Approach Paper

On

TERMS AND CONDITIONS OF TARIFF REGULATIONS

For Tariff Period

1.4.2024 TO 31.3.2029

No. L-1/268/2022/CERC

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Disclaimer

The issues and suggestions presented in this approach paper do not reflect the views of the Central Electricity Regulatory Commission, its Chairperson, or individual members, and are not binding on the Commission. The views are essentially submitted by staff of the CERC and are circulated with the prime aim of initiating discussions on various aspects of tariff determination and soliciting inputs of the stakeholders in this regard.

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List of Abbreviations

ACM	Authority for Consumers & Markets
ACoS	Average Cost of Supply
AER	Australian Energy Regulator
AFC	Annual Fixed Cost
APPC	Average Power Purchase Cost
BSE	Bombay Stock Exchange
BU	Billion Units
CDM	Clean Development Mechanism
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CIRP	Corporate Insolvency Resolution Process
CMPDA	Coal Mine Development and Production Agreement
COD	Commercial Operation Date
CPI	Consumer Price Index
DISCOMS	Distribution Companies
ECS	Emission Control System
ERC	Electricity Regulatory Commission
FERC	Federal Electricity Regulatory Commission
FERV	Foreign Exchange Rate Variation
FGD	Flue Gas De-sulphurisation System
GCV	Gross Calorific Value
GDP	Gross Domestic Product
GFA	Gross Fixed Asset
GoI	Government of India
G-SEC	Government Securities
GW	Giga-Watt
HEP	Hydro Electric Plant
HPO	Hydro Purchase Obligation
IBC	Insolvency and Bankruptcy Code
IDC	Interest during Construction
IEDC	Incidental Expenditure during construction
INDC	Intended Nationally Determined Contributions
IoWC	Interest on Working Capital

LHP	Large Hydropower Projects
MAT	Minimum Alternate Tax
MCLR	Marginal Cost of Lending Rate
MoEF&CC	Ministry of Environment, Forest and Climate Change
MoP	Ministry of Power
MRP	Market Risk Premium
MU	Million Units
MVA	Mega Volt-Ampere
MW	Mega-Watt
MYT	Multi Year Tariff
NAPAF	Normative Annual Plant Availability Factor
NATAF	Normative Annual Transmission Availability factor
NCLT	National Company Law Tribunal
NEP	National Electricity Policy
NFA	Net Fixed Asset
O&M	Operation and Maintenance
PLF	Plant Load Factor
PPA	Power Purchase Agreement
PSP	Pumped Storage Plant
RBI	Reserve Bank of India
RE	Renewable Energy
RLDC	Regional Load Despatch Centres
ROCE	Return on Capital Employed
RoE	Return on Equity
ROR	Run of River
RPO	Renewable Purchase Obligation
RTM	Regulated Tariff Mechanism
SCOD	Scheduled Commissioning Date
SERC	State Electricity Regulatory Commission
SFOC	Specific Fuel Oil Consumption
SHR	Station Heat Rate
SPV	Special Purpose Vehicle
STPS	Super Thermal Power Station
WACC	Weighted Average Cost of Capital
WAROI	Weighted Average Rate of Interest
WPI	Wholesale Price Index

Preamble and Invitation for Comments

The Central Electricity Regulatory Commission (CERC), in exercise of powers conferred under Section 178 of the Electricity Act, 2003 (36 of 2003) read with Section 61 thereof, had notified the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 (hereinafter referred to as “CERC Tariff Regulations, 2019”) after carrying out the due public consultation process. The CERC Tariff Regulations, 2019 came into force from 01.04.2019 and shall remain in force for a period of five years i.e., from 01.04.2019 to 31.03.2024.

While framing the terms and conditions of tariff for the above period (01.04.2019 to 31.03.2024), the Commission had reviewed the provisions of the earlier Tariff Regulations. While doing so, the Commission had also considered the macroeconomic and market indicators prevalent at that time. Further, with an objective to balance out the interests of consumers as well as generators and transmission licensees, the Commission made necessary changes to the terms and conditions of tariff without compromising on regulatory certainty and notified the CERC Tariff Regulations, 2019.

The very essence of a multi-year tariff framework is to maintain regulatory certainty by not only considering the existing scenario but also anticipating likely future developments that may impact the tariff. In doing so, the Commission has immensely benefited from the inputs & suggestions received from various stakeholders during such proceedings.

This paper analyses various provisions of earlier Tariff Regulations and their efficacy based on the issues and challenges faced by various stakeholders in the past, and it also attempts to analyse key macroeconomic and other indicators along with issues and challenges that the power sector at large is likely to face going forward, which shall have an impact on the tariff and its determination process under Section 62 of the Electricity Act, 2003.

Another key aspect that the paper focuses on is to look for innovative and efficient ways to simplify the entire tariff determination process, which will require minimal regulatory interface without compromising on the regulatory jurisprudence.

With the above broad objective, views/comments/suggestions of the stakeholders are solicited on the issues raised in this approach paper or any other issue relating to the provisions of the CERC Tariff Regulations, 2019 which can be used as an input for formulating Terms and Conditions for determining Tariff commencing from 1.4.2024 to meet the desired objective(s).

1 Introduction

The Electricity Act, 2003 ("hereinafter referred to as "the Act") aims to consolidate laws pertaining to electricity generation, transmission, distribution, trading, and use of electricity for taking measures conducive to the development of the electricity industry, promoting competition therein, protecting interest of the consumers, and promoting environmentally benign policies. Further, to provide clear direction and long-term perspective and to facilitate development of the power system based on optimal utilisation of resources such as coal, natural gas, nuclear substances or materials, hydro and renewable sources of energy, the Act, under Section 3, mandates the Central Government to formulate, review, revise the National Electricity Policy & Tariff Policy in consultation with State Governments and the Central Electricity Authority.

The Act empowers the Central Electricity Regulatory Commission (CERC) under Section 178 to make regulations consistent with the Act and the Rules generally to carry out the provisions of the Act.

One of the important tasks that the ERCs are entrusted with is the determination of tariff and to regulate generation, transmission, distribution and trading of electricity. Section 178(s) empowers CERC to make regulations with regard to the terms and conditions for the determination of tariff under Section 61.

Section 61 of the Act provides for the guiding principles to be followed by the ERCs while framing such terms and conditions for the determination of tariff. Section 61 of the Act provides as follows.

"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."

The above Section stipulates, inter-alia, that the terms and conditions of the tariff should be based on commercial principles, and should encourage competition, efficiency and shall be performance based. The Tariff terms and conditions should also be such that the tariff determined shall progressively reflect the cost of supply, and in doing so shall be guided by the National Electricity Policy as well as the Tariff Policy.

1.1 National Electricity Policy

The National Electricity Policy (NEP) was notified by the Ministry of Power, Government of India, on 12.02.2005 with the primary objective of making electricity accessible to all at reasonable rates by adding new generation capacity and enhancing per capita availability of electricity. While the NEP deals with the macro aspects of Power Sector, Tariff Policy is a specific document guiding the commercial principles to be adopted to encourage capacity development.

1.2 Tariff Policy, 2016

The Tariff Policy was first notified on 06.01.2006 and has since been amended on 31.03.2008, 20.01.2011 and 08.07.2011. The Tariff Policy was revised on 28.01.2016 to address the changing needs of the sector and through Section 4, aims to achieve the following:

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 a generation, transmission and distribution in advance, for reliability of supply of electricity to consumers.*

1.2.1 Other relevant provisions of the Tariff Policy include:

i. Clause 5.2 provides that all future requirements for power should continue to be procured competitively by distribution licensees except in cases of expansion of existing projects or where there is a company owned or controlled by the State Government as an identified developer and where regulators will need to resort to tariff determination based on norms, provided that expansion of generating capacity by private developers for this purpose would be restricted to onetime addition of not more than 100% of the existing capacity.

ii. Clause 5.4 introduced tariff determination for the generation of electricity from projects using coal washery rejects. The operational norms and approach for the determination of fuel cost need to be worked out for such projects while specifying terms and conditions of tariff.

iii. Clause 5.5 provides fixing of time period for the commissioning of Hydro Electric Projects. The Commission will be required to consider this while determining the commercial operation date of HEPs for tariff purposes.

iv. The second proviso to the clause (c) of clause 5.11 mandates the specification of an upper ceiling of the rate of depreciation and an option for the developer to seek a lower rate of depreciation.

v. Sub-clause 3 of Clause 6.2 provides for the inclusion of the cost of setting up coal washeries, coal beneficiation system and dry ash handling & disposal system in the cost of the project.

vi. Sub-Clause 5 of Clause 6.2 provides for mandatory use of water from sewage water treatment plants.

1.3 Framing of Tariff regulations

The Commission has been framing Regulations stipulating the terms and conditions for the determination of tariffs consistent with the above guiding principles and taking into consideration the prevalent macroeconomic as well as market indicators and the future needs of the sector.

Post enactment of the Act, the Commission has till date notified four Multi Year Tariff (MYT) regulations for the tariff periods 2004-09, 2009-14, 2014-19 and 2019-24.

As the control period for the CERC Tariff Regulations, 2019 is about to end in March 2024, the Staff of the Commission, by way of this Approach Paper, seeks suggestions for the formulation of the Tariff Regulations which shall be applicable for the period FY 2024-25 to FY 2028-29.

This Approach Paper has been structured under seven (7) Sections as follows.

Table 1: Structure of the Approach Paper

Section 1	**"Introduction"** which discusses the Regulatory framework of the past and the need to undertake this exercise**.**
Section 2	**"Review of Past and Emerging Need for Simplification of Tariff Process"** reviews the past growth in the power sector, and discusses the roles of various types of generating stations and transmission systems, and attempts to identify the key challenges going forward requiring simplification of the Tariff Process.
Section 3	**"Possible Approaches to Tariff Determination"** discusses alternate approaches to tariff determination viz, Normative Tariff & Performance Based Hybrid Mechanism.

Section 4	**“Financial Aspects impacting Tariff”** discusses relevant issues pertaining to financial determinants of Tariff Regulations along with a few possible regulatory options.
Section 5	**“Operational Aspects impacting Tariff”** discusses relevant issues pertaining to Performance parameters and Operational performance norms pertaining to generating stations and transmission licensees along with possible regulatory options.
Section 6	**“Other Key Issues”** discusses other important issues that need deliberation while framing the Tariff Regulations.
Section 7	**“Summary and Way Forward” s**ummarises all the issues on which comments & suggestions have been sought in this Approach Paper and also re-emphasises the need to simplify the tariff determination process.

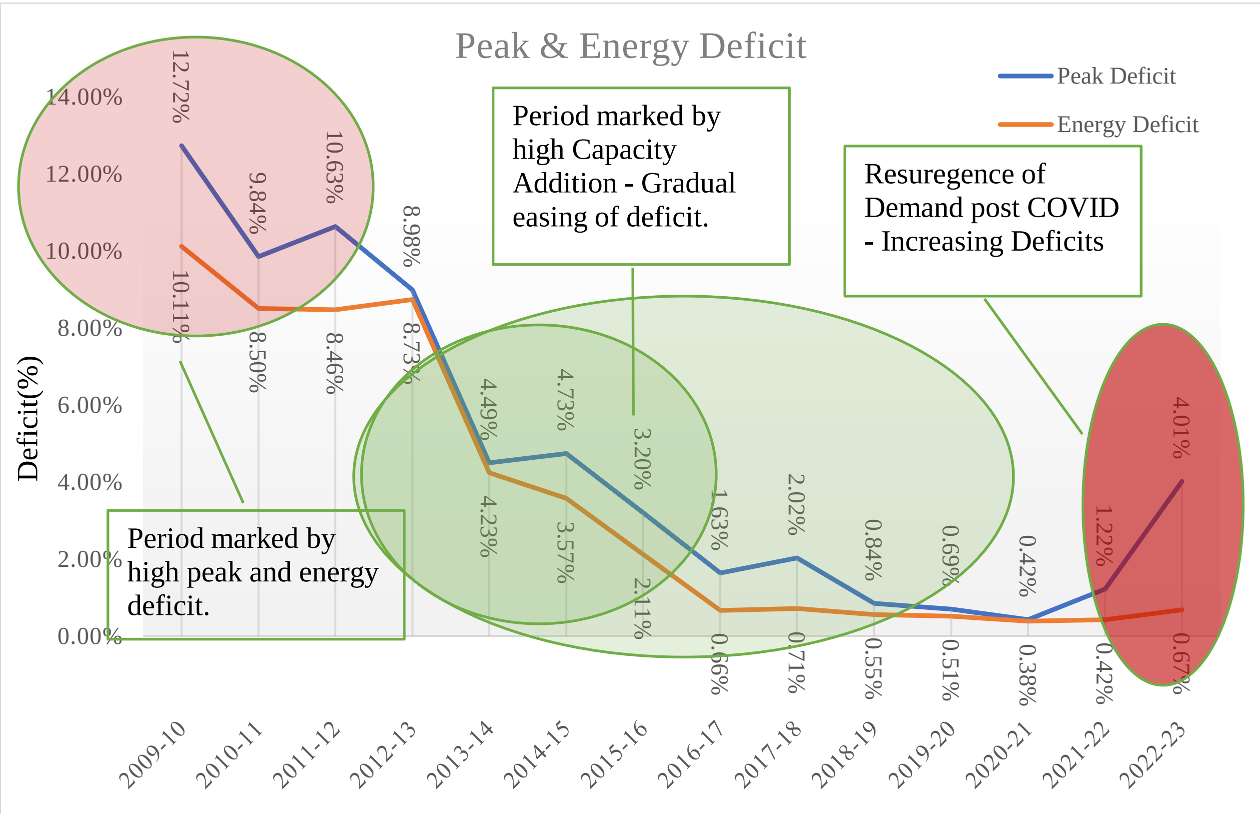
While discussing the issues, possible options have been suggested, and comments and suggestions from stakeholders have been sought on these issues. Stakeholders are also encouraged to provide suggestions on any other relevant issues that they would like to see addressed while framing the Tariff Regulations.

2 Review of Past and Emerging Need for Simplification of Tariff Process

In order to take a holistic view of policy and regulatory interventions that may be required in the future, a review of past performance and key macroeconomic factors is vital. Therefore, for the purpose of this Approach Paper, key aspects, wherever possible, have been analysed for the period from FY 2009-10 to FY 2020-21.

2.1 Review of Power Sector Growth

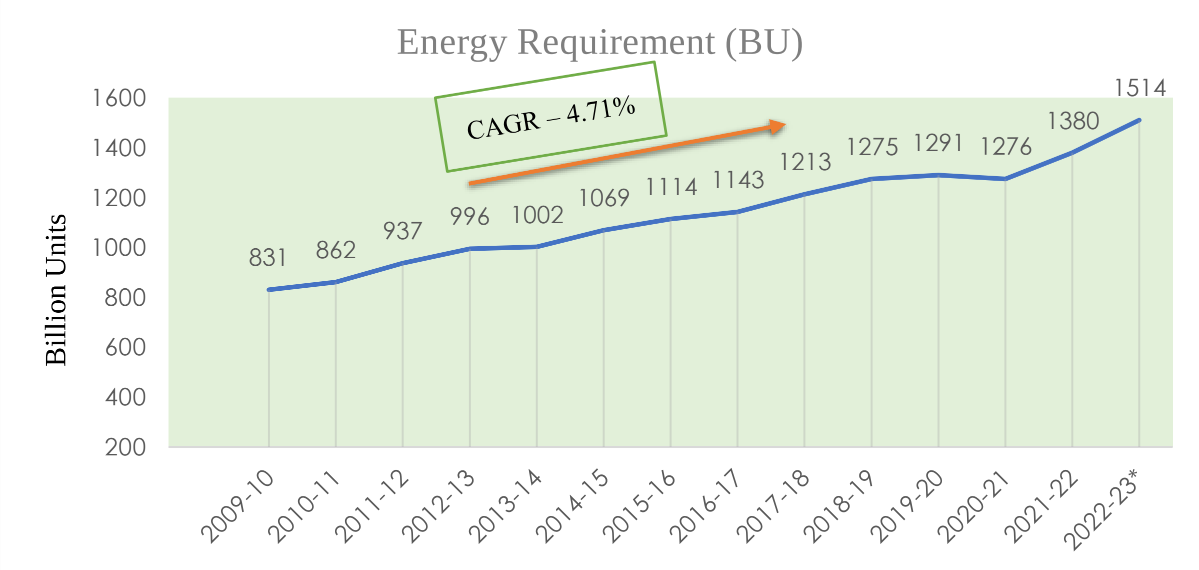
The Indian economy has been on a steady growth trajectory in the past decade, with an exception forced by the worldwide COVID-19 pandemic, which dragged growth of all major economies in FY 2020-21 including that of India. The average GDP growth from FY 2009-10 to FY 2019-20 was 6.74% which was equally supported by a robust growth in power generation capacity. Further, due to robust capacity addition during 2012-17 and the gradual slowdown in economic activity post FY 2017-18 and the subsequent impact of pandemic, the growth in Peak and energy demand reduced, and therefore demand was manageable even though the growth in installed capacity was also impacted during the later part of the decade. The chart below shows the year-on-year peak and energy deficit, along with key markers impacting the gap.



Source: Monthly Report published by CEA

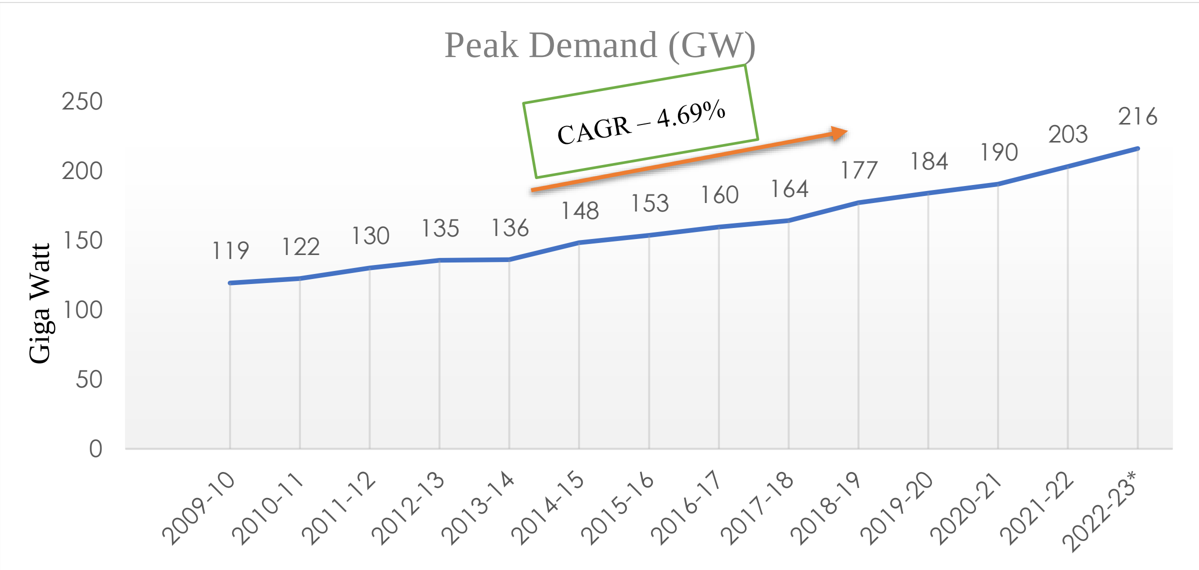
Figure 1: Peak and Energy Deficit – FY 2009-10 to FY 2022-23 (%)

A look at the past year's peak and energy deficit reveals the easing out of supply constraints even though peak and energy demand kept growing. The growth in Energy Requirement and Peak Demand is shown below.



Source: Central Electricity Authority (CEA)
FY 2022-23 – Provisional up to March 2023

Figure 2: Growth in Energy Demand (BU)

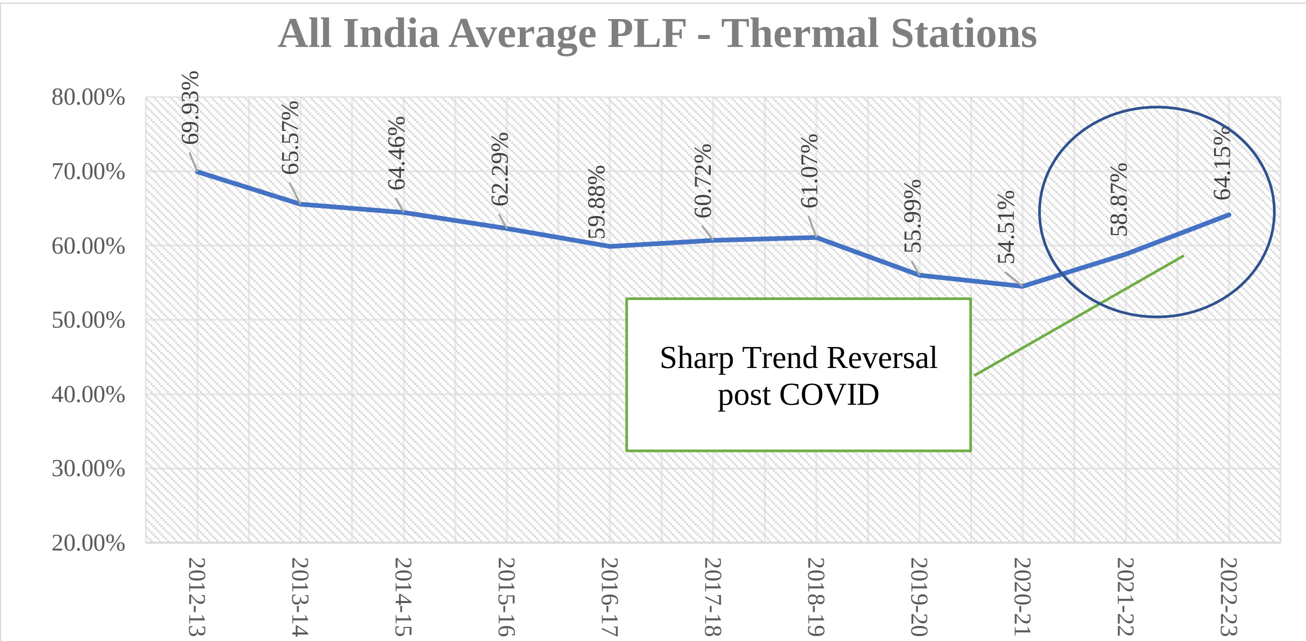


Source: Report published by CEA
** Provisional data upto March 2023*

Figure 3: Growth in Peak Demand (GW)

It is, however, observed that the peak deficit has started to widen from FY 2022-23 owing to a strong revival in demand post COVID-19 pandemic and delayed execution of scheduled projects. As against the scheduled commissioning of thermal capacity of around 65 GW[1], the actual capacity commissioned during 2017-23 is only 32 GW and around 10 GW[2] of thermal capacity was decommissioned during the same period resulting in an increase in net availability from thermal stations in capacity terms of just 22 GW. Further, during the same period, it is observed that the installed capacity from renewable sources, including large hydro increased by 70 GW which though helped manage demand, but these RE sources, except Hydro are not demand responsive, going forward, can have a greater contribution to meeting peak demand only when coupled with storage systems.

