petition is filed plus 250 basis points:*
>
> *Provided that at the time of truing up for any year, interest on working capital shall be allowed at a rate equal to the weighted average State Bank Base Rate (SBBR) /1 year State Bank of India (SBI) Marginal Cost of Funds Based Lending Rate (MCLR) /any replacement thereof by SBI for the time being in effect applicable for 1 year period, as may be applicable prevailing during the financial year plus 250 basis points."*
>
> *………"*

The following table summarily compares the normative rate of interest on working capital for various ERCs.

*Table 4: Normative Rate of Interest on Working Capital*

| State | Interest Rate for Working Capital |
|---|---|
| **Gujarat** | 1-Y SBI MCLR + 2.50% |
| **CERC** | 1-Y SBI MCLR + 3.50% |
| **Maharashtra** | 1-Y SBI MCLR + 1.50% |
| **Rajasthan** | Average Base Rate prevalent during first six months of the year previous to the relevant year + 3.00% |
| **Punjab** | 1-Y SBI MCLR + 3.50% |
| **Himachal Pradesh** | 1-Y SBI MCLR + 3.00% |
| **Delhi** | Bank rate on 1st April of FY + margin specified in business plan |
| **Uttarakhand** | 1-Y SBI MCLR + 3.50% |
| **Madhya Pradesh** | 1-Y SBI MCLR + 3.50% |
| **Karnataka** | Lower of (i) RBI base rate (latest) +2.50% and (ii) wt. av. rate of interest proposed by the licensee |

,It is observed majority of the SERCs have adopted the CERCs normative rate, i.e., 1-Y SBI MCLR +

3.50%, which is much more relaxed than existing normative rate specified by GERC, i.e. 1-Y SBI MCLR + 2.50%, with an exception of MERC, where the margin specified is 1.50% only. Accordingly, it is proposed to consider allowing the Interest on Working Capital at a rate equal to the one-year marginal cost of lending rate (MCLR) of the State Bank of India issued from time to time as on 1st April of the respective financial year plus 150 basis points.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 2.6. Carrying/Holding cost

Regulation 21.6 (c) of the GERC MYT Regulations, 2016 specifies as follows:

> *"Carrying cost to be allowed on the amount of Revenue Gap or Revenue Surplus for the period from the date on which such gap/surplus has become due, i.e., from the end of the year for which true-up has been done, till the end of the year in which it is addressed, calculated on simple interest basis at the weighted average State Bank Base Rate (SBBR) / I year State Bank of India (SBI) Marginal Cost of Funds Bused Lending Rate (MCLR) / only replacement thereof by SBI for the time being in effect applicable for I year period, as may be applicable for the relevant year, i.e. the year for which Revenue Gap or Revenue Surplus is determined:*
>
> *Provided that carrying cost on the amount of Revenue Gap shall be allowed up to the above limit, subject to prudence check and submission of documentary evidence for having incurred the carrying cost in the years prior to the year in which the revenue gap is addressed."*

In addition, the Clause 3(3)(c) of The Interest Act, 1978, states that it is not in the purview of the court to allow interest on interest. The relevant excerpt of the aforesaid Act is stipulated as under for the ready reference:

> *"3. Power of court to allow interest.*
>
> *(3) Nothing in this section, —*
> a) *shall apply in relation to—*
> *(i) any debt or damages upon which interest is payable as of right, by virtue of any agreement; or*
> *(ii) any debt or damages upon which payment of interest is barred, by virtue of an express agreement;*
> b) *shall affect—*
> *(i) the compensation recoverable for the dishonour of a bill of exchange, promissory note or cheque, as defined in the Negotiable Instruments Act, 1881 (26 of 1881); or*
> *(ii) the provisions of rule 2 of Order II of the First Schedule to the Code of Civil Procedure, 1908 (5 of 1908);*
> c) *shall empower the court to award interest upon interest."*

The main objects of the Electricity Act 2003 is to balance the interest of all the stakeholders. Further, the Commission had always endeavor to balance the interest of the consumers on the one hand and the licensees on the other. Protecting the interest of consumers and rationalisation of electricity tariff are the main objects of the Electricity Act 2003. However, if interest upon interest allowed, it will be against one of the main objects of Electricity Act 2003, i.e., balance the interest of all the stakeholders.

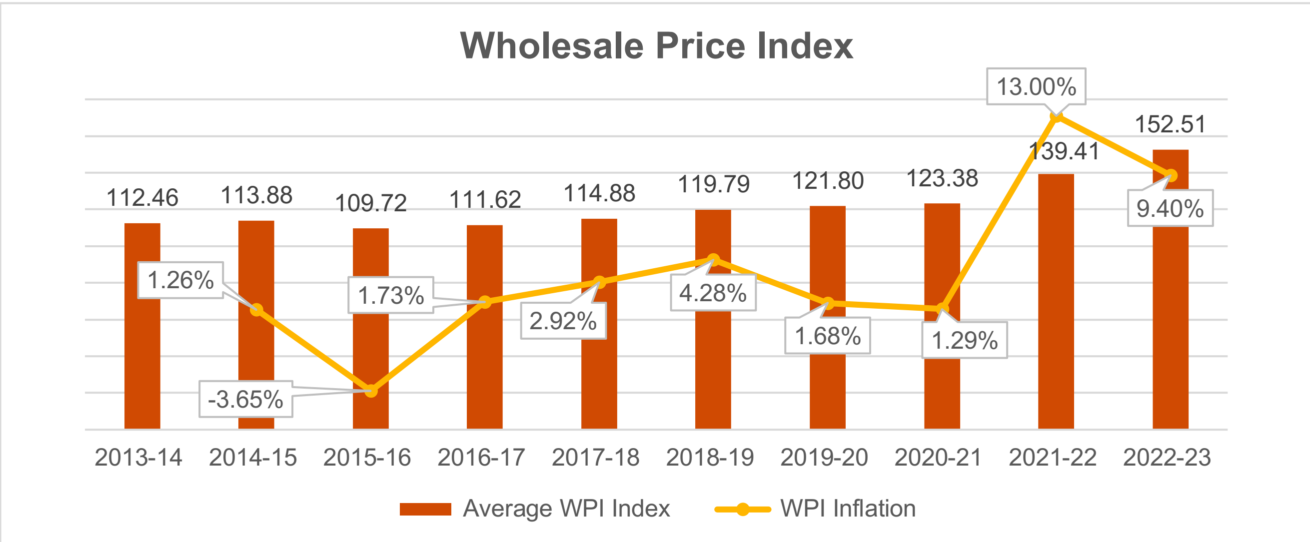
Therefore, the carrying cost/holding cost are worked out by applying the principles of simple interest. If the concept of allowing interest on interest, i.e. compound interest is applied, it would be a never-ending exercise and would create additional burden on the beneficiaries. The Regulation 21.6 (c) of the GERC MYT Regulations, 2016 clearly specifies that carrying cost has to be calculated on simple interest basis. However, in the interest of clarity, it is proposed that the same may be further clarified through specific unambiguous provision and / or with an illustration.

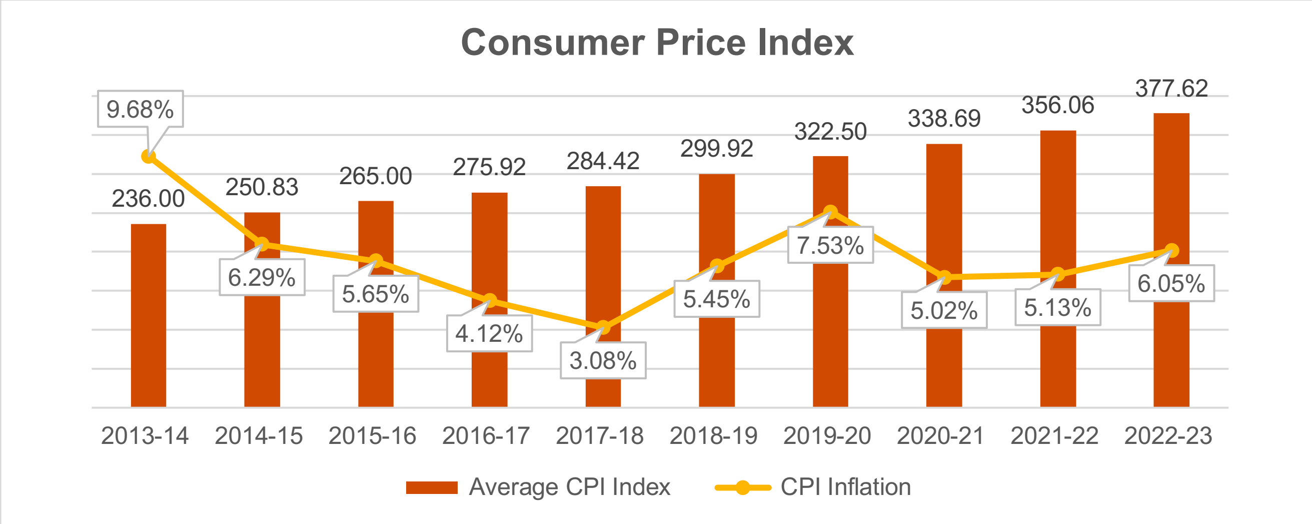
**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 2.7. Escalation Factor

In order to determine the Operation and Maintenance (O&M) expenses for the third control period, the Commission had considered an escalation factor for of 5.72% as specified by Central Electricity Regulatory Commission in its CERC (Terms and Conditions of Tariff) Regulations, 2009. The factor of 5.72% was calculated based on the inflation data up to October 2008. Since the fourth control period shall be starting from FY 2024-25, considering the factor of 5.72% may not be appropriate.

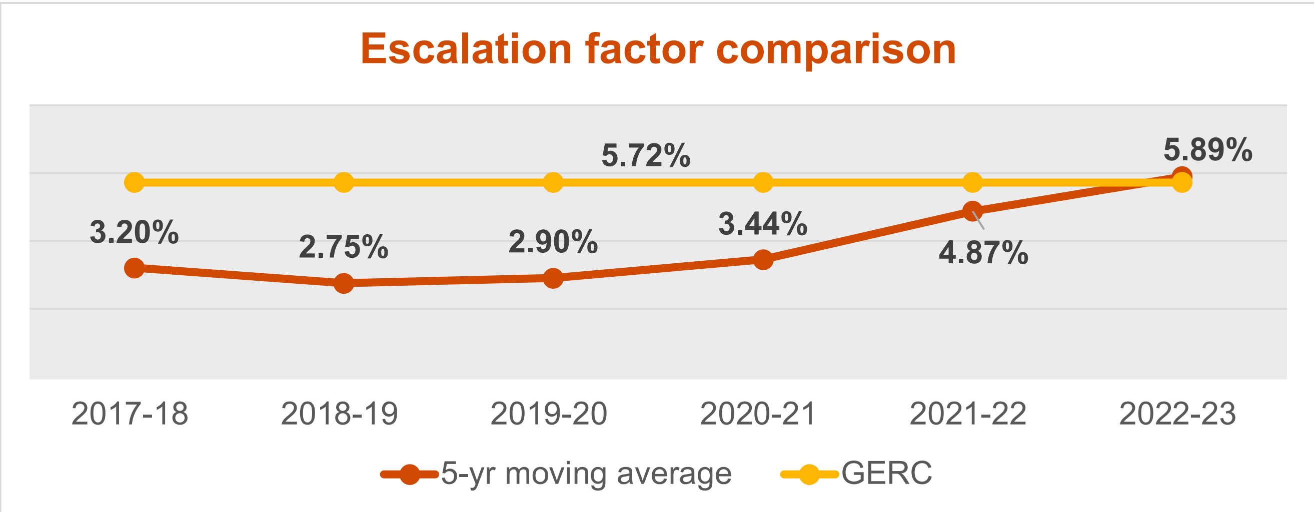
Further, the Wholesale Price Index (WPI) and Consumer Price Index (CPI) have fluctuated in the last few years mainly due to the effects of COVID-19 and global economic changes due to the Russia-Ukraine war. The WPI and CPI inflation for the last 10 years is as follows:






The WPI has fluctuated from 1.29% in FY 2020-21 to 13.00% to FY 2021-22. The CPI has also dipped from 7.53% in FY 2019-20 to 5.02% in FY 2020-21.

Further, the following graph compares the existing escalation rate as per GERC MYT Regulations, 2016 with an escalation factor computed based on a five-year moving average figures of CPI and WPI, which is clearly showing a huge deviation.




Therefore, it is proposed to consider a moving average of last 8 to 10 years' WPI and CPI values for determining the escalation factor for O&M expenses for the Utilities at the beginning of each financial year. The same may be considered to be trued-up based on monthly average actual WPI and CPI values during the true-up of each year of the control period.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

# 3. Generation

## 3.1. Operating Parameters

The operating parameters for Generating Stations include as follows:

- **Thermal Generating stations (Coal/Gas based)**- Normative Annual Plant Availability Factor (NAPAF), Normative Annual Plant Load Factor (NAPLF), Gross Station Heat Rate, Secondary fuel oil consumption, Limestone consumption, Auxiliary Energy Consumption, Transit and Handling Losses

- **Hydro generating stations**- Auxiliary Energy Consumption, Normative Annual Plant Availability Factor (NAPAF).

### 3.1.1. Normative Annual Plant Availability Factor (NAPAF)

GERC MYT Regulations, 2016 prescribes Normative Annual Plant Availability Factor of 85 per cent for full recovery of Annual Fixed Charges for all thermal generating stations, except for GSECL Generating Stations covered under Regulation 53.1. Further, relaxation of 2 per cent is provided in case of shortage of coal and uncertainty of assured coal supply on sustained basis, which shall be reviewed annually.

