6054/2018/CRU-CERC (36)

# GULBARGA ELECTRICITY SUPPLY COMPANY LIMITED

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Corporate Office,
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No. GESCOM/CEE(CP)/SEE(MIS)/EE(RA)/AEE-2/ 18-19/ 22424-29 Date 31 JUL 2018

To,
**The Secretary,**
CERC, 3rd Floor Chandralok Building,
36, Janpat New Delhi – 110001.

**Sir,**

**Sub:-** Comments /Views of GESCOM regarding CERC issues MYT Regulations for determination of Tariff – Reg.

**Ref:-** Ltr., No. 20/2017/CERC/Vol1/Tariff Regu/Fin dated 06.06.2018.

*******

Inviting reference to the subject cited under reference, I am herewith submitting Comments /Views of GESCOM regarding CERC issues MYT Regulations for determination of Tariff under the provisions of EA 2003 commencing from 1st of April 2019.

This is for your kind information and needful.

Yours faithfully,

**Chief Engineer Elecy**
Operations
GESCOM Kalaburagi

Copy to:

1. The Chief Financial Officer, GESCOM Kalaburagi for information SPS to MD/DT for information and to place the subject before the Managing Director / Director (T).
2. Asst. to CEE(O)
   OC/MF

Speed post

## Introduction

1.1 The Central Electricity Regulatory Commission has been vested with theresponsibility of regulation of tariff of generating companies owned or controlled by the Central Government, generating companies having composite scheme for generation and sale of electricity in more than one state and inter-State transmission systems under Section 79 of the Electricity Act, 2003 ("the Act"). The Section 61 of the Act provides the principles for determination of tariff. Relevant provisions of the Act are as under:

***"Section 79. (Functions of Central Commission):***

*(1) The Central Commission shall discharge the following functions, namely:*

*(a) to regulate the tariff of generating companies owned or controlled by the Central Government;*
*(b) to regulate the tariff of generating companies other than those owned or controlled by the Central Government specified in clause (a),if such generating companies enter into or otherwise have a composite scheme for generation and sale of electricity in more than one State;*
*(c) to regulate the inter-State transmission of electricity;*
*(d) to determine tariff for inter-State transmission of electricity;*

*……………………………………………………………….."*

***"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."*

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

I. *Ensure availability of electricity to consumers at reasonable and competitive rates;*

II. *Ensure financial viability of the sector and attract investments;*

III. *Promote transparency, consistency and predictability in regulatory approach across jurisdictions and minimize the perceptions of regulatory risks;*

IV. *Promote competition, efficiency in operations and improvement in quality of supply*

V. *Promote generation of electricity from Renewable sources;*

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

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

VIII. *Facilitate supply of adequate and uninterrupted power to all categories of consumers;*

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

1.3 The Commission has been regulating generation and transmission tariffs by specifying terms and conditions of tariff since 1998. Multi-year tariff regulations have been issued for the tariff periods 2001-04, 2004-09, 2009-14 and 2014-19 for determination of tariff of the generating stations within its jurisdiction and for inter-State transmission of electricity.

1.4 This Commission regulates tariff of about 76 GW1 capacity of generating companies apart from tariff determination and regulation of inter-state transmission system under Section 62 of the Act. The principles of tariff determination specified by the Central Commission may also act as guiding principles for the State Commissions.

1.5 While framing the regulations, the critical challenge before the Commission is to balance the requirements of objectives of the Tariff Policy and the principles under Section 61 of the Act.

1.6 In line with the above, while specifying Terms and Conditions of Tariff, the Commission has endeavored to balance the interest of consumers, generators and transmission licensees. The terms and conditions of tariff specified by the Commission are also aimed at providing direction to the power sector keeping in view the economic and financial scenario of the country. Regulatory certainty is an integral part of tariff approach. The Tariff should also reflect the changing market condition and macroeconomic parameters. The multi-year tariff principle is followed to maintain certainty, both to the generators and the procurers. This paper analyses the power scenario in terms of cost of supply and impact of various components of value chain on the cost of electricity. Based on the analysis, possible regulatory options for the next control period have been discussed in subsequent chapters.

1.7 With the above broad parameters, this paper is brought out with the aim to generate discussion on existing scenario and / likely developments in the power sector having impact on tariff determination during next control period commencing on1.4.2019.

1.8 Views of the stakeholders are solicited on provisions of 2014-19 Tariff Regulations, and issues raised in this consultation paper which can be used as input for formulating Terms and Conditions of Tariff commencing on 1.4.2019. The word tariff and electricity price, KWh and unit are interchangeably used in this paper.

***Gescom views:***

***Gescom welcomes multi year tariff for 5 years for generation and transmission and 3 years for distribution. Gescom is a electricity distribution company one of the five escoms of Karnataka.***

## 2. Evolution of the Regulatory approach

2.1 The enactment of the Electricity Act, 2003 paved the way, inter-alia, for promoting competition and rationalization of tariff. The provisions contained in1 as on 31.3.2017 [Source: Annual Report 2016-17 of CERC] Section 62 and Section 63 of the Act, provide for determination of tariff.

Section 62 of the Act provides the determination of tariff which will act as a ceiling tariff and Section63 of the Act provides for determination of tariff through competitive bidding process. The factors that guide the Appropriate Commission while specifying the terms and conditions for determination of tariff have been prescribed under Section 61 of the Act. The statutory scheme provided under Section 61 to 63 of the Act is intended to promote competition in the sector.

2.2 During 2001-04 period, the tariff was determined based on the cost of service approach. **In** the above backdrop, the two part tariff structure (fixed +variable cost) was being followed for generation tariff with incentive and disincentive mechanism. The tariff structure of transmission system was governed through single component of annual transmission charges with incentive and disincentive linked to availability. While adopting the cost of service approach, the importance of the normative approach was also well recognized, as it promotes efficiency and performance. Overtime, the cost of service approach has been modified gradually towards normative by introducing benchmark norms for determination of one or more components of the tariff. The normative approach has been introduced for operational parameters, operation and maintenance expenses, rate of return, working capital etc. The hybrid approach, consisting of actual cost of service and pre-specified normative parameters have been followed during 2004-09, 2009-14 and 2014-19 tariff periods to induce efficiency in financial and operational performance.

2.3 Section 61 of the Act provides broad principles such as economic efficiency, encouraging competition, economical use of the resources, good performance and optimum investments. In accordance with Section 61 of the Act, the Appropriate Commission has to strike a balance between the consumers' interest and the investors' (generating company, transmission licensee and distribution company)interest, with emphasis on the need for applying commercial principles in conducting the activities of generation, transmission, distribution and supply of electricity. The evolution of regulatory approach has been gradually shifting towards normative approach for inducing efficiency so that tariff becomes affordable and competitive.

The approach for determination of tariff needs to be evolved continuously so that objectives of Section 61 of the Act are met.

***Gescom views:***

***The concept paper has introduced three part tariff for the generation for the multi year tariff period from 1.4.2019 to 31.3.2024 wherein plant availability and plant load factor varies.***

## 4. Value chain of Electricity Generation & Supply

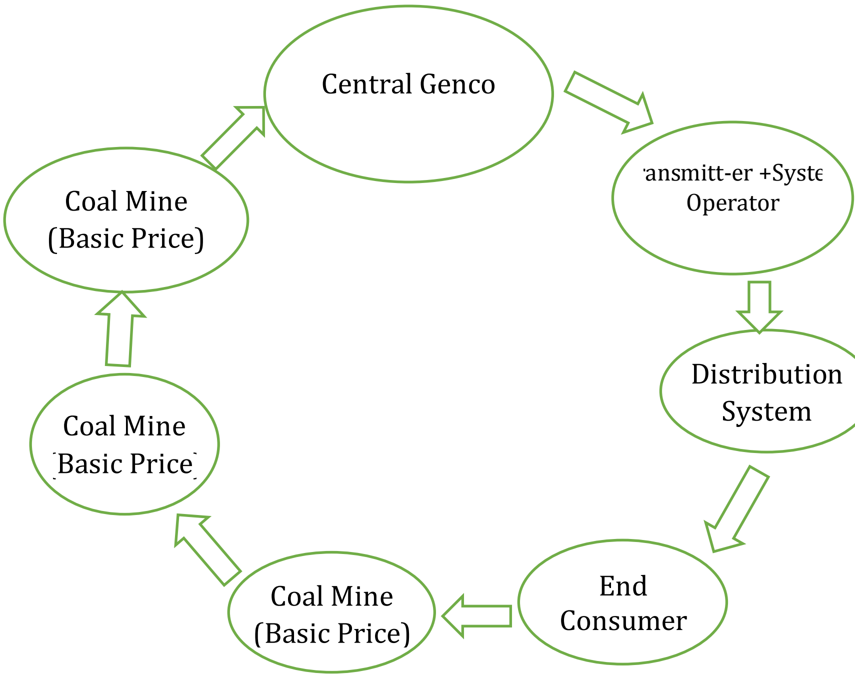
4 *Source: CEA Report on "Growth of Electricity Sector in India from 1947-2017.Chart 29/p 57.*

4.1 In order to appreciate the contributing factors responsible for increase in cost of supply and to identify the areas which require attention to regulate the tariff, the entire value chain of electricity generation and supply need to be looked at.


Figure 2 : Value chain of electricity

4.2 The cost of electricity delivered at the consumer end reflects the cost added at each step of the entire value chain i.e. generation (including fuel), transmission and distribution. Each component of the value chain adds to the cost of supply at each stage depending on the level of efficiency. Since the contribution of electricity generation from coal is higher compared to other sources, contributions of major factors in the value chain have been analyzed in subsequent paragraphs.

**Value Chain of Electricity Generation and Supply from Coal Source**




4.3 Figure 3 represents the value chain of electricity generation& supply from coal. The efficiency of the entire value chain of energy charges can be depicted as conversion ratio of heat value (Kcal). It can be represented by the heat value required at ex-mine end to deliver one unit of electricity (equivalent to 860.42 Kcal) at consumer endi.e. the ratio of heat value at mine end and equivalent heat value of one unit of electricity at consumer end. The conversion depends on several factors such as conversion efficiency of generation technology (which is in the range of 2.82 - 2.76 for sub-critical to super-critical technology), auxiliary consumption, transportation loss, heat loss due to coal grade slippages, transmission (intra state and inter-state) losses and distribution losses. The conversion efficiency is dependent on technology over which there is limited control. At present, there are large capacities in the country with sub-critical technology. However, over the years, trend has been towards installing more units with super-critical technology which will improve the efficiency over the years. Apart from switch over to super-critical technology to improve conversion efficiency, controlling other factors such as auxiliary consumption, transportation losses, heat losses and AT&C losses will help improving the conversion ratio.

4.4 The cost of electricity delivered to the end consumer comprises of costs of various components of value chain - energy charges and fixed charges. The energy charges represent equivalent cost of fuel paid by the end consumer coupled with operational efficiency. It comprises the ex-mine cost of coal, taxes & duties on coal, transportation cost, losses of transmission and distribution network. Fixed charges involve equivalent cost of infrastructure paid by the end consumer comprising of the cost of generating station infrastructure, transmission network and distribution network. The cost of electricity delivered at consumer end varies from station to station due to variations of operational parameters of station, state transmission losses and distribution losses. Cost variations in some of the important components of the value chain between 2009-10 and 2016-17 are analyzed below.

4.5 It may be seen from the Table 5 and Figure 4 given below that during two control periods i.e. between 2009-10 and 2016-17, the coal costs (including taxes and duties) increased by 81.83% whereas the coal transportation cost went up by59.67%. Additionally, basic price of coal increased by 35.71% and Taxes & duties on coal increased by 218.67%. The pricing mechanism of coal was changed from UHVto GCV in 2011.

| Year | | 2009-17 | 2016-7 | Charge |
|---|---|---|---|---|
| Basic Price (ROM)1 | Rs/Tonne | 560.00 | 760.00 | 35.71% |
| Taxes and Duties | Rs/Tonne | 202.31 | 644.71 | 218.67% |
| Coal Cost1 | Rs/Tonne | 847.31 | 1,540.71 | 81.83 % |
| Coal Transportation2 | Rs/Tonne | 512.82 | 818.80 | 59.67% |
| Taxes & Duties on transportation | Rs/Tonne | 44.24 | 194.58 | 339.83% |

Based on Coal India Notifications dated 12th December,2007 (for 2009-10 price) and dated 29th May,2016 (for 2016-17) alongwith taxes and duties of E-Grade in 2009-10 has been compared with G12 grade coal in 2016-17. 2 Basic freight and busyseason surcharge based on Railway Notifications dated 24th August, 2016.

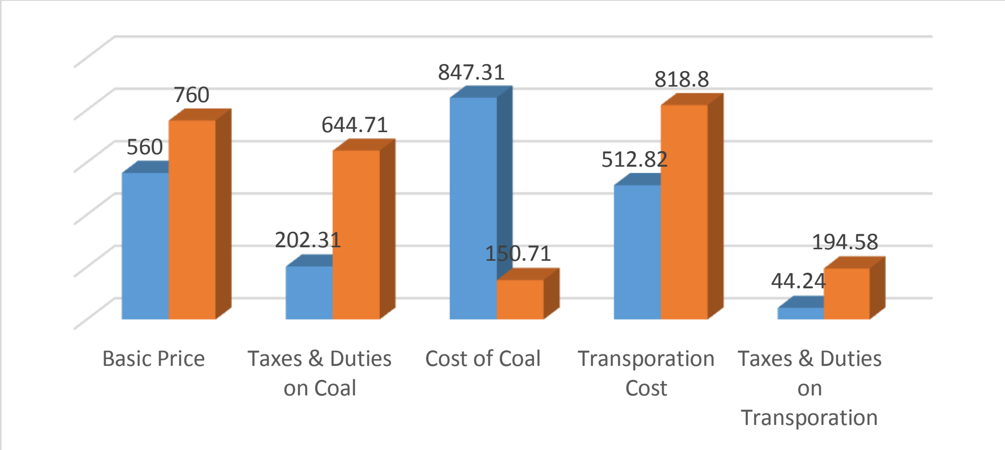



Figure 4: Comparative chart of coal related cost between 2009-10 and 2016-17

4.6 In addition, there are various taxes/duties levied by State Governments, royalty on coal and other charges (like water cess) etc. which add up to the cost of generation. For Example, Clean Energy Cess has been repealed, but has been replaced with GST Compensation Cess @ Rs 400/- per MT.

4.7 The increase of various components in the cost of electricity (per unit) has-been worked out based on specific coal consumption, transmission charges and distribution cost as under.

Table 6 Comparative analysis between 2009-10 and 2016-17

(Figures are in Rs per KWh)

| Year | 2009-10 | 2016-17 | %Change |
|---|---|---|---|
| Basic Price (ROM) | 0.42 | 0.56 | 33.33% |
| Taxes and Duties | 0.13 | 0.40 | 207.69% |
| Coal Transportation | 0.33 | 0.51 | 54.54% |
| Taxes & Duties on Transportation | 0.03 | 0.12 | |
| | **0.91** | **1.59** | 74.72% |
| | | | |
| Generation Plant(Fixed Cost) | 2.01 | 1.66 | -21.08% |
| Transmission Cost(Inter) | 0.23 | 0.39 | 69.56% |
| Transmission Cost(Intra) | 0.12 | 0.14 | 16.67% |
| Transmission losses | 0.29 | 0.33 | |
| | **2.65** | **2.52** | -5.16% |
| | | | |
| Distribution Cost | 0.48 | 1.39 | 189.58% |
| Distribution Losses ( AT&C) | 1.03 | 1.17 | |
| | 1.51 | 2.56 | |
| **Cost of Supply** | **5.07** | **6.67** | 31.56% |

[Note: (1) The above calculations (details at Annexure-1 (A) to 1(C)) are based on operational norms(as given in Table 7) of CERC Tariff Regulations.]

