Consultation Paper
On

TERMS AND CONDITIONS OF TARIFF REGULATIONS

For Tariff Period
1.4.2019 TO 31.3.2024

No. L-1/236/2018/CERC

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Disclaimer

The issues presented in this Consultation paper do not represent the views of the Central Electricity Regulatory Commission, its Chairman, or Individual Members, and are not binding on the Commission. The views are essentially of staff of CERC and are circulated with prime aim of initiating discussions on various aspects of tariff determination and soliciting inputs of the stakeholders in this regard.

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1. Introduction

1.1 The Central Electricity Regulatory Commission has been vested with the responsibility 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 28th January, 2016. The revised Tariff Policy, inter-alia, sets the goal for ensuring availability of electricity to different categories of consumers at reasonable rates for achieving the objectives of rapid economic development of the country and improving the living standards of the people. It also envisages adequate return on investment for the developer to attract investment in the sector. It further envisages transparency, consistency and predictability in approach for tariff fixation. Section 4 lays down the objectives of this Tariff Policy as under:

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

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

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

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

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

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

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

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

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

1.3 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 GW[1] 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 macro-economic 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 on 1.4.2019.

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.

2. Evolution of the Regulatory approach

2.1 The enactment of the Electricity Act, 2003 paved the way, inter-alia, for promoting competition and rationalisation of tariff. The provisions contained in

[1] 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 Section 63 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. Over time, 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.

3. Indian Electricity Sector – Availability & Cost of Supply

3.1 For the purpose of this paper, data relating to two immediate past tariff periods have been considered.

Availability

3.2 A glance at peak demand (in MW) and energy demand (GWh) as depicted in Table 1 below along with availability over the years reflects that both of these have increased substantially between 2009-10 and 2016-17.

Table 1 Demand and Availability from 2009-10 to 2016-17

	Energy Demand				Peak Demand			
	Requirement (GWh)	Availability (GWh)	Deficit Gwh	Deficit (%)	Demand (MW)	Availability (MW)	Deficit (MW)	Deficit (%)
2009-10	830594	746644	83950	10.11	119166	104009	15157	12.72
2010-11	861591	788355	73236	8.50	122287	110256	12031	9.84
2011-12	937199	857886	79313	8.46	130006	116191	13815	10.63
2012-13	998114	911209	86905	8.71	135453	123294	12159	8.98
2013-14	1002257	959829	42428	4.23	135918	129815	6103	4.49
2014-15	1067085	1028955	38130	3.60	148166	141160	7006	4.70
2015-16	1114408	1090850	23558	2.10	153366	148463	4903	3.20
2016-17	1142928	1135332	7596	0.66	159542	156934	2608	1.63

Source: CEA Report on "Growth of Electricity Sector in India from 1947-2017 (Table 8 p/74)".

3.3 From the above table, it may be seen that between 2012-13 and 2016-17, peak demand (in MW) increased at the compounded average growth rate (CAGR) of 3.45% (CAGR). For availability, however, the rate of growth was 5.65% during this period on account of addition of substantial coal based capacity, especially by the private sector. As a result, all India deficit has reduced to 0.66 - 0.70% in 2016-17 from about 10 - 11% about 10 years ago.[2]

3.4 As per Central Electricity Authority, there has been a significant increase in the installed capacity in country from about 105 GW in 2003 to almost 326 GW as on 31.3.2017 as may be seen in Table 2. During this period, the coal based capacity grew at a CAGR of about 10.54% whereas there was not much addition of hydro generation capacity. The per capita consumption of electricity has more than doubled from 559 units in 2002 to 1122 units in March, 2017[3].

Table 2 Installed Capacity and Per Capita Consumption

	Installed Capacity (MW)	Per Capita Consumption (KWh)
31.03.2002 (End of 9th Plan)	105046	559
31.03.2007 (End of 10th Plan)	132329	672
31.03.2012 (End of 11th Plan)	199877	884
31.03.2013 (1st yr of 12th Plan)	223344	914
31.03.2014 (2nd yr of 12th Plan	248554	957
31.03.2015 (3rd yr of 12th Plan)	274904	1010
31.03.2016 (4th yr of 12th Plan)	305162	1075
31.03.2017 (End of 12th Plan)	326833	1122

Cost of Supply (CoS)

3.5 The Average Cost of Supply (ACoS) of electricity for the period 2009-10 to 2015-16 is as under:

[2] CEA Report on "Growth of Electricity Sector in India from 1947-2017"
[3] CEA Monthly Report of February,2018 /Page 29 &31

Year	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16
Total Expenditure (in Crores of rupee)	2,52,125	3,00,678	3,69,275	4,23,377	4,61,625	5,03,774	5,45,779
Energy Sold (in Million Units)	5,29,225	5,80,997	6,24,951	6,57,629	6,98,169	7,53,436	7,89,512
ACoS (Paise/Unit)	476	518	591	644	661	669	691

(Source: PFC report on "The Performance of State Power Utilities" for respective years. Note: ACoS on Energy Sale has been worked out based on total expenditure divided by energy sold out units .Total expenditure comprises purchase cost, own generation cost and distribution cost. Purchase cost comprises generation cost and transmission cost.