The NAPAF is determined based on the past years data available and best industry practices. As, the working environment is evolving day by day due to technological advancements, improved O&M practices, lower shutdowns and outages, the PAF has been improving. However, the availability of fuel and it's blending still remains a constraint. Similarly, the changing hydrology, and restrictions imposed on the flow of water, and changes in the pattern of water usage in the case of multipurpose dam projects, has impacted the NAPAF of the hydro generating stations.

In view of the above, NAPAF may be reviewed considering past years' PAF, arrangement of fuel (Coal), other than designated fuel supply agreements, changes in hydrology, etc. based on the following two methodologies:

1) Historical data of state generating plants – last 8 to 10 years may be considered and any anomalies due to force majeure events such as COVID-19 shall be taken care of;

2) CERC/ other SERC benchmarks considering CEA recommendations-

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

### 3.1.2. Other Operating Norms including SHR, Auxiliary Consumption, etc.

Various Regulations of the GERC MYT Regulations, 2016 prescribes norms for generating stations as follows:

- Regulations 53.3 and 53.4 – Gross Station Heat Rate
- Regulation 53.5 – Secondary Fuel Oil Consumption
- Regulation 53.6 – Lime stone Consumption
- Regulation 53.7 – Auxiliary Energy Consumption
- Regulation 53.8 – Transit and Handling Losses

These operating parameters may be reviewed based on the following two methodologies:

1) Historical data of generating plants – last 8 to 10 years may be considered and any anomalies due to force majeure events such as COVID-19 shall be taken care of;
2) CERC/ other SERC benchmarks considering CEA recommendations

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

## 3.2. Life Extension of a Generating Station

Several thermal as well as hydro generating plants of Gujarat have completed their useful life of 25 and 35 respectively and a few shall be completing the same in the next control period. These plant capacities can either be enhanced by installation of new plants or renovating the existing one or uprating them. In order to incentivise the extension of life beyond the useful life of the generating station or units, the Commission has given a provision for Renovation and Modernisation (R&M) expenses and Special Allowance (in lieu of R&M) forming part of the Annual Fixed Cost.

GERC Regulations 2016 state as follows:

> *"**50. Renovation & Modernisation***
>
> *……….*
>
> *50.5 In case of coal-based/lignite fired thermal generating station, the Generating Company, may, at its discretion, avail of a 'special allowance' in accordance with the norms specified in Regulation 50.6, as compensation for meeting the requirement of expenses including Renovation and Modernisation beyond the useful life of the generating station or a unit thereof, and in such an event, revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the special allowance shall be included in the Annual Fixed Cost:*

*Provided that such option shall not be available for a generating station or Unit for which Renovation and Modernization has been undertaken and the expenditure has been admitted by the Commission before the date of effectiveness of these Regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.*

*50.6 The Special Allowance shall be @ Rs. 7.5 lakh/MW/year for the year 2016-17 and thereafter escalated @ 5.72% every year during the Control Period, unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:*

*Provided that in respect of a unit in commercial operation for more than 25 years as on 1.4.2016, this allowance shall be admissible from the year 2016-17:*

*Provided further that the special allowance for the generating station, which, in its discretion, has already availed of a 'special allowance' in accordance with the norms specified in clause (iv) of Regulation 51.6 of Gujarat Electricity Regulatory Commission (Multi-Year Tariff) Regulations, 2011, shall be allowed Special Allowance by escalating the special allowance allowed for the year 2015-16 @ 5.72% every year during the Control Period.*

*50.7 In the event of granting special allowance by the Commission, the expenditure incurred or utilized from special allowance shall be maintained separately by the separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure."*

Further, CEA has also issued guidelines for renovation & modernisation / life extension works of coal/lignite based thermal power stations and hydro power stations.

R&M ensure extension of life of existing plants and saves huge capital expenditure that could have been incurred for commissioning of new plants. Thermal Generating Station also do have the alternative of opting for Special Allowance. However, while the option of R&M assures life extension of the generating station, there is no such condition in case of option of Special Allowance and it can be claimed on year on year basis, without any commitment for future availability. CERC (Terms and Conditions of Tariff) Regulations, 2019 has removed the escalation factor from the provision of Special Allowance. Further, the Approach Paper for Tariff Regulations for 2024-29 Control Period states that appropriate provisions may be provided wherein any utility that has opted for Special Allowance for the first year of the tariff period shall have to continue with the same for the rest of the tariff period.

Therefore, while the option of undertaking R&M instead of fresh capital investment continue to be explored based on a detailed cost-benefit analysis, the alternative of Special Allowance may also be with conditions and restrictions and also without any escalation.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

## 3.2.1. Normative Working Capital

All SERCs use a standard formula as norm for determination of working capital requirement, wherein cost of primary fuel, O&M expenses as well as cost of maintenance spares is allowed, in addition to the Receivables. Regarding inclusion of fuel expenses and one month of O&M expenses as a part of the working capital requirement, these are incurred for a given month are recoverable along with the tariff in the next month, the same needs to be a part of working capital. In addition, exclusion of the same may also have impact on the liquidity position of the utilities.

Further, the working capital norms as per provisions GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 5: Norms of Working Capital for Thermal Generation adopted by SERCs*

| ERC | Fuel Expenses | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|---|
| **Gujarat** | • Cost of Primary fuel:<br>○ 1 Month for Pit head<br>○ 1 ½ Month for Non-Pit head.<br>• Cost of secondary fuel oil for 2 months | 1 month | 1% of Historical Cost (GFA) | 1 month of the fixed charges and energy charges |
| **CERC** | • Cost of Primary fuel:<br>○ 10 days for Pit head<br>○ 20 days for Non-Pit head<br>• 30 days of cost of coal or lignite and limestone<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 45 days of the capacity charges and energy charges |
| **Maharashtra** | • Cost of Primary fuel:<br>○ 15 days for Pit head<br>○ 30 days for Non-Pit head<br>• 30 days of cost of coal or lignite and limestone<br>• Cost of secondary fuel oil for 2 months | 1 month | 1% of opening GFA | 45 days of the fixed charges and energy charges<br><br>Minus<br>Payables for fuel (including oil and secondary fuel oil) to the extent of 30 days |
| **Rajasthan** | • Cost of Primary fuel:<br>○ ½ Month for Pit head<br>○ 1 ½ Month for Non-Pit head<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 1½ months of the fixed and variable charges |

| ERC | Fuel Expenses | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|---|
| **Punjab** | Fuel Cost including cost of limestone / other reagent for 2 months | 1 month | 15% of O&M expenses | 2 months of the fixed and variable charges |
| **Himachal Pradesh** | NA | NA | NA | NA |
| **Delhi** | • Cost of Primary fuel:<br>○ 15 days for Pit head<br>○ 30 days for Non-Pit head<br>• 30 days of cost of coal<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 2 months of capacity and energy charges |
| **Uttarakhand** | NA | NA | NA | NA |
| **Madhya Pradesh** | • Cost of Primary fuel:<br>○ 15 days for Pit head<br>○ 30 days for Non-Pit head<br>• 30 days of cost of coal<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 45 days of the capacity and energy charges |
| **Karnataka** | • Cost of Primary fuel:<br>○ 10 days for Pit head<br>○ 20 days for Non-Pit head<br>• 30 days of cost of coal or lignite and limestone<br>• Cost of secondary fuel oil for 2 months | 1 month | 20% of O&M expenses | 45 days of the capacity and energy charges |

Regarding the primary fuel stock, the norms of other ERCs including CERC have moved to a much more stringent levels, up to 10 and 15 days for pit-head and non-pit head generating stations respectively. Therefore, the existing norms under GERC MYT Regulations, 2016 may need to be reviewed in the light of sectoral benchmarking and also actual inventory maintained by the generating stations in the State.

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed.

For maintenance spares, 20% of total O&M expenses are considered in the states of Rajasthan, Delhi, Madhya Pradesh, Karnataka etc. whereas the states of Maharashtra and Gujarat consider 1% of historical cost of assets. The existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the generating stations.

While majority of the select states consider 45 days of the capacity and energy charges for receivables, only Maharashtra considers 45 days of the fixed charges and energy charges after deducting payables for fuel (including oil and secondary fuel oil) to the extent of 30 days. Therefore, the Commission may review norms for considering the receivables for computing working capital requirement.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

*Table 6: Norms of Working Capital for Gas based Generation adopted by SERCs*

| ERC | Fuel Expenses | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|---|
| **Gujarat** | • Fuel Cost for 1 month<br>• Liquid fuel stock for 15 days | 1 month | 1% of Historical Cost (GFA) | 1 month of the fixed charges and energy charges |
| **CERC** | • Fuel Cost for 30 days<br>• Liquid fuel stock for 15 days | 1 month | 30% of O&M Expense | 45 days of the capacity and energy charges |
| **Maharashtra** | • Fuel Cost for 30 days<br>• Liquid fuel stock for 15 days | 1 month | 1% of opening GFA | 45 days of the fixed charges and energy charges<br><br>Minus<br>Payables for fuel (including oil and secondary fuel oil) to the extent of 30 days |
| **Rajasthan** | • Fuel Cost for ½ Month<br>• Liquid fuel stock for ½ Month | 1 month | 30% of O&M Expense | 1½ months of the fixed charges and variable charges |
| **Punjab** | • Fuel Cost for ½ Month<br>• Liquid fuel stock for ½ Month | 1 month | 30% of O&M expenses | 2 months of the fixed and variable charges |
| **Himachal** | NA | NA | NA | NA |

| ERC | Fuel Expenses | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|---|
| **Pradesh** | | | | |
| **Delhi** | • Fuel Cost for 30 days<br>• Liquid fuel stock for 15 days | 1 month | 30% of O&M expenses | 2 months of the capacity and energy charges |
| **Uttarakhand** | • Fuel Cost for 1 Month<br>• Liquid fuel stock for ½ Month | 1 month | 30% of O&M expenses | 2 months of the fixed and variable charges |
| **Madhya Pradesh** | NA | NA | NA | NA |
| **Karnataka** | • Fuel Cost for 30 days<br>• Liquid fuel stock for 15 days | 1 month | 30% of O&M expenses | 45 days of the capacity and energy charges |

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed.

For maintenance spares, 30% of total O&M expenses are considered in the states of Rajasthan, Punjab, Delhi, Uttarakhand, Karnataka etc. whereas the states of Maharashtra and Gujarat consider 1% of historical cost of assets. The existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the generating stations.

While majority of the select states consider 45 days to 2 months of the capacity and energy charges only Maharashtra considers 45 days of the fixed charges and energy charges after deducting Payables for fuel (including oil and secondary fuel oil) to the extent of 30 days. Therefore, the Commission may review norms for considering the receivables for computing working capital requirement.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

*Table 7: Norms of Working Capital for Hydro Generation adopted by SERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables |
|---|---|---|---|
| **Gujarat** | 1 month | 1% of Historical Cost (GFA) | 1 Month of fixed cost |
| **CERC** | 1 month | 15% of O&M Expense | 45 days of the fixed cost |
| **Maharashtra** | 1 month | 1% of opening GFA | 45 days of the fixed charges |
| **Rajasthan** | 1 month | 15% of O&M Expense | 1½ Months of the fixed charges |
| **Punjab** | 1 month | 15% of O&M expenses | 2 months of the fixed cost |
| **Himachal Pradesh** | 1 month | 15% of O&M expenses | 2 months of the fixed cost |
| **Delhi** | N/A | N/A | N/A |
| **Uttarakhand** | 1 month | 15% of O&M expenses | 2 months of the fixed charges |
| **Madhya Pradesh** | 1 month | 15% of O&M expenses | 45 days of the fixed cost |
| **Karnataka** | 1 month | 15% of O&M expenses | 45 days of the fixed cost |

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed.

For maintenance spares, 15% of total O&M expenses are considered in the states of Rajasthan, Punjab, Uttarakhand, Madhya Pradesh, Karnataka etc. whereas the states of Maharashtra and Gujarat consider 1% of historical cost of assets. The existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the generating stations.

While majority of the select states consider 45 days to 2 months of the capacity charges only. Therefore, the Commission may review norms for considering the receivables for computing working capital requirement.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

## 3.3. Principles of Tariff recovery

### 3.3.1. Differential Capacity Charges based on availability during Peak Requirement:

GERC MYT Regulations, 2016 has adopted tariff computation approach from the CERC (Terms and Conditions of Tariff) Regulations, 2014. Tariff Policy guidelines specifies for the introduction of differential rates for capacity charges. CERC, in their Tariff Regulations for the Control Period 2019-24 had also introduced the concept of peak and off -peak rates for the thermal generating stations to incentivize the availability during the peak requirement period (detailed provision is reproduced in the Annexure).

Introduction of such differential capacity charges during peak period would motivate higher availability factor and achieving target availability by the generating station, thus making the generating stations available during the hours most required by the beneficiaries. However, constraints may be faced in declaration the high demand and low demand season as the same needs to be notified in advance. Further, the same needs to coincide with the demand and supply forecast.

After issuance of the CERC (Terms and Conditions of Tariff) Regulations, 2019, few of the SERCs adopted the revised CERC approach of differential capacity charges during peak period, while many of them have continued with the old approach mentioned in CERC (Terms and Conditions of Tariff) Regulations, 2014. Further, CERC in its Approach Paper – CERC MYT Regulations for 2024-29 has now proposed deliberations on recovery based on daily peak and off-peak periods also. Accordingly, following few alternatives may be explored.