It can be seen that apart from the increase in cost of coal increases in the cost of supply between 2009-10 and 2016-17 is primarily on account of increase in transmission and distribution costs.

4.8 The Commission stipulated improved operational parameters during the tariff control period 2014-19 as shown below.

Table 7 Comparison of Operational Parameter between 2009-10 and 2016-17
**2009-10**

| | | 2009-10 | 2016-17 | Charges |
|---|---|---|---|---|
| SHR | Kcal/KWh | 2425 | 2375 | -2.06% |
| **Auxiliary** | **%** | 6.00% | 5.25% | -12.50% |
| Distribution losses (AT&C)1 | **%** | 25.39% | 21.31% | -16.07% |
| Specific Coal Consumption2 | Kg/KWh | 0.645 | 0.627 | -2.84% |

[1AT&C losses are as per Figure 1 given in Para 3.8. 2Specific coal consumption is workedout with reference to GCV of 4000 Kcal/Kg.]

However, the increase in fuel cost, transportation cost, taxes and duties nullified the gains on account of improvements in operational efficiency (SHR from 2425 Kcal to2375 Kcal and auxiliary consumption from 6.0% to 5.25%) and reduction in AT&Closses.

4.9 The value chain of the electricity generated from hydro is given in Figure 3.The components involved in the value chain of electricity from hydro sources are comparatively less than those in electricity generated from coal. Despite the initial cost of the hydroelectricity project comparatively high, on the long run, it offers economic advantages to the distribution licensees and end consumers.

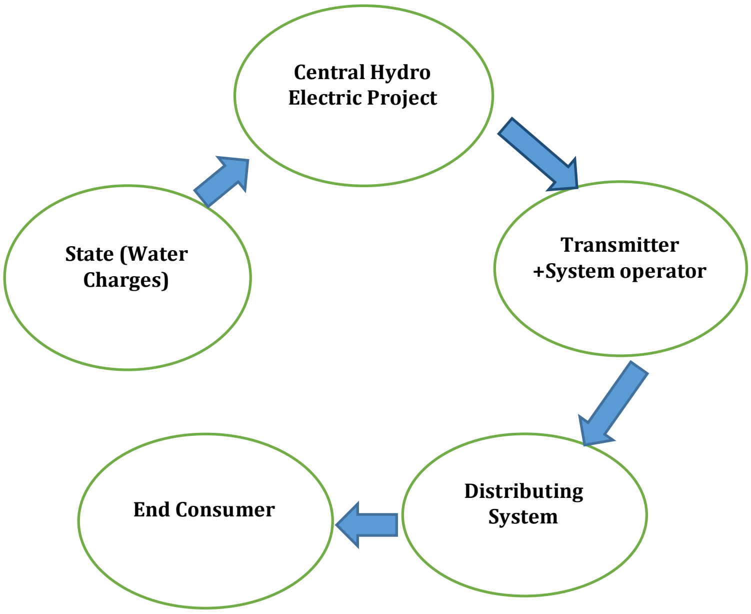
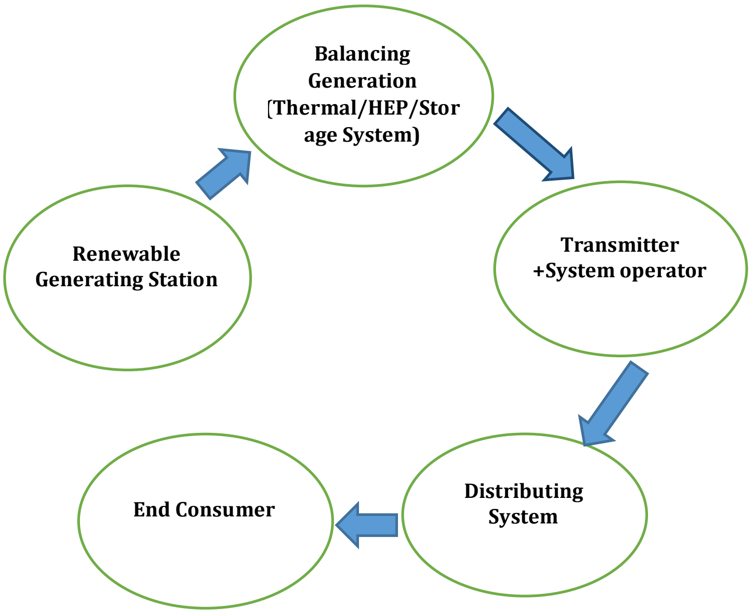



**Figure 5: Value Chair of electricity from hydro source**

4.10 The value chain of the **e**lectricity generated from renewable sources is given in Figure 5. The value chain of electricity from renewable sources is comparatively smaller. However, on account of variability of renewable generation, balancing requirement is to be met from existing thermal plants, Hydro Electric Project or Energy storage system adds to the cost of supply.




## Transmission Cost

4.11 Inter-State transmission tariff (Rs/KWh) ("transmission rates") has gone up during last five years due to expansion in transmission infrastructure. Transmission network capacity is generally planned and needed to meet the peak demand with desired reliability. The transmission charges as on Apr-2011 and Apr-2017 and increases are as under.

### Table 8 Transmission Charges/ Rates

| | Apr-2011 | Apr-2017 | Charge |
|---|---|---|---|
| Capacity * (in MW) | 91174 | 224757 | 146.51% |
| Peak demand (all India) (in MW) | 122391 | 159590 | 30.39% |
| Aggregate Inter State Transmission charges (Rs Cr/Month)** | 725 | 2390 | 229.66% |
| Inter-State transmission rate (Paise/Unit)*** | 23.48 | 38.76 | 65.08% |

[*(ISGS+Pvt.)
**Monthly transmission charges in Cr
***Injection & drawl charges Source: PoC order of 4th quarter of 2016-17]

***Gescom views:***

***The three part tariff comprises of fixed charges, variable charges and energy charges.***

***Fixed charges comprises of debt service obligation allowing depreciation of payment, interest on loan and guaranteed return to the extent of risk free return and part of O&M expenses***

***The variable charges are the difference between availability and dispatch. The variable charges comprising of increment return above guaranteed return and balance operation and maintenance expenses***

***Energy charges comprising of fuel cost, transportation cost and taxes duties of fuel and charges is linked with dispatch.***

***However it is suggested to specify the difference between availability and dispatch.***

**Capital Cost**

4.12 The fixed cost of the generating station represents the infrastructure cost (capital cost) and operation cost of the project. In Table 9 below, the average capital cost per MW and Annual Fixed Charges (AFC) as a percentage of total capital cost have been worked out for different time periods in respect of thermal and hydropower projects**.**

**Table 9 Capital Cost**

| | **Average Capital cost (Cr / Mw)** | **AFC as % Capital Cost** |
|---|---|---|
| **Thermal Plant** | | |
| **1988-2013** | **3.23** | **22.55** |
| **1988-1999** | **1.56** | **26.50** |
| **2000-2007** | **3.00** | **22.14** |
| **2008-2013** | **6.65** | **15.81** |
| **Hydro Plant** | | |
| **1982-2015** | **6.09** | **16.42** |
| **1982-1999** | **3.95** | **-** |
| **2000-2007** | **5.55** | **15.27** |

4.13 Over time, the capital cost per MW on account of various factors has gone up. The shift to super- critical technology in thermal plants might have resulted in cost increase, but at the same time, it leads to improvement in efficiency in terms of O&M and the primary electricity factor.

***Gescom views:***

***Capital cost and spares should be determined periodically for different size of units considering the improvements/advancement of technology to improve the efficiency to the maximum with minimum cost***

## 5. Some Key Challenges

### A. Growth of Demand

5.1 Central Electricity Authority in the National Electricity Plan (NEP) 2018(Volume- I) for Generation, has projected energy and peak demand by 2026-27 asunder.

**Table 10 Projected Demand**

| Year | Energy Demand (BU) | Peak Demand (GW) |
|---|---|---|
| 2021-22 | 1566 | 226 |
| 2026-27 | 2047 | 299 |

### B. Coal based Thermal Generation

5.2.1 On the supply side, rapid capacity addition has taken place during the last five years and is being seen in the renewable energy. Due to rapid addition of renewable capacity & slow growth of demand for electricity, there has been decreasing trend in plant load factor (PLF) of thermal power plants.

**Table 11 Year wise Plant Load Factor (Thermal)**

| 2009-1 | 2010-1 | 2011-1 | 2012-1 | 2013-1 | 2014-1 | 2015-1 | 2016-1 | 2017-1 |
|---|---|---|---|---|---|---|---|---|
| 77.50 | 75.10 | 73.30 | 69.90 | 65.60 | 64.46 | 62.29 | 59.88 | 59.68 |

(Source: CEA Report)

5.2.2 National Electricity Plan (NEP) of Central Electricity Authority (CEA) estimates that the PLF of coal based stations is likely to come down to around 56.50% by2021-22, taking into considerations likely demand growth of 6.34% (CAGR) and175 GW capacities from renewable energy sources.

5.2.3 As may be seen from the Table 11 above, the PLF of the thermal generating stations is low and has been reducing over the years. Consequently, many of the generating stations are not dispatched for large parts of the year. Present regulatory framework recognizes servicing the fixed charges based on target availability factor that is considered based on the possible dispatch scenario. If the PLF reduces significantly; it would be a challenge, especially with regard to servicing of fixed charges.

5.2.4 Most of the coal is located in the eastern parts of the country and requires transportation over long distances, which often results in supply constraints. The thermal plants have been facing the issue of mismatch in quality as well as quantity of coal supplied and received. There is a need for transparency in coal quality assessment of the coal supplied. The third party sampling mechanism may need strengthening along with a mechanism for quick resolution of dispute and settlement of account.

5.2.5 In line with the notification of the Ministry of Environment and Forest, revised environmental and emission norms require installation of flue gas desulphurization (FGD) systems and other control systems such as ESP etc. in both new and old thermal power plants. This would have impact on the tariff as not only additional capital cost would be required but O&M cost would also increase.

5.2.6 As per estimates of Central Electricity Authority, thermal plants are likely to run at low plant load factor (capacity utilization) and many plants may get partial or no schedule of generation. As per the present regulatory framework, the distribution companies will continue to pay the fixed cost. Therefore, optimization of the power generation and rationalization of tariff structure are required.

5.2.7 There are concerns of the generating companies in respect of ensuring performance of the power purchase agreement. Some of the State utilities have initiated actions for cancellation of concluded Power Purchase Agreements with power producers, including surrender of power from centrally owned generating stations on the ground of changes in market conditions.

5.2.8 Significant portion of the installed capacity are based on fossil fuels like coal and natural gas. Environmental concerns demand application of technology for reducing CO2 emission. Though focus is on non-conventional energy sources, power generation is likely to continue to rely on fossil fuel in the coming few years. Decarburizing thermal power plants pose technological challenge and will have implications on the tariff.

5.2.9 The Government of India, Ministry of Environment, Forest and Climate Change(MoEFCC), vide its Notification No.S.O.3305(E) dated 7.12.2015, has notified the Environment (Protection) Amendment Rules, 2015 (Amendment Rules,2015) introducing revised standards for emission of environmental pollutants to be followed by the Thermal Power Plants. All existing Thermal Power Plants are required to meet the revised emission standards within the stipulated period. Large scale installation and up gradation of various emission control systems would be required by TPPs, located across the country to meet the new norms.

5.2.10 The developers would have to make investments in the form of additional capitalization and re-designing in plants for complying with the new environmental norms. An appropriate mechanism is required to be put in place to ensure recovery of the additional investment, in terms of incremental tariff. Therefore, this additional investment would require prudence check by the Appropriate Commission. The additional capital expenditure would depend on the existing emissions at specific project and selection of proposed technology. The retrofitting would also impact O&M expenses and auxiliary consumption.

5.2.11 Presently, there is no benchmarking of capital or operational cost for pollution control system available which poses a challenge to develop a regulatory framework. Central Electricity Authority (CEA) is working towards developing benchmarking and normative parameters in this regard.

5.2.12 The Government of India has set a target of 175 GW of renewable capacity by2022. 100 GW is envisaged from solar projects, of which 60 GW is targeted from ground-mounted, grid-connected projects and remaining 40 GW is expected to come from solar rooftop projects. Further, 60 GW is targeted from wind projects, 5GW from Small Hydro projects and 10GW from Biomass. The renewable energy sources offer competitive advantages due to low generation cost and thus predictability and certainty of the cost. However, the nature of variability and intermittency pose challenge for balancing of grid.

5.2.13 presently, thermal generation is being used for balancing requirements of the grid. The variability of renewable energy generation causes frequent regulations of thermal generation which adversely affect the plant & machinery in terms of reduced life, higher maintenance expenditure, higher down time and lower efficiency (Heat Rate, Auxiliary Power Consumption and Specific Oil Consumption).

***Gescom views:***

***With the increase of about 225 GW in the year 2022-23 the existing thermal generating station will be forced to be back down to accommodate the renewable energy. Therefore incurring the expenditure towards environmental and pollution control in the existing thermal need to be assessed after taking into account of the growth of renewable energy.***

**C. Renewable Energy Generation**

5.7.1 On account of various policy measures taken, at Central as well as State level to encourage the renewable penetration, the electricity generation from intermittent energy sources (wind, solar, tides) is gaining momentum. Now the renewable sources coupled with storage or suitable balancing power mechanism are seen as potential substitute to the conventional sources. The feed-in-tariff structure seems suitable when the contribution of renewable sources in the grid was lower as it would not create distortion. But with increasing penetration of renewable energy, this may not be the case and even feed-in tariff structure may even lead to economic inefficiency.

5.7.2 When the share of renewable generation is low in the grid, the renewable generation may get exemption from scheduling and regulations, as the variations can be met from other source of generation. But as the share of renewable generation increases in the grid, the distribution companies may require to regulate its supply. In case of likely regulation of supply of the renewable generation, the entire tariff of the renewable generation (which is of the nature of fixed cost) is compared with the marginal cost of the other generation (excluding the fixed cost component), for merit order. Therefore, the tariff structure of renewable generation poses specific challenges in operation and for merit order considerations.

***Gescom views:***

***Renewable energy generators are provided with various incentives and also transmission charges are not levied on them and on other side the discoms are compensating the generating station for forced shutdown and paying transmission charges. This issue has be taken up at centre level. However Hon'Kerc have passed impugned order dated 14.5.2018 wherein the renewable generators have to pay transmission charges along with line loss in cash.***

**D. Coal**

**Gross Calorific Value (GCV)**

5.8.1 Gross Calorific Value (GCV) in relation to thermal generation has been defined in successive tariff regulations issued by the Commission since 2001 as "the heat produced in kCal by complete combustion of one kilogram of solid fuel or one litre of liquid fuel or one standard cubic meter of gaseous fuel, as the case may be". GCV is used to compute the Energy Charge payable by the Distribution Companies/Power Utilities to the generating companies.