3.6 For a distribution utility, the key factors impacting cost of supply of electricity are cost of purchase of power and efficiency in operations indicated broadly by AT&C losses. Generally, cost of purchase of power from generating stations constitutes about 60-70% of the total cost of supply of electricity of a distribution licensee. There has been an increase of about 28% in the cost of purchase of power between 2009-10 and 2015-16 as indicated in the table below.

Table 4 Power Purchase Cost (Paise/Unit)

Year	Power Purchase Cost*
2009-10	341
2010-11	376
2011-12	431
2012-13	474
2013-14	428
2014-15	439
2015-16	438

[*on gross generation excluding transmission losses] (Source: PFC Reports on performance of power utilities)

3.7 It may be seen from Table 3 and Table 4 above that the cost of purchase of power that constituted about 71% (=341*100/476) of the cost of supply of electricity in 2009-10 has come down to 63% (=438*100/691) in 2015-16. This implies that other costs viz. the operational cost of distribution utilities, including AT&C losses, have increased at a higher rate.

3.8 As can be seen from Figure 1, AT&C losses[4] of distribution utilities, which constitute a substantial portion of operational cost of distribution licensees, have not reduced much to have any substantial impact on the cost of supply of electricity. During 2009-10 to 2015-16, the AT&C losses have reduced only marginally from 25.39% to 21.81**%.**

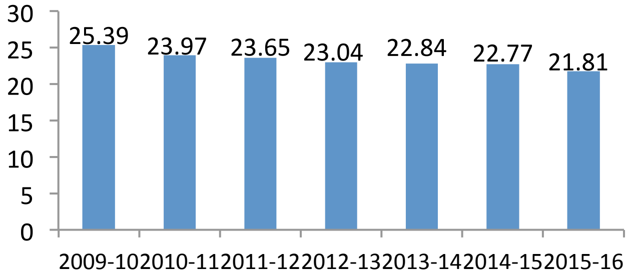


Figure 1: AT&C losses

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.

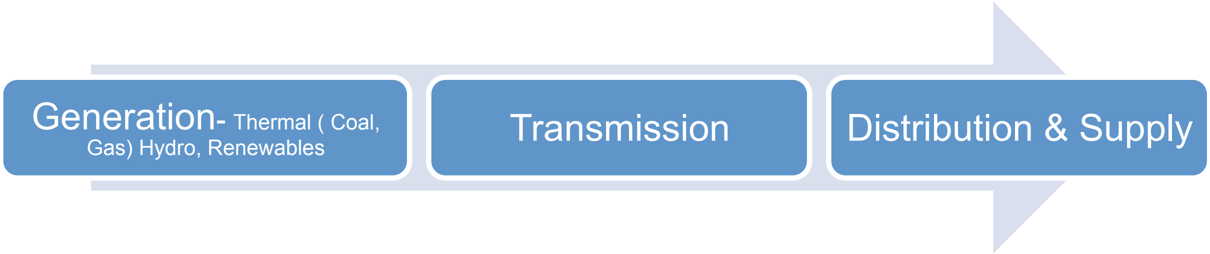


Figure 2: Value chain of electricity

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

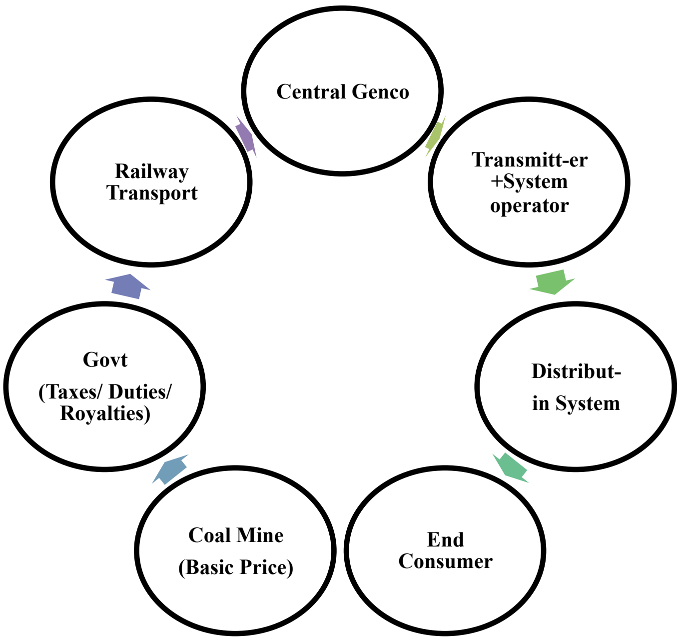


Figure 3: Value chain of electricity from coal source

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 end i.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 by 59.67%. 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 UHV to GCV in 2011.