- To continue with existing methodology based on CERC Tariff Regulations, 2014
- To adopt revised methodology of month-wise peak/off-peak/normal seasons based on CERC Tariff Regulations, 2019
- CERC Approach Paper for 2024 Tariff Regulations has proposed the option of recovery based on daily peak and off-peak periods

**Comments and suggestions are invited from the stakeholders on the possible regulatory options in the matter.**

### 3.3.2. Option of Capacity Charges recovery on Scheduled Generation after completion of useful life

For the generating stations that have completed their useful life from the date of commercial operation, the generating company and the beneficiary shall have an option to arrive at a mutual agreement for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation. However, the beneficiary shall have the first right of refusal and upon its refusal to enter into an arrangement as above, the generating company shall be free to sell the electricity generated from such station in a manner as it deems fit. This is in line with the Regulation 17 of the CERC (Terms and Conditions of Tariff) Regulations, 2019.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options in the matter.**

## 3.4. Incentive

The generating stations shall be incentivized for achieving the targeted NAPAF and NAPLF. The incentives may be introduced based on pro-rata basis for the achieving more than target. Further, the incentives for achieving excess of target during peak periods may be higher than the incentives provided for achieving the targets. CERC Tariff Regulations, 2019 provides for incentive @ 65 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 50 paise/ kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis within each Season (High Demand Season or Low Demand Season, as the case may be).

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

# 4. Transmission

## 4.1. O&M Expenses

O&M expenses for Transmission Licensee can be determined in two ways:

1) By setting O&M norms based on number of bays and transmission line length (in circuit kms) and escalating the same as per inflation for each year of the control period; or

2) By setting norms for Employee, R&M and A&G expenses separately based on historical data and escalating the same as per inflation for each year of the control period.

The GERC MYT Regulations, 2016 provides for Operation and Maintenance expenses for a Transmission Licensee as follows:

*"**68. Calculation of Aggregate Revenue Requirement***

***….***

*68.2 Operation and Maintenance expenses:*

*68.2.1 Existing Transmission Licensee:*

***Gujarat Energy Transmission Company Ltd. (GETCO)***

***Table 14: O&M Expense norms in Rs. Lakh/Bay and Rs. Lakh/cktkm***

| ***Particulars*** | ***FY 2016-17*** | ***FY 2017-18*** | ***FY 2018-19*** | ***FY 2019-20*** | ***FY 2020-21*** |
|---|---|---|---|---|---|
| *O&M Expenses/Bay* | *7.60* | *8.04* | *8.50* | *8.98* | *9.50* |
| *O&M Expenses/ ckt km* | *0.64* | *0.68* | *0.72* | *0.76* | *0.81* |

*Provided that the Transmission Licensee shall submit a certificate from the Chief Electrical Inspector for the number of bays and circuit kilometres of transmission line added during the year at the time of truing up.*

*68.2.2 For New Transmission Licensee:*

*For the New transmission licensees, the year-wise O&M norms shall be determined on case to case basis:*

*Provided that the same shall not be applicable to those new projects, which are awarded on a competitive bidding basis.*

*…."*

Following table shows the practices across different states.

*Table 8: Approach for O&M Expenses by various ERCs*

| Sr. No. | Methodology | States/ CERC | Regulations |
|---|---|---|---|
| 1 | States Using consolidated approach to determine O&M expenses | CERC | Normative O&M expense on basis of number of bays and circuit kilometre for all years of control period, and escalation factor for escalation towards inflation is specified in the MYT Regulations. |
| 2 | | Gujarat | |
| 3 | | Rajasthan | |
| 4 | | Madhya Pradesh | |
| 5 | | Delhi | Normative O&M expense on basis of number of bays and circuit kilometre for all years of control period, Escalation allowed toward inflation based on CPI & WPI |
| 6 | | Maharashtra | |
| 7 | Employee Expenses, A&G, and R&M Expenses calculated separately | Uttarakhand | The O&M expenses for the nth year is calculated as per following formula<br>'EMPn' = [(EMPn-1) x (1+Gn) x (1+CPIinflation)]<br>'A&Gn' = [(A&Gn-1) x (1+WPIinflation)];<br>R&Mn' = K x (GFA n-1 ) x (1+WPIinflation) ;<br>'K' - is a constant (could be expressed in %). Value of K for each year of the control period as specified by the commission |
| 8 | | Himachal Pradesh | The O&M expenses for the nth year is calculated as per following formula:<br>'EMPn' = [(EMPn-1) x (1+Gn) x (CPIinflation)] + Provision(Emp)<br>'A&Gn' = [(A&Gn-1) x (WPIinflation)] + Provision(A&G) ;<br>R&Mn = K x (GFA n-1 ) x (WPIinflation) ;<br>K' - is a constant (could be expressed in %). Value of K for each year of the control period shall be determined by the Commission |
| 9 | | Punjab | Following formula is used to calculate the O&M Expenses:<br>O&Mn = (R&Mn + EMPn + A&Gn) x (1-Xn)<br>(i) R&Mn= K*GFA*WPIn/WPIn-1<br>(ii) EMPn+ A&Gn= (EMPn-1 + A&Gn-1)*(INDEX n/INDEX n-1)<br>INDEXn = 0.50*CPIn + 0.50*WPIn |

The norms set by CERC may be difficult to adopt as it has too many voltage-wise norms for sub-station bays and transformers, and this may not work for the SERCs. But the same may be reviewed as an option. The O&M expenses may be derived on the basis of the average of the Trued-Up values (without efficiency gain / loss, if any) or based on audited accounts for the last five (5) financial years, subject to prudence check by the Commission. This average figure may be considered as O&M expenses for the middle year and may be escalated with year on year basis with suitable escalation factor based on CPI and WPI of the respective financial years. Further, one-time expenses such as expense due to change in accounting policy, arrears paid due to Pay Commissions, etc., and the expenses beyond the control of the Transmission Licensee such as salary arrears,, terminal benefits, etc., in employee cost, may be allowed by the Commission over and above normative O&M expenses after prudence check. The O&M expenses for the nth year of the Control Period shall be approved based on the formula given below:

**$O\&M_n = (R\&M_n + EMP_n + A\&G_n) \times (1 - X_n)$ + Terminal Liabilities and other one-time expenses**

Where,

**$R\&M_n$** = $K \times GFA_{n-1} \times (Indx_n / Indx_{n-1})$

**$EMP_n$** = $(EMP_{n-1}) \times (1+G_n) \times (Indx_n / Indx_{n-1})$

**$A\&G_n$** = $(A\&G_{n-1}) \times (Indx_n / Indx_{n-1})$

**'K'** is a constant (expressed in %). Value of K for each Year of the Control Period shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking of repair and maintenance expenses, approved repair and maintenance expenses vis-à-vis GFA approved by the Commission in past and any other factor considered appropriate by the Commission;

**$INDX_n$** – Inflation factor to be used for indexing may be a combination of the Consumer Price Index (CPI) and the Wholesale Price Index (WPI) for immediately preceding year before the base year;

**EMPn** – Employee expenses of the Transmission Licensee for the nth Year;

**$A\&G_n$** – Administrative and General expenses of the Transmission Licensee for the nth Year;

**$R\&M_n$** – Repair and Maintenance expenses of the Transmission Licensee for the nth Year;

**$GFA_{n-1}$** – Gross Fixed Asset of the Transmission Licensee for the n-1th Year;

**Gn** is a growth factor for the nth Year. Value of $G_n$ shall be determined by the Commission in the MYT tariff order for meeting the additional manpower requirement based on Licensee's filings, benchmarking, approved cost by the Commission in past and any other factor that the Commission feels appropriate.

**$X_n$** is an efficiency factor for nth Year. Value of $X_n$ shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking, approved cost by the Commission in past and any other factor the Commission feels appropriate;

For the purpose of estimation, the same $INDX_n/INDX_{n-1}$ value may be used for all years in MYT by the Commission. However, the Commission may consider the actual values in the $INDX_n/INDX_{n-1}$ during the true up of the O&M expenses for the respective years of the Control Period.

Terminal Liabilities may be approved as per actual submitted by the Distribution Licensee along with documentary evidence and other documents as desired by the Commission.

The Transmission Licensee, in addition to the above details shall also submit the detailed break-up of the Legal/Litigation Expenses for the previous Years along with the details and documentary evidence of incurring such expenses. The Commission may approve the legal expenses based on the necessary documentary evidence submitted by the Transmission Licensee. The Commission may also carry out due prudence check of legal expenses at the time of truing up.

Further, based on the detailed submissions by the Transmission Licensee, the Commission may consider allowing certain specified expenses on actual basis beyond normative O&M expenses, which are not part of the historical O&M expenses and thus couldn't have been included in the norms. However, in such cases the Commission will also appropriately incorporate the efficiency gains on account of such expenses either in the O&M expenses formulae or other performance parameters. Initially, the efficiency factor, Xn may be considered as 1, which may be subsequently determined based on a separate detailed study at the time of mid-term review of the MYT Control Period.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 4.2. Norms of working capital for Transmission Licensee

GERC MYT Tariff Regulations, 2016 stipulate the following norms of working capital for Transmission Licensee:

*"**40 Interest on Working Capital***

***…***

*40.2 Transmission:*

*(i) The Transmission Licensee shall be allowed interest on the estimated level of working capital for the financial year, computed as follows:*

*(i) Operation and maintenance expenses for one month; plus*

*(ii) Maintenance spares at one (1) per cent of the historical cost; plus*

*(iii) Receivables equivalent to one (1) month of transmission charges calculated on target availability level;*

*minus*

*(iv) Amount, if any, held as security deposits except the security deposits held in the form of Bank Guarantee from Transmission System Users:*

*….."*

Further, the working capital norms as per provisions of GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 9: Norms of Working Capital for Transmission Business adopted by ERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| **Gujarat** | 1 month | 1% of Historical Cost (GFA) | 1 month of transmission charges calculated on annual target availability level for transmission licensee<br>Minus<br>Security Deposits from Users other than those in the form of Bank Guarantees |
| **Maharashtra** | 1 month | 1% of opening GFA | 1½ month of the expected revenue from transmission charges at approved tariff for the ensuing year<br>Minus<br>Amount held as security deposits in cash from transmission system users |
| **Rajasthan** | 1 month | 15% of O&M expenses | 1½ month of transmission charges calculated on annual target availability level for transmission licensee<br>Minus<br>Security Deposits from Users other than those in the form of Bank Guarantees<br>(same for transmission and SLDC) |
| **Punjab** | 1 month | 15% of O&M expenses | 2 months of Receivables calculated on normative target availability<br>(same for transmission and SLDC) |
| **Himachal Pradesh** | 1 month | 15% of O&M expenses for one month | 2 months Receivables towards annual transmission charges |
| **Delhi** | 1 month | 15% of O&M expenses | 2 months Receivables towards transmission tariff calculated on NATAF |
| **Uttarakhand** | 1 month | 15% of O&M expenses | 2 months Receivables |
| **Madhya Pradesh** | 1 month | 15% of O&M expenses | 45 days Receivables towards transmission tariff calculated on target availability level |
| **Karnataka** | 1 month | 1% of opening GFA | 2 months Receivables towards transmission charges calculated on target availability level |

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed.

For maintenance spares, 15% of total O&M expenses are considered in the states of Rajasthan, MP, HP, Punjab, etc. whereas the states of Maharashtra and Karnataka consider 1% of historical cost of assets. The existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the transmission licensees.

Considering the billing and recovery efficiency, as well as the current state of the STU, maintaining the receivables equivalent to 1 month of the Annual Fixed Cost should be sufficient for Transmission licensees to maintain their liquidity.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are sought from the stakeholders on continuation of methodology used for determining working capital requirement for Transmission utility.**

## 4.3. Transmission Loss

The Commission conducted a review of regulations adopted by various other SERCs. The regulations are as follows:

*Table 10: Treatment of Transmission Loss by ERCs*

| State | Treatment of Transmission Loss |
|---|---|
| **Maharashtra** | Commission to stipulate Transmission loss trajectory while approving MYT Order |
| **Rajasthan** | The transmission losses to be borne by the users of the transmission system in kind, as percentage of energy transmitted |
| **Punjab** | any gain / loss sharing with the Transmission Licensee on account of overachievement/under- achievement of the Transmission Loss trajectory specified by the Commission, shall be capped to the Return on Equity earned by the Transmission Licensee. |
| **Madhya Pradesh** | Trajectory specified by the Commission based on actual transmission loss of Previous years. Auxiliary consumption on AC sub-substation shall be considered as part of Transmission loss. |
| **Uttarakhand** | As determined by SLDC and approved by the Commission |
| **Himachal Pradesh** | The energy losses in the transmission system of the transmission licensee, as determined by the State Load Despatch Centre. |
| **Karnataka** | Commission to approve Transmission loss Range filed by licensee while approving MYT Order. |
| **Telangana** | Losses below the approved range = Earn incentive and added to the ARR. Losses beyond the approved range = Results in penalty and such penalty shall be deducted from the ARR. Max Penalty < 10% RoE |

If the transmission losses are shared among transmission system users, the transmission utility may not be motivated to reduce these losses. Based on the standards followed in various states, it is proposed to introduce a transmission loss range in the MYT order and any losses falling below this range shall be divided among the Transmission System Users. In order to ensure accountability and to incentivize efficient transmission practices, it is recommended that any losses beyond the established range be evaluated as a penalty to the transmission utility. This penalty should be deducted from the Annual Revenue Requirement (ARR), up to a specified percentage of the rate of RoE.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

## 4.4. Income from Other Business

The GERC MYT Tariff Regulations, 2016 states as follows:

> ***"70. Income from Other Business***
>
> *Where the Transmission Licensee is engaged in any Other Business, an amount equal to two-third of the revenues from such Other Business after deduction of all direct and indirect costs attributed to such Other Business shall be deducted from the Aggregate Revenue Requirement in calculating the annual transmission charges of the Transmission Licensee:*
>
> *Provided that the Transmission Licensee shall follow a reasonable basis for allocation of all joint and common costs between the Transmission Business and the Other Business and shall submit the Allocation Statement, duly audited and certified by the Statutory Auditor, to the Commission along with his application for determination of tariff:*
>
> *Provided further that where the sum total of the direct and indirect costs of such Other Business exceeds the revenues from such Other Business, no amount shall be allowed to be added to the Aggregate Revenue Requirement of the Transmission Licensee on account of such Other Business."*

Further, the provisions GERC MYT Regulations, 2016 have also been compared with the corresponding provisions of other States, which is summarized as follows:

*Table 11: Provisions for Income from Other business for Transmission Licensees adopted by ERCs*

| ERC | Provisions |
|---|---|
| **Gujarat**<br>**Maharashtra** | • Two-third of Revenue net of direct and indirect costs attributed to Other Business deducted from ARR<br>• If the Cost of such other business exceeds Revenue from such other business, , no amount to be added to ARR on account of such business<br>• Licensee to submit audited and certified allocation statement for allocation of all joint and common costs between the Transmission Business and the Other Business |
| **Rajasthan** | • Revenue from other business shall be treated as income to the extent authorized by the Commission |

| ERC | Provisions |
|---|---|
| **Punjab** | • License may engage in any other business, with prior intimation to the Commission<br>• Considered as NTI |
| **Himachal Pradesh** | • The income from such business will be calculated in accordance with the Himachal Pradesh Electricity Regulatory Commission (Treatment of Income of Other Businesses of Transmission Licensees and Distribution Licensees) Regulations, 2005 and shall be deducted from the aggregate revenue requirement in calculating the revenue requirement of the transmission licensee |
| **Delhi** | • The net income after tax from Other Business shall be adjusted in the ARR.<br>• Loss on account of other business shall not be considered |
| **Uttarakhand** | • The net income after tax from Other Business shall be adjusted in the ARR |
| **Madhya Pradesh** | • Considered as Non-Tariff Income |
| **Karnataka** | • Income from Other Business shall be adjusted in the ARR |

In order to promote maximum utilization of resources and gain additional income for the Transmission Licensee, separate Regulations may be notified for dealing with Income from Other Business.

**Comments and suggestions are sought from the stakeholders on notifying separate regulations for Income from other business for Transmission utility.**

## 4.5. Development of Intra-State Transmission projects under TBCB

National Electricity Policy, 2005 encourages private investment and their partnership in power sector including in Transmission sector to meet the need of rapidly growing sector. Clause 5.3.10 and 5.8.9 of the said policy is relevant which is reproduced as below:-

> *"5.3.10 Special mechanisms would be created to encourage private investment in transmission sector so that sufficient investments are made for achieving the objective of demand to be fully met by 2012.*
>
> *….*
>
> *5.8.9 Role of private participation in generation, transmission and distribution would become increasingly critical in view of the rapidly growing investment needs to develop workable and successful models for public private partnership. This would also enable leveraging private investment with the public sector finances. Mechanisms for continuous dialogue with industry for streamlining procedures for encouraging private participation in power sector need to be put in place."*

The Tariff Policy notified on 28th January, 2016 inter-alia states that –

*"5.3 The tariff of all new generation and transmission projects of company owned or controlled by the Central Government shall continue to be determined on the basis of competitive bidding as per the Tariff Policy notified on 6thJanuary, 2006 unless otherwise specified by the Central Government on case to case basis.*

*Further, intra-state transmission projects shall be developed by State Government through competitive bidding process for projects costing above a threshold limit which shall be decided by the SERCs."*

Recently, Hon'ble Supreme Court through its judgement dated 23rd November 2022 in the Civil Appeal No. 1933 of 2022 directed that-

*"130. ………."We are cognizant of the fact that in matters dealing with electricity regulation, the regulatory commissions and the transmission utilities are usually bogged down by factors such as technological uncertainty, requirement of heavy investment and issues of right of way. The ad-hoc functioning of the transmission utilities is also attributable to the lacunae in the regulations guiding the exercise of their functions. The Electricity Act 2003 was enacted with the objective of providing the States with sufficient flexibility to regulate the intra-state electricity system and simultaneously provided the regulatory commissions with the power to determine tariffs. Though the Government, both at the Centre and in the States, have framed statutory policies and guidelines regulating the electricity sector, we have noticed that the Regulatory Commissions have not framed the necessary regulations to put into effect the principles prescribed under the Act.*

*131. We direct all State Regulatory Commissions to frame Regulations under Section 181 of the Act on the terms and conditions for determination of tariff within three months from the date of this judgment. While framing these guidelines on determination of tariff, the Appropriate Commission shall be guided by the principles prescribed in Section 61, which also includes the NEP and NTP. Where the Appropriate Commission(s) has already framed regulations, they shall be amended to include provisions on the criteria for choosing the modalities to determine the tariff, in case they have not been already included. The Commissions while being guided by the principles contained in Section 61 shall effectuate a balance that would create a sustainable model of electricity regulation in the States. The Regulatory Commission shall curate to the specific needs of the State while framing these regulations. Further, the regulations framed must be in consonance with the objective of the Electricity Act 2003, which is to enhance the investment of private stakeholders in the electricity regulatory sector so as to create a sustainable and effective system of tariff determination that is cost efficient so that such benefits percolate to the end consumers."*

In view to above, GERC vide its Order in Suo Moto Petition No. 2171 of 2023, dated 07.03.2023 has notified Threshold limit of Rs. 100 Crore (excluding land cost) for all new and augmentation of Intra-State Transmission projects developed through Tariff Based Competitive Bidding (TBCB).

Further, it is observed that SERCs like Maharashtra, Bihar and Himachal Pradesh have complied with the above-mentioned Hon'ble Supreme Court's judgment for fixing the said threshold limit for development of Intra-State Transmission projects under Tariff Based Competitive Bidding, through amending their respective MYT Regulations. Accordingly, it is proposed to incorporate the threshold limit in the capital expenditure approval guideline, for further clarity in the matter.

**Comments and suggestions are invited from the stakeholders on the above modifications.**

## 4.6. Incentive

GERC MYT Regulations, 2016 provides for computation of incentive based on Annual Transmission Charges on achieving higher transmission availability over target availability. It is proposed to link the incentive to the RoE component in the form of a higher rate of return instead of the entire Annual Transmission Charges of the Transmission Licensee.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

# 5. SLDC

## 5.1. Incorporating SLDC as a separate Entity from Transmission Licensee

Section 31 (1) and 31(2) of the Electricity Act, 2003, state as follows:

> *"**Section 31. (Constitution of State Load Despatch Centres):** --- (1) The State Government shall establish a Centre to be known as the State Load Despatch Centre for the purposes of exercising the powers and discharging the functions under this Part.*
>
> *(2) The State Load Despatch Centre shall be operated by a Government company or any authority or corporation established or constituted by or under any State Act, as may be notified by the State Government:*
>
> *Provided that until a Government company or any authority or corporation is notified by the State Government, the State Transmission Utility shall operate the State Load Despatch Centre:*
>
> *Provided further that no State Load Despatch Centre shall engage in the business of trading in electricity."*

The above sections require the State Government to establish a separate State Load Dispatch Centre (SLDC) and provides that the SLDC shall be operated by a Government company / authority / corporation constituted under any State Act and until such company / authority / corporation is notified by the State Government, the State Transmission Utility (STU) would operate the SLDC. Accordingly, in the State of Gujarat, the STU, viz., Gujarat Energy Transmission Corporation Limited (GETCO), has so far been operating the SLDC. Accordingly, separation of SLDC as an entity from the STU is recommended. Till the same is done, there may be some dis-incentivization on the rate of RoE component of the Transmission Licensee and SLDC.

**Comments and suggestions are invited from the stakeholders on the above option.**

## 5.2. Capital Investment Plan

According to the GERC MYT Regulations, 2016, the Regulations regarding the Capital Investment Plan states as follows:

> *"78.1 The SLDC shall submit a detailed capital investment plan, financing plan and physical targets for each year to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period."*

As per the MERC MYT Tariff Regulations, 2019, the Regulations regarding the Capital Investment Plan states as follows:

*"**74 Capital Investment Plan***

*...*

*74.2 The Capital Investment Plan shall be a least cost plan for undertaking investments and shall cover all capital expenditure projects of a value exceeding Rs. Ten Crore or such other amount as may be stipulated by the Commission from time to time and shall be in such form as may be stipulated by the Commission from time to time:*

*Provided that the limit shall be Rs. One crore for Deemed Distribution Licensees.*

*74.3 The Capital Investment Plan shall be accompanied by such information, particulars and documents as may be required including but not limited to the information such as number of distribution sub-stations, consumer sub-stations, transformation capacity in MVA and details of distribution transformers of different capacities, HT:LT ratio as well as distribution line length showing the need for the proposed investments, alternatives considered, cost-benefit analysis and other aspects that may have a bearing on the Wheeling Charges:*

*Provided that the Distribution Licensee shall submit separate details of Capital Investment being undertaken in each Distribution Franchisee area within its Licence area.*

*74.4 The Commission shall consider the Capital Investment Plan along with the Multi-Year Aggregate Revenue Requirement for the entire Control Period submitted by the Distribution Licensee taking into consideration the prudence of the proposed expenditure and estimated impact on Wheeling Charges.*

*74.5 The Distribution Licensee shall submit, along with the Petition for determination of Wheeling Charges, or along with the Petition for Mid-term Performance Review, as the case may be, details showing the progress of capital expenditure projects, together with such other information, particulars or documents as the Commission may require to assess such progress."*

It is proposed that GERC introduces this investment plan in MYT Regulations for the next control period.

According to the CABIL report published in December 2018, the SLDCs get a large amount of money approved for projects but they don't utilize it in the control period that it was approved for. It is proposed that the SLDCs utilize the capital approved with in the period. In case of not meeting a certain threshold percentage of capex approval, SLDC may be penalised through reduction in the rate of RoE component.

**Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above.**

## 5.3. Norms of Working Capital for SLDC Business

The GERC MYT Tariff Regulations, 2016 stipulate the following norms of working capital for Transmission Licensee:

*"**40 Interest on Working Capital***

***…***

*40.3 SLDC:*

*(a) The SLDC shall be allowed interest on the estimated level of working capital for the financial year, computed as follows:*

*(i) Operation and maintenance expenses for one month; plus*

*(ii) Maintenance spares at one (1) per cent of the historical cost; plus*

*(iii) Receivables equivalent to 15 days of the expected revenue from SLDC Charges;*

*Provided that at the time of truing up for any year, the working capital requirement shall be re-calculated on the basis of the values of components of working capital approved by the Commission in the truing up;*

*….."*

Further, the working capital norms as per provisions GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 12:Norms of Working Capital for SLDC Business adopted by ERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| **Gujarat** | 1 month | 1% of Historical Cost (GFA) | 15 days of Receivables of the expected revenue from SLDC charges |
| **Maharashtra** | 1 month | Nil | 1½ month of the expected revenue from levy of annual fixed charges approved by the Commission |
| **Rajasthan** | 1 month | 15% of O&M expenses | 1½ month of transmission charges calculated on annual target availability level for transmission licensee<br>Minus<br>Security Deposits from Users other than those in the form of Bank Guarantees<br>(same for transmission and SLDC) |
| **Punjab** | 1 month | 15% of O&M expenses | 2 months of Receivables calculated on normative target availability |

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| | | | (same for transmission and SLDC) |
| **Himachal Pradesh** | 1 month | 15% of O&M expenses for one month | 2 months Receivables towards SLDC Charges |
| **Delhi** | NA | NA | NA |
| **Uttarakhand** | 1 month | 15% of O&M expenses | 2 months Receivables |
| **Madhya Pradesh** | NA | NA | NA |
| **Karnataka** | NA | NA | NA |

The above comparison shows that GERC's existing working capital norms are already quite stringent as compared to other ERCs.

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed. Further, existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the generating stations.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

# 6. Distribution

## 6.1. Common Points

### 6.1.1. Separation of Accounts of Distribution Licensee

Section 62 of the Electricity Act, 2003 requires determination of tariff for wheeling of electricity and retail sale of electricity separately by the SERCs. Further, in case of open access is allowed under Section 42 of the Electricity Act, 2003, the SERCs determines wheeling charges and surcharge (cross-subsidy surcharge and additional surcharge), whereas captive consumers under Section 9 of the Electricity Act, 2003, are required to pay wheeling charges for availing open access and are exempted from payment of surcharge (cross-subsidy surcharge and additional surcharge).

The Tariff Policy, 2016 stipulates the following regarding benefits of introducing competition into the market wherever there is no natural monopoly:

> *"5.9 The real benefits of competition would be available only with the emergence of appropriate market conditions. Shortages of power supply will need to be overcome. Multiple players will enhance the quality of service through competition. All efforts will need to be made to bring power industry to this situation as early as possible in the overall interests of consumers. Transmission and distribution, i.e. the wires business is internationally recognized as having the characteristics of a natural monopoly where there are inherent difficulties in going beyond regulated returns on the basis of scrutiny of costs."*

As the distribution wires business is a natural monopoly, separating it from the retail supply of electricity is a pre-requisite to introduce completion in the retail supply market.

Regulation 87 of the GERC MYT Regulations, 2016 provides that the Wheeling Charges of the Distribution Licensee shall be determined by the Commission on the basis of segregated accounts of Distribution Wires Business. However, till audited and certified separate accounts for Distribution Wires Business and Retail Supply Business are not available, it provides for an 'Allocation Matrix' for segregation of expenses between the Wire Business and Retail Supply Business of the Distribution Licensee. Further, it is also stated that the wheeling charges of the Distribution Licensee shall be determined by the Commission on the basis of segregated accounts of Distribution Wires Business, once the Regulations for submission of Regulatory Accounts are notified.