5.8.2 In the entire value chain from mine end to generating station end, the loss of GCV can take place on account of grade slippage at mine end, during transportation (transit with railway) and during storage (at generating stations).The generating companies generally have no control over the grade/GCV of coal received at their generating stations. There are several cases of grade slippages between the mine mouth and at the site of generating stations. Further, there is loss in GCV during transport of coal through Railway. Therefore, the generator may receive coal of lower GCV than what are billed by the coal companies. These are beyond the control of the generating companies.

5.8.3 Since the cost of slippage in grade of coal between the loading point and the site of generating station is ultimately passed on to the beneficiaries, this issue needs to be looked at in terms of risk allocation between the coal company, railways and the generating stations. The issue of grade slippage is signification case of domestic coal as the GCV measurement is being done at free onboard (FOB) through acceptable practice. This poses specific challenges with respect to the measurement point and method/ procedure for measurement of Gross Calorific Value (GCV).

***Gescom views:***

***To mitigate the loss due to slippage in grade of coal, it is suggested that a committee comprising of Ministry of Coal, CEA and CERC may appoint a third party agency for measurement of GCV of Coal at the coal block and at the generator premises at a regular intervals of 3 months.***

**Alternative Source of Coal**

5.8.4 The power plants in the country face shortage of fuel (coal/gas) due to shortage of supply from the supplier or transportation constraints. Coal India Ltd. has not been able to supply committed quantity of coal as per Fuel Supply Agreement. Coal supply also gets affected due to rail transportation related constraints also. Uncertainty about supply of gas continues, both in terms of availability and price. In the above circumstances, the generating stations are either forced to procure fuel from spot market (in case of gas and coal) or to procure imported coal at higher prices.

5.8.5 If power plants rely heavily on coal from alternative sources, the energy charges may increase substantially or the plant may have to be operated at lower PLF if the price restriction on blending as per the regulations triggers. Therefore, the use of coal from a source other than designated under Fuel Supply Agreement poses a specific challenge as it has significant impact on energy charges.

**Landed Fuel (Coal) Cost**

5.8.6 The present regulatory framework provides the computation of energy charges based on landed cost of fuel. The landed cost of fuel includes the cost components up to the delivery point of the generating stations. Further, as per the present regulations, the energy charges are directly pass through based on the formula specified for Energy Charge Rate (ECR) in the Tariff Regulations. The beneficiaries verify the bills or claims of the energy charge rate while making payment.

5.8.7 The approach for allowing pass through of the landed cost of fuel was evolved on the premise that the fuel cost is beyond the control of the generating companies as these were administered prices. After 2012, there have been several developments. The Government has opened the coal mine to private companies. The generating company now has many alternatives for procurement of coal viz. through Coal India Ltd, Open market, e-auction mode, captive mine etc. Further, the Government has also specified the flexible utilization of coal under the existing fuel supply agreement. The generating company has options to optimize the landed cost of fuel based on different procurement and transportation modes, considering the quality, source specific expenses etc. The challenge is to optimize the landed cost of fuel, as there are different components involved in the fuel cost.

5.8.8 As the landed fuel cost involves various components of the fuel cost, there are concerns regarding verification of these components. Further, there is wide variation in terms of cost and number of cost components involved in the landed fuel cost, changes in which cause corresponding fluctuation in the tariff. The challenge is standardization of the components of fuel cost.

***Gescom views:***

***Fuel supply agreement between the generator and the coal supplying agency must ensure that the existing coal block is adequate to meet out the fuel requirements of the generators.***

***There should be a specific clause for indemnification in the event of failure on the part of the coal supply agency to supply the quantum agreed upon and on the part of the generator for not lifting the quantum agreed.***

***For arriving at fuel cost at the generating station end separate calculation has to be done for pithead and non pithead stations. The transport cost will be lesser in case of pithead station when compared to non pit head station resulting in higher variable cost.***

***For example: The base price of coal to be supplied from the same coal block for both pit head and non pit head station will be equal. Only due to transportation of coal from port to the location of the plant the transportation cost has to be included in the base price, thus resulting into higher variable cost for non pit head stations. The non pit head stations are very economical and efficient in running the plant at full capacity level, due to higher variable cost they are not allowed in merit order dispatch.***

***Therefore a mechanism needs to put in place to remove loading of transport charges from the base fuel price for the non pit head stations. This may increase in efficiency of generating station create competitiveness and benefit end users.***

## Thermal Generating Stations –Tariff Structure

7.2.1 Possible three part tariff structure for thermal generating stations is discussed in subsequent paragraphs.

7.2.2 In view of decreasing PLF of thermal generating stations, a need has been felt to look into two part tariff structure being followed now. As discussed in following paragraphs, inter alia, one option may be to introduce three part tariff structure. The two part tariff structure for generating station provides the right to use the infrastructure on payment of fixed component irrespective of quantum of electricity generated and the payment of energy cost for procuring each unit of electricity. However, with this tariff structure, following issues emerge. The two part tariff system structure is suitable when the demand for power ensures utilization of capacity up to or around the target availability. It allows the procurer to get electricity at reasonable per unit cost through optimum utilization of asset. Two part tariff operates well in power deficit scenario. Due to low demand, coal based power plants are running at a PLF of around 60%.Consequently, States have not been coming forward for long term power purchase to avoid fixed cost liability and rather they have been resorting to short term power purchase to meet their demand.

7.2.3 As stated above, the two-part tariff structure works well when the gap between available capacity and dispatch is low. It is because all the procurers are placed in a similar position and it can be said that there is a homogeneous demand. When procurers have homogeneous demand, there is no difference in pricing mechanism whether one procurer purchases electricity from one generating company or many. This situation has undergone change. As the gap between plant availability factor and plant load factor has widened due to low PLF, the procurers are no longer placed in similar position. AFC per unit would be on higher side for the procurers having low demand. When two procurers are not placed on similar positions, the present two-part tariff structure does not provide for charging differential fixed charges from different procurer. Though the tariff determined by the Commission acts as ceiling, there is no mechanism specified to charge the tariff lower than ceiling. Options for Regulatory Framework

7.2.4 The possible options for tariff structure could be to offer to the procurer shaving low demand a menu of options for ensuring dispatch by linking a portion of fixed charges with the actual dispatch and balance of AFC to availability. This will ensure optimum utilization of the infrastructure, as procurers will continue to procure power from the generating stations and the generator will get reasonable return without losing the demand.

***Gescom' views:***

***The option provided in concept paper regarding tariff designed for thermal generating station older than 25 years may be linked to the technical study by CEA and technical consultancy nominated by generating company.***

7.2.5 The tariff for supply of electricity from a thermal generating station could comprise of three parts, namely, fixed charge (for recovery of fixed cost consisting of the components of debt service obligations allowing depreciation for repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses), variable charge(incremental return above guaranteed return and balance operation and maintenance expenses) and energy charges (fuel cost, transportation cost and taxes, duties of fuel).

***Gescom views:***

***Guaranteed rate of return shall be 12% and incremental return above guaranteed return shall be 2%.***
***The portion of O&M cost and maintenance spares shall be included in the interest on working capital and receivable shall be included in variable charges.***

7.2.6 The recovery of fixed component could be linked to target availability, whereas variable component could be linked to the difference between availability and dispatch. Fuel charges could be linked with dispatch.

***Gescom views:***

***The three part tariff comprises of fixed charges, variable charges and energy charges.***

***Fixed charges comprises of debt service obligation allowing depreciation of payment, interest on loan and guaranteed return to the extent of risk free return and part of O&M expenses***

***The variable charge is the difference between availability and dispatch. The variable charges comprising of increment return above guaranteed return and balance operation and maintenance expenses***

***Energy charges comprising of fuel cost, transportation cost and taxes duties of fuel and charges is linked with dispatch.***

***However it is suggested to specify the difference between availability and dispatch.***

***The escoms are having adequate renewable energy resources. They should not be burdened to pay the fixed charges even though there is no drawl from thermal generating stations due to higher penetration in renewable energy.***

***In such case the escoms have to be given option of making the payment of fixed charges only for the drawl and the allocation has to be shared between thermal generator and renewable energy developer.***

**Thermal Generating Stations – Older than 25 years**

7.3.1 As on 31st March 2016, as per CEA total thermal installed capacity in the country was 2, 10,675 MW. Out of this 1, 85,173 MW was from coal based (including lignite) thermal power plants. The supercritical thermal power plants contribute 34,950 MW, which is about 19 % of total coal based generation capacity. The coal based thermal power plants more than 25 years old are about 37,453 MW, out of which around 35,506 MW capacity pertain to State /Central sector.

7.3.2 Present basket of thermal generating stations comprises of several old thermal generating stations which have completed 25 years. These generating stations shave completed useful life, whereas some others have completed 10-12 years of life. Such generating stations are placed differently as they were conceived based on the policy/regulatory environment and technology available at that time. They are not comparable with the new generating stations in terms of operational norms and capital cost.

7.3.3 As most of these have already recovered depreciation and completed loan repayments, they may have advantage from financial consideration. But their operational cost could be higher due to less efficiency, such as high consumption of coal due to higher station heat rate (SHR). Further, their O&Mcost could be high. Options for Regulatory Framework.

7.3.4 A clear policy/ regulatory decision are required in view of a number of thermal stations crossing the age of 25 years. Possible options could be (i)replacement of inefficient sub critical units by super critical units, (ii) phasing out of the old plants, (iii) renovation of old plants or (iv) extension of useful life etc. It is worth to note that performance of a unit does not necessarily deteriorate much with age, if proper O&M practices are followed.

***Gescom views:***

***For thermal generating stations which have completed its useful life of 25 years the option of phasing out/renovation/ extension of useful life***

***need to be made after considering the efficiency of the plant, normative annual plant availability factor for the previous blocks and the cost per kwh.***

***Extending the useful life of the plant by incurring the expenditure like renovation and modernization must be done considering the growth in the renewable energy sector and the other projects.***

***There is a mechanism already exists "Unrequisitioned surplus power" in force to enable the generator to sell the difference in capacity ie the unutilized capacity to exchange and may be given to escoms by recalling the unutilized capacity depending upon demand.***

***The burden of fixed charges still exist on escoms even though the generator is given option of urs when there is low demand or high renewable energy penetration the fixed charges for the unutilized capacity need to be reduced to maximum extent.***

***Techno commercial study is required considering the possible option. Therefore, it is suggested that joint study report by CEA and technical consultancy (nominated by generating company) to be carried out and in consultation with stake holders the best option may be opted.***

**Hydro Generating Stations - Tariff Structure**

7.4.1 The two part tariff structure of hydro generating stations seems adequate in present scenario. However, in view of large capital cost, hydro generating stations often find it difficult to get dispatched due to resultant higher energy charges. In order to address this issue, for the hydro generating stations, the fixed charges and variable charges may need to be reformulated. Options for Regulatory framework

7.4.2 The fixed component may include debt service obligations, interest on loan and risk free return while the variable component may include incremental return above guaranteed return, operation and maintenance expenses and interest on working capital. The annual fixed cost can consist of the components of return on equity, interest on loan capital, depreciation, interest on working capital; and operation and maintenance expenses.

***Gescom views:***

***The useful life of hydro project is served beyond 35 years in Karnataka. Hence for determination of tariff for hydro projects useful life may be extended beyond 35 years. Considering the life of hydro project up to 50 years is acceptable.***

***The loan repayment may be extended to 18 to 20 years as against 10 to 12 years. Further the extension of depreciation period may be extended.***

***For new hydro generating station whose commercial operation date is declared during tariff period the first year normative O&M is based on the percentage of original project cost (excluding cost of R&R works) The capital cost is inclusive of interest during construction and incidental expenditure during construction These values varies from project to project based on the time over run of the project. Therefore the O&M cost for the hydro project shall be based on normative value per MWbasis in line with coal based thermal project.***

***Since Karnataka share from hydro is 25%(hydro installed capacity is 3671MW and total conventional source including CGS, IPPS and state hydro thermal station is 14630MW, assigning of responsibility of operation of hydro power station and pumped mode operation at regional level is acceptable.***

**Inter-State Transmission System - Tariff Structure**

7.5.1 Presently, single part tariff structure is followed for determination of annual transmission tariff of a particular element of the transmission system or entire transmission system covered in the project. This single part tariff structure of transmission consolidates all the costs of providing access to the generating station or the distribution licensee and transmission service. This cost is allocated as per CERC (Sharing of inter-state transmission charges) Regulations, 2010 and subsequent amendment thereto which is based on the principle of usage. The present regulatory framework recognizes the transmission cost as long term access charges, essentially injection and drawl charges irrespective of their actual transactions or transmission service.

7.5.2 At present, there is no distinction between access service and transmission service. The cost associated with the access has been combined with the transmission service. This philosophy is good for long term open access. However, after introduction of other types of transactions such as short term or medium term, the market participants may seek access to the transmission system but may not necessarily avail the transmission service unless there is actual transaction.

7.5.3 The emerging requirement is to recognize the access service separately independent of the quantity for which transmission service is availed. The transmission access may be treated as right to access the transmission system and transmission service may be treated as the right to transfer the electricity through the transmission system. The present tariff structure of transmission system does not meet this emerging requirement. Options for Regulatory Framework.

7.5.4 Transmission tariff can be on two-part basis, wherein the first part can be linked with the access service and second part can be linked with the transmission service.

7.5.5 The tariff for transmission of electricity on inter-State transmission system can consist of fixed components and variable components.

a) The fixed components may consist of either (i) annual fixed cost of some of fixed transmission system designated for access and immediate evacuation, (ii) annual fixed cost of the evacuation transmission system or(iii) part of annual fixed cost of the entire transmission system consisting of debt service obligations, interest on loan, guaranteed return;

b) The variable components may consist of either (i) common transmission system or system strengthening scheme excluding immediate evacuation transmission system, (ii) common transmission system excluding evacuation transmission system or (iii) sum of incremental return above guaranteed return, operation and maintenance expenses and interest on working capital.

7.5.6 The recovery of fixed component can be linked to the extent of access (Transmission Access Charge) and variable component can be linked to the extent of use, to be recovered in proportion to the power flow (Transmission Service Charge). The fixed component may be linked to evacuation system or on normative basis based on aggregate transmission charges of the identified transmission system under the contract. The variable component may be linked with yearly transmission charges based on actual flow or actual dispatch against long term access.

***Gescom views:***

***Gescom accept two part tariff on interstate transmission tariff structure. The first part is linked to the access service .The second part is linked to transmission services which is proportion to usage and reliability.***

***The recovery of fixed component can be linked to the extent of use, to be recovered in proportion to the power flow (Transmission service charge and reliability margin.***

**Renewable Energy Generation – Tariff Structure**

7.6.1 The feed-in tariff structure does not offer the advantage of economic efficiency. Further, the feed-in structure has its limitations.

a) In case of regulation of supply of the renewable generation, it may not be possible to compensate generators with some minimum charges.
b) For merit order operation, the entire tariff of the renewable generation (which is of the nature of fixed cost) is to be compared with the marginal cost of the other generation (excluding the fixed cost component).
c) In case of bundling renewable generation with conventional power generation at the ex-bus of generating station, it may be difficult to combine the tariff as feed-in-tariff structure is a single part tariff and conventional generation has two part tariff structure.

7.6.2 The tariff structure of the renewable generation may be rationalized. Options for Regulatory framework

7.6.3 There can be Two part tariff structure for renewable generation covered under Section 62 of the Act, which comprises fixed component (debt service obligations and depreciation) and variable component (equal to marginal cost O&M expenses and return on equity) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff.