Table 5 Comparison of coal related cost between 2009-10 and 2016-17

Year		2009-10	2016-17	Change
Basic Price (ROM)[1]	Rs/Tonne	560.00	760.00	35.71%
Taxes and Duties	Rs/Tonne	202.31	644.71	218.67%
Coal Cost[1]	Rs/Tonne	847.31	1,540.71	81.83 %
Coal Transportation[2]	Rs/Tonne	512.82	818.80	59.67%
Taxes & Duties on transportation	Rs/Tonne	44.24	194.58	339.83%

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

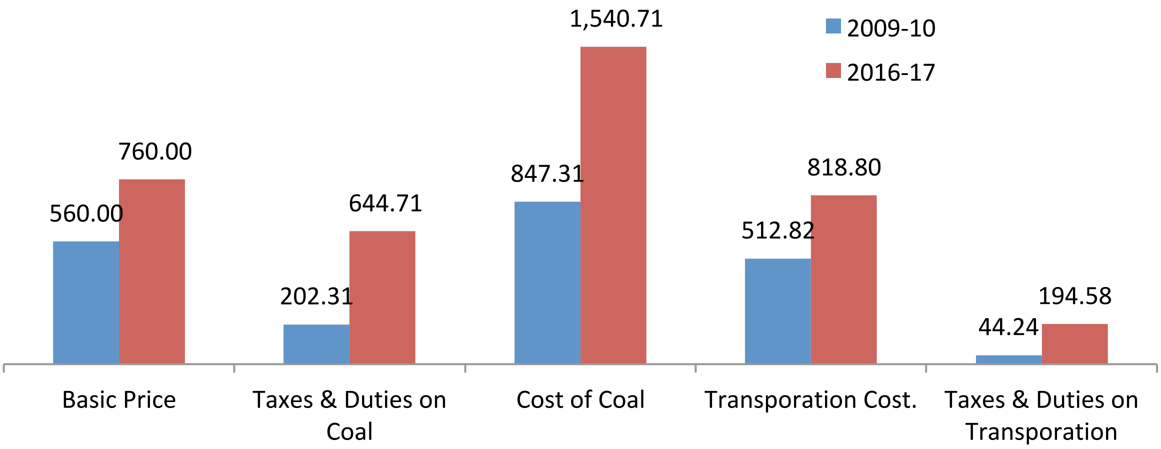


Figure 4: Comparative chart of coal related cost between 2009-10 and 2016-17

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**	69.54%
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	2016-17	Change
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 Consumption[2]	Kg/KWh	0.645	0.627	-2.84%

[[1]AT&C losses are as per Figure 1 given in Para 3.8. [2]Specific coal consumption is worked out 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 to 2375 Kcal and auxiliary consumption from 6.0% to 5.25%) and reduction in AT&C losses.

Value Chain of Electricity Generation and Supply from Hydro Source

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.

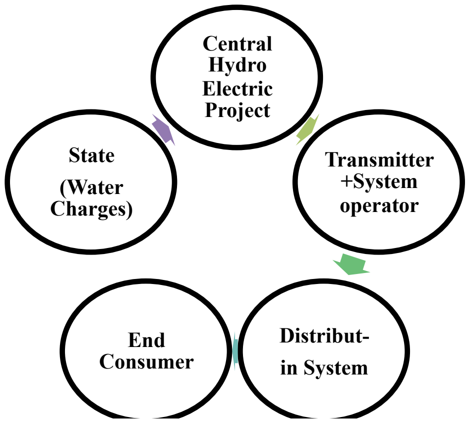


Figure 5: Value chain of electricity from hydro source

Value Chain of Electricity Generation and Supply from Renewable Source

4.10 The value chain of the electricity 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.

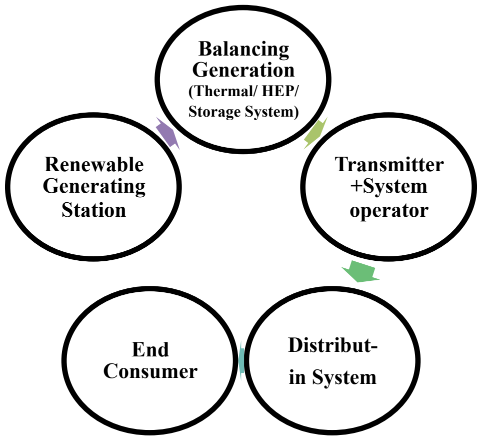


Figure 6: Value chain of electricity from RE sources

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	Change
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]

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 hydro power projects**.**

Table 9 Capital Cost

	Average Capital Cost (Cr / MW)	**AFC as % of 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

Note: Sample size of 30 for thermal and 20 for hydro projects have been considered to arrive the above data based on the various petitions received by the Commission.

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.

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 as under.

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)

2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
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% by 2021-22, taking into considerations likely demand growth of 6.34% (CAGR) and 175 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 utilisation) 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. Decarbonising 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 by 2022. 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).

C. Gas based Thermal Generation

5.3.1 The gas based thermal generating stations offer greater capability of ramping up and ramping down. Thus, gas based generating station can provide alternative source for balancing power to address the intermittency of renewable generation. However, the gas based generating stations having concluded PPA are facing problem due to shortage of supply of gas from domestic source. The alternative may be to source costlier gas either from spot market or R-LNG.

D. Integrated Power Project with Coal Mine

5.4.1 Coal Mines have been allocated to the NTPC Ltd. and Damodar Valley Corporation (DVC). The present regulatory framework allows pass through of the fuel (coal) cost as determined by the Coal India Ltd. However, in case of coal supplied from the integrated mine or mine owned by the generating company, the challenge will be the determination of the coal cost.