It is to be further noted that the **reduced capacity addition and increasing demand has resulted in increased plant load factors for existing thermal capacities**. The all-India average Plant Load Factor for thermal generating stations is shown below.



Source: Central Electricity Authority (CEA)
FY 2022-23 – Provisional up to March 2023

Figure 4: All India Plant Load Factor (%)

[1] As per CEA Report
[2] As per CEA

From the above, it can be inferred that to meet the increasing demand, generation capacity needs to be augmented, and sustained operation of generating capacities needs to be ensured for existing as well as new capacities.

2.2 Review of Transmission Infrastructure Growth

In order to support the growth in installed capacity, matching the growth in transmission infrastructure is of key importance. The transmission infrastructure grew rapidly in the past decade, facilitating the flow of energy from the generation centres to the load centres. Massive growth in transmission infrastructure had its own challenges, such as rising transmission charges. However, the very growth has enabled the grid to absorb the vulnerability associated with the prolific penetration of RE generation witnessed in the last 4-5 years. The growth in transmission capacity is shown in the table below.

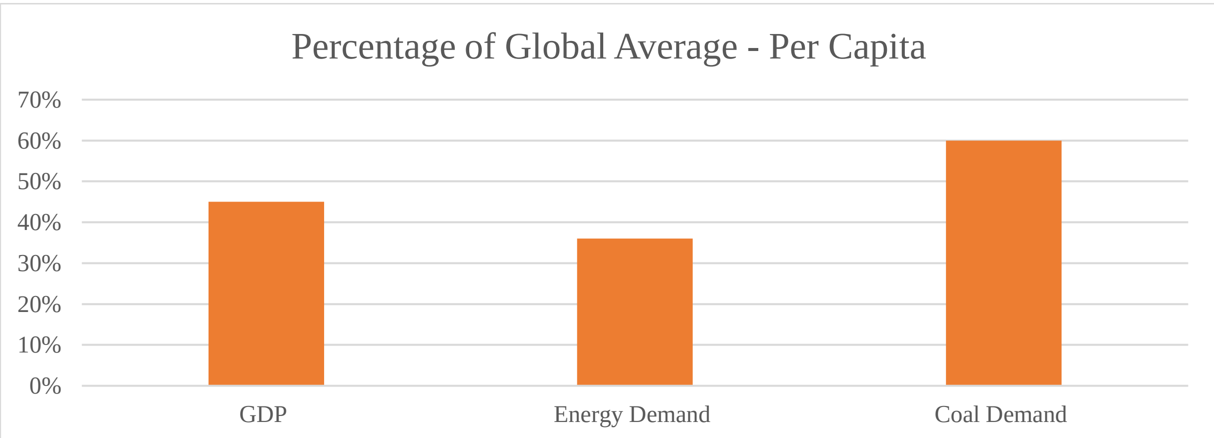
Table 2: Growth in Transmission Infrastructure

S. No	At the end of	CKM	Inter-Regional Transmission Capacity (MVA)
1	10th Plan (2002-07)	196123	-
2	11th Plan (2007-12)	257481	27150
3	12th Plan (2012-17)	367851	75050
4	31.03.2023	471341*	112250

Source: Reports published by CEA
** Status as on March 2023 (provisional)*

2.3 Anticipating Future Growth

India has witnessed steady growth in the past, however, as depicted in the following graph, it is still below the global averages on many key macro-economic indicators.



Source: IEA-Special Report on Indian Energy Outlook 2021

Figure 5: India's position vis-à-vis global averages on key indicators

It can be inferred from the above, that despite the improvement in per capita figures across key parameters there is still considerable scope for growth in energy demand. CEA in its 20th Electric Power Survey, has projected the Peak Demand under a moderate scenario to grow to around 264.33 GW by FY 2026-27 and to 328.59 GW by FY 2031-32. **This translates into an increase in peak demand of 60 GW by FY 2026-27 and by around 125 GW by FY 2031-32.** This will require a considerable enhancement in installed capacity. Though a major part of this requirement will be met through RE sources, to balance it, a base load power plant will also be required. **CEA in its Report on Optimal Generation Mix for FY 2029-30 (Version 2.0) has projected that by 2030 the existing capacity of FY 2021-22 will be required to almost double to approx. 777 GW** out of which the thermal generating capacity will amount to 275 GW **requiring about 38 GW of thermal capacity addition** from the present levels of around 237 GW. In order to meet the target, it would be important that the old generating stations that are still operating economically, are utilised reliably and efficiently; otherwise cost of replacing these old stations will only increase the cost of generation. Further, hydro generating stations that are facing bottlenecks during construction need to be taken up for early completion, which would also help managing growing demand.

India has now targeted to achieve 500 GW of non-fossil fuel based capacity by 2030 and to facilitate the same, CEA has carried out a detailed study on integration of 537 GW of RE capacity by 2030. The Report states that the present transmission system needs to be augmented to accommodate an additional 300 GW which will require considerable capital investment.

Though most of the new generation capacities and transmission schemes will be coming through competitive bidding, existing capacities whose tariff is determined under Section 62 as well as those which shall be awarded under the Regulated Tariff Mechanism (RTM) route will form a major chunk of future capacities, and therefore the risk perception of these investors. including other stakeholders such as lenders, needs to be lowered so that it provides right signal to the investors to invest in the sector for creating the much needed capacity.

2.4 Sustainable Growth and Energy Transition

The Economic Survey of India – FY 2022-23, estimates that the GDP in real terms will grow by around 7% in FY 2022-23 and further projects growth in baseline GDP at 6.5% in real terms for FY 2023-24. India is expected to continue with its robust growth and is well poised to become the third largest economy by FY 2029-30. In order to support such growth, one of the key infrastructures that will be required will be the availability of quality power at economical rates. **The 20th Electric Power Survey estimates peak demand of 335 GW in FY 2029-30 an increase of around 50% from the current peak demand of around 216[3] GW.** India will therefore have to ensure that its power sector keeps growing at around the same rate in order to act as an enabler in achieving the goal.

To ensure the steady growth of Power Sector, any policy interventions and reforms that need to be devised should revolve around the sustainability of such envisaged growth and its carbon footprint in view of its long-term impact on climate and associated eco-systems. Though, the per capita carbon emission of India is insignificant compared to other developed nations, the Government of India acknowledging the seriousness of the issue, has pledged that it shall strive to be a net-zero country by 2070 and in order to do so, India has submitted its revised Intended Nationally Determined Contributions (INDCs) which necessitates the promotion of efficient generation.

In furtherance of these objectives, the following key aspects have been considered while preparing this Approach Paper.

1) Attracting fresh Investments to meet the growing demand.
2) Preserving and augmenting existing capacities – Incentivising life extension, R&M, and efficient old generating stations.
3) Providing the necessary push so that the same encourages private investments through Assured Returns, Mitigation of Risk Perception and Regulatory Certainty.
4) De-risking construction - Removal of current Bottlenecks faced during project execution, especially for Hydro Stations.
5) Incentivising efficient plant operations and sustainable development.

[3] As per CEA – April 2022

2.5 Transition to Sustainable Sources

The tariffs for the major share of the existing coal based thermal generating stations, which are well above 75 GW are determined under Section 62 of the Act. The proposed Tariff Regulations that shall be in force for the period 2024-29, aim to provide proper incentive/disincentive mechanisms so that efficient operations are encouraged, and in-efficient operations are avoided. Given India's development goals, coal-based thermal power plants shall no doubt continue to be the primary[4] source of energy which will be fuelling the economic growth. However, **it is imperative that the focus be on efficient plant operations; and norms for old as well as new generating stations , need to be evaluated.** Therefore, the proposed Tariff Regulations, in a way, need to give indications that can target sustainable capacity additions while lowering the regulatory risk perception of the existing capacities. **The objective of moving towards sustainable generation mix can be achieved by incentivising generation with a lower carbon footprint, such as hydro generating stations, while also incentivising efficient operations of thermal generating stations including gas-based power plants**.

2.6 Role of Hydro Generating Stations

India is endowed with significant hydroelectric potential and ranks fifth in the world in terms of usable potential. As on 31.03.2023, Hydropower Generation contributed 12.46% (Hydro Generation at 11.27% with 46.85 GW[5] Installed Capacity and Small Hydro at 1.19% with 4.94[6] GW Installed Capacity) in the Total Energy Generation Mix of India.

Besides being environmentally friendly, hydropower has several other unique features like the ability for fast ramping, black start, reactive absorption, etc. which make it ideal for peaking power, spinning reserve, and grid balancing/ stability. Further, hydropower also provides water security, irrigation, and flood moderation benefits, apart from contributing to the socio-economic development of the entire region by providing employment opportunities, and boosting tourism, etc. The importance of hydropower is increasing even more as the country has targeted to achieve 50% of the total installed capacity from non-fossil fuel-based energy sources by 2030 to honour its Nationally Determined Contribution

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[4] As per CEA's projection in its Report on Optimal Energy Mix by 2030 (Version 2.0)
[5] As per CEA Generation Report March 2023
[6] As per CEA

to Climate Change. However, the distribution licensees ("DISCOMS") are reluctant to sign Power Purchase Agreements (PPAs) for hydropower due to the higher upfront tariff. One of the reasons for the high tariff of hydropower is the in-ordinate delays leading to cost and time over runs and increase in the cost of flood moderation and enabling infrastructure in the project cost. The share of hydro stations, which once constituted around 28.77% of installed capacity in FY 1989-90 and 19.50% in FY 2011-12, has now reduced to around 12.46%.

To address some of the problems associated with the development of hydro sector and to renew the interest of investors in the sector, the Ministry of Power, Government of India (GoI) has taken the following steps to promote hydro based generating stations.

1. The large hydropower projects have been declared as renewable energy sources.
2. Declaring Large Hydropower Purchase Obligation (HPO).
3. HPO as a separate entity within total Renewable Purchase Obligation to cover LHPs commissioned after notification of these measures (SHPs are already covered under Other Renewable Purchase Obligation).
4. Hydro Purchase Obligation (HPO) trajectory, for the period 2022-23 to 2029-30 has also been notified by the Central Government on 22.07.2022.
5. Tariff rationalization measures including providing flexibility to the developers to determine tariffs by back loading tariffs after increasing the project life to 40 years, increasing debt repayment period to 18 years, and introducing an escalation of tariffs by 2% per annum.
6. Budgetary support for funding the flood moderation component of hydropower projects on a case-to-case basis; and
7. Budgetary support for funding cost of enabling infrastructure, i.e. roads and bridges, on a case to case basis as per actual, limited to Rs. 1.5 crore per MW for up to 200 MW projects and Rs. 1.0 crore per MW for above 200 MW projects.

The Approach Paper discusses further regulatory interventions that may be required to promote the hydropower sector and incentivize expeditious implementation of hydro projects to reduce front loading of tariffs, thus relieving the burden on the consumer.

2.7 Role of Gas Based Generating Station

In view of the high Energy Charges due to high gas prices and reduced gas availability, the PLF of gas power stations has been hovering around 20-25%. **However, as gas based generating stations have distinct advantages with regard to balancing the grid, their role needs to be distinguished from that of the other generation sources**.

Considering the higher anticipated RE penetration, evolution of Ancillary Services and anticipated disruption in hydrogen production costs, gas based generating stations can play a significant role as India transitions to cleaner alternatives and therefore may require some transitional support. This Approach Paper also explores various interventions that gas plants may require so that they act as enablers to manage the anticipated demand.

2.8 Role of Old Generating Stations

Out of the total 237.27[7] GW of installed thermal generation capacity as on 31.03.2023 more than 50 GW of generating stations, including State and private sector generating stations, shall be completing 25 years of life by 01.04.2024. These old generating stations can be classified into the following three categories.

1) Generating Stations that are operating efficiently and are economical.
2) Generating Stations that have deteriorated to the point that they cannot be operated economically.
3) Gas based generating stations that are efficient but are not generally scheduled owing to the high cost of gas.

It is to be analysed how these generating stations can be utilised in the most efficient manner, given the anticipated demand growth and balancing needs. These generating stations are differently placed when compared to newer stations as they have already recovered depreciation and completed loan repayments and thus have an advantage in terms of financial consideration. However, as these stations are old, their operational costs could be higher as compared to new supercritical units, and the O&M expenses for such generating stations are also higher. These generating stations have four options going forward.

[7] As per CEA – March 2023

a) Retirement/decommissioning for those stations that are operating way below the normative parameters thus inflicting loss to both generators and beneficiaries.
b) Replacement by more efficient super-critical units – Will result in efficient utilisation of limited fossil fuel but is a Capital-Intensive Option
c) Renovation of old plants – comparatively less Capital Intensive as compared to total replacement but are subject to Residual Life Assessment studies and Cost Benefit Analysis;
d) Continuation of Operation of such plants after useful life with special allowance to undertake renovation activities on need basis.

The generating stations that cannot be operated economically or the generating stations that cannot comply with environmental norms have no other option but to decommission. It is to be noted that during the period 2017-22 around 10.04[8] GW of thermal capacity has already been decommissioned.

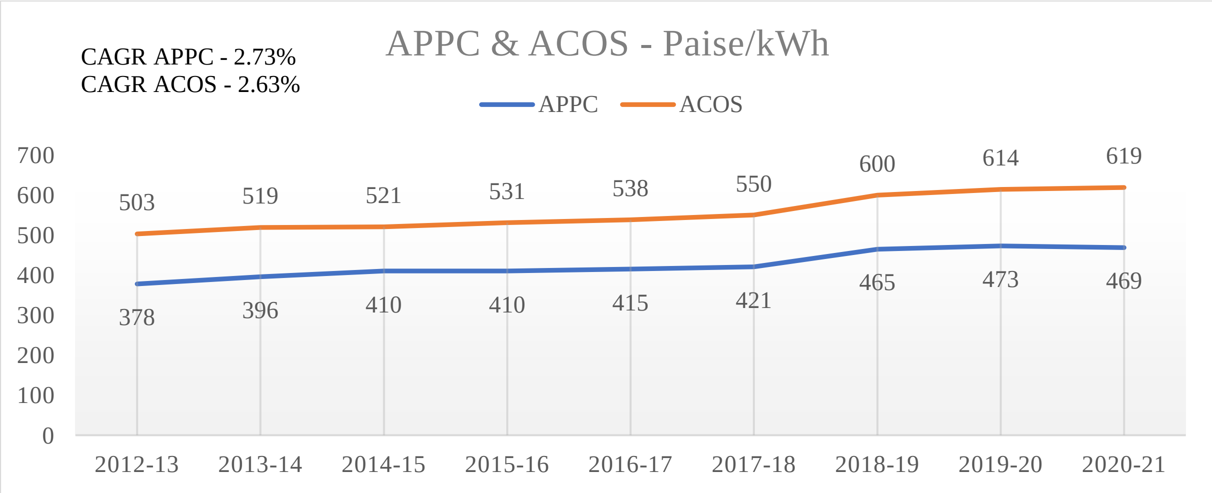
However, the generating companies in the past have argued that most of the old generating stations have been well maintained and are operating efficiently, so supporting provisions such as the current dispensation under special allowance may be continued.

2.9 The Cost Factor

While ascertaining the adequate supply to meet the peak and energy demand is one aspect of energy security, the equally crucial aspect is the cost at which electricity is secured. Electricity is an input to most industries and high cost of power impacts the overall competitiveness of industry. Therefore, while ascertaining energy availability, its cost aspect also needs to be considered and given equal weightage.

The average power purchase cost (APPC) and average cost of supply (ACoS) of distribution utilities have been increasing year on year and are shown below.

[8] As per CEA



Source: PFC-Reports on Performance of State Power Utilities

Figure 6: Trend of APPC & ACoS - Paise/kWh

With regard to Inter-State transmission systems, there have been massive capital investments in the past decade to strengthen the Grid which was carried out to cater to the anticipated growth in demand. The augmentation of the transmission system has enabled the Grid to adjust to the variability due to the increase in Renewable Penetration. As more and more Renewable generation is projected to be integrated with the Grid, augmentation of Grid is required on a continuous basis on commercial principles so that demand growth can be fulfilled in an economical way.

In order to ensure the availability of electricity at a reasonable price, the focus of this Approach Paper has been on the following key aspects that impact costs.

1. Efficient and Performance based Norms
2. Maximising the utilisation of efficient generating stations.
3. De-risking Generation and Transmission Business

2.10 Regulatory Certainty

The other key aspect that has been highlighted while framing Tariff Regulations in the past, is the revision of norms for the existing generating stations. It is observed that these generating stations, at the time of planning, were subjected to a different set of norms, and their individual feasibility was determined based on the then prevailing norms. As these norms are being revised on the basis of actual performance in the past tariff period, utilities have expressed their concern in the past over such revisions affecting the viability of such projects. The basic argument being made is that the revision of norms for the old generating stations aggravates the risk perception of not only the project(s) but also the entire sector. In the past, it has been submitted that any such move may result in an increased cost of lending for additional capitalisation or resetting of interest on loans which would tend to negate the benefits and also result in an increase in the generation cost on an overall basis.

With regard to operational norms such as Heat Rate, Secondary Fuel Oil Consumption (SFOC), Auxiliary Consumption, Boiler Efficiency, the revised norms that are superior to design parameters for the old generating stations, may not be specified for such old generating stations. These aspects have been discussed in detail in **Section 5** of this Approach Paper.

However, other stakeholders have countered the analogy by stating that as norms under Section 62 are based on the actuals achieved in the past and a gradual shift towards efficient operations is much needed, and hence the applicability should also be for older generating stations.

Further, it can be argued that increasing variability in demand requires more flexibility in generation with frequent ramp up and ramp down requirements, which may lead to degradation of operational norms, and therefore such an impact needs to be considered while determining the norms. It is therefore important that appropriate mechanisms be provided so that not only the norms can be made more efficient, but the generating companies are also incentivised to generate economically without compromising on regulatory certainty.

2.11 Simplification of Tariff Determination Process

The evolution of any process/mechanism is characterised by its gradual simplification. The Commission has been specifying the terms and conditions for the determination of tariffs for over two decades now, and as the performance parameters have evolved and achieved some level of stability, it is time that the thrust should now be on the simplification of the process.

It is also observed that due to the increasing number of assets whose tariff needs to be determined under the Regulated Tariff Mechanism (RTM), the tariff determination process has become complex and cumbersome. Further, considering the future growth that is required to sustain the economy, the tariff determination process is required to be simplified and aligned with future requirements**. Therefore, simplification of the tariff determination process is the core idea that shall drive the terms and conditions of tariff determination for the period FY 2024-25 to FY 2028-29**.

Simplification of the process has been envisaged for the following key activities that, over time, have become complex and time consuming.

1. Exploring the option for determination of tariff on a normative basis.
2. Modifying the existing approach to allow more parameters on a normative basis.

3 Possible Approaches to Tariff Determination

3.1 Tariff Determination – General Approach

The Power Sector has been evolving and has witnessed different phases of development, requiring specific interventions and different approaches to tariff setting and its design. Historically, the tariff was set on a cost-of-service approach, wherein utilities were assured full recovery of reasonable expenses along with pre-determined returns that were embedded in the tariff. Though, one can argue that the said tariff principle could have been more efficiency oriented, but considering that the utilities were facing insurmountable losses, the cost plus tariff allowed some comfort to utilities and other investors doing transactions with such utilities. This was important for continuing the development of the power sector and the approach also allowed the utilities much needed time to re-organise and gear up to embrace future changes.

The Act aims to promote competition and rationalisation of tariffs and also recognises the importance of cost-of-service approach to tariff setting. CERC, in line with the prevailing requirements, adopted the cost-of-service approach and gradually introduced norms based on actuals and normative costs, thus embedding efficiency in the tariff. With time, the ambit of normative parameters increased and was coupled with incentive and disincentive mechanisms to promote efficient operations.

The Commission has gradually shifted from the cost-of-service model to a more efficient hybrid approach wherein most of the components of the tariffs are now allowed on a normative basis irrespective of actual cost, while retaining a few of the cost determinants such as capital cost, additional capitalisation, fuel cost, interest rates etc. to be allowed on actual basis subject to a prudence check. Admittedly, though the change has been gradual, the pace has allowed utilities to adjust their approach and contribute towards the development of the sector which is evident from the infrastructure growth witnessed in terms of generation and transmission capacities, as discussed in **section 2** of this Paper.

Section 61 of the Act provides the broad principles to be followed while specifying the terms and conditions for the determination of tariff so that the same are guided by factors that would promote competition and are economically efficient, thus attracting investments. The upcoming Tariff Regulations shall regulate the tariff of existing capacities as well as new projects under the RTM route under Section 62 which would continue to be the major source of power supply and cater to the growing demand of the country.

In view of the above, suggestions are sought as to how the present system of hybrid mechanisms of tariff setting under the cost plus approach can be made more efficient by moving closer to a normative or performance-based approach so that the same would positively impact the interests of consumers as well as utilities. Two possible options could be as follows.

1. **Approach 1: Shift to a normative tariff, wherein, once capital costs are approved on an actual basis after prudence check, all other AFC components are determined on normative basis.**
2. **Approach 2: Further simplification of the existing Performance Based Hybrid Approach, wherein on the basis of admitted capital cost, AFC components can be approved based on actuals or norms as may be specified for the control period. Further, additional capitalisation may be allowed on certain counts on a normative basis.**

The above two approaches have been discussed in detail in subsequent sections of this Approach Paper.

3.2 Approach 1: Normative Tariff

It is observed that once the capital cost, including additional capitalisation up to cut-off date, is approved for a certain project, the fixed charges for such projects follow a certain trajectory, except in the case of sporadic impacts of additional capitalisation. In order to give effect to such recurrent additional capitalisation in fixed charges, the generating companies and transmission licensees under the current mechanism, first file a petition seeking tariff on the basis of projected additional capitalisation and again file a true up petition seeking tariff based on actual additional capitalisation incurred during the tariff period. it has been observed that, in most of the cases, the only variation in the approved vis-à-vis trued-up fixed charges is on account of variation in additional capitalisation which is also insignificant in many of the cases. This requirement of approving additional capital expenditure on an actual basis has resulted in considerable and recurring efforts being put in by the generating companies and transmission licensees as well as the Commission, resulting in regulatory overburden, and therefore, simplification of tariffs by shifting to normative tariff has almost become a necessity.

The Commission, while framing the Tariff Regulations for FY 2019-24, in its Approach Paper[9] had carried out a study of 30 generating stations to analyse the trends of various AFC components and to see whether these components follow a specific trajectory. In the study carried out, components of AFC were clustered into following two groups.

1) AFC component that increases over a period – O&M expenses
2) AFC components that decrease over a period – rest of AFC components.

These different groups of expenses were then plotted year on year, and the following trend was observed.