***Gescom views:***

***In the proposed two part tariff the interest in working capital is not factored both in fixed and variable component. A clarity is required on the fixed component as feed in tariff and variable component equal to capacity augmentation such as storage or back up supply tariff***

7.6.4 In case of integration of the renewable generation with the coal/ lignite based thermal power plant, the following may the alternatives.

a) The renewable generation may be supplied through the existing tariff for the contracted capacity of thermal power plant under PPA. In this alternative, the tariff of renewable generation may replace the energy charges;

***Gescom views:***

***not specified the quantum of renewable generation need clarification.***

b) Tariff of renewable generation may be combined with the fixed and variable components of the thermal generation to the extent of contracted capacity under PPA. The operational norms of conventional plants may require revision such as higher target availability for recovery of fixed charges, higher plant load factor for recovery of incentive;

***Gescom views: need clarification***

c) The tariff for supply of power from renewable generation and thermal power generation may be recovered separately. The operational norms for recovery of tariff may have to be specified separately. Comments/ Suggestions

7.7.1 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternatives, if any.

***GESCOM Views :***

***No Comments***

**8. Deviation from Norms**

8.1 The Commission, during the 2014-19 tariff period, has specified in the Regulation 48 for deviations of norms as below.

*“**48. Deviation from norms:** (1) Tariff for sale of electricity by the generating company or for transmission charges of the transmission licensee, as the case may be, may also be determined in deviation of the norms specified in these regulations subject to the conditions that:*

*(a) The levelised tariff over the useful life of the project on the basis of the norms in deviation does not exceed the levelised tariff calculated on the basis of the norms specified in these regulations and upon submission of complete workings with assumptions to be provided by the generator or the transmission licensee at the time of filing of the application; and*

*(b) Any deviation shall come into effect only after approval by the Commission, for which an application shall be made by the generating company or the transmission licensee, as the case maybe...”*

8.2 Section 61 of the Act provides that the Commission shall be guided by the factors which would encourage competition and recovery of the cost of electricity in a reasonable manner. The present market framework involves the competition for power procurement for securing power purchase agreement. Once the power purchase agreement is secured, there is no framework for competition of dispatch. The distribution licensees follow merit order based on the tariff agreed under PPA under Section 63 of the Act or the tariff determined by the Commission under section 62 of the Act.

8.3 For various reasons, out of tied up capacity by the distribution licensee, some of the capacity often remains undispatched over large part of the year. Since the tariff determined by the Commission acts as ceiling, there is no embargo on the generating stations or the transmission licensee to charge lower tariff. This provides a scope for creating some competition. Options for Regulatory Framework

8.4 Possible option could be to develop for incentive and disincentive mechanism for different levels of dispatch and specifying the target dispatch expanding the scope of Regulation 48 above. Comment/ Suggestions.

8.5 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternatives, if any.

***GESCOM Views :***

***Many generators have filed various Miscellaneous Petitions before the Hon'ble Commission for relaxing the norms pertaining to Gross Station Heat Rate, Auxiliary Energy Consumption, NAPAF and Secondary Fuel Oil consumption.***

***Frequent changes in the norms determined poses problems in Billing and payment.***

***Further, various ISGS generators are following the same methodology for getting relaxation of norms.***

## 9. Components of Tariff

9.1 Unlike the Central Generating Stations, for privately owned generating stations, not all the generating capacity may have tied up power purchase agreements. In such case, part capacity may have been tied up under Section 63 and/or Section 62 of the Act and balance may have remained as merchant capacity.

9.2 Section 62 of the Act provides that the Appropriate Commission shall determine the tariff for (a) supply of electricity by a generating company to a distribution Licensee, (b) transmission of electricity, (c) wheeling of electricity and (d) retail sale of electricity. Section61 (b) of the Act provides that the Appropriate Commission shall specify the terms and conditions of tariff for generation, transmission, distribution and supply of electricity are conducted on commercial principles. The commercial principles inter-alia emphasize the risk allocation through contractual arrangement such as power purchase agreement in case of generation and transmission service agreement or long term access agreement in case of transmission service. Options for Regulatory Framework.

9.3 The question is whether the annual fixed charges and energy charges are to be determined to the extent of the capacity tied up under Section 62 of the

Act or for the entire capacity. One approach could be to determine the tariff of the generating station for entire capacity and restrict the tariff for recovery to the extent of power purchase agreement on pro-rata basis and balance capacity will be merchant capacity or tied up under Section 63, as the case may be. Comments/ Suggestions

9.4 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate options, if any.

***GESCOM Views:***

***Fixed charges and energy charges.***

***Fixed charges comprises of debt service obligation allowing depreciation of payment, interest on loan and guaranteed return to the extent of risk free return and part of O&M expenses***

***The variable charges are the difference between availability and dispatch. The variable charges comprising of increment return above guaranteed return and balance operation and maintenance expenses***

***Energy charges comprising of fuel cost, transportation cost and taxes duties of fuel and charges is linked with dispatch.***

***However it is suggested to specify the difference between availability and dispatch.***

***The escoms are having adequate renewable energy resources. They should not be burdened to pay the fixed charges even though there is no drawl from thermal generating stations due to higher penetration in renewable energy.***

***In such case the escoms have to be given option of making the payment of fixed charges only for the drawl and the allocation has to be shared between thermal generator and renewable energy developer.***

## 10. Optimum utilization of Capacity

### Coal based Thermal Generation

10.1 The unutilized capacity due to partial or less demand has impact on the recovery of the cost by the generating plant. At the same time, the distribution licensee may be impacted by way of liability of fixed charges without availing dispatch from the generating station.

10.2 If the unutilized capacity of the generating station is allowed to be utilized by other distribution companies or through open market, the obligations of the distribution companies may reduce to the extent of utilization. Options for Regulatory framework

10.3 (a) Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the anticipated reduction of utilization. Annual Contracted Capacity (ACC) may be treated as guaranteed contracted capacity during the year for the generating company and the distribution licensee and the capacity beyond the ACC maybe treated as Unutilized Capacity (UC). The distribution licensee will have a right to recall Unutilized Capacity during next year and for securing such rights, some part of fixed cost, say 10-20% or to the extent of debt service obligations, may be paid;

***Gescom' views:***

***The Annual contracted capacity on yearly basis out of total contracted capacity, the flexibility provided to generating company and distribution licensee is appreciable.***

(b)Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.

***Gescom views:***

***The proposal of unutilized capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price shall be agreeable.***

**Hydro Generation**

10.4 The present commercial framework under PPA allows the use of hydro power to meet the demand of the designated beneficiaries under PPA. There is a need to extend the use of hydro power for balancing the variability of renewable generation. In other words, there is a need for a framework for flexible operation of the hydroelectric project. Further, as the scheduling of cascade hydro power station i.e. reservoir operations at a hydro plant affect the cascade downstream and upstream reservoirs, there is a need for a coordinated approach for scheduling of such hydro projects; Options for Regulatory framework

10.5 (a) Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-20 years from existing 10-12 years for moderating upfront loading of the tariff.

***Gescom views:***

***Proposal to extend the useful life of the project from existing 35 years to 50 years and the loan repayment from existing 10-12 years for moderating upfront loading of the tariff is acceptable.***

(c) Assign responsibility of operation of the hydro power stations and pumped mode operations at regional level with the primary objective for balancing. Or this purpose, the scheduling of the hydro power operation (generation and pumped mode operation) may have to be delinked from the requirements of designated beneficiaries with whom agreement exists. The power scheduled to the hydro generation can be dispatched to designate beneficiaries through banking facility so that flexibility in scheduling can be achieved for balancing purpose and to address the difficulties of cascade hydro power station. Some part of fixed charge liability to the extent of 10-20% against the use of flexible operation and pumped operations may be apportioned to the regional beneficiaries as reliability charges.

***Gescom views:***

***It is not acceptable the three mine reservoir based hydropower projects namely Linganamakki (1035MW), Supa (900MW) and Mani(460MW) dam in Karnataka are being used for base load as well as peak load. Total capacity from these three projects is 2395MW. Hence this proposal is not acceptable.***

**Gas based Thermal Generation**

10.6 The use of gas based generating station is important because of possibility of immediate ramp up and ramp down for balancing the variations of renewable generation. Options for Regulatory framework

10.7 Scheduling and dispatch of gas based generating station may be shifted to regional level with the primary objective of balancing. After meeting the requirement of designated beneficiaries, the regional level system operator can use it for balancing power at the rate specified by the generating companies. Alternatively, all the gas based generating station capacities may be pooled at regional level. After meeting the requirement of designated beneficiaries, the balance generation may be offered for balancing purpose as and when required. Comment/ Suggestions.

***Gescom views:***

***The proposal of scheduling and dispatch of gas based generating station may be shifted to regional level is acceptable.***

## 11. Capital Cost

11.1 The approval of Capital Cost is the most critical aspect of tariff determination. Capital cost is considered as the base for determination of return on investment. The existing regulations allow capital cost for the new projects (to be commissioned in the control period) based on the expenditure incurred as on date of commercial operation (COD), duly certified by the Auditors after prudence check. For the existing projects, the capital cost admitted by the Commission during the preceding tariff periods is considered along with additional capitalization during the control period after due diligence.

***GESCOM Views:***

***The Commission approves the IDC/IEDc for the period of delay in commissioning citing the uncontrollable parameters and included the same in the Capital Cost. The Commission has not considered the loss incurred to the DISCOMs due to delayed commissioning of the project. Due to the delayed commissioning of the project, the DISCOMs are unable to meet out the demand and therefore are forced to purchase the power from the alternative sources at higher cost.***

11.2 During the control period 2004-09, the capital cost was determined based on the actual cost as per the balance sheet of the regulated entities. From the control period 2009-14, the Commission switched over to the methodology of determination of capital cost based on the projected capital expenditure. This enabled the generating companies or transmission licensees to file their tariff application prior to commissioning of the project. The undercharged liabilities were not included in the projected/actual capital expenditure for the purpose of capitalization.

11.3 Capital cost includes interest during construction, financing charges and foreign exchange rate variation up to the date of commercial operation of the project. Any revenue generated on account of injection of infirm power through unscheduled interchange in excess of fuel cost is used to reduce capital cost.

11.4 The principles of tariff determination as per the Act mandate balancing of consumer's interest while allowing reasonable cost to the generator. The capital cost has a direct correlation with the cost of value chain of fixed charges and therefore the Commission always endeavors to allow capital cost after prudence check. The Tariff Policy, 2016 stipulates that the Appropriate Commission would evolve benchmark of capital cost as reference to allow reasonable capital cost to the generators or transmission licensees.

11.5 There are several issues and challenges with respect to the capital cost forth transmission system, thermal generating stations and hydro generating stations

i. Variation between actual project cost vis-a-vis projected capital cost.
ii. Additional capital expenditure estimated up to cut-off date on account of reasons like deferment in commissioning of projects, non-placement of orders due to limited vendor responses etc.
iii. Delay in project execution is due to various reasons such as delay in land acquisition, delay in getting statutory approvals/clearances, delay due to geographical location of the site, delay on the part of contractor /supplier of material, execution philosophy etc, leading to increase in IDC, overhead expenses etc.
iv. Absence of benchmark capital cost, leading to use of the estimated capital cost as per investment approval for reference purpose. Estimated capital cost aspen investment approval may not truly reflect the efficiency in procurement and execution of the project when compared to market rates.
v. Use of the audited annual accounts to ascertain the claim of the capital expenses. The tariff filing forms have been prescribed for filing regulatory information to facilitate reconciliation with financial statements prepared as per accounting standards. The financial statements of power companies have been changed w.e.f.1st April, 2016 due to introduction of the Indian Accounting Standards Rules, 2015. The formats for filing regulatory information may need to be reviewed in this context.
vi. On the basis of indicative location, fuel and estimated cost of the generating station (investment approval), the beneficiaries enter into power purchase agreement and undertake the obligations to off-take the power on commercial operation of the project. Often, on declaring commercial operation, the generating companies revise the investment based on revised cost and beneficiaries may not be aware of the revised estimated cost. Similarly, the transmission licensees also revise the costs, which the customers may not be aware of.

11.6 There are specific issues and challenges in respect of thermal generating stations.

i) The claims of deferred works were allowed to be capitalized up to the cut-off date under the head “works deferred for execution/deferred works” but there is no provision for allowing such expenses after cut-off date. In some of the cases, expenditure was allowed even after cut-off date;
ii) The Tariff Regulations, 2014 provides for specific treatment of expenses of capital nature at the fag-end of project life and allows allowances which had

consequential impact on tariff as entire depreciation would have to be charged within balance useful life. This provision may need review in view of the policy of phasing out of old plants and expected benefit for getting dispatch after completion of useful life;

iii) Additional capitalization by thermal generators to meet the efficiency improvement targets under the Perform, Achieve & Trade (PAT) scheme, water from Sewage Thermal Plant (STP), Pollution Control System to meet revised standards of emission norms, adoption of storage facility and combining renewable generation with thermal power project.

iv) The efficacy of normative compensation allowance and special allowance may need to be reviewed vis-à-vis actual expenditure. The regulatory oversight maybe required to address overlapping of expenditure under compensation allowance and O&M allowance.

v) Provisions to handle capital expenditure to comply with new environmental norms, expenditure due to change in law (whether it is possible to specify events),servicing of expenditure relating to rail infrastructure, availability of wagons etc. to tackle major breakdowns and expenditure relating to grid security.

11.7 There are also specific issues and challenges in respect of hydro generating stations.

i) The trend of capital cost of hydro generating stations indicates that the hydro stations are becoming un-viable due to higher tariff. The present approach may need to be reviewed in view of sustainable benefits offered by hydro generation in terms of clean power and high ramping rates. Options for Regulatory Framework

11.8 One of the options is to move away from investment approval as reference cost and shift to benchmark/reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost.

11.9 Higher capital cost allows the developer return on higher base of equity deployed. In the cost plus pricing regime, the developer envisages return on equity as per the original project cost estimation. The regulations allow compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred. Therefore, in new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. There turn on additional equity may be restricted to the extent of weighted average of interest rate of loan portfolio or rate of risk free return. Further, incentive for early completion and disincentive for slippage from scheduled commissioning can also beintroduced.Comments/ Suggestions.

11.10 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternatives, if any

***GESCOM Views:***

***Shifting from Investment approval to Benchmark Cost based on the current market conditions, will lead to a healthier market. The beneficiary DISCOMs will be able to calculate its power purchase cost based on the Benchmark Capital Cost determined by the Commission for various types of units on regular basis.***

***The Benchmark cost should be compared with the Standards and steps need to be taken to curtail the expenditures to the maximum extent.***

***In the absence of credible benchmarking of technology and capital cost, commission has come out with benchmarking pricing mechanism based on technology prior to notify the terms and conditions for tariff regulation and this benchmark shall be considered as a reference further till completion of control period it should be escalated/deescalated as per WPI and CPI. Therefore for the new projects the fixed rate of return may be restricted to base corresponding to the normative equity as envisaged in the benchmark cost. Further, the return on additional equity may be restricted to extent of weighted average of interest, rate of risk free return whichever is lower. The incentive for the early completion and disincentives for slippage from the scheduled commissioning can also be introduced.***

## 12. Renovation &Modernization

12.1 The generating companies and the transmission licensees are allowed to undertake renovation &modernization for the purpose of extension of life beyond the useful life of the generating station or a unit thereof or a transmission system. The admissibility of the renovation &modernization claim are required to be supported by Project Report containing information about reference date, financial package, phasing of expenditure, schedule of completion, useful life, reference price level, estimated completion cost, record of consultation with beneficiaries etc.