E. Hydro Generation

5.5.1 The share of total installed capacity of hydro power is a meagre 14% of the total installed capacity.

5.5.2 Hydro projects are highly capital intensive and have long gestation period. With majority of the plants located at remote and inaccessible regions, hydro projects generally get delayed due to various factors which, inter alia, include geological surprises, natural calamities, lengthy clearance time, law & order problems and delay in implementation of R&R Plans. These factors result in time and cost overrun which in turn increases the capital cost, leading to higher and, often, unviable tariff.

5.5.3 The hydro generation offers greater advantages with its economical and environmental friendly power resource in the long run. However, the cost of electricity of hydro power is comparatively expensive vis a vis coal based power plants in the short-run. In view of this, the hydro projects find it difficult to attract investment and many times, do not find buyers. Since the tariff of hydro power is low in the longer run and that it has inherent flexibility, the hydro power generation will have a significant role in future especially in view of large scale additions of renewable energy sources in the grid that has inherent intermittency. Therefore, there is a need to address factors that currently drive hydropower costs up.

5.5.4 The pumped storage hydropower stations have generally been integrated as a part of the generation project. In present regulatory framework, additional return has been provided for pumped storage plants.

5.5.5 Flexibility of hydro power helps in the grid balancing required due to the renewable generation. The challenge is to evolve a suitable regulatory framework to make the hydro operation flexible.

F. Inter-State Transmission

5.6.1 The transmission system has undergone change after introduction of Central Electricity Regulatory Commission (Grant of Connectivity, Long Term Access and Medium Term Access in inter-State transmission and related matters) Regulations, 2009 & Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010.

5.6.2 However, issues have emerged in development of the transmission system that relate to planning and co-ordination like matching with generation project and readiness of downstream network; delay due to Forest & Wildlife clearance, right of way (RoW) issues; relinquishment of LTA by IPPs and consequent recovery of transmission charges from abandoned/stalled generation projects.

G. 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.

H. 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 is 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 significant in case of domestic coal as the GCV measurement is being done at Free on Board (FOB) through acceptable practice. This poses specific challenges with respect to the measurement point and method/ procedure for measurement of Gross Calorific Value (GCV).

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.

I. Provisions of Revised Tariff Policy, 2016

5.9 Ministry of Power, Government of India, has notified the Revised Tariff Policy, 2016 which came into effect from 28th January 2016. Some provisions in the Tariff Policy, 2016, will have impact on the Tariff Regulations.

a) Clause 5.2 provides exemption to the existing generating companies from competitive bidding to carry out one time expansion of 100% of the existing capacity with a view that the benefit of the infrastructure cost of existing project should be passed on to consumers through tariff. While allowing expansion as per the provision of the Tariff Policy, the Commission has to ensure that the benefit in reduction of costs due to sharing of infrastructure of existing project should be passed on to the consumers. The regulation will need to incorporate provisions of regulatory oversight:

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

c) Clause 5.5 provides that the Appropriate Commission shall fix time period for commissioning of Hydro Electric Project. The Commission will be required to consider this while determination of commercial operation date of HEPs for tariff purpose:

d) 2nd Proviso to the Clause (c) of clause 5.11 has mandated to specify upper ceiling of the rate of depreciation and an option to the developer to seek lower rate of depreciation. The implementation of the above provision would require modification in regulations in terms of treatment of depreciation:

e) Sub-clause 3 of Clause 6.2 provides for inclusion of the cost of setting up coal washeries, coal beneficiation system and dry ash handling & disposal system in the cost of the project. The definition of generating station under the Act and the project as considered in the tariff regulations so far do not include capital cost associated with fuel mine or port handling etc. which is required to be addressed in the regulations:

f) Sub-Clause 5 of Clause 6.2 provides for mandatory use of water from sewage water treatment plant. Since the existing approach provides specific treatment of water charges, same is required to be reviewed in light of the above provision.

6. Some Relevant Factors

6.1 In view of the challenges and the developments that have taken place in the Electricity Sector over time, factors highly relevant while specifying the terms and conditions for determination of tariff are:-

a) Stable and affordable electricity prices;

b) Promoting efficiency in the entire value chain to benefit end consumers:

c) Appropriate allocation of risks based on commercial principle;

d) Encourage commercial contracts with clear risk allocation, responsibility of each party and their rights & obligations;

e) Ensuring optimum utilization of the generation and transmission capacity and recovery of cost in reasonable manner;

7. Tariff Design: Generation and Transmission

7.1.1 The tariff design has evolved in order to harness available resources in an optimal manner to meet the growing demand. For this, performance-based cost of service was evolved and implemented during the previous control periods. Further, in order to induce efficiency, some of the components of tariff were pre-specified on normative basis. Following tariff design has been adopted for generation (thermal, hydro and renewable) and transmission.

7.1.2 The existing tariff structure are as under:

I. Two part tariff structure for generation: -

a) Fixed charges representing fixed cost components and energy charges representing variable component with incentive and disincentive mechanism; and

b) For hydro power plants, the recovery of fixed charges is through two components i.e. "capacity charges" & "energy charges", each component representing 50% of Annual Fixed Charges (AFC). Recovery of "capacity charges" is linked to availability of plant and recovery of "energy charges" is linked to actual energy generated;

II. Single part tariff structure for inter-state Transmission system: -

a) Annual fixed charges with incentive and disincentive linked to availability of the transmission system.