It is observed that despite the continued emphasis of the Commission on separation of the accounting of wires related costs and supply related costs, which is required to move towards greater competition in the retail supply business, as well as determination of true wheeling charges, there is little or no initiative by the Distribution Licensees for segregation of expenses between the Wire Business and Retail Supply Business. One of the possible reasons for this lack of initiative may be due to the fact that the Commission has been providing the 'Allocation Matrix' in its MYT Regulations and not insisting on the time-bound segregation of accounts of Distribution Licensee between Wires Business and Retail Supply Business.

Therefore, while proposing to continue with an 'Allocation Matrix' for the new Control Period, so as to avoid a void, following time-bound action is proposed:

a) Commission to issue guidelines for segregation of accounts of Distribution Licensee between Wires Business and Retail Supply Business in next 6 months;

b) Distribution Licensees to undertake the preparatory work for segregate their accounts of Wires Business and Retail Supply Business in next 6 months;

c) Distribution Licensees to submit their respective audited and certified separate accounts for Distribution Wires Business and Retail Supply Business from the next financial year onwards, i.e. year 2 of the new MYT Control Period, which shall become the basis for determination of wheeling and retail supply ARRs and hence the determination of wheeling charges;

d) Distribution Licensees not able to provide audited and certified separate accounts for Distribution Wires Business and Retail Supply Business, shall continue to segregate the expenses of Distribution Business based on the 'Allocation Matrix' provided in the MYT Regulations. However, in such case, the rate of return on Equity shall be reduced to the base rate / reduced by 1.00% from the normal rate of return of Equity.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.1.2. O&M Expenses

While specifying the normative O&M expenses for the distribution wires business, one of the aspects to be considered is whether the normative O&M expenses should be specified in a consolidated manner or separately, as Employee expenses, A&G expenses, and Repair & Maintenance expenses. Both options have their merits and de-merits. If the O&M expenses are specified in a consolidated manner, the utility has the flexibility to manage its expenditure through own resources (which will increase the employee expenses) or through outsourcing (which will increase the A&G expenses), as appropriate. However, under this dispensation, the variation in the individual heads of Employee expenses, A&G expenses, and Repair & Maintenance expenses are difficult to track, and there are occasions when the Commission may wish to consider these separately, due to specific treatment to be given for pay revision, etc. Therefore, based on past experiences and after reviewing the best practices across states, it is proposed that O&M expenses shall be continued to be considered separately.

Regulation 86.2 of the GERC MYT Regulations, 2016 provides that the O&M expenses shall be derived on the basis of the average of the actual O&M expenses for the three (3) years ending March 31, 2015, which shall be considered as O&M expenses for FY 2013-14. Thereafter, this base O&M expenses shall be escalated by 5.72% per annum to arrive at the O&M expenses for the respective years.

It is observed that the existing practice takes into account only the historical O&M expenses of the utility and the year-on-year escalation factor. There is no consideration of increase in no. of employees, network expansion or increase in GFA base, compliance of new age regulations to meet Standards of Performance, Rights of Consumer Rules, etc. Further, the escalation of O&M expense at fixed rate of 5.72%, doesn't account for any efficiency factors to promote economic O&M practices and new technology adoption by the Distribution Licensee.

Accordingly, based on the review of best practices adopted by other SERCs and also Central Electricity Authority's 'Report on Benchmarking of O&M Practices & O&M Expenses of Distribution Utilities', published in 2022, it is proposed to adopt the following approach for allowing O&M expenses.

The O&M expenses may be derived on the basis of the average of the Trued-Up values (without efficiency gain / loss, if any) or based on audited accounts for the last five (5) financial years, subject to prudence check by the Commission. This average figure may be considered as O&M expenses for the middle year and may be escalated with year on year basis with suitable escalation factor based on CPI and WPI of the respective financial years. Further, one-time expenses such as expense due to change in accounting policy, arrears paid due to Pay Commissions, etc., and the expenses beyond the control of the Distribution Licensee such as salary arrears, terminal benefits, etc., in employee cost, may be allowed by the Commission over and above normative O&M expenses after prudence check. The O&M expenses for the nth year of the Control Period shall be approved based on the formula given below:

**$O\&M_n = (R\&M_n + EMP_n + A\&G_n) \times (1 - X_n)$ + Terminal Liabilities and other one-time expenses**

Where,

**$R\&M_n$** $= K \times GFA_{n-1} \times (Indx_n / Indx_{n-1})$

**$EMP_n$** $= (EMP_{n-1}) \times (1+G_n) \times (Indx_n / Indx_{n-1})$

**$A\&G_n$** $= (A\&G_{n-1}) \times (Indx_n / Indx_{n-1})$

**'K'** is a constant (expressed in %). Value of K for each Year of the Control Period shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking of repair and maintenance expenses, approved repair and maintenance expenses vis-à-vis GFA approved by the Commission in past and any other factor considered appropriate by the Commission;

**$INDX_n$** – Inflation factor to be used for indexing may be a combination of the Consumer Price Index (CPI) and the Wholesale Price Index (WPI) for immediately preceding year before the base year;

**EMPn** – Employee expenses of the Distribution Licensee for the nth Year;

**$A\&G_n$** – Administrative and General expenses of the Distribution Licensee for the nth Year;

**$R\&M_n$** – Repair and Maintenance expenses of the Distribution Licensee for the nth Year;

**$GFA_{n-1}$** – Gross Fixed Asset of the Distribution Licensee for the n-1th Year;

**Gn** is a growth factor for the nth Year. Value of $G_n$ shall be determined by the Commission in the MYT tariff order for meeting the additional manpower requirement based on Licensee's filings, benchmarking, approved cost by the Commission in past and any other factor that the Commission feels appropriate.

**$X_n$** is an efficiency factor for nth Year. Value of $X_n$ shall be determined by the Commission in the MYT Tariff Order based on Licensee's filing, benchmarking, approved cost by the Commission in past and any other factor the Commission feels appropriate;

For the purpose of estimation, the same $INDX_n/INDX_{n-1}$ value may be used for all years in MYT by the Commission. However, the Commission may consider the actual values in the $INDX_n/INDX_{n-1}$ during the true up of the O&M expenses for the respective years of the Control Period.

Terminal Liabilities may be approved as per actual submitted by the Distribution Licensee along with documentary evidence and other documents as desired by the Commission.

The Distribution Licensee, in addition to the above details shall also submit the detailed break-up of the Legal/Litigation Expenses for the previous Years along with the details and documentary evidence of incurring such expenses. The Commission may approve the legal expenses based on the necessary documentary evidence submitted by the Distribution Licensee. The Commission may also carry out due prudence check of legal expenses at the time of truing up.

Further, based on the detailed submissions by the Distribution Licensee, the Commission may consider allowing certain specified expenses like smart meters, etc. on actual basis beyond normative O&M expenses, which are not part of the historical O&M expenses and thus couldn't have been included in the norms. However, in such cases the Commission will also appropriately incorporate the efficiency gains on account of such expenses either in the O&M expenses formulae or other performance parameters. Initially, the efficiency factor, Xn may be considered as 1, which may be subsequently determined based on a separate detailed study at the time of mid-term review of the MYT Control Period.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 6.2. Distribution Wire Business

### 6.2.1. Wheeling Losses - Distribution Loss vs. AT&C loss

Electricity losses in a distribution system occur mainly on two accounts:

- **Technical Losses:** The cumulative energy consumed by all the elements in a power system (line, transformer, etc.) due to energy dissipated on account of resistance to power flow is classified as "**technical losses**".
- **Commercial Losses:** Losses that occur on account of non-performing and under-performing meters, wrong application of multiplying factors, defects in CT and PT circuitry, meters not read, pilferage by manipulating or by-passing of meters, theft by direct tapping, etc., correspond to energy consumed but not metered or billed and are hence, categorised as "c**ommercial losses**".

The combined "Technical" and "Commercial" losses in the electricity distribution business is termed as **Distribution loss**.

In addition to the above, there is also a loss in revenue collected due to collection inefficiency or non-realisation of billed amount. The aggregate of distribution loss and revenue loss due to non-realisation (collection inefficiency) is termed as "**AT&C loss**" (Aggregate Technical and Commercial loss). Therefore, AT&C loss of the distribution licensee is the combination of technical losses, commercial losses and collection inefficiency.

Since the beginning of the reform process, distribution loss reduction has been one of the primary benchmarks for measuring the performance of a distribution utility. The SERCs have either adopted distribution losses reduction or AT&C loss reduction approach as a performance benchmark.

Distribution loss reduction is a widely used approach at the national and international level to measure the performance of the distribution licensee. Distribution loss is simple to compute as it takes into account the energy input and energy billed to the consumers, thereby taking into consideration the technical losses and unaccounted energy due to theft and misuse. However, in many cases, the actual distribution losses are estimated to be higher than the reported losses, on account of the assessment of un-metered agricultural consumption. Thus, distribution loss method has certain limitations, particularly in case of significant un-metered consumption.

On the other hand, AT&C loss method covers the whole basket of losses of the distribution system and includes technical losses, billing inefficiency, theft, and collection inefficiency. If units sold, units billed and units collected can be computed accurately, then AT&C loss method would be the best indicator of measuring the efficiency of the distribution licensee. However, computation of AT&C losses leads to creation of complexities as it combines technical and commercial parameters, i.e., energy input in units and amount collected in Rupees. Some other issues in AT&C loss computation are as follows:

- Units realised have to be derived based on units billed and collection efficiency
- Units billed may not be measured accurately due to un-metered consumption, thus having the same drawback as distribution loss method
- Revenue collected may include the past arrears
- Amount collected against other charges may not be separately accounted for
- If AT&C loss computation is attempted on cash basis alone (total amount collected/total amount spent), it can lead to distorted results.

Considering the high commercial losses in the Indian power system, the Tariff Policy framed under Section 3 of Electricity Act 2003 has favoured the adoption of the AT&C loss method, as reproduced below:

> *"5(a) The State Commission may consider 'distribution margin' as basis for allowing returns in distribution business at an appropriate time. The Forum of Regulators should evolve a comprehensive approach on "distribution margin" within one year.* ***The considerations while preparing such an approach would, inter-alia, include issues such as reduction in Aggregate Technical and Commercial losses****, improving the standards of performance and reduction in cost of supply."* ***(Emphasis added)***

However, till date, only few SERCs like Delhi Electricity Regulatory Commission have adopted the AT&C loss approach for approving the ARR and tariff of distribution licensees. Relevant extract of DERC (Business Plan) Regulation, 2023 is as bellow:

> ***"26. TARGET FOR COLLECTION EFFICIENCY:***
>
> *(1) The targets for Collection Efficiency for FY 2023-24 to FY 2025-26 of the Distribution Licensee shall be 99.80%.*

*(2) The financial impact on account of Collection Efficiency target shall be computed as per the formula specified in Regulation 163 of the DERC (Terms and Conditions for Determination of Tariff) Regulations, 2017 as amended from time to time for the Distribution Licensee.*

*(3) The financial impact on account of over-achievement in terms of Regulation 164 of the DERC (Terms and Conditions for Determination of Tariff) Regulations, 2017 as amended from time to time, for the Distribution Licensee, from the target of 99.80% to 100% shall be shared equally between Consumers and the Distribution Licensees.*

*Provided that there shall be no penalty for Collection Efficiency if the same is in range of 99.50% to 99.80%."*

The Orissa Electricity Regulatory Commission has considered AT&C Loss trajectory for tariff determination, in line with its Vesting Orders issued w.r.t sale of erstwhile Distribution Utilities under Section 20 of the Electricity Act, 2003 and for vesting of Utilities to the intending purchasers under Section 21 of the Electricity Act, 2003.Relevant extract of OERC MYT Regulation, 2022 is as under:

*"3.14.1. The Commission shall consider the **AT&C loss reduction trajectory for tariff determination as provided in Annexure III of these Regulations as per the terms of the Vesting Orders. The Distribution Licensees would be entitled to retain any additional gains resulting from its meeting and surpassing the AT&C loss targets**. This would be over and above the return on equity allowed by the Commission as part of these Regulations and shall not be adjusted as other income or in any way appropriated through any truing up process or future Aggregate Revenue Requirement process."*

Further, it is not prudent to burden consumers who are paying bill on time for the licensees' inability to collect the billed amounts from certain consumers. Further, the inclusion of collection inefficiency by determining the tariffs on the basis of AT&C loss will result in further increase in the consumers' tariff, if collection efficiency is less than 100%. Considering this aspect and in view of issues discussed above, **it is proposed to continue with Distribution Loss approach for approving the ARR and tariff of Distribution Licensees in the State, with the trajectory of distribution loss being stipulated in the multi-year tariff order rather than being specified in the Regulations.**

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.2.2. Norms of Working Capital for Distribution Wires Business

All SERCs use a standard formula as norm for determination of working capital requirement, wherein O&M expenses as well as cost of maintenance spares is allowed, in addition to the receivables less

Security Deposit held by the Utility in cash. Regarding inclusion of one month of O&M expenses as a part of the working capital requirement, as O&M expenses incurred for a given month are recoverable along with the tariff in the next month, the same needs to be a part of working capital. In addition, exclusion of the same may also have impact on the liquidity position of the utilities.