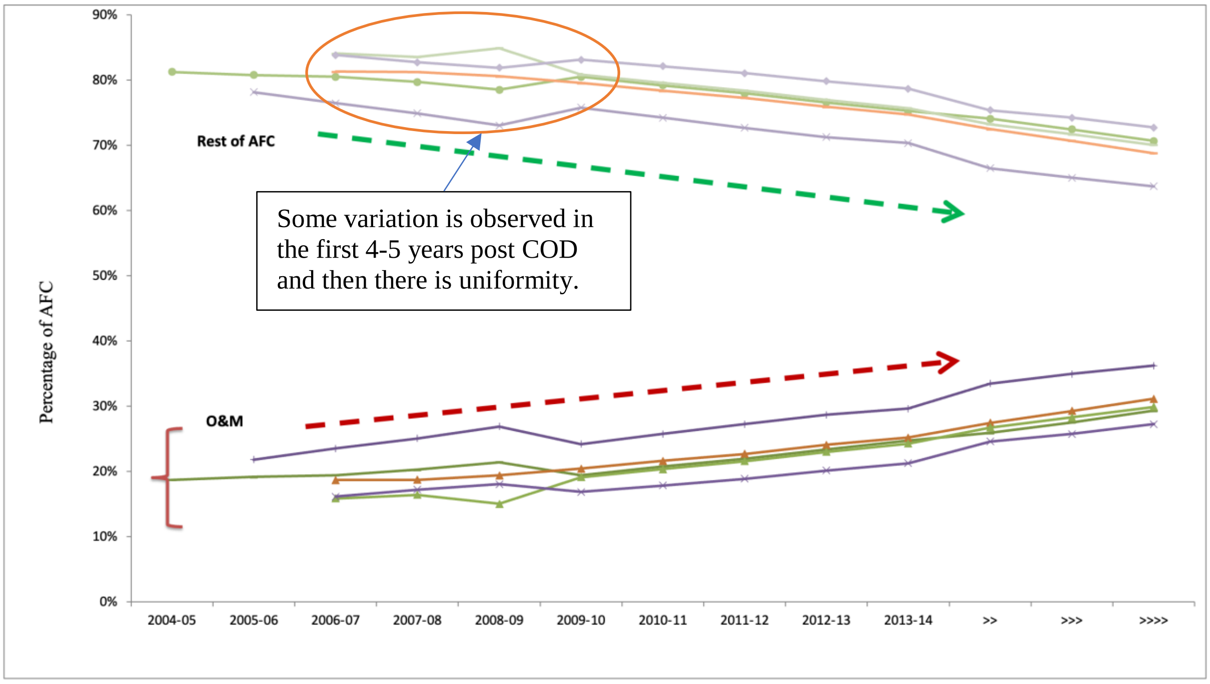


Figure 7: Trend analysis of O&M expenses and rest of AFC components

From the above, the following key conclusions can be drawn:

[9] https://cercind.gov.in/2018/draft_reg/AP.pdf

1. Post COD, there are some variations in the components of AFC mostly due to the impact of additional capitalisation pertaining to balance capital works post COD, commissioning of subsequent units. From the past data, it is observed that major works are incurred primarily in the first 4-5 years, and therefore there is some aberration in AFC in the first 5 years post COD.

2. The near parallel trendlines for various generating stations suggest that though the behaviour of AFC components is similar, the quantum differs owing to different costs of funds, funding patterns, depreciation rates and other plant specific peculiarities.

In order to further analyse the behaviour of AFC components under normal conditions (without additional capitalisation) the various components of AFC were plotted over a period of 25 years, and the following trend was observed.

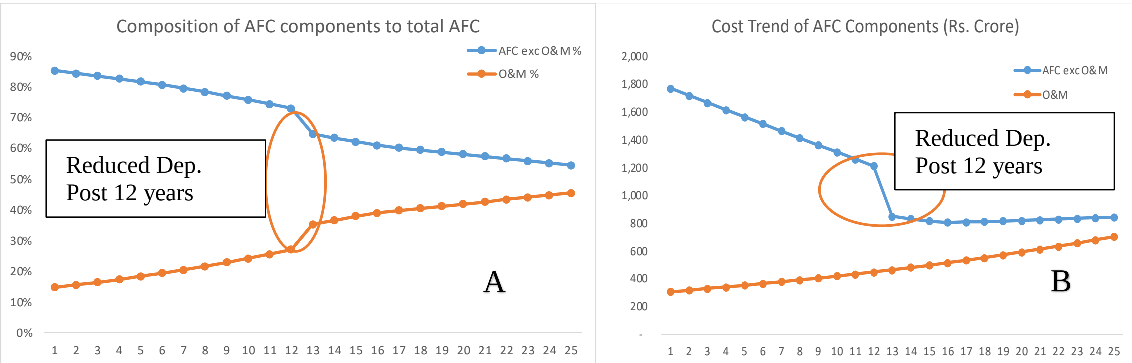


Figure 8: Trend analysis of O&M expenses and the rest of AFC components

The above graphs depict a clear trend of cost components, provided that the terms and conditions of the tariff remain the same throughout the project life. The above trend is equally true in the case of transmission assets.

From the past data, it is observed that there are variations in some of the cost determinants, and if a normative regime is to be adopted, the impact on account of the following factors needs to be duly accounted for from time to time so that the AFC components can be fine-tuned to incorporate the impact of additional capitalisation and changes in market dynamics.

1. Weighted average rate of Interest
2. Interest on Working Capital

3. Additional Capitalisation

It is further observed that apart from the year- on- year variation, which could be station specific, there could be inherent variation due to different costs of funds, funding patterns, depreciation rates, additional capitalisation and other plant specific peculiarities, and therefore a normative tariff for these stations appears to be feasible only when determined asset specific.

The asset specific normative tariff will allow the tariff determined to be close to actuals, thereby eliminating the chance of major gain or loss, and will also help achieve the other objective of eliminating the need for periodic tariff filings.

In order to achieve the dual objectives as flagged above, for existing generating stations and transmission systems whose cut-off date shall be over by 31.03.2024, the gross fixed assets as approved as on 31.03.2024 may be considered for projecting base year AFC i.e., for the first year of the Control Period (FY 2024-25). Subsequently, fixed charges for future years may be approved on the basis of indexation that may be specified for each generating station/transmission system by the Commission from time to time.

In the case of new generating stations and transmission systems, as observed earlier, there is variation in the first 4-5 years causing aberrations, therefore, it is proposed that once the capital cost is approved on an actual basis as on cut-off date (5 years post CoD) after carrying out detailed scrutiny, all components of fixed charges may be determined on a normative basis from the sixth financial year (Base Year).

Further, with regard to Energy Charges, for both new and existing generating stations the same may be approved based on actual fuel cost and normative performance parameters as currently allowed.

The approach is further detailed below.

1. Existing projects

a) For existing generating stations/transmission systems that have been in operation for more than five years as on 31.03.2024, the capital cost as on 01.04.2024 is proposed to be considered for the determination of the tariff for FY 2024-25. Based on the norms to be specified in the CERC Tariff Regulations 2024, Annual Fixed Charges (AFC) for the first year of the next tariff period, i.e., FY 2024-25 are proposed to be determined. The AFC components for the base year (FY 2024-25) can be determined individually and then clubbed under the following two categories.

   1) AFC excluding O&M expenses
   2) O&M expenses

   Once the above two major components of AFC are determined for FY 2024-25 (Base Year), the above two components for the rest of the years of the tariff period shall be determined for the project based on specified indexation.

b) The indexation specified can be with regard to the previous year, i.e., AFC component as computed for the N^{th} year/AFC component as computed for the $N-1^{th}$ year.

c) Post expiry of each tariff period, the Commission shall call upon relevant data (on weighted average rate of interest and Interest on Working Capital, Working Capital) and revise only the indexation factor pertaining to "AFC excluding O&M component" approved at the time of tariff determination for each Project for each year. There shall be no revision to the indexation with regard to O&M expenses pertaining to the past tariff period.

d) Through the same exercise, the Commission can also specify the indexation factor, for the above two categories for the next tariff period (2029-2034).

e) The Commission may issue a combined Order specifying the station wise revised indexation factor and based on the revised indexation of the past tariff period, generating station or transmission licensees can refund/recover the differential amount as done presently.

f) Further, in case any additional capitalisation is incurred or is required, the petitioner may file a separate petition seeking approval of capital expenditure, and once such capital expenditure is allowed, the variation on account of additional capitalisation on the AFC can be serviced by first computing the impact on the AFC and then adjusting the same through the same indexation mechanism as specified above. Such an adjustment can be carried out from the date of capitalisation of such additional capitalisation. The various possible options of allowing additional capitalisation post COD have been discussed in detail in **Section 4** of this Approach Paper.

g) For future tariff periods, the AFC of the existing projects, including servicing of additional capitalisation shall continue to be governed as per the CERC Tariff Regulations, 2024.

h) Energy Charges are already allowed based on normative performance parameters and actual fuel costs and are proposed to be continued.

A sample calculation exhibiting the above approach (under both scenarios, i.e., without additional capitalisation and with additional capitalisation) is attached as Annexure -1 to this Approach Paper.

2. New projects (COD on or after 01.04.2024 or projects that are yet to complete operations for 5 years as on 01.04.2024)

a) The capital cost can be approved on actual basis up to cut-off date. Further, additional capitalisation post cut-off date can be allowed on normative basis and has been discussed in detail in Section 4 of this Approach Paper.

b) The tariff components of AFC shall be determined and trued up on actual basis till the financial year in which the cut-off date of such generating stations ends. The AFC for each station can be determined under the following two categories for the first financial year post cut-off date.

   1. AFC excluding O&M expenses
   2. O&M expenses

c) Thereafter, from 6th financial year onwards, the above AFC categories can be determined based on indexation mechanism as proposed for the existing projects.

d) The current practice of approving Energy Charges can continue in the case of generating stations.

In this context, comments/ observations from stakeholders are invited on the following points:

1) **Whether clustering the components of AFC based on their nature to increase/ decrease will allow better projections? Any other possible method to cluster the AFC components?**
2) **What other methodology can be adopted to determine the increasing/ decreasing factors?**
3) **Whether the impact of additional capitalisation can also be allowed through the same indexation mechanism or through a separate revenue stream?**

3.3 Approach 2: Performance Based Hybrid Approach

The second alternative to further simplifying the tariff determination process is to continue with the current practice of tariff determination with more AFC components being allowed on a normative basis. As more and more AFC components are approved on normative basis, it would ease the transition to a complete normative regime.

3.3.1 Existing Tariff Framework

Under the existing tariff mechanism, once the capital cost and its funding is approved based on actuals, after carrying out a due prudence check, individual components of AFC are allowed as per the following approach.

a) **Depreciation:** For the first 12 years, the depreciation is allowed as per the rates specified in the regulations and thereafter, the balance depreciable value is spread across the useful life of the project.
b) **Interest on Loan:** Based on the admitted capital cost, normative debt is worked out based on the approved debt equity ratio, and interest on such normative debt is computed based on the weighted average rate of interest applicable for the project.
c) **Return on Equity (RoE):** is allowed considering the flat rate of return as specified in the Regulations on the normative equity approved based on the approved debt equity ratio.
d) **O&M expenses:** They are approved on a normative basis as per the norms specified in the Tariff Regulations. Further, these norms are specified considering actual

expenses incurred in the past after carrying out the due normalisation of abnormal or non-recurring expenses.

e) **Interest on Working Capital (IoWC):** Tariff Regulations already specify norms for computing working capital requirements based on which IoWC is allowed by allowing a suitable margin over the Marginal Cost of Lending Rate (MCLR)+350 bps.

As can be inferred, the existing approach already allows various cost components of AFC on a normative basis; however, there is a need to explore options to further simplify the current tariff process, and possible alternatives have been discussed subsequently.

Generation Tariff

In the case of generating stations, although O&M expenses, Depreciation, Return on Equity are specified on a normative basis, the following components, as per the present Regulations require consideration of actual values.

1. Energy Charge – Fuel cost and GCV to be considered.
2. Working Capital – Actual fuel costs keep varying and affect total receivables.
3. Interest rate on loans and interest rate on Working Capital

With regard to Energy Charge, it is observed that the Commission has already specified an adjustment mechanism wherein Energy charges are claimed on an actual basis, however, the possibility of specifying working capital requirements on a normative basis which can factor in the variations due to actual fuel prices and interest rates to be considered for computing interest on working capital on a normative basis, needs to be explored.

Transmission Tariff

As per the current Tariff Regulations governing the determination of transmission charges, the following components of the tariff are already allowed on a normative basis:

1. O&M expenses
2. Depreciation
3. Return on Equity
4. Working Capital requirement and interest thereon.

The Regulation at present only allows interest on normative loan capital at the actual weighted average rate of interest. It is to be analysed whether this interest rate can also be fixed with linkage to the reference rate.

The issues pertaining to capital cost determination, including additional capitalisation and individual AFC components, have been discussed in detail in the following sections of this Approach Paper. As even in the case of Approach 1, the tariff for first six years in the case of new generating stations and for the FY 2024-25 in the case of existing generating stations is required to be determined based on the actual capital cost approved and the tariff norms to be specified in the CERC Tariff Regulations, 2024, it is clarified that the issues flagged herein are equally relevant for both approaches.

It is therefore important that the stakeholders, while providing suggestions, evaluate the options suggested in subsequent sections, considering its applicability for both Approach 1 and Approach 2.

4 Financial Aspects impacting Tariff

4.1 Declaration of Commercial Operation and Commercial Operation Date

The aspect of Date of Commercial Operation (COD) and the manner in which COD shall be declared are being separately dealt with by the Commission in the CERC (Indian Electricity Grid Code) Regulations, 2023 and therefore shall be considered as per the said Regulation.

4.2 Capital Cost

4.2.1 Background

The approval of capital costs is one of the most important aspects of the tariff determination process, as almost the entire fixed charge throughout the life cycle of the project depends upon it. In the process of tariff determination, the Commission has been approving the capital cost of the projects on a case- to- case basis, which is dependent on the actual expenses incurred, duly certified by the auditors, and after carrying out due prudence on the reasonability of the expenses incurred. The CERC Tariff Regulations, 2009, introduced an enabling provision that allows utilities to seek approval of the capital cost of new projects on an anticipated basis, which helps utilities minimise the time gap between the commissioning of the project and the generation of cash flows by means of tariff. **The provision for interim-tariff can, therefore, be continued in the next tariff period as well. However, comments and suggestions are sought from stakeholders on the continuation of the said provision.**

4.2.2 Procurement of Equipment and Services

Section 63 of the Electricity Act, 2003, mandates that tariff be determined based on competitive bidding, Section 62 is about the determination of tariffs under the cost plus mechanism. It is, however, imperative that even under Section 62, the procurement of equipment and services be carried out through competitive bidding. In such a framework, in the interest of consumers, Work Contracts are required to be awarded on the basis of transparent competitive bidding, which shall form the basis of approval of such costs. Further, Tariff Policy, 2016 lays emphasis on the utility and benefits of competitive bidding, and therefore, even for projects being developed under Section 62 of the Act, the works need to be executed following the transparent process of competitive bidding. The Commission, through various Orders, have also laid emphasis on the need to follow a transparent process of competitive bidding for the procurement of equipment and services.

In view of the benefits that a transparent process of competitive bidding has and in order to protect consumer interests, it would be prudent to mandate the procurement of equipment and services duly following the policy/guidelines issued by the Government of India.

Comments and suggestions are therefore invited from stakeholders on the following**:**

1. **Need to mandatorily award work and services contracts for developing projects under the regulated tariff mechanism through a transparent process of competitive bidding, duly complying with the policy/guidelines issued by the Government of India as applicable from time to time.**

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

Another aspect with regard to the approval of capital costs that has been debated while framing earlier Tariff Regulations is the reference cost that needs to be considered while approving capital costs. The existing methodology of relying on the investment approval cost was also debated; however, in the absence of a better reference/benchmark cost due to the paucity of reliable data and the complexities and difficulties involved, the reliance on investment approval has continued. However, the hard costs of recently commissioned projects of similar specifications are referred to for prudence checks.

For a thermal generating station, it is observed that there are several differences with regard to site conditions, water handling, coal handling systems, etc., and one benchmarked cost may not be a true representation of all such plants on the basis of which actual costs can be disallowed. These issues are even more profound in the case of hydro generating stations, as the costs significantly depend on several aspects such as choice of technology, design, reservoir based/Pondage/ROR, etc.

With regards to transmission systems, the cost is affected by tower design, terrain, soil type, and wind zones, and therefore it is generally argued that benchmarking will serve a limited purpose and may not be a better alternative to current project specific Investment Approvals.

Comments and suggestions of stakeholders are invited on other efficient reference costs other than Investment Approval costs that can be considered for prudence checks.

4.2.4 Capital Cost of Hydro Generating Stations

As discussed in Section 3 of this Approach Paper, one of the primary reasons for a higher tariff in the case of hydro generating stations is the high capital cost incurred due to various reasons. The Commission has been carrying out prudence check on the capital cost of hydro generating stations on the basis of actual costs incurred. It has been observed that the major works of these projects are normally awarded through cost based competitive bidding with price escalation clauses. As these projects go on for years due to inordinate delays leading to cost overruns and time overruns, the price bids are rendered irrelevant. Suggestions are, therefore, invited for alternate ways to bid hydro projects as per the policy/guidelines that may be specified by the Government of India from time to time. In such biddings, the minimum implementation schedule quoted can be an important factor in the selection of contractors.

It is also observed that the construction of hydro generating stations does impact local areas, especially those falling under the catchment area. As the people are affected, there is generally a growing dissatisfaction against the developer, which needs proper redress. The developers voluntarily carry out local area development initiatives such as building roads, schools, and clinics for the benefit of the people and to mitigate resistance to the project.

As these expenses towards the advancement of the Local Area are required for the development of the project and for alleviating public resistance and delays, such expenses may be allowed as part of the capital cost with certain limits. Alternatively, these expenses may be met through budgetary support for funding the enabling infrastructure, i.e., roads and bridges, on a case-to-case basis which could be (i) as per actuals, limited to Rs. 1.5 crore per MW for up to 200 MW projects and (ii) Rs. 1.0 crore per MW for above 200 MW projects, as per the Ministry of Power guidelines dated 28.09.2021 for budgetary support for “Flood Moderation” and for budgetary support for “Enabling Infrastructure”.

Comments and suggestions are further sought from stakeholders on ways to expedite the development of hydro generating stations especially the construction phase, and increase their commercial acceptability. Stakeholders are also required to consider the following aspects while making suggestions:

1. Ways to expedite the construction phase by adopting alternate ways of awarding construction contracts.
2. Contract to execute the project to be awarded only when all the required clearances and permits are available as on zero date.
3. Creation of Special Purpose Vehicle (SPV) for obtaining all mandatory approvals
4. Focus on quality and the implementation schedule.
5. Higher return on investments/equity for projects completed in a timely manner.
6. Higher return for dam/reservoir based projects and Pumped Storage Projects.
7. Levelized Tariff based one-time determination of tariff to remain uniform for useful life.
8. Escalable tariff adjusted for year-on-year inflation.
9. Possibility to further increase the useful life.
10. Consideration of expenses towards Local Development/infrastructure for public outreach for better project acceptability as pass through in capital cost or one time re-imbursement.

Comments and suggestions are sought from stakeholders to incentivise the developer if it executes the project faster/ or ahead of schedule and vice-versa if it delays.

4.3 Capital Cost for Projects acquired post NCLT Proceedings

The Ministry of Law and Justice, Government of India, notified "The Insolvency and Bankruptcy Code, 2016 (IBC) on 28.05.2016. As per the IBC, National Company Law Tribunal (NCLT) appointed under Section 408 of the Companies Act, 2013, has been nominated as the Adjudicating Authority.

Under the above Code as amended from time to time, various generating/transmission companies that default on their payments to their creditors are being put under the Corporate Insolvency Resolution Process (CIRP) initiated by the appointed Resolution Professional, wherein Resolution Plans are invited from various Resolution Applicants. Based on the due diligence carried out, the Committee of Creditors approves a Resolution Plan, which is then approved by the NCLT if it is satisfied that the Resolution Plan meets the requirements of the IBC.

In this context, it is observed that the acquisition costs of such assets have been considerably lower than the historical value of the assets, and the creditors have to take a haircut, and so too the defaulting entities, who have had to forego their equity investments. In such cases, if the tariff is to be determined under Section 62, appropriate clarity needs to be provided in the Regulations as to what capital cost is to be considered for the purpose of computing the tariff.

It is perceived that the tariff under Section 62 needs to be determined on the cost plus principle, therefore, the acquisition value should be considered. Further, if the acquisition price is higher than the historical value, the same may be capped at the historical value of such assets, as consumers should not be burdened with the asset premium quoted.

In addition to the above, it is observed that considerable time is exhausted when the entities are under CIRP. Further, before finalisation of Resolution Plan, wherein no debt servicing was done by the utilities, the tariff allowed included such debt servicing and therefore appropriate provisions may be required to be incorporated in the Regulations to govern the determination of tariff for such entities during that period.

Comments and suggestions are sought from stakeholders on the following issues:

1. **Historical Cost or Acquisition Value whichever is lower should be considered for the determination of tariff post approval of Resolution Plan.**
2. **Tariff provisions to be included to address the issue of the cost of debt servicing, including repayment, that were allowed as a part of the tariff during the CIRP process.**

4.4 Computation of Interest During Construction

4.4.1 Computation of IDC – Post Scheduled COD

It is observed that Regulations 21(1) and (2) of the CERC Tariff Regulations, 2019 specify as follows.

*"**21. Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC)***

(1) Interest during construction (IDC) shall be computed corresponding to the loan from the date of infusion of debt fund, and after taking into account the prudent phasing of funds upto SCOD.

(2) Incidental expenditure during construction (IEDC) shall be computed from the zero date, taking into account pre-operative expenses upto SCOD:

Provided that any revenue earned during construction period up to SCOD on account of interest on deposits or advances, or any other receipts shall be taken into account for reduction in incidental expenditure during construction.

(3) In case of additional costs on account of IDC and IEDC due to delay in achieving the COD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds in case of IDC and details of IEDC during the period of delay and liquidated damages recovered or recoverable corresponding to the delay.

(4) If the delay in achieving the COD is not attributable to the generating company or the transmission licensee, IDC and IEDC beyond SCOD may be allowed after prudence check and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be adjusted in the capital cost of the generating station or the transmission system, as the case may be.

(5) If the delay in achieving the COD is attributable either in entirety or[10] *in part to the generating company or the transmission licensee or its contractor or supplier or agency, in such cases, IDC and IEDC beyond SCOD may be disallowed after prudence check either in entirety or on pro-rata basis corresponding to the period of delay not condoned and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be retained by the generating company or the transmission licensee, as the case may be."*

The Commission further amended Regulation 21 through the first amendment to the CERC Tariff Regulations, 2019 and introduced sub-clause 6, which is as stated below.

"(6) For the purpose of Clauses (4) and (5) of this Regulation, IDC on actual loan and normative loan shall be considered in accordance with sub-clause (b) of clause (2) of Regulation 19 of these regulations."

[10] *Amended vide First Amendment*

The above amendment read with Regulation 19(2)(b) of the CERC Tariff Regulations, 2019, provides for the computation of IDC on normative loans in cases of equity infusion in excess of 30% and may be continued.