III. Feed-in Tariff structure for Renewable Generation: -

a) Feed-in Tariff structure comprising fixed charges of the renewable generation project.

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 utilisation 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 procurers having 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.

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).

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.

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 have 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&M cost 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.

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.

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.

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 i.e 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.

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;

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;

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.

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 may be..."*

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.

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. Section 61(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.

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.

<u>Options for Regulatory framework</u>

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 may be 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;

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

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;

<u>Options for Regulatory framework</u>

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.

(b) Assign responsibility of operation of the hydro power stations and pumped mode operations at regional level with the primary objective for balancing. For 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 designated 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.

Gas based Thermal Generations

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

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

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.

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 undischarged 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 for the 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 as per 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 capitalised 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 may be 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.

<u>Options for Regulatory Framework</u>

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. The return 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 be introduced.

Comments/ Suggestions

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

12. Renovation & Modernisation

12.1 The generating companies and the transmission licensees are allowed to undertake renovation & modernisation 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 & modernisation 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 modernisation 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 upgradation 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, hardwares, 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, earthwire etc. The transmission lines which are in service for more than 25 years 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, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The

Commission may allow Renovation & Modernisation (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.

13. Financial Parameters

13.1 The performance based cost of service approach, a combination of actual cost and normative parameters has been evolved for the Tariff regulations. Components like return on equity, operation & maintenance expenses and interest on working capital have been specified on normative basis whereas cost of debt has been allowed based on actual rate of interest on normative debt. The normative parameters are expected to induce operational and financial efficiency. While continuing with the hybrid approach, more weightage may be provided for normative parameters to induce greater efficiency during operation as well as in development phase.

Comments/ Suggestions

13.2 Comments and suggestions are invited from the stakeholders for continuation of normative approach for specifying financial parameters and alternatives, if any.

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 in 2009-14 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.

v) 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 approaches i.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 modernisation 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.

iii) The useful life of Hydro Stations, as specified in Tariff Regulation, 2009, is 35 years. However, the actual life of these Hydro stations may be much more than 35 years. For hydro stations allowing higher depreciation rates during first 12 years 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 28 January 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;

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

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

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;

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.

f) Reduce rates which will act as a ceiling.

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

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 approach as 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.

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% (upto 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

17. Return on Investment

17.1 In a cost plus tariff setting approach, the utilities are allowed to earn a reasonable return on their investments besides recovering all other costs incurred through tariff. The return on investment is allowed as a compensation to the investors for assuming the investment related risks. It is based on opportunity cost principle and risk premium. Under the concept of cost of capital approach, the rate of return is allowed on the basis of different components viz. return on equity, cost of debt etc. catering to the different types of investors.

17.2 Section 61 (d) of the Electricity Act, 2003 and Para 5.11 (a) of Tariff Policy 2016 have laid down broad guiding principles for determination of rate of return. These have mandated to maintain a balance between the interests of consumers and need for investments while laying down the rate of return. It is stipulated that the rate of return should be determined based on the assessment of overall risk and prevalent cost of capital. Further, it should lead to generation of reasonable surplus and attract investment for the growth of the sector. As per the Tariff Policy, the Commission may adopt either Return on Equity (RoE) or Return on Capital Employed (RoCE) approach for providing the return to the investors.

17.3 Over a period of time, allowing fixed rate of return on equity has evolved as an acceptable approach and the same has been followed by most of the State Electricity Regulatory Commissions. The RoE approach has been widely accepted by investors in the sector. The large scale investment in the power sector is attributable to the approach of fixed rate of return. The Commission had compared both the approaches viz. RoE and RoCE while framing the Tariff Regulations for 2014-19 and decided to continue with RoE approach with the following observations in the Explanatory Memorandum;

> *"As the tariff is determined on multiyear principles, it is important to maintain certainty in approach over each control period to maintain the confidence of investors and regulated entities. In view of the fluctuating interest rate, shallow debt market and considering the financial health of Utilities and the other serious issues faced by Developers in sector such as fuel shortages etc., it appears that it is not the desirable to switch to ROCE approach and thus the Commission proposes to continue with the ROE approach for next Tariff Period. Further most of the stakeholders have suggested for continuing the existing ROE approach."*

Comments/ Suggestions

17.4 Comment and suggestions are invited from the stakeholders on the continuation of fixed rate of return approach or alternatives, if any.

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 CAPM model 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 in completion 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.