Further, the working capital norms as per provisions GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 13: Norms of Working Capital for Distribution Wires Business adopted by SERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| **Gujarat** | 1 month | 1% of Historical Cost (GFA) | 1 month of the expected revenue from charges for use of Distribution Wires<br>Minus<br>Security Deposits other than those in the form of Bank Guarantees |
| **Maharashtra** | 1 month | 1% of opening GFA | 1½ month of the expected revenue from charges for use of Distribution Wires<br>Minus<br>Amount held as security deposits in cash from Distribution System Users |
| **Rajasthan** | 1 month | 15% of O&M expenses | 1½ month of billing of consumers<br>Minus<br>Security Deposits from Distribution System Users other than those in the form of Bank Guarantees<br>(same for wheeling and retail supply) |
| **Punjab** | 1 month | 15% of O&M expenses | 2 months of the expected revenue from charges for use of Distribution Wires<br>Minus<br>Security Deposits from Distribution System Users |
| **Himachal Pradesh** | 1 month | 15% of O&M expenses for one month (excluding provisions, arrears, terminal benefits) | 2 months of the Wheeling Charges<br>Minus<br>Security Deposits from Distribution System Users |
| **Delhi** | NA | NA | 2 months of Wheeling Charges |
| **Uttarakhand** | 1 month | 15% of O&M expenses | 2 months of the expected revenue from sale of electricity<br>Plus<br>Capital required to fiancé such shortfall in collection of current dues as may be allowed by the Commission<br>Minus<br>One month of power purchase cost based on annual power procurement plan |

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| **Madhya Pradesh** | 1 month | 1% of opening GFA | Nil |
| **Karnataka** | 1 month | 1% of opening GFA | 2 months of average revenue |

The above comparison shows that GERC's existing working capital norms are already quite stringent as compared to other ERCs.

In most of the states in India, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed. Further, the existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the Distribution Licensees.

Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.2.3. Reliability of Supply

National Tariff Policy (NTP), 2016 stipulates that the SERCs shall devise a specific trajectory so that 24 hours supply of adequate and uninterrupted power can be ensured to all categories of consumers by FY 2021-22 or earlier depending upon the prevailing situation in the State.

Further, Rule 10 of Electricity (Rights of Consumers) Rules, 2020 specifies that the distribution licensee shall supply 24x7 power to all consumers, with exception some categories of consumers like agriculture. Further, following guidelines has been issued in this regard:

> *"(2) The **distribution licensee shall put in place a mechanism, preferably with automated tools** to the extent possible, for monitoring and restoring outages.*
>
> *(3) In view of the increasing pollution level particularly in the metros and the cities with a population 100,000 and above, **the distribution licensee shall ensure 24x7 uninterrupted power supply to all the consumers, so that there is no requirement of running the diesel generator sets and accordingly, the State Commission shall give trajectory of system average interruption frequency index and system average interruption duration index for such cities**.*

*(4) The **State Commission may consider the customer average interruption duration index, customer average interruption frequency index and momentary average interruption frequency index as additional indicators of reliability of supply and the minimum interruption time for calculation of additional reliability indicators shall be as specified by the State Commission and in case the interruption time is not specified by the State Commission**, three minutes shall be considered as interruption time for calculating the additional reliability indicators.*

*(5) The **State Commission shall have an online mechanism for reviewing and monitoring of reliability indices of distribution licensees** and such Commission may consider a separate reliability charge for the distribution company, if they require funds for investment in the infrastructure for ensuring the reliability of supply to the consumers." {Emphasis added}*

MERC in its MYT Regulation, 2019 had defined target wires availability, and introduced incentive mechanism linked additional RoE for overachievement of Target availability.

In view of above, its proposed to specify trajectory for the Reliability Index (such as SAIDI, SAIFI, CAIDI, CAIFI and MAFIFI) for Distribution Licensee and further device an incentive mechanism linked to wire availability and reliable supply, which is to be derived on the basis of the interruption in the power availability.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.2.4. Pre-Payment / Smart Metering

The Ministry of Power (MoP), Government of India, has launched Revamped Distribution Sector Scheme (RDSS) for the period from FY 2021-22 to FY 2025-26. Part A, Component I of the scheme covers prepaid/smart metering for consumers and system metering at Distribution Transformer at feeder level with Communication feature etc. Under scheme MoP has sanctioned 16,481,871 number of smart prepaid consumer meters to be installed in Gujarat.

Further, regarding Pre-paid metering Clause 5 of Electricity (Rights of Consumers) Rules, 2020 specifies as follows:

*"Metering – (1) **No connection shall be given without a meter and such meter shall be the smart prepayment meter or pre-payment meter**. Any exception to the smart meter or prepayment meter shall have to be duly approved by the Commission. The Commission, while doing so, shall record proper justification for allowing the deviation from installation of the smart pre-payment meter or prepayment meter."*

In view of above, it is proposed to specify the category-wise trajectory for smart pre-paid metering, at time of approval of Tariff in MYT Order. Based on achievement of Target, Distribution licensee may be incentivized or penalised.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.2.5. R&M Expenses

R&M expenses are incurred towards the day-to-day upkeep of the distribution network and form an integral part of the efforts towards reliable and quality power supply as also in the reduction of losses in the distribution system.

In order to encourage distribution licensee to perform adequate R&M activity in their area, MPERC in MPERC MYT Regulation, 2021, allows additional Return on Equity based on R&M expense incurred during the Financial Year. Under this mechanism additional RoE is allowed to the distribution licensee for achieving 95% of approved R&M Expenses. Accordingly, similar incentive mechanism is proposed to adopt in next control period to encourage licensee to opt for efficient operating techniques.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 6.3. Distribution (Retail Supply Business)

### 6.3.1. Sales and Demand Forecast

Electricity sales forecast is an indispensable part of ARR projection, since it assists distribution licensee in anticipating revenue inflow, formulate capital investment planning as well as economic power purchase planning. Therefore, in order to ensure economic operation of distribution licensee, there is a need of reliable sales forecast methodology and tolls. At the same time, it is also important to note that the very nature of business is such that uncontrollable factors like weather, growth in consumer load/number on account of Government policies, economic conditions of supply area, open-access consumers, etc. could significantly affect the demand forecasts.

GERC MYT Regulations, 2016 provides for submission of category / sub-category / slab-wise sales forecast based on the past data and reasonable assumptions regarding the future. Further, GERC has also framed guidelines for procurement of power by the Distribution Licensees in 2013, which provides as follows:

> *“3. Every year by 31st January, the Distribution licensees shall submit power procurement plan for 5 years which will include:*
>
> *a. Peak load and energy forecasts of their respective license areas for each of the successive 10 years. The peak load and energy forecasts shall be made for the overall Area of Supply.*

*b. Anticipated power supply position for each of the successive five years along with the projections for additional requirement of procurement of power, if any.*

*c. Hourly load duration projection for each of the successive 5 years."*

Recently in April 2023, the Central Electricity Authority (CEA) has published draft "Guidelines for Medium and Long Term Power Demand Forecast", with an objective to serve as a guiding document for power utilities to bring uniformity in their power demand forecast approach. The draft guidelines are summarized as follows:

- Forecast to be prepared for medium term (1 to 5 years) and long term (at least for next 10 years), which should be reviewed and updated on yearly basis;
- Apart from forecast at Discom and yearly levels, attempts should be made for granular forecast to facilitate power infrastructure planning
    - Spatial - zonal/circle/district/sub-station/transformer level
    - Time – month-wise/day-wise/hour-wise/time-block wise
- Forecast should be carried out for at least three scenarios – Optimistic scenario, Business As Usual (BAU) scenario & Pessimistic scenario, duly taking into consideration the extreme weather parameters, business cycle, impact of emerging aspects, etc. Advanced statistical tools like Multivariate Regression Analysis should also be used for this purpose.
- The power demand forecast should be done under the unrestricted scenario which essentially is reflective of the case when all the unserved demand currently not served by the utilities due to various supply side barriers such as generation & network constraints (resulting in planned load shedding and unplanned outages) is also included.
- Forecasting method should aim at analysing past consumption data of each category separately and factoring in impacts of emerging aspects to arrive at appropriate future growth trends. CEA has suggested use of Partial End Use Method (PEUM), which is used for carrying out Electric Power Survey (EPS) exercises.
- The forecasting results obtained should be validated through at least one different method, say Econometric Method.

Most of the SERCs, in their MYT Regulations, require the Distribution Licensee to submit its yearly (in some cases monthly) sales forecast in MU terms for the MYT control period, based on past data and reasonable assumptions and have not specified any approach or methodology for the same. However, in the wake of its Guidelines for procurement of power by the Distribution Licensees and also above-mentioned CEA guidelines, the it is proposed to introduce a comprehensive approach for Sales (MU) and Demand (MW) forecasts based on load research studies, advance statistical methods including PEUM and econometric methods, and exploring use of various IT tools, including Artificial Intelligence and Machine Learning (AI/ML) to improve accuracy in forecasting and planning, in the new MYT Regulations.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.3.2. Power Procurement Guidelines

Various provisions of the Electricity Act, 2003 provides for regulating purchase of electricity by the distribution licensee. Sections 42 and 43 of the Electricity Act, 2003 cast a duty upon the Distribution Licensee to ensure electricity supply to the consumers within its license area on request. Section 86 (1) (b) of the Electricity Act, 2003, envisages the SERC to regulate the electricity purchase and procurement process of distribution licensees including the price at which electricity shall be procured from various sources.

Power purchase cost accounts for approximately 70%-80% of the total cost of the retail supply business and therefore, the power procurement plan is amongst the most vital aspect of distribution retail supply plan. Therefore, the SERC need to ensure transparent, economic and optimal procurement of power by the Distribution Licensee for sale to its consumers. GERC MYT Regulations, 2016 provides for power procurement as follows:

> *"19.4 The Distribution Licensee shall project the power purchase requirement based on the Merit Order Despatch principles of all Generating Stations considered for power purchase, the Quantum of Renewable Purchase Obligation (RPO) under Regulation 4 of Gujarat Electricity Regulatory Commission (Procurement of Energy from Renewable Sources) (First Amendment) Regulations, 2014 and the target set, if any, for Energy Efficiency (EE) and Demand Side Management (DSM) schemes.*
>
> *….*
>
> *94.5.1 The Distribution Licensee shall be allowed to recover the cost of power generated by the Generation Business or purchased from approved sources for supply to consumers based on the power procurement plan of the Distribution Licensee, approved by the Commission."*

Further, GERC has also framed guidelines for procurement of power by the Distribution Licensees in 2013, which provides as follows:

> *"4. Distribution Licensees shall have long-term / medium-term tie up to meet load requirement of at least 75% duration of the fifth year. In case of any shortfall to meet load requirement of 75% of duration of the fifth year through long-term / medium term arrangement, the Distribution Licensee shall initiate the process of long-term procurement of power.*

*5. Distribution Licensees shall have long-term / medium-term tie up to meet load requirement of at least 85% of duration of the third year. In case of any shortfall to meet load requirement of 85% of duration of the third year through long-term / medium-term arrangement, the Distribution Licensee shall initiate the process of medium-term procurement of power.*

*6. The Distribution Licensee shall normally endeavour to procure power through competitive bidding. In case of any proposal for procurement of power through MoU route, the Distribution Licensee shall obtain prior approval of the GERC.*

*7. In case of procurement of power through competitive bidding, the Distribution Licensees shall initiate the process for long-term / medium-term power procurement in accordance with the Ministry of Power's 'Guidelines for Determination of Tariff by Bidding Process for Procurement of Power by Distribution Licensees' notified by the Ministry of Power on 19/01/2005 and in force from time to time…*

*….*

*13. Where the Distribution Licensee is to procure power on a short-term basis or there is a shortfall due to any reason whatsoever, or failure in the supply of electricity from any approved source of supply during the year, for any reason whatsoever, the licensee may enter into a short-term arrangement or agreement for procurement of power through power exchanges or through a transparent process of open tendering and competitive bidding.*

*14. In case of procurement of power through competitive bidding, the Distribution Licensees shall initiate the process for short-term power procurement in accordance with the Ministry of Power's 'Guidelines for Short-Term Procurement of Power by Distribution Licensees through Tariff based bidding process' notified by the Ministry of Power on 15/05/2012 and in force from time to time….*

*….*

*17. The GERC may permit any Distribution Licensee to make purchase of power without requiring that such purchase be subject to Competitive/Open Process in the event of an unforeseen and an exceptional situation. However, the Distribution Licensee shall not, thereby, be exempted from demonstrating the need and the reason for departure from a competitive process together with the economic justification for the purchase, the means, whereby, in the absence of competition, the Distribution Licensee proposes to secure the best possible terms and such other information as the GERC may require."*

Resource Adequacy has attained a center stage in the power procurement planning. The Electricity (Amendment) Rules, 2022 notified by the Ministry of Power, Government of India, provided that the

Central Government, in consultation with Central Electricity Authority will issue Resource Adequacy Guidelines for assessment of resource adequacy during the generation planning stage (one year or beyond) as well as during the operational planning stage (up to one year). It also provided that the SERC shall frame regulations on resource adequacy, based on which the distribution licensees shall formulate the resource adequacy plan and seek approval of the SERC. Recently, the Ministry of Power, Government of India, in consultation with the Central Electricity Authority, has issued the 'Guidelines for Resource Adequacy Planning Framework for India' aiming to establish a Resource Adequacy framework for power procurement by distribution licensees, ensuring a reliable operation of the power system across all timeframes, by laying down the optimal capacity mix required to meet the projected demand at minimum cost.