12.2 At times the generating companies file their petitions for renovation and modernization without giving estimated life extension period, which makes it difficult to carry out cost benefit analysis. In old plants, R&M nature of works are sometimes claimed without specific life extension. Servicing of such R&M expenditure at the end of useful life of the station without extension of useful life may be difficult to justify.

12.3 An alternative provision was made in the Tariff Regulations, 2009 in the form of special allowance to be allowed in lieu of R&M for coal/lignite based thermal power stations. This provision enabled generating companies to meet the requirement of expenses including R&M on completion of 25 years of useful life to a unit /station without any need for seeking resetting of capital base.

12.4 The old transmission lines and substations are sometimes inadequate to cater to the new demand due to capacity degradation and obsolesce of technology. However, construction of new transmission lines and sub-stations require high initial capital investment and substantial time towards seeking approvals, tackling right of way (ROW) issues and environmental clearances. R&M with and without up-gradation of existing projects is one of the cost effective alternatives to increase the power transmission capabilities. The up gradation of transmission line and substation to higher voltages has emerged as a viable alternative to cater to the load growth or transmission requirements. It also offers commercial advantages as some of the original foundations, structure, or equipment can be re-used with minimal modifications.

12.5 In coastal areas, line structures/ towers, hard wares, conductors etc. get rusted due to saline atmosphere. Lines passing through chemical zones also require to be strengthened by stub strengthening, replacement of conductors, hardwares, insulators, earth wire etc. The transmission lines which are in service for more than 25years are affected due to atmospheric conditions and aging. Options for Regulatory Framework

12.6 The R&M of transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Up gradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow Renovation &Modernization (R&M) for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, the Commission may allow special allowance for R&M of transmission assets. Such provision will enable the transmission companies to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/transmission line without any need for seeking resetting of capital base. Comments/ Suggestions

12.7 Comments and suggestions are invited from the stakeholders on the options discussed above and alternatives, if any.

***GESCOM Views :***

***In the present scenario where Renewable Energy plays a major role, the Thermal Generating stations do not run at the full capacity level, therefore deterioration of plant and equipment will not be the same as was before. Therefore, the option of allowing the R&M expenses has to be considered taking into account of the NAPAF achieved by the plant in the previous years***

***and should not be always based on the life of the generating station as default.***

***Provisions in the tariff regulation 2009 in the form of special allowance to be allowed in lieu of R&M for coal/lignite based thermal power stations may be continued.***

## 14. Depreciation

14.1 Depreciation is a major component of the annual fixed cost. Para 5.8.2 of the National Electricity Policy, 2006 provided that "depreciation reserve is created so as to fully meet the debt service obligation." The regulatory principle evolved over time stipulates that there should be enough cash flow available to meet the repayment obligations of the generating company or transmission licensee during first 12 years of operation. The depreciation rate has been considered based on the above principle. The Tariff Policy, 2016 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.

14.2 The depreciation depends on three factors viz. rate base which includes subsequent additions also, method of depreciation and useful life. The following factors are relevant for determination of depreciation:

i) The tariff setting approach, ROE based or ROCE based, has a bearing on depreciation. Presently Historical cost (HC) based approach for determining the rate base is in place.

ii) Straight Line method of depreciation has been used in all the four tariff periods. In the context of tariff setting, useful lives for all the technologies except gas based stations have remained the same in all the tariff periods. For gas based stations, life of 15 years was used in tariff period 2001-04 & 2004-09. It was enhanced to 25 years in tariff period 2009-14 and continued in 2014-19 period;

iii) With passage of time, the regulatory definition of depreciation, as pronounced in2009-14 tariff regulations viz. enough cash flow to meet the repayment obligations of the generator during first 12 years of operation, has gained precedence in tariff setting. Accordingly, depreciation rate is arrived at by considering normative repayment period of 12 years to repay the loan (70% of the capital cost).

iv) In line with the tariff policy notified in 2006, to dispense with the provision of AAD (which was adopted during tariff period 2001-04 & 2004-09) and to have uniformity in depreciation rates for accounting as well as tariff setting, the aspect of fair life got delinked in 2009-14 and 2014-19 at least for first 12 years of operation, while setting the depreciation rates.

vi) There are two sets of assets viz. those coming under cost plus (section 62) and others through competitive bidding (section 63). Further, within the subset of cost plus assets, many of existing units/stations have already outlived or will outlive their originally envisaged useful life of 25 years in the tariff setting period of 2019-24. Renovation and Modernization is allowed based on two approachesi.e. Actual expenditure incurred and normative special allowance for coal based/lignite fired thermal generating station. In case of former approach, proposal includes estimated life extension wherein the calculation of allowable depreciation is feasible. However, in case where special allowance is allowed, it is not feasible to workout depreciation in absence of life extension.

14.3 In the following circumstances, treatment of depreciation is contingent upon period of extension of useful life or assessment of residual life which would be admissible on satisfying the extension of life :

i) Additional capital expenditure at the end of life or special allowance approved in lieu of renovation and modernization have consequential impact on the tariff due to recovery of depreciation over balance useful life;
ii) Additional capital expenditure after allowing the special allowance has an impact on recovery of depreciation.
ii) The useful life of Hydro Stations, as specified in Tariff Regulation, 2009, is 35years. However, the actual life of these Hydro stations may be much more than35 years. For hydro stations allowing higher depreciation rates during first 12years results in front loaded tariff. To keep the tariff on lower side, the depreciation rate for hydro stations could be spread over the entire useful life i.e.35 years. Similarly for thermal stations, the life may be more than 25 years and the International experience in this regard needs to be looked into to bring further improvements.

14.4 Section 123 of the Companies Act 2013, under Schedule II- provides life of Special Plant and Machinery, as 40 years for generation, transmission and distribution of power whereas Part B of the same has linked useful life to be as specified by regulatory authority. The relevant portion of Part B is extracted under:
"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".

14.5 Books of Accounts are required to be prepared as per Ind AS (Ind Accounting Standard) for generators whose tariff is determined based on regulations notified by Commission. RBI's notification dated July 15, 2014 regarding flexible structuring of long term project loans to infrastructure and core industries covers power industry. Stipulations relating to depreciation have been laid down in Tariff policy notified on 28January 2016.

14.6 Options for Regulatory Framework

a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff;

***Gescom views:***

***The useful life of the both thermal, gas, hydro projects and transmission assets shall be up to the years specified as above***

b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units;

***Gescom views:***

***Treatment of weighted average useful life in case of combination due to gradual commissioning of units should be continued***

c) Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment;

***Gescom views:***

***This has to be specified by commission in consultation with CEA***

d) Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Ind AS and corresponding treatment of depreciation thereof;

***Gescom views:***

***In case of any add cap, the effective life should at least be extended to the end of that control period. The assessment of every additional expenditure in line with accounting standard is a better option***

e) Extend useful life of the transmission assets and hydro station to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation.

***Gescom views:***

***Depreciation should be charged over the revised balance life Of the assets along with the written down value upto905 of revised GFA.***

f) Reduce rates which will act as a ceiling.

***Gescom views: The reduced rates maybe treated as ceiling rates***

g) Continue with the existing policy of charging depreciation. However, the Tariff Policy allows developer to opt for lower depreciation rate subject to ceiling limit as set by notified Regulation which causes difficulty in setting floor rate, including zero rate as depreciation in some of the year(s).Comments/ Suggestions

***Gescom views:***

***The depreciation policy shall be continue with change of useful life of the assets. The depreciation opted by the developer for lower than notified rates shall be considered for the computation of the tariff.***

14.7 Comments and suggestions are invited from the stakeholders on the possible Regulatory options discussed above and alternatives, if any.

## 15. Gross Fixed Asset (GFA) Approach

15.1 The Commission in the previous Tariff Regulations has adopted GFA approaches it incentivizes the equity investors to efficiently operate and maintain the infrastructure, even after the plant has been fully depreciated. The internal resources generated by way of depreciation are reutilized for further capacity addition. CEA has estimated that in view of present demand growth rate and availability of commissioned and under construction capacity, no new coal based capacity may be required till 2027.Option for Regulatory Framework

15.2 An option could be to base the returns on the modified gross fixed assets arrived at by reducing the balance depreciation after repayment of loan in respect of original project cost. Comments/ Suggestions

15.3 Comments and suggestions are invited from the stakeholders on any other possible regulatory options or to continue with the existing mechanism.

***GESCOM Views :***

***The Capital expenditure of the Thermal Generating Station are being serviced by the beneficiary utilities. Therefore, increasing the useful life of well maintained plants for the purpose of determination of tariff will benefit the Utilities by reduced depreciation rates for the remaining life period of the asset.***

***The GFA approach may be continued with certain changes that once the loan amount is repaid, the equity should be reduced in proportionate to***

***the depreciation amount paid on every year.This helps in reduction in tariff***

**16. Debt: Equity Ratio**

16.1 The capital cost for generation and transmission projects commissioned after

1.4.2019 is considered to be financed through a debt equity ratio of 70:30. Further, it is provided that if the actual equity deployed is more than 30% of the capital cost, the equity in excess of 30% shall be treated as normative loan whereas if the equity deployed is less than 30% of the capital cost, the actual equity shall be considered for determination of tariff. The above provision in Tariff Regulations is consistent with the principles laid down in the Revised Tariff Policy 2016.

16.2 Some of the utilities in private sector operate with a very high financial leverage. Also, it is observed that financial institutions are willing to extend finance up to debt equity ratio of 80:20 depending on the credit appraisal of the utilities. When demand for capacity addition is low, maintaining debt: equity of 70:30 may need review.

16.3 Further, for some of the old plants, the equity base has been maintained beyond 30% (up to 50%) for the purpose of fixed return to enable the developer to generate internal resource for further capacity addition. In view of availability of sufficient capacity in the market, there is a need for review of the same. Options for Regulatory framework

16.4 For future investments, modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved. Comments/ Suggestions.

16.5 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate options, if any

***GESCOM Views :***

***Allowing the Debt-Equity Ratio of 70:30 for existing thermal generating stations and 80:20 for new thermal generating stations is the in the optimal mix. The return on the equity is being serviced by the utilities till the life of the plant. In case of the life period extended beyond the useful life, there should be a provision to predetermine the equity percentage, so as to benefit both the generator and beneficiary utility.***

***Normally, the LTA executed between the Generators and Beneficiary utilities are for the life period of the plant. When the life period is completed, the beneficiary may have a choice of willing to continue to***

***procure power from the plant only in case when the rates are competitive. Therefore, redetermination of equity percentage has to be done after life period of the plant.***

**18. Rate of Return on Equity**

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

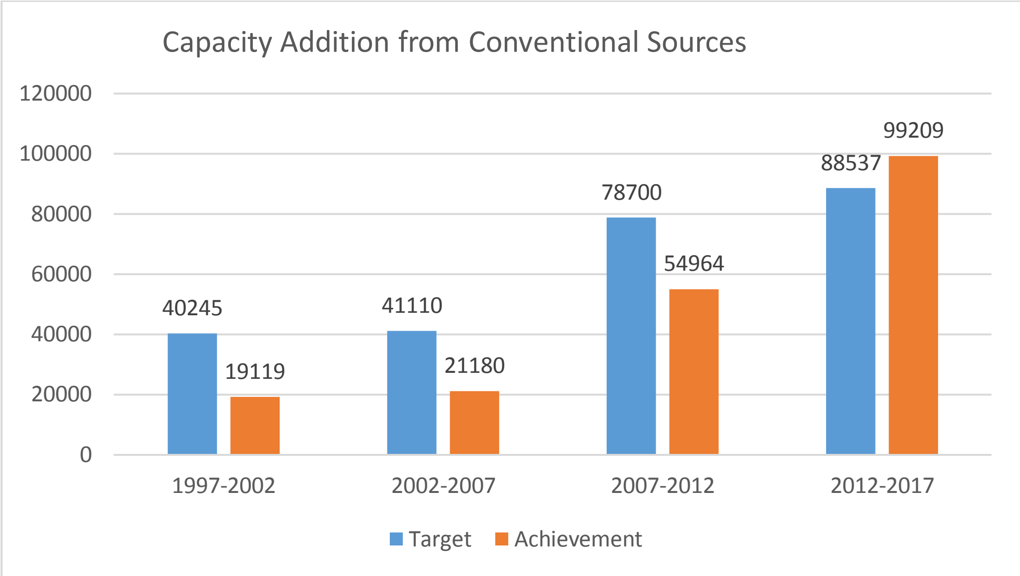
18.2 The Commission had specified a post tax RoE of 16% and 14% respectively for the tariff periods 2001-04 and 2004-09 respectively. For the tariff period 2009-14, the Commission had specified a post tax base rate of 15.5% and allowed it to be grossed up by the applicable tax rate. An incentive of 0.5% was also allowed for the generation/transmission projects completed within the prescribed timeline. For the tariff period 2014-19, the Commission continued with the post tax base rate of 15.5%as allowed for 2009-14 tariff period with an additional 1% RoE i.e. 16.5% allowed for storage type hydro generating stations.

18.3 As per the present regulatory framework, the additional return on equity is allowed for all the units or the transmission elements irrespective of their size or length of line if such assets have been commissioned as per the timeline specified by the Commission. The timeline applied is same irrespective of size of the project-length of line in transmission project or capacity of the unit in generation projects.

18.4 Further, the additional return of 0.5% is given to incentivize the project developer for timely completion. However, there is no disincentive for delay incompletion of the project.

18.5 Following key trends have been observed during recent times: -

- The capacity addition (as per CEA report) achieved from conventional sources during the plan period 2012-2017 exceeded the target with more than 50% of the capacity addition coming from the private sector. Besides, there has been a rapid increase in renewable energy capacity addition.




Capacity Addition from Conventional Sources

- The draft National Electricity Plan 2016 of CEA has indicated that there will be no need for additional on-renewable power plant still 2027 with the commissioning of 50,025MW of under construction coal based power plants and additional 1,00,000 MWrenewable power capacity.

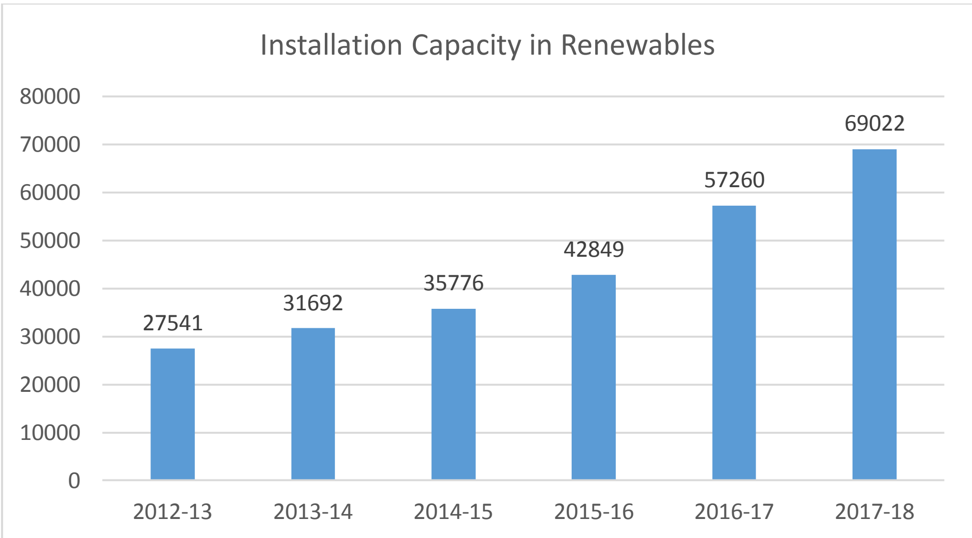



Figure 8: Installation Capacity in Renewables

- The PLF of thermal power plant has come down steadily during last 4-5years (as per CEA report), mainly due to higher capacity additions, low demand growth and increase availability of renewable energy.