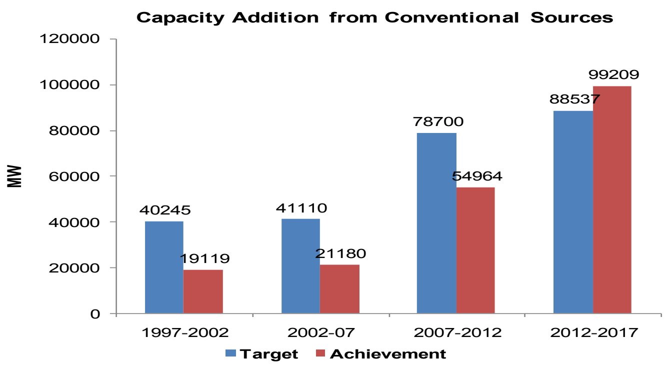


Figure 7: Capacity addition from conventional sources

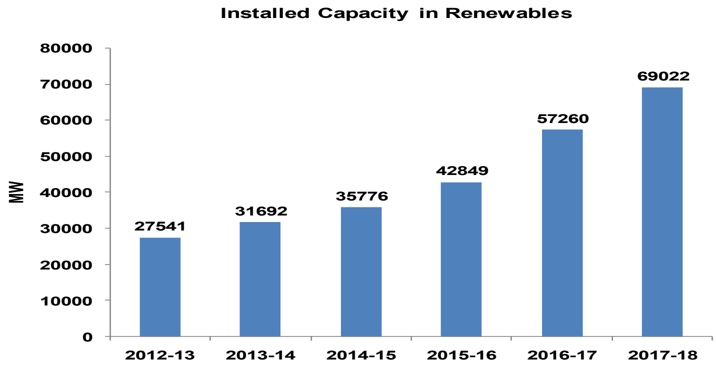


Figure 8: Installed capacity of renewables

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

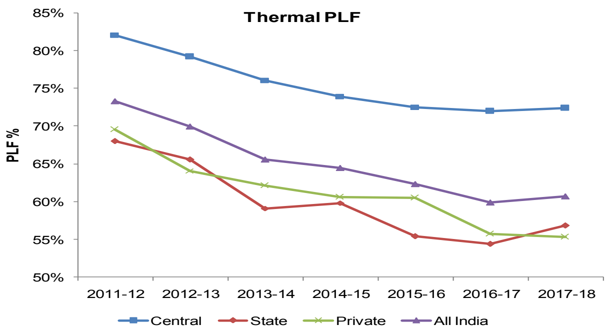


Figure 9: Plant load factor (thermal)

• The PLF of thermal power plant has come down steadily during last 4-5 years (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 term.

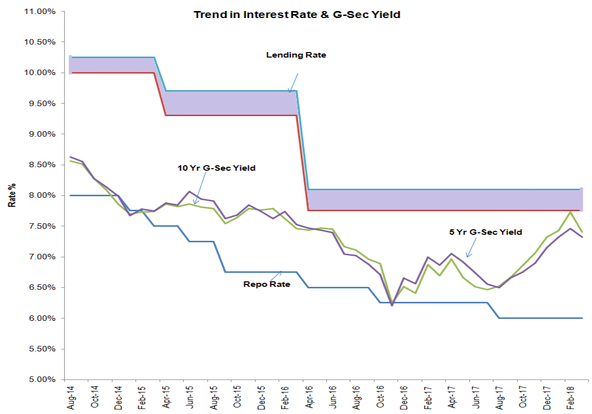


Figure 10: Trend in interest rate & G-Sec yield

• 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.

<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;

(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;

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

(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;

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

(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;

(g) Reduction of return on equity in case of delay of the project;

Comments/ Suggestions

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 at is 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.

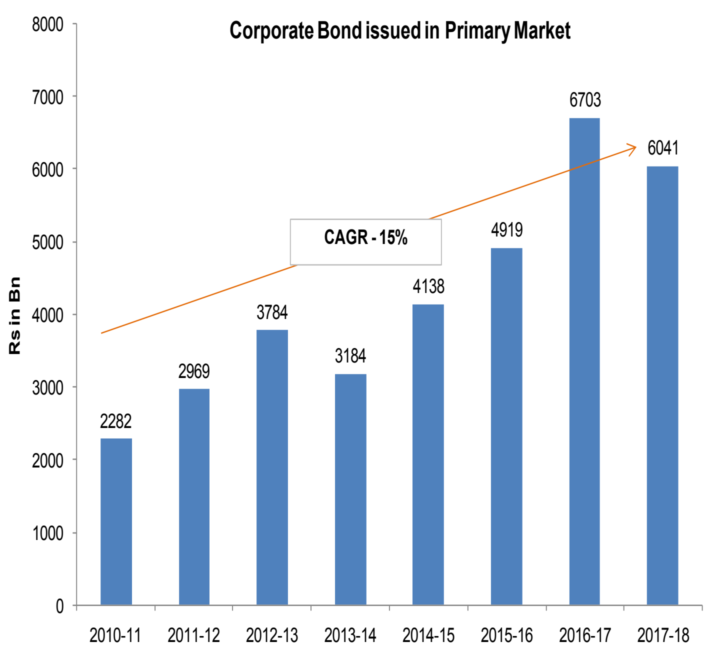
19.2 Clause (d) of para 5.11 of Tariff Policy, 2016 has stipulated that the utilities should be encouraged and suitably incentivized to restructure their debt for bringing down the tariff. The Tariff Regulations for 2014-19 has provided that the regulated entities shall make every effort to refinance 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 factors viz. quantum, tenor, type, timing, etc. As of now utilities are predominantly borrowing from banks and other financial institutions for capital expenditure through non-standardized and 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/debt market depend 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 GDP have grown from around 5% in 2012 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 around 15%. 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.