It is further observed that there have been instances wherein the developer did not incur any IDC till SCOD as interest liability for the project started after SCOD and due to the above provision, in case the delay is not condoned, the entire IDC gets disallowed, which does not seem to be appropriate. **In view of the above, it has been argued that the provision can be modified so as to allow proportionate IDC upto SCOD or upto the date of delay condoned on the basis of total IDC worked out till actual COD.**

It is further observed that in the original Investment Approval of any project, the cost of the project is approved, which also includes IDC expenses under the no delay scenario. The cost is based on the scope of work, implementation schedule, and proposed funding as envisaged in the DPR. The IDC expense envisaged in the Investment Approval is computed without considering any delay and on the basis of the funding pattern as may be required based on the implementation schedule. It is observed that at times, even though the project is delayed, due to prudent phasing of funds, the actual IDC, considering the delay impact, is well within the amount approved in the Investment Approval. Even in such scenarios, wherein the actual IDC is below that approved in original Investment Approval, due to existing provisions disallowing IDC corresponding to delay, the utilities are denied IDC. Therefore, to have a pragmatic and holistic approach towards approving IDC, the amount approved in Investment Approval may also be considered. In case the actual IDC is below that approved in the original Investment Approval, the same may be allowed as a lower IDC even if a delayed project is due to prudent phasing of funds adopted by the utilities.

Further, sub-clause 5 of Regulation 21 stipulates that in the event of any delay, excess IDC shall be disallowed on a pro-rata basis. There is another argument by utilities that maximum IDC is towards the end of the construction cycle, and any disallowance during this period will disproportionately reduce IDC. Comments and suggestions are sought from stakeholders on the following options for allowing IDC**:**

1. **Existing mechanism wherein the pro-rata deduction (based on delay not condoned) is done on IDC beyond SCOD.**
2. **Pro-rata IDC may be allowed considering the total implementation period wherein the actual IDC till implementation of the project is pro-rated considering the period upto SCOD and period of delay condoned over total implementation period.**
3. **IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay.**

Illustration: Consider an asset that was supposed to be implemented in 36 months but suffers a delay of 12 months. Further, suppose IDC up to SCOD is Rs. X and IDC beyond SCOD till actual COD is Rs. Y, and the Commission has condoned a delay of 4 months then the IDC allowable under the above two scenarios (mentioned at Sr. No. 1 & 2) shall be as follows.

Under **Option 1** above the allowable IDC shall be Rs. X + [Y*(4/12)], i.e., only IDC pertaining to delay is pro-rated.

Whereas,

Under **Option 2** the allowable IDC shall be Rs. (X+Y)*[(36+4)/48] wherein the total IDC is pro-rated based on the SCOD and delay condoned vis-à-vis the actual implementation period of 48 months.

4.4.2 Treatment of Liquidated Damages

It is observed that the current provisions specify that in the event that the delay is not attributable to the generating company or transmission licensee, the additional IDC and IEDC beyond SCOD shall be allowed and the total LD amount collected shall be deducted. Further, in case the delay is fully or partially attributable to the generating station or transmission licensees the additional IDC and IEDC shall be disallowed completely or allowed partially on a pro-rata basis, and the LD amount shall be retained by the generating company or transmission licensee as the case may be.

In this regard, it is observed that APTEL in its Judgment in Appeal no. 72 of 2010 has laid down very specific approach that can be adopted while treating Liquidated Damages.

APTEL has then specified the following method by which delay impacts need to be allowed.

a) If the delay is entirely due to the Implementing Agency's fault, the LD amount collected by it should be allowed to be retained by the Implementing Agency.
b) In case the entire delay is way beyond the control of the Implementing Agency then the entire LD if any shall be deducted before allowing the impact.
c) Under the third scenario, where partial delay is on account of the Implementing Agency and the rest of the delay is due to uncontrollable factors, LD if any, should be shared equally between the consumers and the Implementing Agency.

In view of the same, LD may be accounted for as specified by APTEL.

In addition to above, it is further observed that in the CERC Tariff Regulations, 2019, difficulties have been faced in ascertaining the amount of liquidated damages (LD) to be retained by the generating stations and transmission licensees from the additional capitalisation claim made subsequently as the amount of LD is being adjusted by these utilities from the balance payable and payment is made on net basis to such vendors. In the absence of such clarity in the tariff forms without being supported with auditor certificate there may be chances of double deduction, i.e., first in the form of deduction in IDC and then LD which was supposed to be retained by the utilities which gets adjusted in additional capitalisation. In such cases, utilities are required to declare such adjustments upfront to avoid any double accounting. In order to address this issue, it is proposed that the additional capitalisation forms need to be tweaked so that such information is submitted along with the tariff petition.

In view of the above, comments and suggestions are sought from stakeholders on necessary changes in tariff forms and regulations, if any, to provide further clarity on the adjustment of LD.

4.5 Price Variation

It is observed that time overrun due to delay in commissioning of projects not only increases IDC and IEDC, it may also result in increase in the hard cost in case the contract provides for cost escalation beyond SCOD. In such cases, if the impact corresponding to such delay is dis-allowed for the delay not condoned, it appears logical to extend the same treatment to price variation. **Therefore, for allowing price variation, the utilities may be mandated to submit the statutory auditor certificate along with the petition duly certifying the price variation corresponding to delay and the same may be allowed on pro-rata basis corresponding to the delay condoned. Further, a separate form may also be specified to submit the relevant information pertaining to price variation.**

Comments and suggestions are sought from stakeholders on the above proposal and suggest alternatives, if any.

4.6 Renovation and Modernisation (R&M)

Regulation 27 of the CERC Tariff Regulations, 2019 allows generating stations or transmission licensees to opt for R&M for the old generating stations and transmission systems that have outlived their useful life with the consent of the beneficiaries. The provisions also specify the manner in which such costs shall be considered for tariff purposes once cost reasonability is ascertained based on the residual life assessment and cost benefit analysis submitted along with the petition. Further, CEA, with an objective to maximise generation with efficiency enhancement, has already issued guidelines for R&M of Hydro and Thermal generating stations that need to be followed.

As R&M allows the deferral of huge capital investments on the construction of new capacities and avoids seeking fresh approvals and clearances, it is a cost effective alternative and hence has been allowed in the past.

In addition to the above, Regulation 28 of the CERC Tariff Regulations, 2019 provides for Special Allowance in lieu of R&M. Presently, the utilities have the option to choose between Special Allowance or to undertake R&M. In this regard, it is felt that in the event that an utility intends to undertake R&M, the same cannot be an abrupt choice as it requires proper planning, and therefore, 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.

In view of the inherent benefits of undertaking R&M as against going for fresh capital investment, the current provisions may be continued.

Further, utilities that opt for a special allowance for the first year of the tariff period shall have to continue with the same for the rest of the tariff period.

Comments and suggestions are sought from stakeholders on continuation of the existing provisions and on the above suggestion of continuing with Special Allowance, if opted at the beginning of the tariff period for the rest of the tariff period.

4.7 Initial Spares

The Commission, in its Explanatory Memorandum to the draft Tariff Regulations for 2019-24 observed as follows.

> *"2.5.7 It is noticed that there is not much difference between the initial spares of green field and brown field substations. Further, the initial spares of all compensation devices including series and shunt compensation and HVDC are kept at the same. The Commission proposes to maintain same level of initial spares for green field and brown field substation."*

The Commission accordingly removed the distinction between green and brown field projects and specified the draft norms. However, on the basis of comments received from various stakeholders, the Commission while finalising the norms in its Statement of Reasons observed as follows.

> *".....The stakeholder submitted detailed reasons for the need of higher ceiling norms for brown filed substations, both AIS and GIS. Further, for new technology equipment, which are fewer in numbers and are generally manufactured and supplied by foreign manufacturers, there is a need to provide higher initial spares norms. The Commission, after considering the suggestions made by the stakeholders, revised the provision by allowing separate initial spares norms for AIS Sub-station (Brown Field) at 6% and GIS Sub-station (Brown Field) at 7% and increasing the norm for Static Synchronous Compensator from 3.5% to 6%."*

It is observed that there are eleven (11) separate categories and sub-categories pertaining to ceiling norms for initial spares. A need is felt to simplify the classifications, and further, a single norm for green and brown field projects can also be considered.

It is further observed that the use of HV underground cables is now increasingly common in ISTS systems for which there are no separate norms to allow initial spares and may require appropriate provisions allowing the same. Alternatively, as not much actual data is available, it may also be considered on an actual basis, subject to prudence check.

In view of the above, a single norm can be considered for each of the following classes of transmission assets:

1. **Transmission Lines, including HVDC lines**
2. **Substations (including HVDC S/s)**
3. **Dynamic Reactive Compensation devices**
4. **Communication Systems**
5. **Underground cable**

Comments and suggestions are sought from stakeholders on the above proposed approach and alternative options to standardise and simplify the norms for initial spares.

4.8 Controllable and Un-Controllable Factors

4.8.1 Delay towards obtaining Forest Clearance

The Commission, 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…"*

For the reasons mentioned above, the Commission included the delay on account of land acquisition in the list of uncontrollable factors along with Change in Law and Force Majeure. In this regard, it has been observed during the current period that, apart from land acquisition, delays on account of getting forest clearances may also be many times beyond the control of utilities and therefore have been condoned in the rightful cases. **In view of the same, delays on account of forest clearances can also be considered for inclusion as uncontrollable factor provided that such delays are not attributable to the generating company or the transmission licensee.**

Comments and suggestions are sought from stakeholders on continued inclusion of delay on account of land acquisition as an uncontrollable factor and on the further inclusion of delay on account of forest clearances as an uncontrollable factor.

4.9 Differential Norms - Servicing Impact of Delay

While dealing with various generation as well as transmission petitions in the past, it has been observed that in several cases the delays are attributable to lack of timely clearances, forest approvals, etc. which require constant and rigorous follow up. In most of these cases, it has been observed that these delays could have been restricted if the approvals were sought more assertively instead of merely through written correspondence. It is observed that it is always not possible for the Commission to ascertain if adequate efforts have been made at the senior level to get the clearances. Therefore, though impact of delay on account of uncontrollable factors may be allowed, **in order to encourage rigorous pursuit of such approvals, even if delay beyond SCOD is condoned for any reasons, some part of the cost impact (Say 20%) corresponding to the delay condoned may be disallowed.**

Alternatively, servicing such costs at par with other capital expenditures may need to be re-looked at, as servicing the cost overrun at RoE creates a perverse incentive on the part of the project developer. The generating stations or transmission licensees are allowed such an impact, but at the same time, the cost of servicing such a delay should not result in an increase in RoE for such utilities; instead, such cost should be merely compensatory in nature.

Contrary to the above, there is another school of thought as per which, if a project is delayed, even if the entire delay is condoned, the internal rate of return (IRR) for the project reduces due to deferment of future cash inflows, which automatically disincentivises the generating company or transmission licensees and therefore further disincentives may result in a double whammy for the utilities. In order to study the impact of an increase in gestation period on equity IRR, workings were carried out, and it was observed that if a project that was to be executed in 5 years is executed in 7 years with a 2 year delay, even if RoE is allowed at 15.50% and the entire delay is condoned, the Equity IRR reduces from around 12% to 11% and for every subsequent year of delay, the Equity IRR reduces further.

In view of the above, comments and suggestions are sought on the following:

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

Comments and suggestions are sought from stakeholders on the above so that developers may make more efforts to control the delays.

4.10 Additional Capitalisation

As per CERC Tariff Regulations, 2019, additional capitalisation for generating stations and transmission licensees is allowed under the following main categories.

1. Additional Capitalisation within the original scope of work executed up to cut-off date (Regulation 24).
2. Additional Capitalisation within the original scope of work executed after the cut-off date, including replacement under certain conditions. (Regulation 25).
3. Additional Capitalisation beyond the original scope of work includes increased need for safety and security, Change in Law, Arbitration Award, Force Majeure, deferred works related to the ash handling system. (Regulation 26).
4. Additional Capitalisation on account of Renovation & Modernisation. (Regulation 27).
5. Additional Capitalisation on account of revised emission standards. (Regulation 29).

It is however observed that the above provisions under which additional capitalisation is allowed is for specific works that are part of the original scope of work, are to carry out R&M, pertain to ash handling, are required due to uncontrollable factors such as a change in law or force majeure.

It is further observed that Regulation 19(3)(e) of the CERC Tariff Regulations, 2019 specify that the capital cost of any existing generating station shall include the cost of railway infrastructure and its augmentation for the transportation of coal up to the receiving end. However, there are no enabling provisions under which a generating station can seek approval of costs pertaining to Railway Infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station (excluding any transportation cost and any other appurtenant cost paid to railways) that are not covered under the above provisions that may result in better fuel management, can lead to a reduction in operation costs, or shall have other tangible benefits. **Therefore, in order to have an enabling provision under which such additional capitalisation can be allowed with prior approval, a provision may be introduced to existing Regulation 26 to allow such expenses if they are found to be beneficial/essential for continued operations.**

Comments and suggestions are sought from stakeholders on the above and any other ways to address the issue flagged above.

It is observed that additional capitalisation under Sr. No.1 relates to additional capitalisation up to the cut-off date and pertains to works that are generally within the original scope of work and are relevant and incurred by both generating stations and transmission licensees. These expenses are incurred mainly for deferred works and the discharge of liabilities for works already executed. As these expenses are required to be analysed only once in the project life cycle, the current practice of allowing the same on an actual basis may be continued subject to a prudence check.

Further, with regard to additional capitalisation under Sr. Nos. 3, 4 & 5 above, which are non-recurring and generally require substantial expenses to be incurred, the current practice of allowing the same on an actual basis may be continued as such non-recurring and heterogeneous expenses cannot be translated into norms.

However, additional capitalisation under Sr. No. 2 are generally not substantial but recurring in nature, and it has been observed that the same, for one reason or another have been recurring time and again, which is one of the prime reasons for which the entire exercise of tariff determination of hundreds of assets is done twice in the same tariff period. As the entire exercise does not have big impact on tariffs, possible options, if any, need to be explored to eliminate the need for such an elaborate exercise.

4.10.1 Normative Add-Cap - Generating Station

For the purpose of simplifying the approval of additional capitalisation, the generating stations can be broadly classified into two categories.

1. **Existing Generating Stations –** These generating stations can further be classified into the following two sub-categories.
    a) Existing generating stations with a cut-off date on or before 31.03.2024.
    b) Existing generating stations whose cut-off date shall fall in the upcoming tariff block 2024-29.
2. **New Generating Stations –** Generating stations that shall achieve COD in the next tariff block, i.e., 2024-29.

For generating stations that have already crossed the cut-off date as on 31.03.2024, the additional capitalisation for such generating stations can be considered as per the following.

1. **Thermal Generating Stations – Based on the analysis of actual additional capitalisation incurred by such generating stations in the past (15-20 years) and co-relating such expenses to different unit sizes such as 200/210 MW series, 500/660 MW Series and different vintages (5-10, 10-15, 15-20, 20-25 years post COD), a special compensation in the form of yearly allowance may be allowed based on unit sizes and vintage, which shall not be subject to any true up and shall not be required to be capitalised.**

2. **Hydro Generating Stations – As each hydro generating station is unique owing to various factors, additional capitalisation of such generating stations may not be**

benchmarked as can be done for thermal generating stations. However, in the case of a specific hydro generating station, the additional capitalisation is recurring in nature, and hence station wise normative additional capitalisation may be approved in the form of special compensation which shall not be subject to any true up and shall not be required to be capitalised.

3. **While determining such special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulation 26 to Regulation 29, wherever applicable, may not be included as these expenses may be allowed separately.**

4. **Further, any items that cost below Rs. 20 lakhs that may be in the nature of minor items such as tools and tackles, and those pertaining to Capital Spares may be allowed only as part of O&M expenses and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations.**

5. **Further, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged.**

Further, for generating stations whose cut-off date falls in the next tariff block (2024-29), or are expected to achieve COD after 31.03.2024, the following approach can be adopted.

1. **By extending the cut-off date from the current 3 years to 5 years, which shall allow time to close contracts and discharge liabilities and eliminate the need to allow additional capitalisation post cut-off date unless in the case of Change in Law and Force Majeure.**

2. **However, based on past data of similar existing generating stations, if there is a need to allow additional capitalisation that may be legitimately required post cut-off date other than those presently allowed under Regulation 26 to 29, the same may be allowed as special compensation as proposed in the case of existing station that have crossed the cut-off date.**

3. **While determining special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulations 26 to**

29, wherever applicable, may not be included as these expenses may be allowed separately.

4. **Further, any item that costs below Rs. 20 lakhs that is in the nature of minor assets, including Capital Spares below Rs 20 lakh, can be allowed only as part of O&M expenses and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations. Further, any major capital spares costing above Rs. 20 lakh may form part of the special compensation.**

5. **Further, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged.**

Comments and suggestions are sought from stakeholders on the above suggested approaches and other alternatives, if any.

4.10.2 Normative Add-Cap – Transmission System

Unlike generating stations, additional capitalisation post cut-off date is rarely required in the case of transmission systems unless due to completion of useful life, performance degradation, the need for induction of new and efficient technology, Obsolescence of assets, or the absence of support from Original Equipment Manufacturer (OEM). **Therefore, for Transmission Systems, additional capitalisation post cut-off date may be allowed on technological obsolescence, change in law, force majeure, or due to replacement as presently allowed under Regulation 26 and 27 of the CERC Tariff Regulations, 2019.**

Comments and suggestions are sought from stakeholders on the above suggested approaches and other alternatives, if any.

4.11 GFA/NFA/Modified GFA approach

CERC Tariff Regulations permit depreciation till 90% and Equity infusions of up to 30% of capital cost. Further, the generating company/transmission licensees is allowed RoE on gross equity infused even when the cumulative depreciation exceeds the debt component. This has allowed the creation of internal resources for further capacity augmentation which was much needed considering the infrastructure support that was required to meet the double-digit peak and energy deficit that the country was facing a decade ago. The approach also created predictability in returns even under uncertain market conditions, thus increasing investors' confidence.

Prior to 2019, the Commission, had adopted the Gross Fixed Asset (Liability Side) approach for all generating stations and transmission assets for the primary reason that it provides internal resources for capacity replacement/addition through return on equity, which is allowed even when the cumulative depreciation on the assets goes beyond the debt component. While framing CERC Tariff Regulations, 2019, the Commission adopted a modified GFA approach for a few specific generating and transmission assets that were funded through a debt equity ratio of 50:50 and have either completed or are about to complete their useful life. While doing so, the Commission observed the following:

"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 is 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."

While the Net Fixed Approach is based on gradual reduction in the fixed assets to be considered for tariff purposes, wherein cumulative depreciation is deducted from the GFA and the resultant Net Fixed Assets are considered for the purpose of computation of tariff. The NFA approach is further suitable in context with the ROCE approach, wherein returns are allowed on the NFA based on the Weighted Average Cost of Capital (WACC). However, as interest rates keep varying, there is uncertainty with regard to returns to investors. As evident, the approach could result in reducing returns for investors as the project ages and may reduce the bankability of power sector projects, which could be detrimental, especially when the generating and transmission companies are expected to provide the much-needed infrastructure support that the economy will require in the next decade.

Increasing the Investors confidence by ensuring assured returns is important, and further considering the recent spikes in power tariffs in power exchanges indicating shortage of power availability, investment in Power sector needs a boost, and therefore the existing GFA approach, being a balanced approach, may be continued. However, comments/ suggestions are invited on alternate approaches, i.e. GFA/ NFA/ Modified GFA approach.

4.12 O&M Expenses

4.12.1 Segregation of Normative O&M Expenses

In the past, the Commission, has approved normative O&M expenses for Generating Stations and Transmission Licensees based on actuals incurred in the past, along with a certain escalation rate to cater to inflation and other changes. These O&M expenses primarily comprise three broad types of expenses, as mentioned below.

1. Employee Expenses
2. Repair and Maintenance Expenses
3. Administrative and General Expenses

In the past, it has been observed that whenever there is a requirement to give effect to some issues affecting one or more of the above nature of expenses, e.g., Pay/Wage Revision impact, it becomes difficult to do so due to the absence of segregation of baseline expenses forming part of O&M expenses. As the Commission, while approving the norms, does not factor in such expenses, these expenses if deemed legitimate, may need to be allowed.

The Commission observes that it is mostly in the case of employee expenses that such a one-time effect, mostly pay revision impact, is required to be given, and further, in the forthcoming tariff period, wage/salary revision is also anticipated, so **O&M norms may be specified under the following two categories.**

1. **Employee Expenses**
2. **Other O&M Expenses comprise Repair and Maintenance and Administrative and General Expenses.**

However, considering that systems that are more automated will require less manpower and systems that are less automated will require more manpower, approving separate norms may result in inequity even though the total O&M expenses of such systems may be comparable. **Therefore, the above suggestion may also be seen from the perspective that these expenses have historically been allowed as one expense, and any change in the methodology as suggested above may result in unnecessary complications.**

Alternatively, to give effect to the impact of pay/wage revision, 50% of the actual wage revision can be allowed on a normative basis.

Comments and suggestions are sought from stakeholders on above suggestions and alternatives, if any.

4.12.2 Norms for HVDC Stations

The Commission, in its CERC Tariff Regulations, 2019, has approved normative O&M expenses for HVDC schemes wherein specific norms have been specified for some of the schemes and for the rest of the schemes, formulation of normative O&M expenses have been specified linking it with similar nature schemes for which specific O&M expenses are approved. **It is observed that there is a need to simplify the same and therefore one norm for all HVDC schemes in terms of per MW considering the actual expenses incurred in the past may be specified.**

Comments and suggestions are sought from stakeholders on above suggestions and alternatives, if any.

4.12.3 O&M Norms for Special Cases

It is observed that the O&M expenses towards the upkeep of transmission systems in the North Eastern and hilly regions of India entail additional costs due to logistical challenges as well as the inadequate infrastructure growth of the region. Several representations have been made by various entities seeking additional O&M expenses for transmission licensees that are operating in these regions. In this context, possible solutions need to be explored so that the development of electrical infrastructure in these regions is encouraged.

In view of the above, comments and suggestions are sought from stakeholders on whether additional O&M expenses can be given for transmission assets being operated in the North Eastern and Hilly Regions and the manner in which such additional costs can be considered.

4.12.4 Inclusion of Capital Spares

The Commission has been allowing the following types of spares for a generating station as well as transmission licensee.

1. Initial Spares allowed on a normative basis.
2. Capital Spares that are not part of O&M expenses allowed on an actual basis.
3. Maintenance Spares that are allowed as part of normative O&M expenses

Due to the fact that some of the spares are being allowed on the basis of actuals and some are being allowed on a normative basis, considerable effort is required to map these expenses. It is observed that initial spares and maintenance spares (part of O&M expenses) are already allowed on a normative basis and it's only the capital spares that are allowed on an actual basis. Further, the challenge with capital spares is that these expenses are non-recurring and sporadic, so benchmarking them can be difficult. However, it is anticipated that if Capital Spares are analysed for a longer duration, say 15-20 years, there can be some correlation and predictability to such expenses. Therefore, **if the same can be projected with some degree of predictability, the same may be allowed on a normative basis along with O&M expenses. Alternatively, instead of including all such capital spares as part of normative O&M expenses, recurring and low value spares below Rs. 20 lakh may be made part of normative O&M expenses, while for capital spares with a value in excess of Rs. 20 lakh, utilities may submit the same on a case to case basis for reimbursement with appropriate justification for the Commission's consideration.**

Comments and suggestion are sought from stakeholders on the above suggested approach and alternatives, if any, to streamline the approval process for spares.