- As per RBI database, notwithstanding the recent increase in the yield for 10 year benchmark government securities, the overall interest rate has shown a declining trend during the period 2014-19. The yield on 10 year benchmark Government Bond has come down to 7-7.5% during 2018 as compared to 8-8.5%during 2014. The RBI repo rate, interbank rate and SBI base rate have also come down during this period. With better control over inflation, the interest rates are expected to remain low and stable over short & medium ter

- The Tariff Policy has mandated the distribution licensees to procure their future requirement of power through Tariff Based Competitive Bidding. The market forces are likely to exert downward pressure on the IRR of the new projects.

  ***Gescom views:***

  ***The existing base rates of return of equity for thermal generating stations need to be reduced. The existing base rate 15.5% needs to be reduced to 11%.***

  ***The return on equity is a liability to the beneficiaries till the beneficiary purchases power from the generator or duration of the power purchase agreement whichever is earlier. Further the beneficiaries are liable to pay the tax on the ROE by grossing up of income tax. This is also an additional financial burden upon the beneficiary utilities.***

  ***There is urgent need to define and quantify components on the basis of which the rate of return on equity is being determined. It is suggested that the level of return being earned by other business entities may be examined to determine the rate of return. The rate should be such that the investor may be able to earn atleast the prevailing rate of interest being offered by the bank and additional component to counter the risk factor.***

<u>Options for Regulatory Framework.</u>

18.6 According to CEA, the capacity addition is no more a major challenge and adequate installed capacity (along with currently under installation) exists to meet the demand for the next 8-10 years. Further, the rate of interest has also come down in recent times. Therefore, there is market dynamics which favors reduction of rate of return. However, any such reduction will have negative impact on the equity already invested in the existing and under construction projects, creating further financial stress on such projects. Different rate of return for new projects (where financial closure is yet to be achieved), may be thought of, with different rates for generation and transmission projects.

18.7 (a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects;

***Gescom views:***

***Guaranteed rate of return is 12% and incremental ROE linked to market maximum2%***

(b) Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects

***Gescom views:***

***Different rates of return for thermal and hydro projects with additional incentives to storage based hydrogenating projects shall be allowed***

© Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects;

***Gescom views:***

***different rates of return for thermal and hydro projects with additional incentives to storage based hydrogenating station projects shall be allowed***

(d) In respect of Hydro sector, as it experiences geological surprises leading to delays, the rate of return can be bifurcated into two parts. The first component can be assured whereas the second component is linked to timely completion of the project;

***Gescom views:***

***Keeping into consideration the location, construction methodology, time period required for construction compliance requirements etc the differential rate of return should be decided and made applicable for hydro and thermal projects. The hydro power projects should have more rate of return in comparison to the thermal power station***

(e) Continue with pre-tax return on equity or switch to post tax Return on equity;

***Gescom views:***

***continue the post tax return on equity tax paid by the generating company or transmission company shall not reimburse by the beneficiaries with whom power purchase exist.***

(f) Have differential additional return on equity for different unit size for generating station, different line length in case of the transmission system and different size of substation;

***Gescom views:***

***fixing different rate of return for different size is not practical and is not rational.***

(g) Reduction of return on equity in case of delay of the project; Comments/ Suggestions.

***Gescom views:***

***The reduction of return on equity shall be allowed ie in case of delay by more than six months the ROE reduced by .5% and delay by 1 year the roe shallbe reduced to 1% and so on***

18.8 Comments and suggestions are invited from the stakeholders on the possible options discussed above and alternate options, if any.

**19. Cost of Debt**

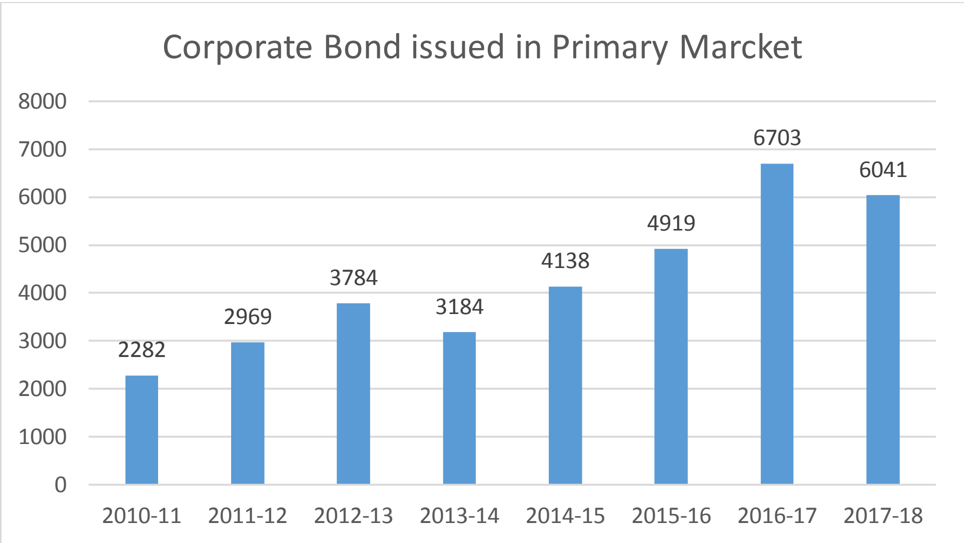
19.1 Cost of debt is the cost incurred by the utility in the form of interest payments and upfront fee for raising finances through debt. As per the prevailing Tariff Regulations, the weighted average interest rate calculated on the basis of actual loan portfolio of the utility is considered as the cost of debt. The cost of debt thus arrived atis applied on the normative outstanding loan to compute the annual interest expenses of the utility which is given a pass through in the tariff. This approach does not provide incentive to the utility to lower the cost of borrowings, as even higher rates are given as pass through in tariff.

19.2 Clause (d) of para 5.11 of Tariff Policy, 2016 has stipulated that the utilities should be encouraged and suitably incentivized to restructure their debt for bringing down the tariff. The Tariff Regulations for 2014-19 has provided that the regulated entities shall make every effort to refinance the loan to lower the interest costs. And for this purpose, while the costs associated with refinancing shall be borne by the beneficiaries, the savings on interest shall be shared between the beneficiaries and the utilities in the ratio of 2:1.

19.3 Following key trends have been observed during recent times.

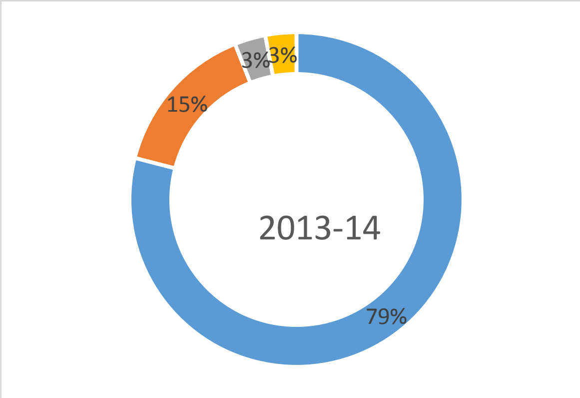
- Regulated entities are availing long term loan from different sources viz. banks, financial institutions, debt markets both in India and abroad. The terms & conditions of debt including the interest rate varies across sources depending upon several factories. quantum, tenor, type, timing, etc. As of now utilities are predominantly borrowing from banks and other financial institutions for capital expenditure through no standardizedand negotiated bank loans in the form of corporate loan, project loans, syndicated loans etc. Long term credit rating of utilities varies across utilities. The interest rates at which funds are borrowed from banks/financial institutions/debtmarketdepend upon the credit rating of the utilities.

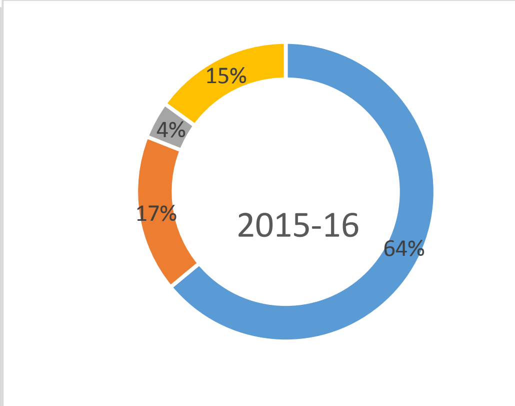
- As per RBI database, the size of the Indian corporate bond market vis-a-vis GDP is still low in comparison to developed and even several developing countries. However, corporate bonds outstanding as a % of GDPhave grown from around 5% in2012 to 23% during 2017-18.Further, amount of corporate loan raised through issuing bonds in primary market during last 7 years has grown at a CAGR of around15%. Historically, the corporate bond market has been dominated by PSU's AAA and AA rated bonds. However, the trend seems to be changing with a number of mutual funds investing in debt portfolio with low rated bonds.




- As of now except the better rated utilities like NTPC Ltd. and PGCIL, others utilities are primarily dependent upon banks& financial institutions for meeting their loan requirement. However, with the strengthening of corporate bond market, it will provide an alternative for the companies to raise their finances.

- RBI has gradually revised its repo rate downward from 8% during 2014 to6% in August, 2017. Since August 2017RBI has maintained status quo in the policy rates based on the recommendations given by the Monetary Policy Committee (MPC) during its bi-monthly meetings. Further, RBI has introduced the Marginal Cost of Fund Based Lending Rate (MCLR)system during 2016 as an alternative to the base rate system for efficient transmission of policy rates into the money market. As a result, the bank lending rates have also reduced during this period.






Options for Regulatory Framework

19.4 While allowing the cost of debt as pass through, options available for regulatory framework are either to consider normative cost of debt based on market parameters or actual cost of debt based on loan portfolio. As the tariff is determined for multi-year period and cost of debt varies based on changing market conditions, linking cost of debt to market parameters such as MCLR & G-sec will bring a degree of unpredictability. The regulatory approach evolved so far has been to allow the cost of debt based on actual loan portfolio. This does not incentivize the developers to restructure the loan portfolio to reduce the cost of debt. The current incentive structure may need review to encourage developers to go for reduction of cost of debt.

19.5 (a) Continue with existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan, or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects;

b) Review of the existing incentives for restructuring or refinancing of debt;

c) Link reasonableness of cost of debt with reference to certain benchmark viz. RBIpolicy repo rate or 10 year Government Bond yield and have frequency of resetting normative cost of debt; Comments/ Suggestions

19.6 Comment and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate, if any.

***GESCOM Views:***

***Continuing with existing approach of allowing cost of debt based on actual weighted average rate of interest will be best option for calculation of interest on loans.***

***It is the responsibility of the Generator to negotiate with the banks for lower interest rates. When the market condition is good, the Generator should explore the possibility of transferring the high cost loans to other bankers and financial institutions and to pass on the benefit to the utilities.***

***The actual repayment of loans by the generator or the depreciation whichever is higher needs to be considered instead of it being the depreciation allowed for the year. The generators should act responsibly in bringing the interest cost to the lowest level so that it can benefit the beneficiaries as well as the end consumers.***

## 20. Interest on Working Capital (IOWC)

20.1 The working capital is separately specified by the Commission for coal based or lignite-fired thermal generating station, open-cycle gas turbine/combined Cycle thermal generating stations and hydro generating station & transmission system. The working capital is determined based on fuel stock, inventory of maintenance spares, one month operation and maintenance cost and two months receivables depending on the type of thermal generating station, hydro and transmission projects.

20.2 The existing Tariff Regulations provides the definition of bank rate as the Base Rate of interest specified by the State Bank of India (SBI) from time to time or any replacement thereof for the time being in effect, plus 350 basis points. The Reserve Bank of India (RBI), vide ref. RBI/2015-16/273 DBR.No.Dir.BC.67/13.03.00/2015-16dated 17.12.2015, introduced Marginal Cost of funds-based Lending Rate (MCLR).The new methodology for computing benchmark lending rates came into effect from April 1, 2016. The objective of MCLR is to get response of bank faster to policy rate revisions. As per the reference of RBI, MCLR will automatically apply to new loans. However, the existing borrowings linked to the Base Rate may continue till repayment or renewal, as the case may. Alignment of Regulations to above development may therefore, be required. Options for Regulatory Framework

20.3(a) Assuming that internal resources will not be available for meeting working capital requirement and short-term funding has to be obtained from banking institutions for working capital, whose interest liability has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed or change can be made.

(b) As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken.

( C) While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say,15% maintenance spares being made part of working capital or O&Mexpenses.

(d) Maintenance spares in IWC which is also a part of O&M expenses results in
higher IWC for new hydro plants with time and cost overrun. For old hydro stations, the higher O&M expenses due to higher number of employees al so yield higher cost for "Maintenance Spares" in IWC. Therefore, option could be to de-link "Maintenance Spares" in IWC from O&M expenses.

Comments/ Suggestions

20.4 Comments and suggestions are invited from the stakeholders on the regulatory options discussed above and alternate, if any.

***GESCOM Views :***

***The Coal (Stock) – 15 days for pithead stations and 30 days for non-pithead stations needs to be revised.***

***The Coal (generation) – 30 days for NAPAF also need to be revised.***

***In the present trend of growth of Renewable Energy, many thermal stations are being backed down so as to accommodate the Renewable Energy to the maximum extent possible. Further, the availability of Coal is not adequate to run the thermal plants at the NAPAF.***

***Therefore, the Coal stock of 45 days (15+30) needs to be revised to 20 days (15 days for stock + 5 days for generation).***

***Similarly, the stock of secondary fuel oil needs to be revised to 15 days in accordance with the generation activity instead of two months as provided in the earlier Regulations.***

***Receivables needs to be reduced to 1 month of capacity charge and energy charge instead of 2 months as provided in the earlier Regulations.***

***The non cash expenditure including the depreciation and roe may be excluded from the working capital requirement. Even a week stock is not available. The stock of fuel considered for working capital is very high.***

***IWC on fuel oil, gas and coal cannot be provided equal wieghtage as there is no time required for piping gas and oil but the coal required considerable time for transportation. Interest on working capital shallbe linked to MCLR rates***

***As on 1.4.2019 for existing projects and as on the date of commission of the new projects***

***Normative availability factor for coal consumption shall be reduced in view of renewable source as well as low demand for thermal projects.***

## 21. Operation and Maintenance (O&M) expenses

21.1 The Commission has notified normative O&M expenses for thermal generating stations and transmission system in the existing tariff regulations based on the data of2009-10 to 2013-14. Presently O&M expenses have been specified on per MW basis for generation and per bay basis for the transmission system.