In the said Guidelines, it is stated that the Distribution Licensees shall prepare its Long-term Discom Resource Adequacy Plan (LT-DRAP) for a 10 year horizon [Long-term Distribution Licensee Resource Adequacy Plan (LT-DRAP)], on an annual rolling basis, to meet their own peak and electrical energy requirement, which shall be vetted by CEA. The Distribution Licensees shall take inputs if required from the Long-term Discom Resource Adequacy Plan (LT-NRAP), Planning Reserve Margin (PRM), capacity credits, etc., while formulating their LT-DRAP and submit their plans to CEA by the month of September for the period starting from the month of April in the subsequent year. After being vetted by CEA, the plan LT-DRAP along with details for meeting the RAR of national peak for the utility may be submitted to SERC/JERC by the month of November for the period starting from the month of April in the subsequent year for their approval. The Guidelines also provides that the CERC in consultation with the Forum of Regulators (FOR) may come out with model regulations for implementing the resource adequacy process in the States/UTs and the distribution utilities.

The Resource Adequacies studies by the Distribution Licensees would require inputs regarding long-term demand projections, demand pattern, load growth estimates, RE generation profile, technical specification of base load generating stations (ramp rates, minimum technical load, heat rate, start-up cost, time, etc.), generation capacities (existing and planned), various costs parameters (capital cost, variable cost, O&M costs, start-up and shut-down costs, reserve offers) of the generators, historical forced outage rates and planned maintenance rates of generation capacities, tie line details and transmission expansion plans, RPO / HPO / Energy Storage obligation targets, spinning reserve and planning reserve margins, etc. Resource Adequacy would not only ensure quality, uninterrupted and cost effective power supply to consumers, but also facilitate optimal generation capacity development and utilization. It will also enable integration of variable RE generation, ensure system reliability and grid security.

Considering the amended Electricity Amendment Rules, 2022, and the Guidelines for Resource Adequacy Planning Framework issued by the Ministry of Power, it is proposed that the new MYT

Regulations to provide for developing Resource Adequacy Plan by the Distribution Licensees to determine the target generation capacities for meeting the forecasted energy demand over a specified future period.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.3.3. Fuel and Power Purchase Price Adjustment (FPPPA)

The Commission in its Order in Case No. 1309/2013 and 1313/2013 vide dated 29.10.2013, has revised the formula for Fuel Price and Power Purchase Price Adjustment (FPPPA) to recover the difference between actual power purchase cost and base power purchase cost approved by the Commission as follows:

**FPPPA = [(PPCA-PPCB)]/ [100-Loss in %]**

Where

**'PPCA'** is the average power purchase cost per unit of delivered energy (including transmission cost), computed based on the operational parameters approved by the Commission or principles laid down in the power purchase agreements in Rs./kWh for all the generation sources as approved by the Commission while determining ARR and who have supplied power in the given quarter and transmission charges as approved by the Commission for transmission network calculated as total power purchase cost billed in Rs. Million divided by the total quantum of power purchase in Million Units made during the quarter.

**'PPCB'** is the approved average base power purchase cost per unit of delivered energy (including transmission cost) for all the generating stations considered by the Commission for supplying power to the company in Rs./kWh and transmission charges as approved by the Commission calculated as the total power purchase cost approved by the Commission in Rs. Million divided by the total quantum of power purchase in Million Units considered by the Commission.

**'Loss in %'** is the weighted average of the approved level of Transmission and Distribution losses (%) for the four DISCOMs / GUVNL and TPL applicable for a particular quarter or actual weighted average in Transmission and Distribution losses (%) for four DISCOMs / GUVNL and TPL of the previous year for which true-up have been done by the Commission, whichever is lower.

The Commission in aforesaid Order has directed the Licensee to approach the Commission for the prior approval for any increase in FPPPA beyond ten paise per kWh in a quarter, along with computation of FPPPA charge. The Commission has also directed that the FPPPA calculations shall be submitted to the Commission within one month from the end of the relevant quarter and same has to be published in the Licensee's website.

Further, the recently notified Electricity (Amendment) Rules, 2022 by the Ministry of Power, Government of India, provide as follows:

> *"14.* ***Timely recovery of power purchase costs by distribution licensee.-****The Appropriate Commission shall within ninety days of publication of these rules, specify a price adjustment formula for recovery of the costs, arising on account of the variation in the price of fuel, or power purchase costs and the impact in the cost due to such variation shall be automatically passed through in the consumer tariff, on a monthly basis, using this formula and such monthly automatic adjustment shall be trued up on annual basis by the Appropriate Commission:*
>
> *Provided that till such a methodology and formula is specified by the Appropriate Commission, the methodology and formula specified in the Schedule – II annexed to these rules shall be applicable:*
>
> *Provided further that the existing methodology and the formula specified by the Appropriate Commission shall suitably be amended in accordance with these rules, to implement the automatic pass through of fuel and power purchase adjustment surcharge, on a monthly basis:*
>
> *Provided also that in case the distribution licensee fails to compute and charge fuel and power purchase adjustment surcharge within the time line, specified by the Appropriate Commission, except in case of any force majeure condition, its right for recovery of costs on account of fuel and power purchase adjustment surcharge shall be forfeited and in such cases, the right to recovery the fuel and power purchase adjustment surcharge determined during true-up shall also be forfeited and the true up of fuel and power purchase adjustment surcharge by the Appropriate Commission, for any financial Year, shall be completed by 30th June of the next financial year."*

In the wake of the abovesaid MoP Rules, it is proposed to include the said approach and the formula (mentioned in Annexure), in its new MYT Regulations.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

## 6.3.4. Norms of Working Capital for Distribution Retail Supply Business

All SERCs use a standard formula as norm for determination of working capital requirement, wherein O&M expenses as well as cost of maintenance spares is allowed, in addition to the receivables less Security Deposit held by the Utility in cash. Regarding inclusion of one month of O&M expenses as a part of the working capital requirement, as O&M expenses incurred for a given month are recoverable along with the tariff in the next month, the same needs to be a part of working capital. In addition, exclusion of the same may also have impact on the liquidity position of the utilities.

The GERC MYT Regulations, 2016 provides for computation of normative working capital requirement for the retail supply business as follows:

*"(i) Operation and maintenance expenses for one month; plus*

*(ii) Maintenance spares at one (1) per cent of the historical cost; plus*

*(iii) Receivables equivalent to one (1) month of the expected revenue from sale of electricity at the prevailing tariffs;*

*minus*

*Amount held as security deposits under clause (a) and clause (b) of sub-section (1) of Section 47 of the Act from consumers except the security deposits held in the form of Bank Guarantees:*

*……"*

Further, the working capital norms as per provisions GERC MYT Regulations, 2016 have also been compared with the corresponding norms of other States, which is summarized as follows:

*Table 14: Norms of Working Capital for Distribution Retail Supply Business adopted by SERCs*

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| Gujarat | 1 month | 1% of Historical Cost (GFA) | 1 month of the expected revenue from sale of electricity at the prevailing tariffs<br>Minus<br>Security Deposits other than those in the form of Bank Guarantees |
| Maharashtra | 1 month | 1% of opening GFA | 1½ month of the expected revenue from sale of electricity at approved tariff for ensuing year including revenue from CSS and Additional Surcharge<br>Minus<br>• Amount held as security deposits in cash<br>One month of power purchase cost based on power procurement plan, including transmission and SLDC charges |
| Rajasthan | 1 month | 15% of O&M expenses | 1½ month of billing of consumers<br>Minus<br>Security Deposits from Distribution System Users other than those in the form of Bank Guarantees<br>(same for wheeling and retail supply) |
| Punjab | 1 month | 15% of O&M expenses | 2 months of the expected revenue from sale of electricity<br>Minus<br>• Security Deposits<br>One month of power procurement cost including associated cost |
| Himachal Pradesh | 1 month | 15% of O&M expenses for one month (excluding | 2 months of revenue from sale of electricity<br>Minus |

| ERC | O&M Expenses | Maintenance Spares | Receivables Less Security Deposit |
|---|---|---|---|
| | | provisions, arrears, terminal benefits) | • Security Deposits from Distribution System Users; and<br>Power purchase Cost for one month |
| Delhi | NA | NA | 2 months of ARR of retail supply business<br>Minus<br>• 1 month net power purchase expenses<br>1 month transmission charges |
| Uttarakhand | 1 month | 15% of O&M expenses | • 2 months of the expected revenue from sale of electricity<br>Plus<br>• Capital required to fiancé such shortfall in collection of current dues as may be allowed by the Commission<br>Minus<br>One month of power purchase cost based on annual power procurement plan |
| Madhya Pradesh | 1 month | 1% of opening GFA | 2 months of Receivables<br>Minus<br>• 1 month of power purchase cost;<br>• consumer security deposit; and<br>• any amount paid by prepaid consumers |
| Karnataka | 1 month | 1% of opening GFA | 2 months of average revenue |

Comparing with the corresponding norms of other SERCs, it is observed that the GERC's existing working capital norms are already quite stringent with receivables considered for one month only, whereas in other SERCs it is either 45 days or 2 months. Therefore, it is proposed to continue with the provision of Receivables for 1 month net of consumer security deposits (in cash). Further, it is also proposed to deduct the revenue received from pre-paid consumers, as it is received in advance by the Utilities. Regarding other components of the normative working capital requirement, it is observed that in most of the ERCs, O&M expenses of 1 month are considered for determining the IoWC. However, considering the fact that majority of the O&M expenses becomes due at the end of the month, the need for allowing 1 month O&M expenses while computing the normative working capital requirement may be reviewed. Further, the existing norm for maintenance spares as 1% of GFA may be reviewed taking into consideration the actual average inventory of maintenance spares being maintained by the Distribution Licensees.

Regarding the margin above the benchmark rate, the same may be considered for further revision. Further, presently the interest on working capital is allowed on normative basis, irrespective of the actual expense incurred by the utility. While framing the MYT Regulations for the new Control Period, the possibility of sharing of gains (and not the loss) between normative and actual interest on working capital, may be explored.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

### 6.3.5. Bad debts written off

Regarding Bad debts written off, Regulation 94.9 of GERC MYT Regulation, 2016 specifies as follows:

> *"94.9 Bad debts written off:*
>
> *94.9.1 The Commission may allow bad debts written off as a pass through in the Aggregate Revenue Requirement, based on the trend of write off of bad debts in the previous years, subject to prudence check:*
>
> *Provided that the Commission shall true up the bad debts written off in the Aggregate Revenue Requirement, based on the actual write off of bad debts excluding DPC waived off, if any, during the year, subject to prudence check:*
>
> *Provided further that if subsequent to the write off of a particular bad debt, revenue is realised from such bad debt, the same shall be included as an uncontrollable item under the Non-Tariff Income of the year in which such revenue is realised."*

From above it can be observed that, existing provision doesn't specify any celling on allowable bad debts written off as a pass through in the Aggregate Revenue Requirement. In order to safeguard the interest of honestly paying consumers it is proposed to cap the Bad debts written off during a Financial Year.

**Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.**

**Annexure**

# 1. CERC (Terms and Conditions of Tariff) Regulations, 2019

**42. Computation and Payment of Capacity Charge for Thermal Generating Stations:**

(1) The fixed cost of a thermal generating station shall be computed on annual basis based on the norms specified under these regulations and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station. The capacity charge shall be recovered under two segments of the year, i.e. High Demand Season (period of three months) and Low Demand Season (period of remaining nine months), and within each season in two parts viz., Capacity Charge for Peak Hours of the month and Capacity Charge for Off- Peak Hours of the month as follows:

Capacity Charge for the Year ($CC_y$) = Sum of Capacity Charge for three months of High Demand Season + Sum of Capacity Charge for nine months of Low Demand Season

(2) The Capacity Charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:

Capacity Charge for the Month (CCm) = Capacity Charge for Peak Hours of the Month (CCp) + Capacity Charge for Off-Peak Hours of the Month (CCop)

Where,

<u>**High Demand Season:**</u>

$CC_{p1}$= (0.20 $x$ AFC) $x$ ( $\frac{1}{12}$ ) x ( $\frac{\text{PAFMp}}{NAPAF}$) subject to ceiling of (0.20 $x$ AFC) $x$ ( $\frac{1}{12}$ )

$CC_{p2}$ = {(0.20 $x$AFC) $x$ ( $\frac{1}{6}$ ) x ( $\frac{\text{PAFMp2}}{NAPAF}$) subject to ceiling of (0.20 $x$ AFC) $x$ ( $\frac{1}{6}$ )} – $CC_{p1}$

$CC_{p3}$ = {(0.20 $x$AFC) $x$ ( $\frac{1}{4}$ ) x ( $\frac{\text{PAFMp}}{NAPAF}$) subject to ceiling of (0.20 $x$ AFC) $x$ ( $\frac{1}{4}$ )} – ($CC_{p1}$ + $CC_{p2}$)

$CC_{op1}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{12}$ ) x ( $\frac{\text{PAFMop1}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{12}$ )}

$CC_{op2} = \{(0.80\ x AFC)\ x\ (\frac{1}{6})\ \ x\ (\frac{PAFMop2}{NAPAF})$ subject to ceiling of $(0.80\ x\ AFC)\ x\ (\frac{1}{6})\} - CC_{op1}$

$CC_{op3} = \{(0.80\ x AFC)\ x\ (\frac{1}{12})\ \ x\ (\frac{PAFMop3}{NAPAF})$ subject to ceiling of $(0.80\ x\ AFC)\ x\ (\frac{1}{4})\} - (CC_{op1} + CC_{op2})$

**Low Demand Season:**

$CC_{p1} = (0.20\ x\ AFC)\ x\ (\frac{1}{12})\ \ x\ (\frac{PAFMp1}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{12})$

$CC_{p2} = \{(0.20\ x AFC)\ x\ (\frac{1}{6})\ \ x\ (\frac{PAFMp2}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{6})\} - CC_{p1}$

$CC_{p3} = \{(0.20\ x AFC)\ x\ (\frac{1}{4})\ \ x\ (\frac{PAFMp3}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{4})\} - (CC_{p1} + CC_{p2})$