4.12.5 Impact on account of Change in Law and Taxes

It is observed that there are no provisions with regard to allowing additional expenses on account of any change in law resulting in an increase in O&M expenses. However, including the same may lead to recurring impacts, and claims that may result in regulatory overburden.

Comments and suggestions are therefore sought from stakeholders on whether to include any provisions with regard to allowing impact of a change in law on O&M expenses.

4.13 Depreciation

Depreciation is one of the cost components that is allowed, along with other cost components, in the form of annual fixed charges. The regulatory meaning of depreciation was pronounced in the 2009-14 tariff period, where it was held that there should be enough cash flow available to meet the repayment obligations of the generating company or transmission licensee which was in accordance with Clause 5.8.2 of the National Electricity Policy 2005, which specifies that depreciation should be able to fully meet the debt service obligations. The Commission, while formulating the CERC Tariff Regulations, 2009, specified depreciation rates considering a repayment period of 12 years to repay a normative loan corresponding to 70% of capital cost, and since then, the rate of depreciation has been specified based on this approach.

The Tariff Policy, 2016 also stipulates that, the Central Commission may notify the rates of depreciation in respect of generation and transmission assets, and the rates so notified would be applicable for the purpose of tariffs as well as accounting.

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).

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

4.14 Interest on Loans

4.14.1 Weighted Average Rate of Interest and FERV

The cost of debt is the cost incurred by the utility in the form of interest payments and an upfront fee for raising finances through debt. As per the prevailing Tariff Regulations, the weighted average interest rate calculated on the basis of the actual loan portfolio deployed towards the asset by the utility is considered the cost of debt. The cost of debt thus arrived at is applied to the normative outstanding loan to compute the annual interest expenses of the utility, which are allowed to be passed through in the tariff. In addition to the same, in the case of foreign debt, the utility is required to carry out hedging to take care of exchange rate variations, the cost of which is allowed to be recovered separately.

It has been observed while dealing with tariff petitions, especially in the case of transmission licensees that in most cases the loans are not availed for specific project, and in such cases, it becomes a cumbersome task to ascertain one to one co-relation between assets and loans, which also requires considerable time and effort. To address the same, the possibility of computing interest on loans on the basis of the actual weighted average rate of interest for a company as a whole can be explored.

It is further observed that the current Regulations already have such a provision for those generating stations or transmission systems that do not have any actual loans. According to the provision, interest on loans is computed based on the WAROI of the generating company or transmission licensee. However, it is also observed that there are certain foreign loans that entail FERV/hedging costs in terms of repayment of the loan as well as interest. In this context, the Tariff Policy 2016 states that only for projects where the tariff has not been determined on the basis of competitive bids, the cost of hedging and swapping such loans to take care of FERV shall be allowed without allowing any actual FERV.

To simplify the approval of interest on loans, the weighted average actual rate of interest of the generating company or transmission licensee may be considered instead of project specific interest on loans. Further, the cost of hedging related to foreign loans be allowed on an actual basis, without allowing any actual FERV.

Comments and suggestions are sought from stakeholders on the above suggestions and alternatives, including in respect of treatment of FERV/cost of hedging

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

These are two different approaches that can be adopted to allow a return on investments made by generating companies or transmission licensees.

In brief, under the RoE method, return at a specified percentage is calculated based on market data and allowed on equity investments, whereas interest on debt is allowed on the basis of the actual interest rate. Under the RoCE approach, the return on total capital employed is allowed on the basis of the weighted average cost of capital (WACC), wherein the cost of debt and equity needs to be estimated for the computation of the WACC.

The issue whether to adopt RoE or RoCE has been deliberated while framing all the preceding Tariff Regulations. The Commission, however, due to following limitations and de-merits, up till now has decided in favour of RoE:

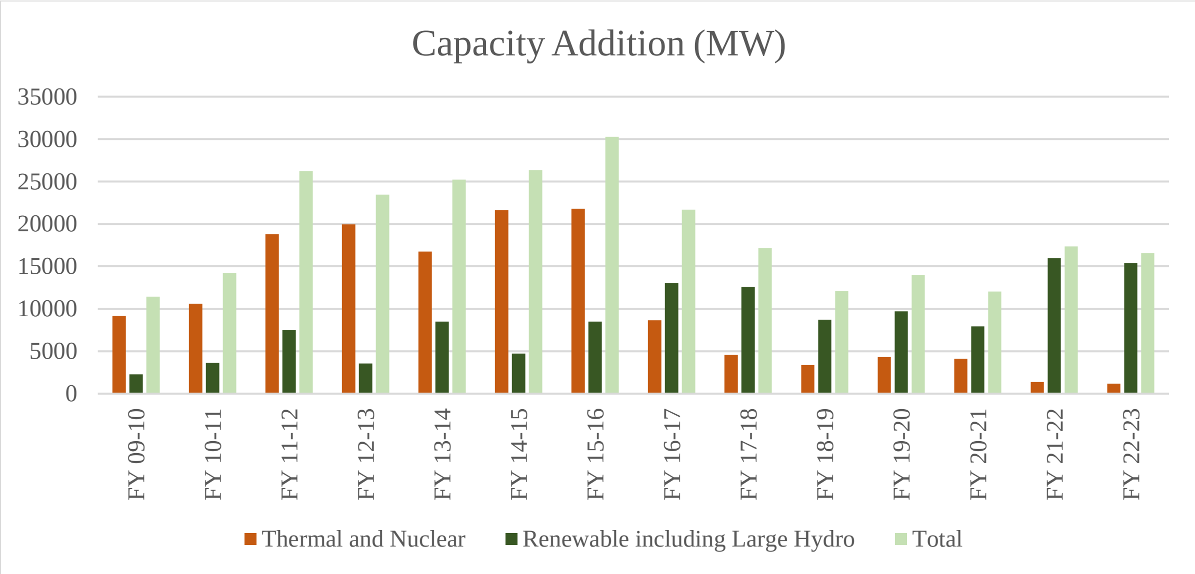
1. Fluctuation of Interest Rates make benchmarking the cost of debt difficult.
2. Requirement of annual determination of WACC due to progressive change and reduction in capital employed.
3. Problems associated with benchmarking of the debt equity ratio
4. The evolving Indian Corporate Bond Market
5. The Majority of the stakeholders' views are in favour of the RoE approach.

As in the past, much has been deliberated and discussed on the two approaches, and in view of the long-standing position of this Commission, the present system, or RoE approach, may be continued. Comments and suggestions are, however, sought from stakeholders on the continuation of the RoE approach.

4.16 Rate of Return on Equity

4.16.1 Purpose

Section 61 (d) of the Electricity Act, 2003, and Paragraph 5.11 (a) of Tariff Policy 2016 have laid down broad guiding principles for the determination of the rate of return. These have been mandated to maintain a balance between the interests of consumers and the need for investments while laying down the rate of return. It is stipulated that the rate of return should be determined based on the assessment of overall risk and the prevalent cost of capital. Further, it should lead to the generation of a reasonable surplus and attract investment for the growth of the sector. The large-scale investments that the sector has witnessed in the past decade are a result of the appropriate fixed returns allowed. The year wise capacity addition in the last decade is shown in the following chart.



Source: Reports published by CEA

Figure 9: Year Wise Addition in Generation Capacity (MW)

4.16.2 Differential RoE

Further, Forum of Regulators, in its Report on "Analysis of Factors Impacting Retail Tariff And Measures To Address Them" with regard to RoE, 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."

FOR has recommended differential RoE for Generation and Transmission Businesses with a reduction in RoE for Transmission Business.

4.16.3 Attracting Investments

However, as per CEA's report on Optimal Generation Capacity Mix by FY 2029-30 (Version 2.0), the present installed capacity needs to be almost doubled by FY 2029-30 and the augmentation of the grid has been planned to accommodate 537 GW of RE capacity by the year 2030 which will require big investments, including those from the private sector.

4.16.4 Methodology

To ensure that RoE is fair to both investors and consumers, the return allowed should be commensurate with the returns available from alternate investment opportunities with comparable risk. Different models, viz. Discounted Cash Flows (DCF), Risk Premium Model (RPM), Capital Asset Pricing Model (CAPM) etc. are available for the estimation of the cost of equity/RoE. However, the Commission has been largely dependent on the CAPM model for arriving at RoE during previous tariff periods.

The formula for computing the return on equity based on CAPM is as under:

$$\mathbf{Re = Rf + \beta \times (Rm - Rf)}$$

Where:

Rf = risk-free rate

β = equity beta

Rm-Rf = equity market risk premium

There are different ways of estimating the above parameters. However, the following approaches are proposed for the estimation of the above parameters:

a. **Risk-free Rate:** The risk-free rate is the return that can be earned by investing in a risk-free security, e.g., a Government of India (GOI) bond. Most of the electricity/energy regulators, including FERC, USA, have been using an average 10-year bond yield over a six month to one-year horizon. **Keeping in view the international approaches to regulated rates of return, the average 10-year GOI securities rate over a one-year horizon may be considered a risk free rate.**
b. **Equity Beta:** Most electricity/energy regulators calculate beta using a group of companies comparable to the target utility. This is mainly for the reason that the portfolio approach to estimating beta tends to provide more stable results as compared to company specific estimation methods. As for the beta estimates, a period long enough should be considered to create stability and statistically meaningful estimates. The period should reasonably reflect the current systemic risk of utilities as well as market conditions. The most common estimation window among regulators is 3-5 years using daily or weekly data. ACM, Netherlands, has been considering 3 years as a period of estimation, whereas FERC, USA, and Ofgem, UK, have been considering 5 years as

a period of estimation. For computing returns, AER, Australia, and FERC, USA, have been considering weekly data, whereas ACM, Netherlands, has been considering daily data. **Keeping in view the international approaches, daily data on the SENSEX and BSE Power Index for the latest 5 years may be considered for equity beta estimation.**

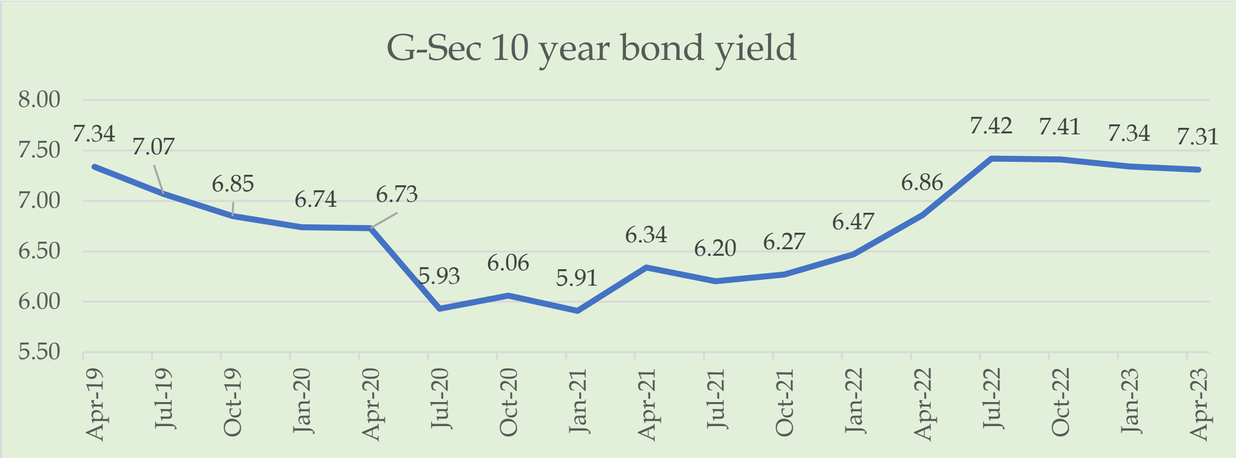
c. **Market Risk Premium (MRP):** It is defined as the extra yield that can be earned over the risk-free rate by investing in the stock market. One simple way to estimate MRP is to subtract the risk-free return from the market return. There are multiple methods that can be used to estimate the MRP. The period of maturity of the risk-free rate (i.e. 10 years) should match the period of the MRP while determining the MRP. Finance textbooks such as Stephen A. Ross, Randolph W. Westerfield and Jaffrey F. Jaffe "Corporate Finance," (2013) recommend using as long a period as possible, provided reliable data is available. That is the approach explicitly taken by the ACM, Netherlands, and FERC, USA and has the advantage of making the MRP, very stable and predictable. The AER, Australia, chose MRP reflecting the historical 30-year average. **Keeping in view the international approaches, the MRP reflecting the historical returns for a period of 30-years or beyond instead of the existing practice of considering 20 years may be considered for MRP estimation.**

   Alternatively, MRP may be computed using any other method, including the Survey Method.

Comments and suggestions are sought from stakeholders on the above proposed methodology for estimation of RoE and alternative suggestions, if any.

It is further observed that the risk perception of financial institutions towards the power sector has increased due to the initiation of insolvency proceedings against these projects, forcing lending institutions to take massive haircuts. This has resulted in an increase in risk perception towards power projects, especially generation projects.

It is further observed that the current 10 year G-Sec yield is around 7.31% which is almost the same as it was at the time of the commencement of the current tariff period, i.e., April 2019. The figure below represents the 10 year G-Sec yield from April 2019 to April 2023.



Source: RBI Data Base

Figure 10: 10-Year Government Securities Yield Trend (%)

Though there is not much change in the yield between the two reference points, the key difference is the requirement for additional capacity anticipated then and now. It is observed that at the time of the formulation of the CERC Tariff Regulations, 2019, in view of reducing the PLF of base load plants, increasing RE generation capacities, and projects under execution, it was estimated that no new thermal generating stations would be required for another 8-10 years. However, the scenario has changed due to a delay in the commissioning of generating stations during 2017-22 due to the COVID pandemic and the strong demand revival post pandemic resulting in an increase in the deficit requiring additional capacity. The CEA has also projected a requirement for additional thermal capacity of 67 GW by 2029-30 in its Report on Optimal Generation Mix by 2030 and to support such growth, the CEA has also planned to augment the present transmission system to accommodate another 300 GW of generation capacity.

Further, post pandemic, global economies have suffered and are still reeling under pressure due to stubborn inflation. India, too, witnessed high inflation owing to high fuel prices and food shortages due to supply constraints and the war in Ukraine. However, it was short-lived and inflation is currently under control at around 5%. The RBI has targeted containing retail inflation to 4% ± 2% and therefore, it is most likely that inflation will remain around current levels.

Further, considering the difference in gestation periods and construction risks associated with thermal, hydro generation stations and transmission systems, the need to specify differential equity also needs to be evaluated. Hydro generating stations except ROR based are already allowed 1% higher RoE, however, not much capacity addition has been witnessed in recent times due to delays so additional RoE in the form of timely completion of projects may also be an option to attract investors.

It is further observed that even though the present Tariff Regulations, specify RoE @ 15.50%, considering the gestation period involved, the effective IRR works around 12%. While IRR of 12% is considered reasonable, the effective return is adversely impacted with delay and even if the entire delay is condoned, the effective return keeps on reducing.

Comments and suggestions are sought from stakeholders on the following issues:

1. **Review of Rate of RoE to be allowed, including that to be allowed on additional capitalisation that is carried out on account of Change in Law and Force Majeure.**
2. **Whether the revised rate of RoE to be made applicable to only new projects or to both existing and new projects?**
3. **Whether timely completion of hydro generating stations can be incentivised to attract investments?**
4. **Merit behind approving different Rate of RoE to thermal, hydro generation and transmission projects with further incentives for dam/reservoir based projects including PSP.**
5. **Merit in allowing RoE by linking the rate of return with market interest rates such as G-SEC rates/MCLR/RBI Base Rate.**

4.16.5 Rate of Return – Old Thermal Generating Station

Out of the total 237.27[11] GW of installed thermal generation capacity as on 31.03.2023 more than 50 GW of generating stations, including state and private sector generating stations shall be completing their useful life by 01.04.2024.

These generating stations are differently placed when compared to newer stations as they have already recovered depreciation and have completed loan repayments and thus have a financial advantage. However, as these stations are old, their operational costs could be higher as compared to new super critical units, and the O&M expenses for such generating stations are also higher.

[11] As per CEA – March 2023

It is further observed that the energy charges of most of the old stations, especially the pit -head based, are low, and these stations are currently being continuously scheduled. As a result, the PLF of these stations is significantly higher than the national average and, in some cases, even higher than the target PLF. Therefore, it would be in the interest of beneficiaries that these stations continue to operate, as they are one of the cheapest sources of power.

It is further observed that these stations are vintage plants for which the approved capital base is around Rs. 1.5-2 Cr/MW and therefore the equity component of these generating stations is comparatively low. Due to low equity base the RoE in today's term may not be significant enough when compared to the risks associated with these plants.

In order to measure the effectiveness of this suggestion, the RoE component of the following generating stations was analysed and it was observed that the weighted average RoE cost is around 22 paise/kWh (at 85% generation) as opposed to new generating stations where RoE works out to be around 65 paise/kWh (at 85% generation). List of generating stations that have been analysed is as follows.

Table 3: RoE approved for old and new generating stations (Paise/kWh)

Name of Project	Installed Capacity (MW)	FY 2018-19* (Paise/kWh)
Old Generating Station		
Korba-I&II	2100.00	10.90
Singrauli	2000.00	8.31
Rihand-I	1000.00	41.07
Vindhyanchal-I	1260.00	16.96
Ramagundam-I&II	2100.00	15.47
Kahalgaon-I	840.00	41.80
Farakka-I&II	1600.00	27.71
Dadri-I	840.00	
Unchahar-I	420.00	33.14
Talcher-I	1000.00	38.24
Kawas	656.20	35.65

Name of Project	Installed Capacity (MW)	FY 2018-19* (Paise/kWh)
Gandhar	657.39	54.03
Auraiya	663.36	18.23
Anta	419.33	22.20
Dadri Gas	829.78	15.23
New Generating Station		
Bongaigaon	250	79.31
Kudgi STPS	2400	92.46
Bokaro `A` TPS	500.00	46.16
Indira Gandhi STPP	1500.00	48.99
Mauda TPS	1000.00	55.46
Solapur STPS	1320.00	67.33
Simhadri TPS	1000.00	45.72

** Computed based on RoE approved by CERC*

It may be inferred from above, that by lowering the equity base or reducing the return for old generating stations, there is not much to gain in overall terms considering the risks involved in operating these stations. In such cases, if the returns are reduced, there may be too little incentive for the generating companies to manage the operations of such plants. Therefore, to encourage the continued operation of these plants, additional incentives for such generating stations may be considered. This will encourage these generating companies to continue operating such power plants.

As sustained operations of these units are in the best interest of beneficiaries, incentivising these low-cost generating stations would prove mutually beneficial.

Possible options to encourage higher availability and generation from old generating stations can be as follows.

1) **Allowing additional incentive in the form of paise/kWh apart from those currently allowed may be allowed to such generating stations against generation beyond the target PLF.**

Comments and suggestions are sought from stakeholders on various possible alternatives that incentivises generation from these efficient old generating stations.

4.17 Tax Rate

In the CERC Tariff Regulations, 2014, the concept of an effective tax rate was introduced. This was done in order to pass on the benefits and concessions available in income tax to the beneficiaries. The income tax rate for grossing up purposes was the MAT rate, if the generating company or the transmission licensee was paying MAT, or the Corporate Tax rate, if the generating company or the transmission licensee was paying income tax at the Corporate Tax rate. The provisions with regard to tax were unchanged in the CERC Tariff Regulations, 2019.

While dealing with tariff petitions seeking the truing up of income tax, it has been observed that generating companies are seeking income tax rate to be determined based on the actual income tax paid as per the following formula, even though the MAT rate is applicable to such entities.

$$\textbf{Effective tax rate (\%)} = \frac{\textbf{Actual tax paid}}{\textbf{Profit Before Tax}}$$

It is observed that instead of seeking the truing up of tax rate on the basis of actual tax paid and book profit as considered by tax authorities as per Section 115JB, a claim has been made as per the above formula.

With regard to the rate to be considered for grossing up the tax rate Regulation 31(2) of the CERC Tariff Regulations, 2019 clearly specifies as follows.

"...

(2) Rate of return on equity shall be rounded off to three decimal places and shall be computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)

Where "t" is the effective tax rate in accordance with clause (1) of this Regulation and shall be calculated at the beginning of every financial year based on the estimated profit and tax to be paid estimated in line with the provisions of the relevant Finance Act applicable for that financial year to the company on pro-rata basis by excluding the income of non-generation or non-transmission business, as the case may be, and the corresponding tax thereon. <u>In case of generating company or transmission licensee paying Minimum Alternate Tax (MAT), "t" shall be considered as MAT rate including surcharge and cess</u>."

As evident from above, the Commission has clearly specified that the MAT rate shall be considered for grossing up RoE in cases where the company is paying MAT, as the MAT Rate cannot be higher than the rate notified under the relevant Finance Act. A similar analogy is relevant in case the company is required to pay Corporate Tax Rate or falls under any other tax bracket as per the relevant Finance Act as applicable from time to time. In such cases, the grossing up of RoE shall be at the effective tax rate which can be a rate in between MAT and the Corporate Tax Rate, or any other tax bracket as may be specified from time to time, however, such effective tax rate considered for the grossing up of RoE under no circumstances can be higher than the rate specified under the relevant Finance Act.

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.

In view of the above discussion, comments and suggestions are sought on the above and any other alternative(s).

4.18 Interest on Working Capital

Interest on working capital depends on the following two cost factors.

1. Working Capital requirement.
2. Rate of interest to be considered.

The Commission, while formulating CERC Tariff Regulations, 2019, has carried out several changes in the norms pertaining to working capital as well as the rate of interest to be considered for computing interest on working capital for generating stations and transmission licensees. Each of the above two key parameters has been discussed separately as below.

4.18.1 Working Capital Requirement

The Commission has been specifying different norms for approving working capital requirements for coal/lignite, gas, hydro generating stations and transmission business. The Commission, while formulating the CERC Tariff Regulations, 2019, has adjusted the norms considering the following key determinants.

1. Actual fuel stock position maintained by plants – Pit Head (changed to 10 days from 15 days) and Non-Pit Head (changed to 20 Days from the earlier 30 days)
2. Average Credit Cycle – Changed to 45 days Receivables.

The CERC Tariff Regulations, 2019 also allowed the fuel cost for the purpose of computation of working capital to be linked with the latest available prices, as against the previous mechanism of calculating the fuel cost at the commencement of the tariff period without any price escalation. The Commission has now allowed the reset of the fuel price during every financial year of the tariff period.

In addition to the above, the Commission also specified the working capital norms for Emission Control System through the first amendment to CERC Tariff Regulations, 2019.

It is observed that the working capital norms are efficient, so the existing norms may be retained. However, comments and suggestions are invited on any modification that may be required in the norms.