Figure 11: Corporate bonds issued in primary market



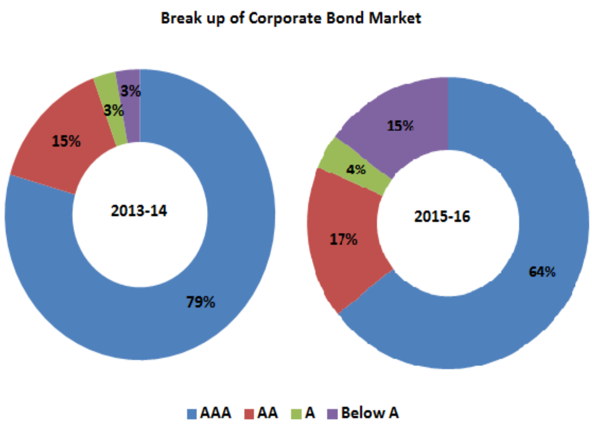


Figure 12: Break-up of corporate bond market

- 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 to 6% in August, 2017. Since August 2017

RBI 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. RBI policy 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.

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.67/13.03.00/2015-16 dated 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&M expenses.

(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 also yield higher cost for “Maintenance Spares” in IWC. Therefore, option could be to de-link “Maintenance Spares” in IWC from O&M expenses.

(e) In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with “target availability” can be reviewed.

Comments/ Suggestions

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

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 of 2009-10 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 period 2014-19, 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 200 MW projects and for stations more than 200 MW respectively. But O&M expenses 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, 0.85 and 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 for O&M expenses for all plants irrespective of its life may need a relook.

Options for Regulatory Framework

21.7 (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

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

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 is used 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 of SHR 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 in the 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 a 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 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 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 GCV measurement is followed on Air Dryed basis at CIF for billing purpose, whereas in case 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.

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 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. 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.

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,dated 30.12.2012, 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.

24. Fuel - Landed Cost

24.1 The present regulatory framework provides for the computation of energy charges based on landed cost of fuel. The landed cost of fuel includes the cost components upto 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.

24.2 The generating company has to provide the necessary details of the cost included in the landed cost of fuel. Different generating companies follow different practices for supplying such information. Further, asymmetry of information for different fuel sources creates ambiguity for billing energy charges. There may be a need to specify the required information to be supplied and the standard procedure to be followed while claiming bills for energy charges.

24.3 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 prices were administered. Subsequently, there have been several developments. The Government has opened the coal mine to private companies. Today, the generating company may procure coal either 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.

24.4 The landed cost of fuel constitutes different components such as basic run of mine (ROM) price, sizing charges, surface transportation charges, royalty, stowing excise duty, fuel surcharge, cess etc. Further, the components may vary depending upon the source of coal. In case of railway transport, it involves basic freight, terminal charges, busy season surcharges etc. In case of imported coal, it includes the FOB price, over sea transportation, port handling charges, rail transportation, road transportation etc. As a result, there is wide variations in terms of cost and number of cost components involved in the landed fuel cost, changes in which cause corresponding fluctuations in the tariff. The energy charges largely depend on the fuel cost which is determined by the cost components allowable as part of tariff.

Option for Regulatory Framework:

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.

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

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

26. Operational Norms

26.1 The Tariff Policy dated 28th January, 2016 provides the guiding principle for fixation of operational norms as under:

- Suitable performance norms of operations together with incentives and dis-incentives would need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. The operating parameters in tariffs should be at "normative levels" and not at "lower of normative and actual".

- The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipments, nature of operations, level of service to be provided to consumers etc.

26.2 The regulatory approach evolved for specifying operation norms was based on historical data analysis and consideration of efficiencies, technological advancement, vintage etc. However, in case of existing projects, where projects specific notifications of Government of India existed or if there was a PPA entered between the parties, the norms specified therein were applied. In so far, as the operational norms in respect of PLF and Target Availability are concerned, these were separately laid down by the Commission.

26.3 Thermal Generation (Coal based)

Station Heat Rate

26.3.1 Station Heat rate (SHR) refers to the conversion efficiency of thermal heat energy into electrical energy and used for computation of energy charges. The Commission while framing the Regulations for terms and conditions of tariff for different tariff periods has been considering the operational data of the generating stations for the past 5 years. The methodology of considering 5 years data ensures that the generator is able to recover the cost of electricity in a reasonable manner and covers the reduction in the generation level. The heat rate norm specified during previous tariff periods are as under:

Table 12 Comparison of SHR between 2009-14 and 2014-19 tariff periods

2009-14 Tariff Period	2014-19 Tariff Period
200/210/250 MW Sets - 2500 Kcal/kWh	200/210/250 MW Sets - 2425 Kcal/kWh
500MW and above - 2425 Kcal/kWh	500MW and above - 2375 Kcal/kWh
Coal & Lignite: GSHR= 1.065 X Design Heat Rate,	Coal & Lignite: GSHR= 1.045 X Design Heat Rate,
Natural Gas & RLNG: GSHR= 1.05 X Design Heat Rate,	Natural Gas & RLNG: GSHR= 1.05 X Design Heat Rate,
Liquid Fuel: GSHR= 1.071 X Design Heat Rate	Liquid Fuel: GSHR= 1.071 X Design Heat Rate

26.3.2 The GCV measurement of coal was shifted to “As Received” basis for the purpose of energy charges computation in the Tariff Regulations for the period 2014-19 as per the advice of Central Electricity Authority.