21.2 Some of the issues and challenges in fixation of O&M expenses norms are:

- The fixed escalation rate used for arriving year on year O&M cost, takes into account WPI and CPI indexation. However, variations in WPI & CPI index pose challenge in specifying the fixed escalation rate for the entire tariff period. Further, the fixed escalation rate does not capture the variation due to unexpected expenses such as wage revision etc.
- For new hydro stations whose COD was declared during the tariff period2014-19, the first year normative O&M has been specified as 4% and 2.5% of original project cost (excluding cost of R&R works) for stations less than 200MW projects and for stations more than 200 MW respectively. But O&Mexpenses could vary depending on the type of plant and number of units.
- O&M expense of hydro stations is given as a percentage of capital cost, which is inclusive of IDC & IEDC. Thus, projects with substantial time &cost overrun get higher O&M.
- There could be overlapping of the O&M expenses and the compensation allowance, due to overlapping of items covered under these two.

21.3 O&M expenses vary if the dispatch of the generating station is continuously low, as in the case of gas/ naptha based generating stations. In such cases, specifying recovery of O&M expenses based on installed capacity may need review.

21.4 The O&M expenses of transmission substation comprises O&M expenses for transformer, reactors, bays, compensation devices, transmission lines, control room switchgears, DC system, switchyard etc. When the number of bays increases, there will be a corresponding increase in switchgear panel in the control room. However, there may not be increase in the capacity of transformer and other components of the substations. As an alternative, the O&M expenses may need to worked out on the basis of

MVA capacity instead of individual components else some weightage may be accorded to different components.

21.5 In case of expansion of capacity in existing generating station or existing transmission substation, the O&M expenses may vary on account of economies of scale. The O&M expenses have been rationalized by multiplying factor of 0.90, 0.85and 0.80 to O&M expenses per MW depending on the size of the units. Rationalization similar to generating stations could be considered for the transmission system where the generating stations receive lower amount towards O&M expenses in case of addition of units in same generating stations as stated above. At the same time, different multiplying factor can be prescribed for different unit sizes even in case of the generating stations.

21.6 The O&M expenses of a generating station generally increase with increase in the life completed by it. That is to say, the new plants requires less O&M expenses whereas old plants requires higher O&M expenses. Specifying generic norms forO&M expenses for all plants irrespective of its life may need a relook.

Options for Regulatory Framework

21.6 (a) Review the escalation factor for determining O&M cost based on WPI CPI indexation as they do not capture unexpected expenditure;

(b) Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost.
(c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects;
(d) Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naptha and R-LNG based plants).
(e) Rationalization of O&M expenses in case of the addition of components like the bays or transformer or transmission lines of transmission system and review of the multiplying factor in case of addition of units in existing stations;

(f) Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system.

(g) Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.

Comments/ Suggestions

21.7 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate, if any.

***GESCOM Views:***

***Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system.***

***Thermal generating stations are in the combination of old and newer ones. The generating stations which have been commissioned in the last 10 years will not require huge O&M expenses for running of the plant Similarly, age old plants which have served their life may be given the option of phasing out instead of incurring huge Operation and Maintenance expenses and running the plants at the low PLF level.***

***Due to fixing the O&M norms for old and new thermal stations as common, the beneficiaries are forced to bear the additional expenditure in the form of capacity charges, which also results into higher fixed cost. Therefore, there should be a separate mechanism for determination of Operation and Maintenance expenses for aged plants and new plants.***

***The same procedure needs to be followed for Transmission projects also.***

***Similarly, there should be a separate mechanism for determination of water charges for aged plants and new plants depending on the type of the plant and the requirement of water for efficient operation of the plant. In the event of the thermal station running below the PLF level, then allowing a normative percentage of water charges will increase the fixed charges and only will benefit the generators at the cost of the beneficiaries.***

## 22. Fuel – Gross Calorific Value (GCV)

22.1 Gross Calorific Value (GCV) in relation to thermal generation has been defined in successive tariff regulations issued by the Commission since 2001 as "the heat produced in kCal by complete combustion of one kilogram of solid fuel or one litre of liquid fuel or one standard cubic meter of gaseous fuel, as the case may be". GCV issued to compute the Energy Charge payable by the distribution companies/power utilities to the generating companies. The normative energy consumption admissible per unit of electricity generated has been specified by the Commission in the tariff regulations as normative Station Heat Rate (SHR) in terms of kcal/kWh. The ratio ofSHR and GCV gives the quantity of coal used per unit of electricity generated. Therefore, GCV being used for the computation of energy input becomes extremely important as any increase/reduction in GCV decreases/increases the admissible coal consumption affecting the cost of power.

22.2 Energy Charge constituting about 60-70% of the total cost of generation tariff has major impact on cost to end consumers. In order to balance the interest of both the generating companies as well as the distribution companies (and ultimately the end consumers), the measurement of GCV of coal used needs to be as accurate as the true representative of the coal consumption is required.

22.3 GCV of coal is measured at different points and accordingly, various GCV terminologies are used namely “GCV As Billed”, "GCV As Received" and "GCV As Fired". “GCV As Billed”, also called as “Invoice GCV” is indicated by the suppliers inthe dispatch invoice and payment for the coal is made to the suppliers on the basis of“GCV As Billed”. However, “GCV As Billed” is based on GCV measured in controlled environment. "GCV As Received" is GCV measured at the generating station upon receipt of coal in the station. "GCV As Fired" is computed before feeding coal into coal bunkers of the generating unit for power generation.

22.4 The “GCV As Billed” is indicative of total energy content dispatched by the suppliers and normally paid for by the recipient stations. The "GCV As Received" is expected to be same as “GCV As Billed” barring minor transit losses. "GCV As Fired “is computed at the time of actual use of coal in the generating unit for power generation. For a coal consignment, "GCV As Fired" would be equal to "GCV As Received" minus the heat loss due to storage, as coal may undergo certain quality changes/degradation over the storage periods.

22.5 In the entire value chain from mine end to generating station end, the loss ofGCV can take place on account of grade slippage at mine end, during transportation(transit with railway) and during storage (at generating stations). The generating companies generally have no control over the grade/GCV of coal received at their generating stations. There are several cases of grade slippages between the mine mouth and at the site of generating stations. Further, there is loss in GCV during transport of coal through Railway. Therefore, the generator may receive lower energy than what was billed by the coal companies. These are beyond the control of the generating companies.

22.6 Since the cost of slippage in grade of coal between the loading point and the site of generating station is ultimately passed on to the beneficiaries, this issue needs to be looked at in terms of risk allocation between the coal company, railways and the generating stations.

22.7 In case of imported coal, sampling and proximate analysis are being done at Free on Board (FOB) and at Cost Insurance Freight (CIF). The coal is transported by rail from port to the generating stations. Since the existing regulatory framework provides that the GCV is to be measured as on received basis at generating end, the same is followed for imported coal too. In case of imported coal, the GCVmeasurement is followed on Air Dryed basis at CIF for billing purpose, whereas incase of domestic coal, the same is measured at the mine end.

Option for Regulatory Framework

22.8 (a) Take actual GCV and quantity at the generating station end and add normative transportation losses for GCV and quantity for each mode of transport and distance between the mine and plant for payment purpose by the generating companies. In other words, specify normative GCV loss between "As Billed" and "As Received" at the generating station end and identify losses to be booked to Coal supplier or Railways.

b) Similarly, specify normative GCV loss between "As Received" and "As Fired" in the generating stations.
c) Standardize GCV computation method on "As Received' and "Air-Dry basis'' for procurement of coal both from domestic and international suppliers.

Comments/ Suggestions

22.9 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate options, if any.

***GESCOM Views:***

***Taking a actual GCV of fuel at a three months interval by a third party agency for measurement of Coal at the Coal block and at the Generators premises on "Received Basis" with comparison to the Fuel Supply Agreement executed between the Generator and Coal block agency has to be done***

**23. Fuel - Blending of Imported Coal**

23.1 The power plants in the country face shortage of fuel (coal/gas) due to shortage of supply from the supplier or due to transportation constraints. Coal IndiaLtd. has not been able to supply committed quantity of coal as per Fuel SupplyAgreement. Coal supply also gets affected due to Rail transportation related constraints. Uncertainty about supply of gas continues, both in terms of availabilityand price. In the above circumstances, the generating stations are either forced toprocure fuel from spot market (in case of gas and coal) or to procure imported coal athigher prices.

23.2 The Tariff Regulations, 2014 allowed procurement of balance coal from alternate sources like import/e-auction for blending. Under restrictions prescribed in the regulations relating to quantum/price of alternate coal, the generating companies meet shortfall in supply of coal under FSA through alternate sources (which are generally costlier). If power plants rely heavily on coal from alternative sources, the energy charges may increase substantially or the plant may have to be operated at lower PLF if distribution licensees do not give consent to blend higher percentage of imported coal than the threshold prescribed in the regulations.

23.3 There is difficulty in verification of GCV of blended coal, due to unavailability of separate value of GCV of domestic and imported coal on "As Fired Basis". It may therefore, be necessary to provide for payment of energy charges based on "As Received" GCV of domestic and imported coal with suitable margin and adjustment for arriving at "As Fired" GCV. This would require development of norms for such adjustment.

23.4 Alternatively, normative blending ratio may be decided in advance in consultation with the beneficiaries in terms of technical limitation of steam generator. The blending ratio in the domestic coal based plants may vary depending upon the quality of coal, the quality of actual coal being received, age of plant, unit loading etc.

23.5 The Central Commission, vide Third Amendment to Tariff Regulations, dated30.12.2012, has already incorporated the regulation for maintaining transparency in fuel procurement by generator and sharing of fuel prices including, fuel procurement through e-auction and imported coal. Option for Regulatory Framework

23.6 Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.

Comments/suggestions

Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate options, if any.

***GESCOM Views***

***The Coal blocks in the Country are not in a better position to meet out the growing demand of the Energy sector. Therefore, it is the responsibility of the Generator to look for alternative sources to cater to the demand. There is a huge difference between the Imported Coal and the Inland coal. While calculating the blending percentage the plant size, boilers efficiency level etc are to be considered.***

24.5 (a) All cost components of the landed fuel cost may be allowed as part of tariff. Or alternatively, specify the list of standard cost components may be specified;

(b) The source of coal, distance (rail and road transportation) and quality of coal may be fixed or specified for a minimum period, so that the distribution company will have reasonable predictability over variation of the energy charges.

***Gescom's views:***

***The coal blocks in the country are not in a better position to meet out the growing demand of the energy sector. Therefore, it is the responsibility of the generator to look for alternative source to cater the demand. There is a huge difference between the imported coal and the inland coal. While calculating the blending percentage the plant size, boilers, efficiency level etc are to be considered.***

***Domestic coal-- landed cost of coal for domestic shall be included cost of coal, transportation, royalties and taxes. Any other charges, dues and arrears shall be claimed separately in the bill for reimbursement. Any penalty/revenue earned by generating company from any agency shall also be allowed as credit in the month. Each loaded wagon/ shipment shall be supported by the document.***

***Imported coal based generating plants using jetty for external coal handling, the costs associates with coal handling as follows:***

1. ***Stevedoring charge***
2. ***Shore handling charges***
3. ***Insurance***
4. ***Lc establishment charges***
5. ***Lease rent***
6. ***Railway bonus***
7. ***Sampling analysis***
8. ***License fee***
9. ***Dredging cost***
10. ***Loss of capacity charge***
11. ***Demurrage charges***
12. ***Annual maintenance charges***
13. ***Land license and maintenance fee***
14. ***50%of railway marshalling yard charges***
15. ***Ship related charges***
    - ***Port dues***
    - ***Water charges***
    - ***Any other charges for the specific services requested and availed***

Comments/ Suggestions.

24.6 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate options, if any.

## 25. Fuel - Alternate Source

25.1 The present regulatory framework provides that the generators resorting the alternate source of fuel, other than designated fuel supply agreement, require prior consultation only if the energy charge rate exceeds 30% of the base energy charge rate or 20% of energy charge rate of the previous month. These provisions were introduced w.e.f. 1.4.2014 in view of the shortage of fuel at that time. Options for Regulatory Framework

25.2 (a) stipulate procedure for sourcing fuel from alternate source including ceiling rate;

(b) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014.

Comments/ Suggestions

***Gescom' views:***

***In case of alternate source the price should not deviate from more than 5% of energy charge rate of the designated source during that period. In case the price deviation more than 55 approval of the procurer is mandatory subject that aggregate capacity from the procurer shall not be less that the technical minimum as specified in IEGC. All cases if it is in supply from alternate sources the generating company intimate to the procurer with complete detail calculation.***

## 37. Alternative Approach to Tariff Design

37.1 Tariffs for generating stations and transmission systems are determined by the Commission as per the terms and conditions specified in the Tariff Regulations as applicable from time to time. Currently, CERC (Terms and Conditions of Tariff) Regulations, 2014 are in place. The tariff regulations provide for detailed procedure for computation of different components of tariff and the generating companies /transmission licensees are required to file tariff petitions with requisite details in accordance with the provisions of the regulations. The Regulations provide for a two-part tariff for a generation station, viz. Fixed Cost (Annual Fixed Charge – AFC) and Energy Charge (EC). For a transmission licensee the tariff comprises only the Fixed Charge.

37.2 The Annual Fixed Charge (AFC) is determined based on the admitted capital cost as on the Date of Commercial Operation (COD) after carrying out prudence check of the individual component of costs. In this process, the Commission examines vast data which is required to be submitted before it in respect of each of the components to arrive at permissible costs for recovery through tariff. Accordingly, substantial efforts are made towards determination of Annual Fixed Cost which constitutes on an average 30% – 40% of total cost of generation. It has often been argued by various stakeholders at different fora, that such a system of elaborate examination of data to determine AFC needs a revisit. It is in this context that an alternate approach to tariff determination is proposed.

**Normative Tariff by Benchmarking of Capital Cost**

37.3 Capital cost is the starting point for tariff fixation. Therefore, the first question that arises is as to whether the capital cost could be determined on normative basis as against the existing practice of detailed cost component wise examination?

37.4 In order to benchmark the capital cost of various generating stations (sample size 30) of varying vintage, unit size, fuel type etc. was analyzed. The Normative Value of the capital cost per MW approved by the Commission during the year of Commissioning of respective sample plants was calculated by applying the normalization factor of 6.85%. The normalization factor was computed taking average of the WPI inflation from the FY 1988-89 to FY 2013-14. It was observed that the distribution of capital cost per MW is denser near the Mean and Median i.e. Rs.6.30Crore/MW. However, the standard deviation for the above distribution was as high asRs.2.44 core/MW. It showed that the Capital Cost per MW of the sample plants varied from Rs.3.87 Crore/MW to Rs.8.74 Crore/MW.

37.5 This variation could be attributed to many factors such as cost of land & site development, project specific Sub/Super critical status of the Plant, technology &equipment and material handling system which includes distance from the Coal Mine etc. In case of COD delay, Interest during construction, financing charges, taxes and duties etc. might have impacted the total project cost. This high variation indicates a need to conduct a more rigorous component-wise analysis of Capital cost for generation as well as transmission projects and understand the deviation to figure out appropriate benchmark capital cost for thermal generation stations

37.6 Views and comments are therefore being solicited on the following questions:

a. Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost?
b. What are the variables that should be considered for the purpose of determining Capital Cost on normative basis?
c. Any other methodology for benchmarking the capital cost for generation and transmission projects?