It is further observed that CEA has revised coal stocking norms for coal based thermal generating stations with effect from 06.12.2021 and CEA has suggested disincentives for thermal power plants in the event the availability of any coal based power plant is lower than the normative availability (as per prevailing CERC Regulations/Norms, as applicable) due to a lower stock of coal maintained by the power plant as compared to the norm specified by the CEA. A Staff Paper titled *"Methodology for Computing*

Deterrent Charges for maintaining lower coal stock by coal based thermal generating stations" was issued in May 2022 wherein the methodology for determining deterrent charges was proposed. In this regard, comments and suggestions were invited from generating stations and stakeholders. Various generating stations and stakeholders have submitted their responses, however, any further suggestions on the issues flagged therein may be submitted for consideration.

With regard to gas based generating stations, from the operational data in recent years, it is observed that the PLF of such generating stations is around 20%-25%. As power from these plants is costlier it is generally scheduled by beneficiaries only to meet peak requirements. It is anticipated that these generating stations will continue to operate at such low PLFs in the next tariff period, and therefore, the current practice of allowing working capital requirements considering generation at normative PLF may need review.

Comments and suggestions are invited on any modification that may be required in the norms of old gas generating stations to factor in the actual generation while allowing for the working capital requirement for gas based generating stations.

4.18.2 Rate of Interest on Working Capital

The Commission, while formulating the CERC Tariff Regulations, 2019, shifted from base rate to a more efficient MCLR based funding which is more responsive to policy rate changes. **As per the existing Regulations, the Bank Rate for the purpose of computing the Interest on Working Capital (IoWC) is defined as one-year MCLR plus 350 bps. Stakeholders may comment as to whether the same may be continued or may suggest any better alternative to the same.**

4.18.3 Normative Working Capital and interest thereon

As discussed in Section 3 of this Approach Paper, in order to simplify the process of tariff filing and its determination and reduce the regulatory burden on generating and transmission companies, the possibility of determining Annual Fixed Charges (AFC) on a normative basis is being evaluated. Most of the cost components, such as Depreciation, RoE, O&M Expenses, are already determined on a normative basis.

It is further observed that the working capital norms are allowed and then trued up after factoring in the actual receivables, fuel prices (Thermal Generation), MCLR and normative O&M expenses.

With regard to thermal and gas based generating stations, fuel costs form sizeable part of the working capital requirement, and as working capital requires truing up on the basis of actuals primarily because of changing fuel expenses, it is to be explored how working capital can be approved such that yearly truing up is not required.

Comments and suggestions are sought from stakeholders on the ways to determine IoWC along with any other alternatives, if any, so that the same may not require periodic truing up.

4.19 Life of Generating Stations and Transmission System

The Commission, in its Explanatory Memorandum to the draft CERC Tariff Regulations, 2019, has carried out a detailed analysis of increasing the life of assets and its impact on tariff, as well as a sensitivity analysis of the various components of tariff vis-à-vis asset life and has re-assessed the life. Based on the study carried out, the Commission increased the life of hydro generating stations from 35 years to 40 years, keeping the life of other asset classes same as specified in the CERC Tariff Regulations, 2014.

Further, the Commission, through the second amendment to the CERC Tariff Regulations, 2019, has recently specified the life of mines and related assets on the basis of a detailed study carried out by the Working Group.

It is observed that as more and more coal based thermal generating stations are operating efficiently even beyond 25 years, there may be a case to align the normative life of these stations, considering that with proper upkeep, these generating stations can operate even beyond 30 years. Similarly, in the case of transmission sub-stations it is observed that these assets can operate way beyond 25 years similar to transmission lines, and therefore, **the useful life of coal based thermal generating stations and transmission sub-stations may be increased to 35 years from the current specified useful life of 25 years.**

It is, however, observed that one of the factors that has enabled these assets to operate beyond 25 years is the regular operations and maintenance carried out by the utilities. In the past, the Commission has allowed a special allowance for these assets in order to take care of the increasing need for repairs that are required to keep the equipment operating efficiently. **As the need for higher repairs will still be required, the current dispensation of allowing a special allowance or provision of R&M may be continued after 25 years.**

Comments and suggestions are sought from stakeholders on the above proposal and the necessity of further changes, if required.

4.20 Input Price of coal – Integrated Mine

The Government of India, on 21.10.2014 notified "The Coal Mines (Special Provisions) Ordinance, 2014, [now "The Coal Mines (Special Provisions) Act, 2015 (11 of 2015) or "The Coal Mine Act"] which provides for the coal allocation through public auction or through an allotment order. As per Section 5 of the Coal Mine Act, the allocation of mine through allotment order is allowed to a Government Company and Case-2 generation projects.

Unlike allocation by auction, allocation by Allotment Order on the basis of Government dispensation, is made without specifying the cost of coal mining or the price of coal. The allotment documents and standard Coal Mine Development and Production Agreement (CMDPA) issued by the Ministry of Coal, GoI does not provide any coal price for using coal in specified end use plants, except for specifying the end use as power generation.

The Commission, vide the second amendment to CERC Tariff Regulations, 2019 has incorporated provisions with regard to the determination of the input price of coal and lignite, wherein such mines have been allocated to the generating stations. The Commission, before specifying the norms, had constituted a Working Group to suggest a regulatory framework for the determination of input price of the coal and lignite. The Commission, on the basis of the report submitted and after considering the suggestions received from various stakeholders, notified the second amendment to CERC Tariff Regulations, 2019 on 19.02.2021 which specified the terms of the determination of the input price of coal to be considered for the determination of energy charges for power stations with integrated mine.

It is observed that so far the Commission has received a couple of petitions for the determination of the input price of coal and therefore not much actual data is available to review the current operational norms and other provisions. In view of no compelling reasons to revisit the current terms and conditions for the determination of the input price of coal, it is proposed that the current provisions be continued.

Comments and suggestions are sought from the stakeholders on any modifications that may be required to current tariff provisions with regard to the determination of the input price of coal and lignite from integrated mines.

4.21 Sharing of Gains

Regulation 60 of the CERC Tariff Regulations 2019, allows sharing of gains on account of the following:

1. Due to efficiency gains related to operational parameters namely Station Heat Rate, Auxiliary Energy Consumption, SFOC which are to be shared in the ratio of 50:50.
2. Due to the refinancing or restructuring of loans, net gains are to be shared in the ratio 50:50.
3. Non-Tariff Income – The net income to be shared in the ratio of 50:50.
4. Clean Development Mechanism (CDM) Benefits – 100% of gross proceeds towards CDM benefits in the first year are to be retained by the developer, and from the second year onwards, 10% is to be shared with beneficiaries, and thereafter, every year 10% incremental benefits are to be shared, subject to a maximum of 50%.
5. Sharing of income from other businesses of transmission licensees – To be shared with the beneficiaries as per the Central Electricity Regulatory Commission (Sharing of revenue derived from utilization of transmission assets for other business) Regulations, 2007.

It is observed that both generating companies as well as transmission utilities have considerable resources in the form of assets such as land banks and other enabling infrastructure and human resources that can be utilised to increase non-core revenues through lease, data centres, eco-tourism, etc., which should be explored, and in order to generate such lateral revenue opportunities, the utilities need to be incentivised.

Comments and suggestions are sought from the stakeholders on the following:

1. **Ways to increase non-core revenues through optimal utilisation of available resources.**
2. **Any modification in the sharing mechanism that may be required.**

4.22 Treatment of arbitration award – Servicing of Principal and Interest Payment

The CERC Tariff Regulations, 2019 provide for allowing Additional capitalisation including liabilities, to meet an award of arbitration or for compliance with the directions or an order of any statutory authority, or order or decree of any court of law.

It is observed that in certain cases, these awards are issued after prolonged litigation. In general, these awards have two components the principal amount and the interest amount. At times, the financial impact associated with these matters is considerable, and capitalising the entire award amount may result in increased AFC, leading to an additional recurring burden on the beneficiaries over the remaining useful life of the asset. **To avoid such situations, the principal amount may be capitalised and the interest amount may be allowed to be recovered in instalments from the beneficiaries. However, such a recovery of interest may also involve carrying cost.**

Comments and suggestions are sought from stakeholders on the above approach and alternative ways, if any.

4.23 Treatment of interest on differential tariff after truing up

Regulation 10(7) of the CERC Tariff Regulations, 2019, specifies as follows:

"(7) The difference between the tariff determined in accordance with clauses (3) and (5) above and clauses (4) and (5) above, shall be recovered from or refunded to, the beneficiaries or the long term customers, as the case may be, with simple interest at the rate equal to the bank rate prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments."

As per the above, the differential amount of tariff needs to be recovered or refunded with simple interest in six equal monthly instalments. However, stakeholders have raised concerns over the method of charging interest on the differential amount up to the liquidation of the last instalment.

In order to streamline the rate of interest on the differential amount, the current practice of allowing a simple interest rate as per Regulation 10(7) in the 2024-29 tariff block may be continued. Further, interest may be allowed to be charged on the differential amount by the utility only until the issuance of the order, and no interest may be allowed during the recovery in six equal monthly instalments.

Comments and suggestions are sought from stakeholders on the above approach and alternative ways, if any.

5 Operational Parameters impacting Tariff

5.1 Normative Annual Plant Availability Factor (NAPAF)

5.1.1 Review of Existing Norms

Historically, the target availability has been determined based on the data available for the few past years. The recovery of fixed charges was linked to the Plant Availability Factor (PAF). The Normative Annual Plant Availability Factor (NAPAF) has been specified considering the past years' data and best industry practices. However, due to changing dynamics such as technological improvement, better O&M practices, and shorter shutdowns and outages, the PAF has improved.

However, a shortage of domestic fuel affects PAF, and it has been an area of concern in recent years. In the event of bridging the gap through e-auction, or imported coal (other than fuel arrangements agreed in PPA), the need for prior consent of beneficiaries, the maximum permissible limit of blending, etc. has also been deliberated under Section 5.9 of this Approach Paper.

Similarly, for Hydro generating stations, PAF is impacted due to 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.

In view of the above, the existing norms of NAPAF may need review by considering past years' PAF, the procurement of coal from alternate sources, other than designated fuel supply agreements, changes in hydrology, etc.

Further, it is observed that current Regulations, although specifies the mechanism for computing PAF of storage based hydro generating stations, do not specify a methodology for computing PAF of Run-of River (ROR) Plants. There is a need to specify a mechanism for the same, and based on such a specified mechanism, the current NAPAF value may need reconsideration.

One option can be to re-introduce the methodology that was being adopted in the CERC Tariff Regulations, 2004. Based on Regulation XI (b) under Chapter 3 of the Tariff Regulations, 2004, the methodology can be specified as follows:

"In case of purely run-of-river power stations, declared capacity means the ex-bus capacity in MW expected to be available from the generating station during the day (all blocks), as declared by the generating station, taking into account the availability of water, optimum use of water and availability of machines;"

Comments and suggestions are sought from stakeholders on the above suggested option and any other methodology that can be considered for the computation of plant availability for ROR based hydro generating plants.

5.1.2 Recovery of Energy Charge for Hydro Generating Stations

The Commission, while framing the CERC Tariff Regulations for the period 2009-14, modified the tariff structure for hydro generating stations, wherein a two-part tariff was structured in such a manner that 50% of the recovery of AFC was linked to achieving NAPAF, and the balance 50% was termed as Energy Charge and its recovery was linked to actual generation.

It is observed that in the current mechanism, recovery of 50% of AFC is linked to actual generation, and in the event of any shortfall in actual generation below the saleable design energy, the same is allowed to be recovered as per Regulation 44(7). As the hydrological risk is eventually passed on to consumers, the usefulness of a two-part tariff may need to be reviewed. The existing provisions of the shortfall in recovery of AFC are leading to complications in the recovery process, wherein the affected generating company has to file petitions seeking such recovery.

Comments and suggestions are sought from stakeholders on ways to simplify the tariff recovery process for hydro generating stations.

5.2 Peak and Off-Peak Tariff

In the tariff period FY 2019-24, the concept of peak and off-peak tariff was introduced for thermal generating stations to incentivise peak period availability and availability during peak demand season. Further, the Tariff Policy also specifies that differential rates for fixed charges should be introduced.

By introducing the mandatory requirement of achieving target availability during peak hours and during high demand season, the generating stations were incentivised to be available during the time beneficiaries needed them the most. The Regulations stipulate the requirement for the generating stations to maintain specified target availability against the regional peak hours/demand season as declared by RLDCs.

It is observed that though the segregation of recovery through peak and off-peak periods has brought in more accountability, there have been some operational difficulties while declaring high demand and low demand season which need to be taken care of. The current provisions require the Regional Load Despatch Centres (RLDCs) to notify in advance the months of high-demand season and low demand season so that overhauling can be planned by the generators accordingly. The following issues have been brought before the Commission in this context:

1) The actual period of high demand did not coincide with the forecast, and the generators had to postpone overhauling considering the sudden increase in demand. In some cases, such deferment has led to forced outages, thereby impacting the recovery of the AFC.
2) The period of high demand and low demand is not the same for all the States in the Region, so declaring the common high and low demand period for all the States has its own challenges. For example, in Northern Region, the high demand season for hilly States such as Uttarakhand and Himachal Pradesh is the winter months, whereas for adjacent Punjab the same lies in the months of August-September and for Delhi it is the summer months.
3) Some of the generating stations have beneficiaries in different regions, which again increases the diversity of demand. Therefore, declaring common high and low demand period is practically not possible. For example, Kahalgaon STPS and Farakka STPS have allocations to beneficiaries that belong to all five regions; therefore, in such cases, the objective of devising the above mechanism is rendered ineffective and may require tweaking of existing practice by RLDCs.
4) While States have been demanding availability from the generators coinciding with State Peak, the generators have difficulty meeting this requirement due to the wide diversity of peak in different States.

5) On the other hand, suggestions have also been received for a 'National' level Peak Period in view of the fact that the grid is integrated and India has a National market in operations.

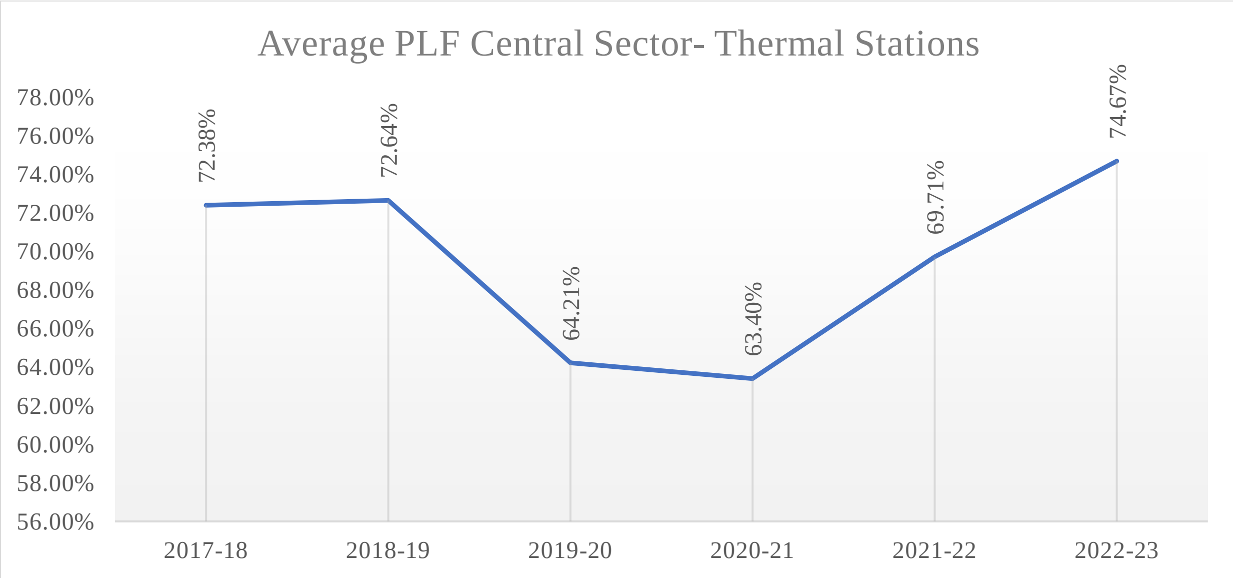
As recovery of reasonable costs is of prime importance for any infrastructure sectoral growth, comments/suggestions are sought on the possible interventions/modifications required to address the issues highlighted above. Specific suggestions are also sought on the following.

1. **Whether it would be advisable to limit the recovery based on daily peak and off-peak periods.**
2. **Suggestions on National versus Regional Peak as a reference point for recovery of fixed charges.**

5.3 Operational Norms

The Commission, while framing the Regulations for terms and conditions of tariff for different tariff periods, has been considering the operational data of the generating stations for the past 5 years. The methodology of considering 5 years' data ensures that the generator is able to recover the cost of electricity generation in a reasonable manner.

It is observed that the Central Generating Stations that used to operate at around 80%-85% PLF prior to FY 2013-14 have now been operating at part load and much below the target PLF due to the need for higher RE integration, as evident from the following figure:



Source: Reports published by CEA

Figure 11: Average PLF for Central Generating Stations (%)

As these generating stations are operating at a much lower PLF, the actual performance data will also have a degradation impact. **Further, as the generating stations are separately allowed degradation impact due to low load operations, it is felt that the norms may be fixed considering the ideal loading of generating units.**

Comments and suggestions are sought from stakeholders on the above proposal and other key determinants to be considered while approving the norms.

5.4 Operational Norms – Inefficient Generating Stations

For those generating stations that have not been operating efficiently in the past and for which the Commission has been considering actual achievements to fix relaxed norms, in the interest of limited resources, such relaxation of norms may need re-consideration. This is necessary as the coal/lignite is limited resource that needs to be consumed efficiently and can be re-allocated to more efficient plants.

Comments and suggestions are sought from stakeholders on the option to do away with relaxed norms currently allowed on the basis of actual performance for various efficiency norms of generating stations.

5.5 Operational Norms for Washery Rejects based Plants

The Commission, while formulating the CERC Tariff Regulations, 2019, has specified the following operational norms for washery reject-based power plants:

1. Station Heat Rate – To be approved on a case-to-case basis.
2. Auxiliary Energy Consumption – 10%
3. Secondary Fuel Oil Consumption – 2ml/kWh
4. NAPAF – 75% (First three years from COD) and 80% thereafter.

In view of no compelling reasons to amend the same, the existing norms for such plants may be continued in the next tariff period.
Comments and suggestions are sought from stakeholders on the above proposal.

5.6 Operational Norms - Emission Control System

The Commission included the need to determine the tariff and the norms for ECS in view of the Ministry of Environment, Forest, and Climate Change's (MoEF&CC) notification mandating implementation of Flue Gas De-sulphurisation System (FGD) and other ECS in its Staff Paper while framing the CERC Tariff Regulations for 2019-24. As adequate actual operational data were not available, the Commission in the Principal Regulations only provided for in-principle approval of additional capital expenditure, admissibility, and tariff structure (Supplementary Energy Charges and Fixed Charges) and stipulated the operational and financial norms subsequently through the first amendment to CERC Tariff Regulations, 2019, which were based on inputs from CEA and various other stakeholders.

As only very few of such emission control systems have been commissioned, and in the absence of sufficient data on actual operational performance and its impact on auxiliary consumption, the current tariff norms may be continued for the next control period. However, comments and suggestions are sought from stakeholders on the continuation of the existing norms, or is there a need to modify the same?

Further, as considerable expenses have been incurred to reduce the adverse impact on the environment, suggestions are also sought on ways to incentivizing proper operation

of such emission control systems so that the very purpose of incurring such huge expenses can be achieved and accounted for.

Implementation of an emission control system also requires the determination of supplementary energy charges, which impacts the power plant's standing on merit order. The Commission, considering that most of the generating stations are yet to install these systems, ruled that these supplementary energy charges shall not be considered while preparing merit order. In view of the earlier approach and considering that most of these generating stations are still in the process of implementing such systems, the current practice of excluding such expenses while preparing merit order may be continued.

Comments and suggestions are sought from stakeholders on whether the current mechanism to exclude these expenses may continue until these generating stations equip themselves with emission control systems as per the MoEF&CC notification dated 31.03.2021?

5.7 Compensation for Part-Load Operations

The compensation mechanism for the thermal generating stations operating on loads below normative level up to the technical minimum, was included as part of the amendment to the Indian Electricity Grid Code, 2010, in the year 2017. The compensation was introduced mainly because the norms for Section 62 projects under the Tariff Regulations have been specified considering specific past data, and if loading is below the data based on which the norms were specified, the variable charge based on the norms may not correspond to the actual parameters of Station Heat rate, Auxiliary Energy Consumption etc. Further, the Commission, in its Explanatory Memorandum to the draft IEGC, 2022 has mentioned that since norms for generating stations under Section 62 are determined under the Tariff Regulations, the appropriate placement of compensation for such projects should be through the Tariff Regulations. Therefore, the norms are now to be dealt with as a part of the Tariff Regulations and therefore, appropriate provisions need to be inserted.

It is observed that the current dispensation allows degradation in the following operational norms, for part load operations of the generating stations.

1. Station Heat Rate

2. Auxiliary Energy Consumption
3. Secondary Fuel Oil Consumption

It is observed that currently the impact is being allowed considering the norms or actuals, whichever is lower. This mechanism results in operational gains being passed on to the beneficiaries, while any losses are borne by the generator. The mechanism may need a review wherein either normative norms are followed, or compensation is limited to actuals.

It is further observed that there have been instances where the actual PLF of plants has been even below 55%. The current provisions for compensation do not cover operating PLF below 55%, and therefore, devising a compensation mechanism to govern such cases may also be required.

With regard to the compensation norms, an Expert Committee has already been constituted; however, in view of the above discussion, **comments and suggestions are sought from stakeholders on the earlier norms and any changes that may be required to compensate the generators to operate the plants in a flexible manner to support the Grid.**

5.8 Gross Calorific Value (GCV) of Fuel

Gross Calorific Value (GCV) of fuel is one of the most important factors on which energy charges depend. Based on the measurement points, the GCV of any specific fuel can be different, such as GCV "as Billed" (As billed by Coal Company), GCV "as Received" (GCV measured when the fuel is received) and GCV "as fired" (GCV of coal just before it is sent for firing). The GCV of fuel keeps on varying at different reference points due to various factors such as moisture content, and grade slippages at the mine end, or during transportation or during storage at the plant end. The current Regulations specify that the GCV of fuel for the purpose of allowing energy charges shall be considered on an as received basis as other factors due to which there is a loss in GCV are not under the control of the generating stations. The Commission, considering the same allowed computation of energy charges on the basis of GCV "as received" basis plus an additional margin of 85 kCal/kg towards storage losses without differentiating between pit head and non-pit head stations.

The approach has found wider acceptance, however, it is observed that the variation in GCV "as billed" and "as received" is significant due to loss of GCV at mine end and during transportation, often leading to grade slippages. Though, the magnitude of such losses has reduced in the past, they are still significant and may need to be accounted for in terms of risk sharing between the coal company, the railways and the generating station. At present, the generator pays for the coal based on GCV "as billed" and quantum of coal at the loading point. It is observed that the loss in GCV from "as billed" to "as received" has been allowed on an actual basis. As mentioned earlier, even though the loss in GCV "as received" vis-à-vis "as billed" has reduced, one can argue that as the actual loss has been allowed in the past, there have not been considerable efforts made by generators in minimising the loss.