$CC_{p4} = \{(0.20\ x AFC)\ x\ (\frac{1}{3})\ \ x\ (\frac{PAFMp4}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{3})\} - (CC_{p1} + CC_{p2} + CC_{p3})$

$CC_{p5} = \{(0.20\ x AFC)\ x\ (\frac{5}{12})\ \ x\ (\frac{PAFMp5}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{5}{12})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4})$

$CC_{p6} = \{(0.20\ x AFC)\ x\ (\frac{1}{2})\ \ x\ (\frac{PAFMp}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{1}{2})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5})$

$CC_{p7} = \{(0.20\ x AFC)\ x\ (\frac{7}{12})\ \ x\ (\frac{PAFMp7}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{7}{12})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6})$

$CC_{p8} = \{(0.20\ x AFC)\ x\ (\frac{2}{3})\ \ x\ (\frac{PAFMp8}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{2}{3})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7})$

$CC_{p9} = \{(0.20\ x AFC)\ x\ (\frac{3}{4})\ \ x\ (\frac{PAFMp}{NAPAF})$ subject to ceiling of $(0.20\ x\ AFC)\ x\ (\frac{3}{4})\} - (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7} + CC_{p7})$

$CC_{op1}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{12}$ ) x ( $\frac{\text{PAFMop1}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{12}$ )}

$CC_{op2}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{6}$ ) x ( $\frac{\text{PAFMop2}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{6}$ )} – $CC_{op1}$

$CC_{op3}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{12}$ ) x ( $\frac{\text{PAFMop3}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{4}$ )} – ($CC_{op1}$ + $CC_{op2}$)

$CC_{op4}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{3}$ ) x ( $\frac{\text{PAFMop4}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{3}$ )} – ($CC_{op1}$ + $CC_{op2}$ + $CC_{op3}$)

$CC_{op5}$ = {(0.80 $x$AFC) $x$ ( $\frac{5}{12}$ ) x ( $\frac{\text{PAFMop5}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{5}{12}$ )} – ($CC_{op1}$ + $CC_{op2}$ + $CC_{op3}$ + $CC_{op4}$)

$CC_{op6}$ = {(0.80 $x$AFC) $x$ ( $\frac{1}{2}$ ) x ( $\frac{\text{PAFMop6}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{1}{2}$ )} – ($CC_{op1}$ + $CC_{op2}$ + $CC_{op3}$ + $CC_{op4}$ + $CC_{op5}$)

CCop7 = {(0.80 $x$AFC) $x$ ( $\frac{7}{12}$ ) x ( $\frac{\text{PAFMop7}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{7}{12}$ )} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6)

CCop8 = {(0.80 $x$AFC) $x$ ( $\frac{2}{3}$ ) x ( $\frac{\text{PAFMop8}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{2}{3}$ )} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7)

CCop9 = {(0.80 $x$AFC) $x$ ( $\frac{3}{4}$ ) x ( $\frac{\text{PAFMop9}}{NAPAF}$) subject to ceiling of (0.80 $x$ AFC) $x$ ( $\frac{3}{4}$ )} – (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7 + CCop8)

Provided that in case of generating station or unit thereof under shutdown due to Renovation and Modernisation, the generating company shall be allowed to recover O&M expenses and interest on loan only.

Where,

$CC_m$= Capacity Charge for the Month;

$CC_p$= Capacity Charge for the Peak Hours of the Month;

$CC_{op}$= Capacity Charge for the Off-Peak Hours of the Month;

$CC_{pn}$= Capacity Charge for the Peak Hours of nth Month in a specific Season;

$CC_{opn}$= Capacity Charge for the Off-Peak of nth Month in a specific Season;

AFC = Annual Fixed Cost;

$PAFM_{pn}$ = Plant Availability Factor achieved during Peak Hours upto the end of nth Month in a Season;

$PAFM_{opn}$ = Plant Availability Factor achieved during Off-Peak Hours upto the end of nth Month in a Season;

NAPAF= Normative Annual Plant Availability Factor.

(3) Normative Plant Availability Factor for “Peak” and “Off-Peak” Hours in a month shall be equivalent to the NAPAF specified in Clause (A) of Regulation 49 of these regulations. The number of hours of “Peak” and “Off-Peak” periods during a day shall be four and twenty respectively. The hours of Peak and Off-Peak periods during a day shall be declared by the concerned RLDC at least a week in advance. The High Demand Season (period of three months, consecutive or otherwise) and Low Demand Season (period of remaining nine months, consecutive or otherwise) in a region shall be declared by the concerned RLDC, at least six months in advance: Provided that RLDC, after duly considering the comments of the concerned stakeholders, shall declare Peak Hours and High Demand Season in such a way as to coincide with the majority of the Peak Hours and High Demand Season of the region to the maximum extent possible:

Provided further that in respect of a generating station having beneficiaries across different regions, the High Demand Season and the Peak Hours shall correspond to the High Demand Season and Peak Hours of the region in which majority of its beneficiaries, in terms of percentage of allocation of share, are located.

(4) Any under-recovery or over-recovery of Capacity Charge as a result of underachievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of a Season (High Demand Season or Low Demand Season, as the case may be) shall not be adjusted with under-achievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of the other Season:

Provided that within a Season, the shortfall in recovery of Capacity Charge for cumulative Off-Peak Hours derived based on NAPAF, shall be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Peak Hours in that Season:

Provided further that within a Season, the shortfall in recovery of Capacity Charge for cumulative Peak Hours derived based on NAPAF, shall not be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Off-Peak Hours in that Season.

(5) The Plant Availability Factor achieved for a Month (PAFM) shall be computed in accordance with the following formula:

$$PAFM = 1000\ x \sum_{i=1}^{n} \frac{\mathrm{DCi}}{[\mathrm{N\ x\ IC\ x\ (100 - Aux)}]}\ x\ 100\ \%$$

Where,

AUX = Normative auxiliary energy consumption in percentage.

DCi = Average declared capacity (in ex-bus MW), for the $i^{th}$ day of the period i.e. the month or the year as the case may be, as certified by the concerned load dispatch centre after the day is over.

IC = Installed Capacity (in MW) of the generating station

N = Number of days during the period

Note: DCi and IC shall exclude the capacity of generating units not declared under commercial operation. In case of a change in IC during the concerned period, its average value shall be taken.

(6) In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 50 paise/ kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis within each Season (High Demand Season or Low Demand Season, as the case may be), as specified in Clause (B) of Regulation 49 of these regulations.

(7) The provisions under Clauses (1) to (6) of this Regulation shall come into force with effect from 1.4.2020. Till that date, the capacity charge for a thermal generating station determined under these regulations shall be recovered in accordance with the provisions contained in Clauses (1) to (4) of Regulation 30 of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014, subject to the condition that the NAPAF and NAPLF shall be taken as specified under these regulations.

## 2. MoP’s FPPAS Formula

Ministry of Power, Government of India, in Rule 14 of the Electricity (Amendment) Rules, 2022, notified on 29th December, 2022 has specified the methodology and formula for computation of FPPAS the of the ibid methodology, provides as under:-

“1. Computation of fuel and power purchase adjustment surcharge:

> (1) For these rules “Fuel and Power Purchase Adjustment Surcharge” (FPPAS) means the increase in cost of power, supplied to consumers, due to change in Fuel cost, power purchase cost and transmission charges with reference to cost of supply approved by the State Commission
>
> (2) Fuel and power purchase adjustment surcharge shall be calculated and billed to consumers, automatically, without going through regulatory approval process, on a monthly basis, according to the formula, prescribed by the respective the State Commission, subject to true up, on an annual basis, as decided by the State Commission:
>
> Provided that the automatic pass through shall be adjusted for monthly billing in accordance with these rules.
>
> (3) Fuel and Power Purchase Adjustment Surcharge shall be computed and charged by the distribution licensee, in (n+2)th month, on the basis of actual variation, in cost of fuel and power purchase and Interstate Transmission Charges for the power procured during the nth month. For example, the fuel and power purchase adjustment surcharge on account of changes in tariff for power supplied during the month of April of any financial year shall be computed and billed in the month of June of the same financial year:
>
> Provided that in case the distribution licensee fails to compute and charge fuel and power purchase adjustment surcharge within this time line, except in case of any force majeure condition, its right for recovery of costs on account of fuel and power purchase adjustment surcharge shall be forfeited and in such cases, the right to recovery the fuel and power purchase adjustment surcharge determined during true-up shall also be forfeited.

(4) The distribution licensee may decide, fuel and power purchase adjustment surcharge or a part thereof, to be carried forward to the subsequent month in order to avoid any tariff shock to consumers, but the carry forward of fuel and power purchase adjustment surcharge shall not exceed a maximum duration of two months and such carry forward shall only be applicable, if the total fuel and power purchase adjustment surcharge for a Billing Month, including any carry forward of fuel and power purchase adjustment surcharge over the previous month exceeds twenty per cent of variable component of approved tariff.

(5) The carry forward shall be recovered within one year or before the next tariff cycle whichever is earlier and the money recovered through fuel and power purchase adjustment surcharge shall first be accounted towards the oldest carry forward portion of the fuel and power purchase adjustment surcharge followed by the subsequent month.

(6) In case of carry forward of fuel and power purchase adjustment surcharge, the carrying cost at the rate of State Bank of India Marginal cost of Funds-based lending Rate plus one hundred and fifty basis points shall be allowed till the same is recovered through tariff and this carrying cost shall be trued up in the year under consideration.

(7) Depending upon quantum of fuel and power purchase adjustment surcharge, the automatic pass through shall be adjusted in such a manner that,

(i) If fuel and power purchase adjustment surcharge≤5%, 100% cost recoverable of computed fuel and power purchase adjustment surcharge by distribution licensee shall be levied automatically using the formula.

(ii) If fuel and power purchase adjustment surcharge>5%, 5% fuel and power purchase adjustment surcharge shall be recoverable automatically as per 6(i) above. 90% of the balance fuel and power purchase adjustment surcharge shall be recoverable automatically using the formula and the differential claim shall be recoverable after approval by the State Commission during true up.

(8) The revenue recovered on account of pass through fuel and power purchase adjustment surcharge by the distribution licensee, shall be trued up later for the year under consideration and the true up for any financial Year shall be completed by 30th June of the next financial year.

(9) In case of excess revenue recovered for the year against the fuel and power purchase adjustment surcharge, the same shall be recovered from the licensee at the

time of true up along with its carrying cost to be charged at 1.20 times of the carrying cost rate approved by the State Commission and the under recovery of fuel and power purchase adjustment surcharge shall be allowed during true up, to be billed along with the automatic Fuel and Power Purchase Adjustment Surcharge amount.

Explanation:-For example in the month of July, the automatic pass through component for the power supplied in May and additional Fuel and Power Purchase Adjustment Surcharge, if any, recoverable after true up for the month of April in the previous financial year, shall be billed.

(10) The distribution licensee shall submit such details, in the stipulated formats, of the variation between expenses incurred and the fuel and power purchase adjustment surcharge recovered, and the detailed computations and supporting documents, as required by the State Commission, during true up of the normal tariff.

(11) To ensure smooth implementation of the fuel and power purchase adjustment surcharge mechanism and its recovery, the distribution licensee shall ensure that the licensee billing system is updated to take this into account and a unified billing system shall be implemented to ensure that there is a uniform billing system irrespective of the billing and metering vendor through interoperability or use of open source software as available.

(12) The licensee shall publish all details including the fuel and power purchase adjustment surcharge formula, calculation of monthly fuel and power purchase adjustment surcharge and recovery of fuel and power purchase adjustment surcharge (separately for automatic and approved portions) on its website and archive the same through a dedicated web address.

3. Computation of Fuel and Power Purchase Adjustment Surcharge:

(4) Formula:

$$\text{Monthly FPPAS for nth Month } (\%) = \frac{(A - B) * C + (D - E)}{\{Z * (1 - \text{Distribution losses in}\%/100)\} * \text{ABR}}$$

Where,

Nth month means the month in which billing of fuel and power purchase adjustment surcharge component is done. This fuel and power purchase adjustment surcharge is due to changes in tariff for the power supplied in (n-2)th month

A is Total units procured in (n-2)th Month (in kWh) from all Sources including Long-term, Medium –term and Short-term Power purchases(To be taken from the bills issued to distribution licensees)

B is bulk sale of power from all Sources in (n-2)th Month. (in kWh) = (to be taken from provisional accounts to be issued by State Load Dispatch Centre by the 10th day of each month).

C is incremental Average Power Purchase Cost= Actual average Power Purchase Cost (PPC) from all Sources in (n-2) month (Rs./ kWh) ( computed) - Projected average Power Purchase Cost (PPC) from all Sources (Rs./ kWh)- (from tariff order)

D = Actual inter-state and intra-state Transmission Charges in the (n-2)th Month, (From the bills by Transcos to Discom) (in Rs)

E = Base Cost of Transmission Charges for (n-2)th Month. = (Approved Transmission Charges/12) (in Rs)

Z = [{Actual Power purchased from all the sources outside the State in (n-2)th Month. (in kWh)* (1 – Interstate transmission losses in % /100 ) + Power purchased from all the sources within the State(in kWh)}*(1 – Intra state Transmission losses in %) – B]/100 in kWh

ABR = Average Billing Rate for the year (to be taken from the Tariff Order in Rs/kWh) Distribution Losses (in %) = Target Distribution Losses (from Tariff Order) Inter-state transmission Losses (in %) = As per Tariff Order

(5) The Power Purchase Cost shall exclude any charges on account of Deviation Settlement Mechanism.

(6) Other charges which include Ancillary Services and Security Constrained Economic Despatch shall not be included in Fuel and Power Purchase Adjustment Surcharge and adjusted though the true-up approved by the State Commission.