**Normative Tariff by fixing AFC as a percentage of Capital Cost**

37.7 As the next potential option for determination of tariff on normative basis, the possibility of fixing total AFC as a percentage of initial capital cost, is explored. In this context, sample size of 30 generating stations was examined to analyze the AFC of first year of operation as a percentage of the approved capital cost. It was observed that correlation coefficient between AFC approved for the first year of operation and approved capital cost was around 0.84. Similarly, correlation coefficient between average AFC approved per year (till FY 2016-17) and capital cost was 0.95. The significant correlation between AFC and capital cost indicates the possibility of benchmarking AFC as percentage of capital cost to save resources and time spent on conducting component wise prudence check. However, a further analysis showed Mean of AFC as percentage of Capital Cost as 22.55% and standard deviation for the distribution was as high as 7.17%.

37.8 The available data and the connected analysis highlights the necessity for alarger database facilitating bigger cluster-wise sample sizes and a more rigorousexercise, which could possibly facilitate drawing conclusions about whether AFCcould be normatively determined by considering it as a percentage of capital cost.

37.9 In this regard, views/ comments are solicited on the following:-

a. Whether it is a good idea to determine AFC as percentage of Capital Cost on normative basis?
b. What could be the possible methodology to establish the relation between AFC and Capital Cost so that it meets the interests of both buyers and sellers?

**Normative Tariff by fixing each component of AFC as a percentage of total AFC**

37.10 Given the constraints as explained above, the option of determination of tariff on normative basis by fixing each component of AFC as percentage of total AFC was considered. A sample size of 30 generating stations was considered to examine trends of various components of AFC as percentage of total AFC. Accordingly, trajectories of each of the five components of annual fixed cost (i.e. return on equity, interest on loan, depreciation, operation and maintenance, interest on working capital etc.) of the generating stations of the same sample size were drawn for the period from CoD till 2016-17.

37.11 It was observed that for all generating stations, in general, the trend of component "Operation & Maintenance" was found to be increasing, while the other components were either decreasing or remained static. In order to further analyse,the "Operation & Maintenance" component was isolated, while keeping the remaining components as one group. Such segregation indicated clear trends. The graph for "Operation & Maintenance" and "Rest of the Components of AFC" for the generating stations with CoD from 2004 (sample size 10) onwards is provided below.

Figure 13: "O&M" and "Rest of the Components of AFC" for the generating stations with CoD from 2004 onwards

37.12 Therefore, in order to determine tariff on normative basis, as the next possible option, components of AFC could be clustered into two groups, i.e. "Group of AFCComponents which escalate / increase over the period" and "Group of AFCComponents which de-escalate / decrease over the period". Each group may be assigned with a factor (escalation or deceleration factor), as the case may be. Such increasing / decreasing factors will be determined by the Commission for each year separately.

37.13 However, the above analysis also highlights that the overall trend line impacted on account of two major factors, viz. "Additional Capitalization (Add. Cap) /De Capitalization (De Cap.)" and "Change in Control Period".

37.14 The component of "Additional Capitalization (Add. Cap.)" assumes significance as it causes change in the Capital Cost. The current provisions allow additional capitalization, primarily to meet the expenditure towards the left over works from the original scope of work. This Additional capitalization is permissible for a period from the Cod up to the "Cut-Off Date". The Regulations indicate "Cut-Off Date "as 31st March of the year closing after two years of the year of commercial operation of whole or part of the project, and in case the whole or part of the project is declared under commercial operation in the last quarter of a year, the cut-off date shall be 31stMarch of the year closing after three years of the year of commercial operation.

37.15 Hence, the generator has approximately three years duration beyond CoD for additional capitalization. Therefore, in order to provide regulatory certainty, the "Additional Capitalization" could be strictly restricted to the period between "Cod" and the "Cut-Off Date". This would imply that the "Capital Cost" as on "Cut-Off Date "would remain unaltered for the rest of the useful life of the plant. However, any reasonable expenditure in future, such as cost towards meeting new environmental norms etc. if considered uncontrollable / unavoidable may be treated as a separate stream of revenue and recovery could be allowed as a separate component on annuity basis.

37.16 The next issue is surge/ dip owing to change of control period. As per current practice, for each control period, the revised tariff principles are made applicable on new as well as existing generating stations. Such revision in principles, viz. change of Roe, O&M etc. causes a sudden surge or dip in the trend of the respective components. Therefore, in order to provide regulatory certainty, it could be proposed that the revised tariff principles of each control period be restricted to the new plants commissioned during that control period only. In other words, the existing plants could continue to be governed by the same sets of tariff principles as applicable on their CoD.

37.17 In this context comments/ observations of stakeholders are invited on the following points.

a. Whether clustering the components of AFC based on their nature to increase/ decrease in order? Any other possible method to cluster the AFC components?
b. What methodology should be adopted to determine the escalable (increasing)/ non-escalable (decreasing) factors?
c. Whether escalable (increasing) / non-escalable (decreasing) factors should remain same for all plants/transmission systems (or) they be separate for each of the plants/transmission systems based on vintage / capacity / fuel type/ fuel linkages etc.
d. Whether isolation of "Additional Capitalization" as a separate stream of revenue would provide for recovery of AFC on a normative basis inrealisticterms?
e. Alternatively, do you suggest any other methodology to treat "Additional Capitalization" for determination of AFC on normative basis?
f. Whether applicability of change in tariff principles in each control period for the new plants would allow regulatory certainty to the existing plants?
g. Alternatively, is there any other methodology to minimize the impact onAFC on account of change in control period?

**Principles of Cost Recovery - Approach towards Multi-Part Tariff**

37.18 The Commission introduced Availability Based Tariff (ABT) in the year 2000.Under the Availability Based Tariff (ABT), the annual bulk power tariff for supply of electricity from a generating station of a generating company as determined by the Central Commission comprises two components, viz. Annual Fixed Charges (AFC)and Energy Charge (EC). The fixed charges are payable fully on achieving the plant availability factor as per the benchmark level specified by the Commission. All the generating stations regulated by CERC are required to follow the scheduling and dispatch mechanism specified by the Commission. The generating station has to declare availability on daily basis. The failure to achieve the target plant availability factor leads to dis-incentive in terms of reduction of the fixed charges on proportionate basis, and there is a provision for incentive for actual generation above the target availability factor.

37.19 In the emerging scenario of slackness in demand, growing penetration of RE,the overall utilization of generation assets (PLF) has been decreasing.

However, in the current circumstances, once the generator declares plant availability at the normative level of 85%, the distribution utilities are required to pay the AFC in full irrespective of scheduling of energy. There is a rationale behind this framework. The fixed cost is sunk as the asset is created to service the buyers on long term basis. Hence there is a need for certainty of recovery of investments. However, thechanging circumstances have highlighted the need for a re-think on the approach of fixed cost recovery (based on uniform availability throughout the year). The proposition in the succeeding paras stems from this background.

37.20 The proposition is to introduce the system of differential AFC recovery linked to peak and off-peak periods in the following manner:-

a. Off-peak component of AFC: The generating station has to declare a PAF of 80% for the year, which allows recovery of 80% of the AFC. Any slippage to meet the above norm would result in reduction in 80% of AFC in proportionate manner.
b. Peak component of AFC: The remaining 20% of the AFC is recoverable from the beneficiaries, if the generating station achieves a PAF of 95% for the peak period, say of 4 months. During the currency of peak period, adherence to the norm of 95% PAF will be reconciled on monthly basis and slippages from this norm i.e. 95% up to the limit of 80%, would result in reduction in higher peak AFC for that month.
c. The peak and off-peak months for each generating station will be declare by the appropriate RLDC by considering load profile of beneficiaries.

The proposed mechanism also seeks to provide for a higher peak price, say at 25%over the off-peak price. Accordingly, the weightage factors can be calculated by considering:

i. Recovery of 80% of AFC, upon declaration of 80% PAF during the year and remaining 20% of AFC upon achieving 95% PAF during the peak period, say of 4 months.
ii. Higher peak price (i.e. by 25% over the off-peak price)

37.21 In this context, comments of stakeholders are invited on the following points.

a. Does the proposal of differential recovery of AFC by segregating into peak and off-peak periods balance the need for both the buyers and sellers?
b. What could be the weightage factors for peak and off-peak periods along with the PAF for each segment?
c. What could be other mechanisms to arrive at peak and off peak AFCtariffs?

37.22 The flow process for determination of normative tariff is summarized below.

**Table 13 Proposed Flow Process for Determination of Normative Tariff**

| | "Existing" Generating Stations | "New" Generating Stations |
|---|---|---|
| **1** | Initial Capital Cost has already been approved. | Approval of initial Capital Cost andAFC for the first year by the Commission, till the Capital Cost is benchmarked and/or a correlation between Capital Cost and AFC is established for determination ofAFC on a normative basis. |
| **2** | Components of AFC be segregated into "escalable / increasing" and "none scalable/decreasing" segments<br>a. Segment -1 (Non-Escalable/ decreasing) comprising of RoE, IoL,IoWC, Depreciation<br>b. Segment -2 (Escalable) comprising O&M | |
| **3** | Current Regulations provide for "Add. Cap." as permissible for a per from Cod upto Cut-Off date | |
| **4** | "Cut-off Date" means 31st March of the year closing after two years of year of commercial operation of whole or part of the project, and in c the whole or part of the project is declared under commercial operat in the last quarter of a year, the cut- off date shall be 31st March of year closing after three years of the year of commercial operation | |
| **5** | Add. Cap be isolated and the components of AFC be derived with giving effect to Add. Cap. (from Cut-Date onwards) | Add. Cap be allowed till Cut-Off Date ("Capital Base" may vary during the period). However, upo reaching the Cut-Off Date, the Capital Cost be free zed. |
| **6** | For each year the "CAGR" or escalation / de-escalation factors, the case may be, for the two segme ofAFC (namely "O&M" & "RoE+IoL+IoWC+Dep") (without Ad Cap) are determined by Commission. | For each year the escalation / escalation factors, as the case ma be, for the two segments of AFC (namely "O&M" & "RoE+IoL+IoWC+Dep") (without Add. Cap) are determined by the Commission. |
| **7** | No "Additional Capital", Compensation Allowance, Special Allowance b provided from the current control period | |
| **8** | Uncontrollable/ unavoidable expenditure beyond the Cut Off Date, if a which is considered reasonable and permitted by the Commission, allowed as a separate stream on annuity basis | |
| **9** | Add. Cap. availed, be liquidated before the plant completes its useful li | |
| **10** | From FY 2019-20 onwards till completion of useful life of plant trajectory ofAFC (including the trajectory for liquidation of Add. Cap) | |

| | |
|---|---|
| | derived |
| **11** | AFC be recovered by the Generating Company from the beneficiaries two parts, i.e. Peak AFC and Off-Peak AFC |
| **12** | As part of this, 80% of AFC be paid (guaranteed), upon declaration 80% PAFduring the year. Remaining 20% of AFC be paid upon achiev 95% PAFduring the peak period of 4 months, as declared by concerned RLDC |
| **13** | AFC Recovery (peak and off peak shares) be arrived at by considering following<br>• Peak price over off peak price<br>• PAF (Off Peak & Peak) (%)<br>• No. of Months (Off Peak & Peak)<br>• Weightage Factors for Peak and Off Peak components |
| **14** | Month-wise trajectory AFC recovery for the rest of the useful life of plant is arrived at |
| **15** | The operating and financial norms for any new control period need apply on the existing plants |

37.23 In the backdrop of experiences on tariff determination over the period, this section places for discussion the possible alternative approaches for tariff determination. This proposal primarily suggests that ideally the capital cost of a project should be benchmarked based as the first move towards a normative regulation; and thereafter, Annual Fixed Charge (AFC) should be derived as a pre-specified percentage of capital cost. However, this needs large database and rigorous exercise of data analysis. It would be appreciated if the stakeholders provide their insight into this and also furnish data to enable us to carry out the exercise. However, until the capital cost is benchmarked and the AFC is fixed on normative basis as percentage of capital cost, the following is suggested - 'Fixed Cost' for the first / reference year, be determined based on cost plus principles of RoE / RoCE, as the case may be. The fixed cost so arrived at then be escalated from subsequent year onwards by specified normative principles and trajectories. The components of Fixed Cost could be categorized under two broad categories viz., "Escalable / Increasing" and "Non-Escalable / Decreasing" – the former to be escalated at an escalation rate and the latter to be decelerated at a rate to be determined by the Commission. "Additional Capitalization" could be treated as a separate stream of revenue on annuity basis. The operating and financial norms for any new control period need not apply on the existing plants (both thermal and hydro stations). The mechanism also proposes to revisit the principles of cost recovery. It is proposed to split the "Fixed Charges payable to the Generator" into two components,viz., "Off-Peak Fixed Charge (OPFC)" and "Peak Fixed Charge (PFC)", linked to the availability of plant during off-peak and peak periods at specified levels. This frameworkcould also apply mutatis mutandis for transmission projects. In so far as the energy charges for the thermal stations are concerned, the proposition is that the operational norms as prevalent on their date of commercial operation (COD) will continue to be applicable to them through their useful life, subject to the condition that the savings vis-à-vis the operational norms be shared with the beneficiaries in the ratio of 60:40.

**Gescom views:**

**Many generators have filed various petitions before Hon commission for relaxing the norm pertaining to gross station heat rate, auxiliary energy consumption NAPAF and secondary fuel oil consumption. Frequent changes in the norms determined poses problems in billing and payment.**

**Further, ISGS generators are following the same methodology for getting relaxation of norms**

**The operational norms determined by the commission are based on the actual datas submitted by the respective generators in the previous tariff block.**

**Therefore, if there is any change occurs during the course of the current tariff block, it should be addressed only at the next tariff block and not in the intervening period.**

41 **Applications for Tariff Determination: Review of Process in Case of Transmission System**

41.1 Unlike the case of generating stations, the transmission system involves a large number of individual transmission elements which are commissioned at different point of time over the span of 1-2 years. Sometimes, commissioning of individual elements takes more time due to ROW issues, forest clearance and matching with upstream/ downstream system. Therefore, the number of tariff petitions intransmission projects is high and spread over a period of time as they depend upon the commissioning of different elements. The finalization of tariff for an individual element also involves judicial processes which is same for the whole project.

41.2 The determination of capital cost of transmission system is distinguished on two counts – existing assets i.e. those commissioned prior to commencement ofrelevant tariff period and new assets commissioned during tariff period. Presently, the capital cost of the existing assets is determined on projected basis at the beginning of the tariff period and trued up on completion of the tariff period i.e. twice during tariff period. One alternative to simplify the process is to determine the tariff of existing assets based on actual capital expenditure instead of projected capital expenditure, so that two applications of existing assets can be reduced to one in each tariff period. Further, the tariff of new assets can be determined during tariff period after commissioning of the new assets.

41.3 Further in case of new assets of transmission system, single petition may be admitted for all the individual elements of the project which have been commissioned within a year. Then annual fixed charges may be determined on consolidated basis and apportioned on proportion to the capital cost of individual elements. The true up maybe carried out on completion of the project based on balance sheet of individual project.

***Gescom views:***

***The cerc (terms and conditions of tariff) regulations 2019 has to be notified at least 6 months before the date of commencement of the tariff block ie 1.4.2019 to enable the generators to file the tariff petitions well in advance so that the tariff orders for the block commencing from 1.4.2019 to enable the generators to file the tariff petitions well in advance so that the tariff orders for the block commencing from 1.4.2019 will be issued by the commission in time. Further it will also enable the beneficiaries to know their liabilities and to execute their financial planning in aproper phased manner.***