Comments and suggestions are sought from stakeholders on ways to reduce the gap between GCV "as billed" and "as received".

5.9 Blending of Coal

In order to address the issue of depleting coal stocks and building stocks before the monsoon, the Ministry of Power issued an advisory dated 07.12.2021 to all domestic coal based power plants to import coal to meet their requirements by blending with imported coal to an extent of 4% by State generating companies & Independent Power Producers (IPPs). MoP again vide its letter dated 28.04.2022 directed the concerned stake holders to import at least 10% of their coal requirements for blending. Due to the easing out of the shortage situation, MoP again, issued revised directions vide letter dated 09.01.2023 wherein the domestic coal based generating stations are required to plan for 6% blending until September 2023.

The generating companies are reported to be facing problems complying with the above directions of the Ministry of Power on account of the absence of permission by the concerned beneficiaries, which is required under Regulation 43(3) of the CERC Tariff Regulations, 2019. Regulation 43(2)(b)(3) of the CERC Tariff Regulations, 2019 stipulates as follows:

*"**43 Computation and Payment of Energy Charge for Thermal Generating Stations***

(1) ..

(3) In case of part or full use of alternative source of fuel supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power purchase agreement for supply of contracted power on account of shortage of fuel or optimization of economical operation through blending, the use of alternative source of fuel supply shall be permitted to generating station:

Provided that in such case, prior permission from beneficiaries shall not be a pre-condition, unless otherwise agreed specifically in the power purchase agreement:

Provided further that the weighted average price of alternative source of fuel shall not exceed 30% of base price of fuel computed as per clause (5) of this Regulation:

Provided also that where the energy charge rate based on weighted average price of fuel upon use of alternative source of fuel supply exceeds 30% of base energy charge rate as approved by the Commission for that year or exceeds 20% of energy charge rate for the previous month, whichever is lower shall be considered and in that event, prior consultation with beneficiary shall be made at least three days in advance."

Staff of the Commission, in June 2022, published a paper analysing the impact of blending of coal on the energy charges and noted that even when blending of coal is less than 10%, the 30% ECR threshold limit gets breached. In view of the same and considering that the shortage situation may recur, following can be analysed.

Linking the consent of beneficiaries with the percentage blending of imported coal instead of an increase in ECR may enable a swift response to an increase in demand by the generating company. Procurement of such coal (other than linkage coal) has to be done through a transparent competitive bidding process.

Comments and suggestions are sought from stakeholders on the above proposal and any other alternative, if any.

5.10 Incentives

It is observed that the incentives linked to NAPLF, NAPAF and NATAF have been specified in existing Tariff Regulations. In this regard, it is observed that the incentive linked to availability is already allowed as per the prescribed formulation on a pro-rata basis and may be continued. **However, incentives linked to generation in excess of target PLF/NAPAF especially during peak periods, in the case of hydro stations and old pit-head generating stations, may need a review in order to encourage higher generation from such plants. This will result in increased generation from such plants and will also benefit beneficiaries.**

Comments and suggestions are sought from beneficiaries on the above proposal and any other alternative options, if any.

6 Other Key Issues

6.1 Separate Norms for ROR/Storage Based Hydro Projects

Hydro generating stations can primarily be classified into the following three main categories.

1. **Run-of-River (ROR) Hydro Stations:** These stations utilise water that runs off the river by channelling some of the flow through a canal or penstock. As these types of stations do not have any storage facilities, generation is purely dependent upon the flow of water and has little scope to adjust to demand needs.
2. **Pondage/Storage based Hydro Stations:** These stations use a dam or reservoir that acts as a storage facility to store water, and therefore, depending upon the grid requirements, the generation can be controlled and principally should be used as peaking plants for peak shaving.
3. **Pumped Storage Plant - Hydro Stations (PSP):** These stations are primarily pumping facilities that pump water from a reservoir at a lower level to a reservoir at a higher level during off-peak times and generate power during peak times by releasing water from the reservoir at a higher level to the lower level utilising the differential head between the two reservoirs.

Currently, the terms and conditions for tariff components, stipulated in the CERC Tariff Regulations, 2019, for all these types of hydro stations are the same except for the higher RoE allowed for storage based hydro stations and PSP. In addition to the cost components, in general, the NAPAF of storage based generating stations is higher than that of ROR based projects considering the ability of storage based generating stations to generate on demand.

However, it is observed that there is a need for a more enabling framework or incentive mechanism for dam/reservoir based generating stations to operate as peaking plants. **Considering the anticipated increase in peaking loads, these stations may be incentivised to operate as peaking plants. One way to do so is by providing additional incentives for energy supplied during peak periods.**

Comments and suggestions are sought from stakeholders on the above proposal and any alternative solutions, if any.

6.2 Tariff Structure for Cost Recovery for Emission Control System

The Commission, in Tariff Regulations, 2019, specified recovery of the impact of the installation of emission control systems through Supplementary Fixed Charges and Supplementary Energy Charges. While specifying the said recovery mechanism, the Commission in its explanatory memorandum specified as follows:

"The Commission is aware of the fact that the additional capital expenditure on account of setting up the pollution control facilities to meet the revised emission standards in the generating stations will result in increase in the capacity charge of the generating station. Further, the pollution control facilities shall also require additional recurring expenses in the form of reagent, consumables, additional O&M expenses and also result in additional impact on the operating norms, specifically the auxiliary energy consumption of the generating station. Thus, the impact will result in increase in capacity charges as well as energy charges of the generating stations. The generating stations which set up the pollution control facilities for meeting the revised emission standards earlier will be at competitive disadvantage in terms of landed cost of power to the beneficiaries, as compared to the generating stations which may set up such pollution control facilities for meeting the revised emission standards at a later stage.

Therefore, with a view to provide level playing field to all generating stations in the transition phase, till the time the revised emission standards are met by all the generating stations, the Commission has proposed that the tariff on account of additional capital expenditure incurred for setting up the pollution control facilities shall be determined separately as supplementary tariff."

The Commission, subsequently, through first amendment to CERC Tariff Regulations, 2019 introduced a following proviso under Clause 1 of Regulation 9.

"Provided also that the generating company shall file an application for determination of supplementary tariff for the emission control system installed in coal or lignite based thermal generating station in accordance with these regulations not later than 60 days from the date of operation of such emission control system."

The Commission also provided appropriate provisions for the computation of supplementary capacity charges and supplementary energy charges in the first amendment.

As not all generating stations have installed the emission control system, and most of these works are in the execution stage, therefore the existing tariff recovery mechanism may be continued. However, comments and suggestions are sought from stakeholders on alternatives to the existing tariff mechanism for recovering the impact of the installation of emission control systems.

6.3 Decommissioning of Generating Station and Transmission Assets

With the growing concerns over inefficient generating stations and their impact on climate change, it is imperative to have appropriate provisions in the Tariff Regulations to deal with all eventualities. Also, there would be the scenario wherein any generating station or transmission system is decommissioned prior to the completion of its useful life in order to comply with any statutory orders or due to technological obsolescence duly approved by RPC or any other uncontrollable factors. It is observed that, on one hand, the disposal of such decommissioned generating station/system entails a cost (unrecovered depreciation) towards such pre-closure, on the other hand, these generating stations have some salvage value that can be realised. It is to be analysed how these costs and revenues can be accounted for so that they can be cost neutral to the generating or transmission company and also do not impact the beneficiaries. This would also reduce risk perception among investors and may provide necessary clarity on such matters thus reducing litigations.

One approach could be that the net profit/loss post decommissioning and disposal of assets may be adjusted in one go from the beneficiaries, duly factoring in the un-recovered depreciation admissible under the Tariff Regulations.

In view of the above, comments and suggestions are sought from stakeholders on the possible approaches to recover or refund the impact of decommissioning costs in case the generating stations/transmission systems are decommissioned before the completion of their useful lives, if such decommissioning is done in compliance of a statutory order or due to technological obsolescence duly approved by RPC.

6.4 Simplification of Tariff Formats

Some stakeholders have expressed the view that the tariff formats, required to be submitted along with the tariff petitions, instead of being simpler, are getting more intricate. The information filling and preparation of tariff forms takes considerable time and effort on the part of the petitioner and also results in delays in processing as these formats are required to be thoroughly checked by the Commission. **Comments and suggestions are invited from stakeholders for simplifying the existing tariff formats.**

6.5 Approval process for carrying out non-ISTS lines carrying inter-state power and associated Capital Cost

The Commission, in order dated 14.3.2012 in Petition No.15/SM/2012, taking into consideration the request of the State utilities, proposed to include the transmission lines connecting two States in the PoC charges and had accordingly directed the States owning these transmission lines, to file appropriate petitions for determination of tariff for the 2011-14 period in accordance with the provisions of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009). Further, for the 2014-19 tariff period, the Commission, vide order dated 12.5.2017 in Petition No.7/SM/2017 directed the State utilities to file tariff petitions for these transmission lines along with the certificate of the concerned RPC in accordance with the provisions of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014.

The Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010 which were in force till 31.10.2020, provided for consideration of an intra-State transmission system as an inter-State transmission system on the basis of power flow. The relevant portion of paragraph 2.1.3 of Annexure-I to the Sharing Regulations, 2010 provides as follows:

" …… Certification of non-ISTS lines carrying inter-State power, which were not approved by the RPCs on the date of notification of the Central Electricity Regulatory Commission (Sharing of Transmission Charges and Losses) Regulations, 2009, shall be done on the basis of load flow studies. For this purpose, STU shall put up proposal to the respective RPC Secretariat for approval. RPC Secretariat, in consultation with RLDC, using Web Net Software would examine the proposal. The results of the load flow studies and participation

factor indicating flow of Inter State power on these lines shall be used to compute the percentage of usage of these lines as inter State transmission. The software in the considered scenario will give percentage of usage of these lines by home State and other than home State. For testing the usage, tariff of similar ISTS line may be used. The tariff of the line will also be allocated by software to the home State and other than home State. Based on percentage usage of ISTS in base case, RPC will approve whether the particular State line is being used as ISTS or not. Concerned STU will submit asset wise tariff. If asset wise tariff is not available, STU will file petition before the Commission for approval of tariff of such lines. The tariff in respect of these lines shall be computed based on Approved ARR and it shall be allocated to lines of different voltage levels and configurations on the basis of methodology which is being done for ISTS lines.”

Thus, in accordance with paragraph 2.1.3 of Annexure-I, the certification of non-ISTS lines used for carrying inter-State power was done on the basis of load flow studies of a line if STU puts up a proposal to RPC and RPC based on the percentage of usage of these lines approves the said lines as being used as ISTS.

Regulation 13(13) of the CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020 is extracted as under:

> *“13. Treatment of transmission charges and losses in specific cases*
>
> ---
>
> *(13) An intra-State transmission system for which tariff is approved by the Commission shall be included for sharing of transmission charges of DICs in accordance with Regulations 5 to 8 of these regulations, only for the period for which such tariff has been approved.”*

Section 2(36)(i) of the Act, which provides as follows:

> *“2 (36) inter-State transmission system” includes –*
>
> *(i) any system for the conveyance of electricity by means of main transmission line from the territory of one State to another State;*
>
> *(ii) the conveyance of electricity across the territory of an intervening State as well as conveyance within the State which is incidental to such inter-State transmission of electricity;*

iii) the transmission of electricity within the territory of a State on a system built, owned, operated, maintained or controlled by a Central Transmission Utility

A transmission line can be considered as an inter-State transmission line in three circumstances, as mentioned under Section 2(36) of the Act. It is observed that many of the State transmission licensees are claiming tariff of the transmission lines either due to the creation of LILO on the existing transmission lines or systems or the construction of new transmission lines and intra-state lines converted into inter-state lines due to the bifurcation of a State. It is further observed that State transmission licensees are not taking any prior approval from the Commission, for the implementation of new transmission lines and also many of the State transmission licensees are claiming tariff for the transmission lines without submitting any approvals of SCM and RPC.

In view of the above, comments and suggestions are invited from stakeholders, particularly, from STUs and State transmission licensees, for the approval process to be followed before undertaking the construction of new intra-state transmission lines carrying inter-state power.

The transmission charges of such Intra-State transmission lines (carrying inter-state power) of the State transmission utilities are determined based on the benchmark capital cost derived on the basis of the average cost of CTU lines for old transmission lines or based on the auditor's certified cost, in accordance with the CERC Tariff Regulations, 2014 and the CERC Tariff Regulations, 2019, as the case may be.
Comments and suggestions are sought from stakeholders on the capital cost to be considered for the computation of transmission charges in respect of intra-State lines (carrying inter-state power) of the State transmission utilities.

6.6 Up-gradation of Asset/Replacement

Regulation 19(5) of the Tariff Regulations, 2019, provides for the exclusion of certain assets from the Capital Cost of existing and new projects, including cases where assets are not in use, i.e. assets replaced or removed from service on account of upgradation or obsolescence.

Representations have been received regarding the non-recovery of the full capital cost of the assets, on account of de-capitalization due to upgradation or modification of existing transmission assets, much before the completion of their useful life.

It is observed that a large number of projects that involves upgradation and modification have already been planned and assigned to transmission licensees for implementation, therefore appropriate provisions may be required to be included in the upcoming tariff regulations.

In view of the above, comments and suggestions are invited from stakeholders regarding the treatment of unrecovered depreciation.

6.7 Assumed Deletions

When an asset, that forms part of Gross Fixed Assets (GFA) gets decapitalised, then ideally the historical cost of such an asset should be reduced from the GFA. However, in certain cases, where the asset under consideration is part of a larger scheme, the individual value of the asset may not be available, and while removing/replacing the said asset from service, a corresponding reference cost is needed to be deleted from the GFA.

As per the extant methodology, the Commission verifies the expenditure on replacement of assets; and if found justified, the same is allowed for the purpose of tariff, provided that the capitalization of the asset is considered against the de-capitalization of the original value of the corresponding old asset. However, in certain cases where de-capitalization is affected in books during the years following the year of capitalization of a new asset, the de-capitalization of the old asset for the purpose of tariff, is affected from the very same year in which the capitalization of the new asset is allowed. Such decapitalization, which is not a book entry in the year of capitalization, is termed "Assumed deletion". Further, in the absence of the gross value of the asset being de-capitalized, the same is calculated by de-escalating the gross value of the new asset @ 5% per annum until the year of capitalization of the old asset.

Stakeholders may comment on whether to continue to consider the gross value of the asset being de-capitalized, by de-escalating the gross value of the new asset @ 5% per

annum until the year of capitalization of the old asset, or may suggest any other methodology to compute assumed deletions.

6.8 Necessity to Review the need of Regulation 17 (2)

The Commission, in its Tariff Regulations, 2019 introduced the following Regulation.

> *"**17. Special Provisions for Tariff for Thermal Generating Station which have Completed 25 Years of Operation from Date of Commercial Operation:** (1) In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation, the generating company and the beneficiary may agree on an arrangement, including provisions 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.*
>
> *(2) 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."*

As per Regulation 17 above, the generating stations and beneficiaries have the option after 25 years of operation to enter into a mutual agreement to recover capacity charges based on scheduled generation. However, the beneficiaries are allowed under 17(2) with the first right of refusal to such arrangement and can exit from the ongoing PPA. It is observed that generation, being a delicensed activity, is purely guided by terms and conditions of PPA and unilateral right to any party, bound by a contract, should not be allowed through Regulations.

Further, commercial mechanisms and terms & conditions for transactions between a generator and beneficiaries are governed by the long term PPAs executed between them, which are generally valid through the life of the PPA. It is noted that a number of generating stations, at times, operate beyond the tenure of the PPA, and that such extended operations should also be governed by the PPA as in the case of the original PPA period, and any interventions in the PPA through tariff Regulations, that too, every five-year, including such a unilateral exit clause, may not be desirable as it may violate contract sanctity and could be inequitable.

In view of the above, the provision under Regulation 17(2) of Tariff Regulations, 2019 may result in further complication and being seen as inequitable for the generator, is required to be modified.

Comments and suggestions are sought from stakeholders on the above.

7 Summary and Way Forward

7.1 Summary of Issues

The issues raised in this Approach Paper have been summarised herein for easy reference for the stakeholders.

7.1.1 Alternative Approach to Tariff Determination

Suggestions are sought as to how the present system of hybrid mechanisms of tariff setting under the cost plus approach can be made more efficient by moving closer to a normative or performance-based approach so that the same would positively impact the interests of consumers as well as utilities. Two possible options could be as follows.

1. Approach 1: Shift to a normative tariff wherein, once capital costs are approved on an actual basis after a prudence check, all other AFC components are determined on normative basis.
2. Approach 2: Further simplification of the existing Performance Based Hybrid Approach, wherein on the basis of admitted capital cost, AFC components can be approved **based on actuals or norms as may be specified for the control period. Further, additional capitalisation may be allowed on certain counts on a normative basis.**

(Refer 3.1)

7.1.2 Normative Tariff

In the context of discussions held in Section **3.2,** comments/ observations of stakeholders are invited on the following points.

3. Whether clustering the components of AFC based on their nature to increase/ decrease will allow better projections? Any other possible method to cluster the AFC components?
4. What other methodology can be adopted to determine the increasing/ decreasing factors?
5. Whether the impact of additional capitalisation can also be allowed through the same indexation mechanism or through a separate revenue stream?

(Refer 3.2)

7.1.3 Interim Tariff

6. The provisions for interim-tariff can, therefore, be continued in the next tariff period as well. However, comments and suggestions are sought from stakeholders on the continuation of the said provision. **(Refer 4.2.1).**

7.1.4 Procurement of Equipment and Services

7. Need to mandatorily award work and services contracts for developing projects under the regulated tariff mechanism through a transparent process of competitive bidding, duly complying with the policy/guidelines issued by the Government of India as applicable from time to time.
   (Refer 4.2.2).

7.1.5 Reference Cost – Benchmark Cost V/s Investment Approval

8. Comments and suggestions of stakeholders are invited on other efficient reference costs other than Investment Approval costs that can be considered for prudence check. **(Refer 4.2.3)**

7.1.6 Capital Cost – Hydro Generating Stations

9. As these expenses towards the advancement of the Local Area are required for the development of the project and for alleviating public resistance and delays, such expenses may be allowed as part of the capital cost with certain limits. Alternatively, these expenses may be met through Budgetary support for funding the enabling infrastructure, i.e., roads and bridges on a case-to-case basis, which could be (i) as per actuals, limited to Rs. 1.5 crore per MW for up to 200 MW projects and (ii) Rs. 1.0 crore per MW for above 200 MW projects, as per the Ministry of Power guidelines dated 28.09.2021 for Budgetary support for Flood Moderation and for Budgetary Support for Enabling Infrastructure.

10. Comments and suggestions are further sought from stakeholders on ways to expedite development of hydro generating stations especially the construction phase, and increase their commercial acceptability.

11. Comments and suggestions are sought from stakeholders to incentivise the developer if it executes the project faster/or ahead of schedule and vice-versa if it delays.
    (Refer 4.2.4)

7.1.7 Capital Cost – Projects Acquired post NCLT Proceedings

12. Historical Cost or Acquisition Value, whichever is lower, should be considered for the determination of tariff post approval of Resolution Plan.
13. Tariff provisions to be included to address the issue of the cost of debt servicing, including repayment, that were allowed as a part of the tariff during the CIRP process.
    (Refer 4.3)

7.1.8 Computation of IDC

14. Existing mechanism wherein the pro-rata deduction (based on delay not condoned) is done on IDC beyond SCOD.
15. Pro-rata IDC may be allowed considering the total implementation period wherein the actual IDC till the implementation of the project is pro-rated considering the period upto SCOD and period of delay condoned over total implementation period.
16. IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay.
    (Refer 4.4.1)

7.1.9 Treatment of LD

17. In view of discussion held in Section **4.4.2**, comments and suggestions are sought from stakeholders on necessary changes in tariff forms and regulations, if any, to provide further clarity on the adjustment of LD. **(Refer 4.4.2)**

7.1.10 Price Variation

18. Therefore, for allowing price variation, the utilities may be mandated to submit the statutory auditor certificate along with the petition duly certifying the price variation corresponding to the delay and the same may be allowed on pro-rata basis corresponding

to the delay condoned. Further, a separate form may also be specified to submit the relevant information pertaining to price variations. **(Refer 4.5)**

7.1.11 Renovation and Modernisation (R&M)

19. In view of the inherent benefits of undertaking R&M as against going for fresh capital investment, the current provisions may be continued.
20. Further, utilities that opt 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. **(Refer 4.6)**

7.1.12 Initial Spares

21. In view of discussion held in Section 4.7, single norm can be considered for each of the following classes of transmissions assets.
    1. Transmission Lines including HVDC lines
    2. Substations (including HVDC S/s)
    3. Dynamic Reactive Compensation devices
    4. Communication Systems
    5. Underground cable

    (Refer 4.7)

7.1.13 Controllable and Uncontrollable Factors

22. In view of the discussion held in Section **4.8.1**, delays on account of forest clearances can also be considered for inclusion as uncontrollable factor.

    (Refer 4.8.1)

7.1.14 Differential Norms – Servicing Impact of Delay

23. To encourage rigorous pursuit of approvals from statutory authorities, even if delay beyond SCOD is condoned, on account of any reasons are condoned, some part of the cost impact (Say 20%) corresponding to the delay condoned may be disallowed.
24. Alternatively, RoE on Equity corresponding to cost and time overrun allowed over and above project cost as per investment approval may be allowed at the weighted average rate of interest on loan instead of fixed RoE.

25. The current mechanism of treating time overrun may be continued considering that utilities are automatically disincentivised if the project gets delayed.

(Refer 4.9)

7.1.15 Additional Capitalisation

26. In view of discussion held under Section 4.10, in order to have an enabling provision under which additional capitalisation can be allowed with prior approval, a provision may be introduced to existing Regulation 26 to allow such expenses if they are found to be beneficial/essential for continued operations.

    (Refer 4.10)

7.1.16 Normative Add-Cap - Generating Station

For generating stations that have already crossed the cut-off date as on 31.03.2024, the additional capitalisation for such generating stations may be allowed as per the following.

27. Thermal Generating Stations – Based on the analysis of actual additional capitalisation incurred by such generating stations in the past (15-20 years) and co-relating such expenses to different unit sizes such as 200/210 MW series, 500/660 MW Series and different vintages (5-10, 10-15, 15-20, 20-25 years post COD) a special compensation in the form of yearly allowance may be allowed based on unit sizes and vintage which shall not be subject to any true up and shall not be required to be capitalised.

28. Hydro Generating Stations – As each hydro generating station is unique owing to various factors additional capitalisation of such generating stations may not be benchmarked as can be done for thermal generating stations. However, in the case of a specific hydro generating station, the additional capitalisation is recurring in nature, and hence, station wise normative additional capitalisation may be approved in the form of special compensation which shall not be subject to any true up and shall not be required to be capitalised.

29. While determining such special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulation 26 to Regulation 29, wherever applicable, may not be included as these expenses may be allowed separately.

30. Further, any items that costs below Rs. 20 lakhs that may be in the nature of minor items such as tools and tackles and those pertaining to Capital Spares may be allowed only as part of O&M expenses and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations.

31. Further, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged.

Further, for generating station whose cut-off date falls in the next tariff block (2024-29), or are expected to achieve COD after 31.03.2024, the following approach may be adopted.

32. By extending the cut-off date from the current 3 years to 5 years which shall allow time to close contracts and discharge liabilities and eliminate the need to allow additional capitalisation post cut-off date unless in the case of Change in Law and Force Majeure.

33. However, based on past data of similar existing generating stations, if there is a need to allow additional capitalisation that may be legitimately required post cut-off date other than those presently allowed under Regulations 26 to 29, the same may be allowed as special compensation as proposed in the case of existing station that have crossed the cut-off date.

34. While determining such special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulations 26 to Regulation 29, wherever applicable, may not be included as these expenses but may be allowed separately.

35. Further, any item that costs below Rs. 20 lakhs that is in the nature of minor assets, including Capital Spares below Rs 20 lakh, can be allowed only as part of O&M expenses and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations. Further, any major capital spares costing above Rs. 20 lakh may form part of the special compensation.

36. Further, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged.

    (Refer 4.10.1)

7.1.17 Normative Add-Cap – Transmission System

37. For reasons discussed in Section 4.10.2, for Transmission Systems, additional capitalisation post cut-off date may be allowed on technological obsolescence, change in law, force majeure, or due to replacement as presently allowed under Regulation 26 and 27 of the CERC Tariff Regulations, 2019.

    (Refer 4.10.2)

7.1.18 GFA/NFA/Modified GFA approach

38. Increasing the Investors confidence by ensuring assured returns is important, and further considering the recent spikes in power tariffs in power exchanges indicating a shortage of power availability, investment in Power sector needs a boost, and therefore the existing GFA approach, being a balanced approach may be continued. However, comments/ suggestions are invited on alternate approaches, i.e. GFA/ NFA/ Modified GFA approach.

    (Refer 4.11)

7.1.19 O&M Expenses

39. O&M norms may be specified under the following two categories.

    1. Employee Expenses
    2. Other O&M Expenses comprise of Repair and Maintenance and Administrative and General Expenses.

    However, considering that systems that are more automated will require less manpower and systems that are less automated will require more manpower, approving separate norms may result in inequity even though the total O&M expenses of such systems may be comparable.

    Therefore, the above suggestion may also be seen from the perspective that these expenses have historically been allowed as one expense and any change in the methodology as suggested above may result in unnecessary complications.

Alternatively, to give effect to the impact of pay/wage revision, 50% of the actual wage revision can be allowed on a normative basis.
(Refer 4.12.1)

40. It is observed that there is a need to simplify the same and therefore one norm for all HVDC schemes in terms of per MW considering the actual expenses incurred in the past may be specified. **(Refer 4.12.2)**

41. Comments and suggestions are sought from stakeholders on whether additional O&M expenses can be given for transmission assets being operated in the North Eastern and Hilly Regions and the manner in which such additional costs can be considered.
(Refer 4.12.3)

42. In view of discussion held in Section 4.12.4, it is anticipated that if Capital Spares are analysed for a longer duration say 15-20 years, there can be some correlation and predictability to such expenses. Therefore, if the same can be projected with some degree of predictability, the same may be allowed on a normative basis along with O&M expenses. Alternatively, instead of including all such capital spares as part of normative O&M expenses, recurring and low value spares below Rs. 20 lakh may be made part of normative O&M expenses, while for capital spares with a value in excess of Rs. 20 lakh, utilities may submit the same on a case to case basis for reimbursement with appropriate justification for the Commission's consideration.
(Refer 4.12.4)

43. Comments and suggestions are therefore sought from stakeholders on whether to include any provisions with regard to allowing impact of change in law in O&M expenses. **(Refer 4.12.5)**

7.1.20 Depreciation

44. In view of discussion held in Section **4.13**, depreciation rate may be specified considering a loan tenure of 15 years instead of the current practice of 12 years. Further, additional provision may also be specified that allows lower rate of depreciation to be charged by the generator in the initial years if mutually agreed upon with the beneficiary(ies).

(Refer 4.13)

7.1.21 Interest on Loan

45. To simplify the approval of interest on loan, the weighted average actual rate of interest of the generating company or transmission licensee may be considered instead of project specific interest on loan. Further, the cost of hedging related to foreign loans be allowed on actual basis, without allowing any actual FERV. **(Refer 4.14)**

7.1.22 RoE/RoCE Approach

46. As in the past much has been deliberated and discussed on the two approaches and in view of the long-standing position of this Commission, the present system, or RoE approach, may be continued. **(Refer 4.15)**

7.1.23 Rate of Return on Equity

Methodology

47. Keeping in view the international approaches to regulated rates of return, the average of 10-year GOI securities rate over a one-year horizon may be considered a risk free rate.
48. Keeping in view the international approaches, daily data on the SENSEX and BSE Power Index for the latest 5 years may be considered for equity beta estimation.
49. Keeping in view the international approaches, the Market Risk Premium (MRP) reflecting the historical returns for a period of 30-years or beyond instead of the existing practice of considering 20 years may be considered for MRP estimation.
50. Alternatively, MRP may be computed using any other method including the Survey Method.

    (Refer 4.16.4)

Other Key Issues

51. Review of Rate of RoE to be allowed including that to be allowed on additional capitalisation that is carried out on account of Change in Law and Force Majeure.
52. Whether the revised rate of RoE to be made applicable to only new projects or to both existing and new projects?

53. Whether timely completion of hydro generating stations can be incentivised to attract investments?
54. Merit behind approving different Rate of RoE to thermal, hydro generation and transmission projects with further incentives for dam/reservoir-based projects including PSP.
55. Merit in allowing RoE by linking the rate of return with market interest rates such as G-SEC rates/MCLR/RBI Base Rate.

    (Refer 4.16.4)

56. Possible options to encourage higher availability and generation from Old Generating Stations can be as follows.

    Allowing additional incentive in the form of paise/kWh apart from those being currently allowed may be allowed to such generating stations against generation beyond the target PLF.

    (Refer 4.16.5)

7.1.24 Tax Rate

57. In view of the discussion held in Section **4.17** 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.
58. 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.

    (Refer 4.17)

7.1.25 Interest on Working Capital

59. It is observed that the working capital norms are efficient, so the existing norms may be retained. However, comments and suggestions are invited on any modification that may be required in the norms.
60. Comments and suggestions are invited on any modification that may be required in the norms of old gas generating stations to factor in the actual generation while allowing for the working capital requirement for gas based generating stations.
61. As per the existing Regulations, the Bank Rate for the purpose of computing the Interest on Working Capital (IoWC) is defined as one-year MCLR plus 350 bps. Stakeholders may comment as to whether the same may be continued or may suggest any better alternative to the same.
62. Comments and suggestions are sought from stakeholders on the ways to determine IoWC along with any other alternatives if any, so that the same may not require periodic truing up.

    (Refer 4.18)

7.1.26 Life of Generating Stations and Transmission System

63. The useful life of coal based thermal generating stations and Transmission Sub-stations may be increased to 35 years from the current specified useful life of 25 years.
64. As the need for higher repairs will still be required, the current dispensation of allowing a special allowance or provision of R&M may be continued after 25 years.

    (Refer 4.19)

7.1.27 Input Price of coal – Integrated Mine

65. Comments and suggestions are sought from the stakeholders on any modifications that may be required to current tariff provisions with regard to the determination of the input price of coal and lignite from integrated mines.

    (Refer 4.20)

7.1.28 Sharing of Gains

66. Ways to increase non-core revenues through optimal utilisation of available resources.
67. Any modification in the sharing mechanism that may be required.

(Refer 4.21)

7.1.29 Treatment of arbitration award – Servicing of Principal and Interest Payment

68. Principal amount may be capitalised and the interest amount may be allowed to be recovered in instalments from the beneficiaries. However, such a recovery of interest amount may also involve carrying cost.
(Refer 4.22)

7.1.30 Treatment of interest on differential tariff after truing up

69. Interest may be allowed to be charged on the differential amount by the utility only till the issuance of the order and no interest may be allowed during the recovery in six equal monthly instalments.
(Refer 4.23)

7.1.31 Normative Annual Plant Availability Factor (NAPAF)

70. As discussed in Section 5.1, One option to measure PAF of ROR plants can be to re-introduce the methodology that was being adopted in the CERC Tariff Regulations, 2004. Based on Regulation XI (b) under Chapter 3 of the Tariff Regulations, 2004, the methodology can be specified as follows.

> "In case of purely run-of-river power stations, declared capacity means the ex-bus capacity in MW expected to be available from the generating station during the day (all blocks), as declared by the generating station, taking into account the availability of water, optimum use of water and availability of machines;"

71. Comments and suggestions are sought from stakeholders on ways to simplify the tariff recovery process for hydro generating station.
(Refer 5.1)

7.1.32 Peak and Off-Peak Tariff

As recovery of reasonable costs is of prime importance for any infrastructure sectoral growth, comments/suggestions are sought on the possible interventions/modifications required to address the issues highlighted above. Specific suggestions are also sought on the following.

1. Whether it would be advisable to limit the recovery based on daily peak and off-peak periods.
2. Suggestions on National versus Regional Peak as a reference point for recovery of fixed charges.

   (Refer 5.2)

7.1.33 Operational Norms

72. Further, as the generating stations are being separately allowed degradation impact due to low load operations, it is felt that the norms may be fixed considering the ideal loading of generating units.

    (Refer 5.3)

7.1.34 Operational Norms – Inefficient Generating Stations

73. Comments and suggestions are sought from stakeholders on the option to do away with relaxed norms currently allowed on the basis of actual performance for various efficiency norms of generating stations.

    (Refer 5.4)

7.1.35 Operational Norms for Washery Rejects based Plants

74. In view of no compelling reasons to amend the same, the existing norms for such plants may be continued in the next tariff period.

    (Refer 5.5)

7.1.36 Operational Norms - Emission Control System

75. As only very few of such emission control systems have been commissioned, and in the absence of sufficient data on actual operational performance and its impact on the auxiliary consumption, the current tariff norms may be continued for the next control period. However, comments and suggestions are sought from stakeholders on the continuation of the existing norms, or is there a need to modify the same?
76. Further, as considerable expenses have been incurred to reduce the adverse impact on the environment, suggestions are also sought on ways to incentivizing proper operations of such emission control system so that the very purpose of incurring such huge expenses can be achieved and accounted for.

77. Comments and suggestions are sought from stakeholders on whether the current mechanism to exclude these expenses may continue until these generating stations equip themselves with emission control systems as per the timelines specified in the MoEF&CC notification dated 31.03.2021?

    (Refer 5.6)

7.1.37 Compensation for Part-Load Operations

78. Comments and suggestions are sought from stakeholders on the earlier norms and any changes that may be required to compensate the generators to operate the plants in a flexible manner to support the Grid.

    (Refer 5.7)

7.1.38 Gross Calorific Value (GCV) of Fuel

79. In view of discussions held under Section 5.8, comments and suggestions are sought from stakeholders on ways to reduce the gap between GCV "as billed" and "as received".

    (Refer 5.8)

7.1.39 Blending of Coal

80. Linking the consent of beneficiaries with the percentage blending of imported coal instead of an increase in ECR may enable a swift response to an increase in demand by the generating company. Procurement of such coal (other than linkage coal) has to be done through a transparent competitive bidding process.

    (Refer 5.9)

7.1.40 Incentives

81. Incentives linked to generation in excess of target PLF/NAPAF especially during peak periods, in the case of hydro stations and old pit head generating stations, may need a review in order to encourage higher generation from such plants. based may need a review in order to encourage higher generation from such plants. This will result in increased generation from such plants and will also benefit beneficiaries.

    (Refer 5.10)

7.1.41 Separate Norms for ROR/Storage Based Hydro Projects

82. Considering the anticipated increase in peaking loads these stations may be incentivised to operate as peaking plants. One way to do so is by providing additional incentives for energy supplied during peak period.

    (Refer 6.1)

7.1.42 Tariff Structure for Cost Recovery for Emission Control System

83. As not all generating stations have installed the emission control systems, and most of these works are in the execution stage, therefore the existing tariff recovery mechanism may be continued. However, comments and suggestions are sought from stakeholders on alternatives to the existing tariff mechanism for recovering the impact of the installation of emission control systems.

    (Refer 6.2)

7.1.43 Decommissioning of Generating Station and Transmission Assets

84. In view of discussion held in Section 6.3, comments and suggestions are sought from stakeholders on the possible approaches to recover or refund the impact of decommissioning costs in case the generating stations/transmission systems are decommissioned before the completion of their useful lives, if such decommissioning is done in compliance of a statutory order or due to technological obsolescence duly approved by RPC.

    (Refer 6.3)

7.1.44 Simplification of Tariff Formats

85. Comments and suggestions are invited from stakeholders for simplifying the existing tariff formats. (**Refer 6.4)**

7.1.45 Approval process for carrying out non-ISTS lines carrying inter-state power and associated Capital Cost

86. Comments and suggestions are invited from stakeholders, particularly, from STUs and State transmission licensees, for the approval process to be followed before undertaking the construction of new Intra State transmissions lines carrying inter-state power.

87. In view of changes that may be required to be carried out in CERC Tariff Regulations, 2024 comments and suggestions are sought from stakeholders on the capital cost to be considered for the computation of transmission charges in respect of intra-State lines (carrying inter-state power) of the State transmission utilities.
(Refer 6.5)

7.1.46 Up-gradation of Asset/Replacement

88. In view of the discussion held in Section 6.6 suggestions are invited from stakeholders regarding the treatment of unrecovered depreciation. **(Refer 6.6)**

7.1.47 Assumed Deletions

89. Comments and suggestions are sought from stakeholders on whether to continue to consider the gross value of the asset being de-capitalized, by de-escalating the gross value of the new asset @ 5% per annum until the year of capitalization of the old asset, or may suggest any other methodology to compute assumed deletions. **(Refer 6.7)**

7.1.48 Necessity to Review the need of Regulation 17(2)

90. The provision under Regulation 17(2) of Tariff Regulations, 2019 may result in further complication and being seen as inequitable for the generator, is required to be modified. **(Refer 6.8)**

7.2 Way Forward

Given that the tariff determination process has considerably evolved in the past two decades and has achieved a level of standardisation, it is imperative that the tariff determination process is simplified and a more pragmatic approach which does not involve microanalysis of each cost component is adopted. Past experiences suggest that the approach of dwelling into minute details has only complicated the process without providing any commensurate benefit.

As detailed in **Section 3** of this Approach Paper, comments and suggestions from stakeholders have been sought on shifting to Normative based Tariff mechanism (**Approach 1**) or adopted a simplified performance-based hybrid approach (**Approach 2**).

In this context, it is re-iterated that the issues flagged in this Approach Paper especially pertaining to those affecting Capital Cost, Additional Capitalisation, AFC components and its determinants should be analysed by the stakeholders in this context of adopting Normative Tariff based on **Approach 1** as well as **Approach 2** which also eventually guides to transitioning smoothly to normative tariff regime.

Annexure -1

Tariff Order specifying Indexation at the beginning of the tariff period

Particulars	UoM	Assumptions
		Tariff Order
Commercial Date of Operation	01/04/19	
Installed Capacity	MW	500
Capital Cost as on COD	Rs. Lakh	380036
Debt	%	70%
Equity	%	30%
Debt	Rs. Lakh	266025
Equity	Rs. Lakh	114011
Cost of Debt	%	6.63%
Cost of Equity	%	15.50%
Depreciation	%	5.11%
IoWC Rate	%	10.00%

Existing Project

Normative Approach - Tariff Order Issued at the beginning of Tariff Period 2024-29 for Asset-X

Tariff Order Issued at the beginning of Tariff Period

	Year>>>	Truing Up shall be done for 2019-24 tariff block					First Year Tariff and Indexation for the rest shall be specified.				
AFC - Tariff Order for FY 2024-29	**UoM**	**FY 2019-20**	**FY 2020-21**	**FY 2021-22**	**FY 2022-23**	**FY 2023-24**	**FY 2024-25**	**FY 2025-26**	**FY 2026-27**	**FY 2027-28**	**FY 2028-29**
RoE	Rs. Lakh	17672	17672	17672	17672	17672	17672	17672	17672	17672	17672
Depreciation	Rs. Lakh	19429	19429	19429	19429	19429	19429	19429	19429	19429	19429
Cumulative Dep	Rs. Lakh	19429	38857	58286	77714	97143	116571	136000	155429	174857	194286
O&M Expenses	Rs. Lakh	11255	11650	12060	12485	12920	13566	14244	14957	15704	16490
Interest on loan	Rs. Lakh	16994	15706	14418	13130	11842	10553	9265	7977	6689	5401
IoWC	Rs. Lakh	2927	2980	3036	3093	3153	3224	3297	3374	3454	3538
AFC Total	Rs. Lakh	68276	67437	66614	65809	65015	64444	63907	63408	62948	62528

Indexation specified at the time of tariff Order **Year>>>**

Particulars	**UoM**	**FY 2019-20**	**FY 2020-21**	**FY 2021-22**	**FY 2022-23**	**FY 2023-24**	**FY 2024-25**	**FY 2025-26**	**FY 2026-27**	**FY 2027-28**	**FY 2028-29**
O&M Expenses	Rs. Lakh	11,255	11,650	12,060	12,485	12,920	13,566	14,244	14,957	15,704	16,490
Rest of AFC Components	Rs. Lakh	57,021	55,787	54,554	53,324	52,095	50,878	49,663	48,451	47,243	46,039
O&M Indexation*	Factor #	**AFC till cut-off date to be specified under the current mechanism**						**1.05**	**1.05**	**1.05**	**1.05**
Rest of AFC Indexation*	Factor #							**0.98**	**0.98**	**0.98**	**0.97**

*Y-O-Y escalation/de-escalation as per the computations of individual components of AFC

Indexation for a Particular Year = (Expenses of Current Year/Expenses of Preceeding Year)

Revision of Indexation for the past tariff period and specifying new indexation for the next tariff period

Particulars	UoM	Assumptions	Based on Indexation	New Indexation
		Tariff Order	Revision 2024-29	2029-34
Commercial Date of Operation	01/04/19			
Installed Capacity	MW	500		
Capital Cost as on COD	Rs. Lakh	380036	380036	380036
Add Cap approved	Rs. Lakh	0	Rs. 2000 Lakh (FY 27) Rs. 2200 Lakh (FY 29)	
Debt	%	70%	70%	70%
Equity	%	30%	30%	30%
Debt	Rs. Lakh	266025	266025	266025
Equity	Rs. Lakh	114011	114011	114011
Cost of Debt	%	6.63%	8.58%	8.58%
Cost of Equity	%	15.50%	15.50%	15.50%
Depreciation	%	5.11%	5.11%	5.11%
IoWC Rate	%	10.00%	12.00%	12.00%

Existing Project

Normative Approach - Revision in Indexation at the end of Tariff Period 2024-29- In case Additional Capitalisation is approved in Tariff Period 2024-29

Commission to call out for relevant data at the end of the Tariff Period and revised Indexation for 2024-29 and new Indexation for 2029-34 to be issued

	Year>>>	Revision of AFC at the end of Tariff Period - Revised Indexation specified					New Indexation to be specified for next Tariff Period				
AFC	**UoM**	**FY 2024-25**	**FY 2025-26**	**FY 2026-27**	**FY 2027-28**	**FY 2028-29**	**FY 2029-30**	**FY 2030-31**	**FY 2031-32**	**FY 2032-33**	**FY 2033-34**
RoE	Rs. Lakh	17672	17672	17672	17672	17672	17672	17672	17672	17672	17672
Depreciation	Rs. Lakh	19429	19429	19429	19429	19429	19429	19429	8376	8376	8376
Cumulative Dep	Rs. Lakh	116571	136000	155429	174857	194286	213714	233143	241519	249895	258271
O&M Expenses	Rs. Lakh	13566	14244	14957	15704	16490	17479	18528	19639	20818	22067
Interest on loan	Rs. Lakh	13649	11983	10317	8651	6985	5319	3653	2461	1742	1024
IoWC	Rs. Lakh	3926	4008	4095	4186	4280	4388	4501	4459	4598	4743
O&M Expenses	Rs. Lakh	13566	14244	14957	15704	16490	17479	18528	19639	20818	22067
Rest of AFC Comp.	Rs. Lakh	54675	53092	51512	49937	48366	46807	45254	32967	32388	31815
AFC Total	Rs. Lakh	68241	67336	66469	65641	64855	64286	63782	52606	53205	53882

AFC - Add Cap Impa	**UoM**	**FY 2024-25**	**FY 2025-26**	**FY 2026-27**	**FY 2027-28**	**FY 2028-29**	**FY 2029-30**	**FY 2030-31**	**FY 2031-32**	**FY 2032-33**	**FY 2033-34**
RoE	Rs. Lakh			46.50	144.15	195.30	195.30	195.30	195.30	195.30	195.30
Depreciation	Rs. Lakh			51.12	158.48	214.72	214.72	214.72	214.72	208.58	208.58
Cumulative Dep	Rs. Lakh			51.12	209.60	424.32	639.04	853.75	1,068.47	1,277.05	1,485.63
O&M Expenses	Rs. Lakh			-	-	-	-	-	-	-	-
Interest on loan	Rs. Lakh			57.84	174.90	224.93	206.52	188.11	169.70	151.55	133.66
IoWC	Rs. Lakh			2.4	7.3	9.7	3.1	2.9	2.6	2.3	2.0
O&M Expenses	Rs. Lakh	-	-	-	-	-	-	-	-	-	-
Rest of AFC Comp	Rs. Lakh	-	-	157.83	484.81	644.62	619.68	600.99	582.30	557.73	539.57
AFC Total	Rs. Lakh			157.83	484.81	644.62	619.68	600.99	582.30	557.73	539.57

Revised Indexation

Particulars	**UoM**	**FY 2024-25**	**FY 2025-26**	**FY 2026-27**	**FY 2027-28**	**FY 2028-29**	**FY 2029-30**	**FY 2030-31**	**FY 2031-32**	**FY 2032-33**	**FY 2033-34**
O&M Expenses	Rs. Lakh	13,566	14,244	14,957	15,704	16,490	17,479	18,528	19,639	20,818	22,067
Rest of AFC Compor	Rs. Lakh	54,675	53,092	51,670	50,422	49,010	47,427	45,855	33,549	32,946	32,354
O&M Indexation*	Factor#	**No Revision in Indexation for O&M**					1.060	1.060	1.060	1.060	1.060
Rest of AFC Indexation*	Factor#	1.075	0.971	0.973	0.976	0.972	0.968	0.967	0.732	0.982	0.982

*Y-O-Y escalation/de-escalation as per the computations of individual components of AFC

* FY 2024-25 - Indexation w.r.t cost approved in Tariff Order

Indexation for a Particular Year = (Expenses of Current Year/Expenses of Preceeding Year)