26.3.3 In the present scenario, most of the coal/lignite/gas based thermal power plants are running at low utilization (PLF) levels due to various reasons including shortage of coal/gas, lower demand etc. Machines working at lower PLF have adverse impact on the operational norms and hence, the existing heat rate norms for the new and existing generating stations are required to be reviewed along with the need for margin. The norms of heat rate will be over and above the heat rate guaranteed by the OEM based on actual performance data during the last five years.

26.3.4 The heat rate is a crucial parameter as it has substantial impact on tariff. The gain/savings on account of heat rate are to be shared with the beneficiaries. Therefore, heat rate is required to be specified giving due consideration to all relevant factors including shortage of domestic coal supply in the country. The heat rate norms would also required to be seen in the light of efficiency improvement targets achieved by the generating stations under the PAT scheme. The heat rate norms varies with the passage of useful life of the project due to degradation and therefore, the norms specified based on the recently commissioned plants may not be attainable by older plants.

26.3.5 The existing regulations provides for calculation of Gross Station Heat rate for new stations based on Designed Heat Rate with margin of 4.5%. This margin specified for gross station heat rate is based on recommendation of the Central Electricity Authority.

26.3.6 Approach for determination of station heat rate may need review including the criteria for specifying heat rate of old plants, continuation of relaxed norms for specific stations and possible changes required in the existing norms given in Tariff Regulation 2014-19.

Specific Secondary Fuel Oil Consumption

26.3.7 The existing norm for the Secondary Fuel Oil Consumption is 1.00 ml/KWh for lignite based CFBC technology with some exception in case of TPS-I and 0.50 ml/KWh for Coal based project with the provision for sharing of savings with the beneficiaries. Further reduction in specific secondary fuel oil consumption norms may adversely affect the boiler operations under different operating conditions including partial loading of units due to fuel shortage conditions. With contribution from renewable generation increasing in the grid, thermal power plants are facing frequent regulations of supply and operations at lower PLF up to technical minimum. The consumption of secondary fuel oil would change on account of nature of operations.

Auxiliary Energy Consumption

26.3.8 The existing norms of auxiliary consumption of coal based generating station varies from 5.25% for unit size of 500 MW and above to 8.5% for 200 MW series units with steam driven boiler feed pumps and electrically driven boiler feed pumps and relaxed norms for specific generating stations of smaller size. Auxiliary consumption for gas based generating station varies from 1.0- 2.5% depending on open or combined cycle operation. The existing norm of auxiliary consumption of lignite based generating station is 0.5% more than coal based generating station with electrically driven feed pump and 1.5% more if the lignite fired station is using CFBC technology. The auxiliary consumption does not include colony power consumption and construction power consumption.

26.3.9 Presently, the auxiliary consumption of 800 MW is fixed based on 500MW sets. The auxiliary consumption of 800 MW sets may vary depending on the size of the unit and economies of scale.

26.3.10 Generating stations which have less auxiliary consumption than the norms, are able to declare higher availability by making adjustment of difference between actual (lower) and normative auxiliary consumption. Further, colony consumption is not a part of auxiliary consumption w.e.f. 1.4.2014 and therefore, the same cannot be accounted for against auxiliary consumption while declaring availability. Methodology of declaring availability after reduction of normative auxiliary consumption and colony consumption need elaboration. .

Normative Annual Plant Availability

26.3.11 In control period 2014-19, the target availability has been determined based on the data available for the past years. The recovery of fixed charges was linked to availability. The availability of 85% is specified with exceptions of specific plant wise availability. The existing availability norms are uniform for all the generating stations. Now with the increase of private participation, access to imported fuel by private developers and technological improvement may have improved the availability. The issue of different availability norms for existing and new plants can be contemplated.

26.3.12 Shortage of domestic fuel affects availability of the plants and their scheduling. The existing norm for availability may therefore to be revisited. In the event of bridging gap through e-auction or imported coal (other than fuel arrangement agreed in purchase agreement), the need of prior consent of beneficiary, maximum permissible limit of blending etc. also need to be deliberated.

26.3.13 As per present regulatory framework, the recovery of annual fixed charges is based on cumulative availability during the year. There may be a chances of declaring lower availability during the peak demand period when the beneficiaries may be required toe resort to procurement from short term market to meet their demand. However, during low demand period, the generating station may declare higher availability so as to achieve the target cumulative availability on annual basis to recover the full annual fixed charges. In this process, the beneficiaries may not get the electricity when required at the time of high demand.

26.3.14 In case of partly tied up capacity, the plant availability factor for whole plant may not be relevant. The consideration of merchant capacity for the purpose of plant availability declaration is not relevant**.**

26.3.15 The existing norms of annual plant availability may need review by considering fuel availability, procurement of coal from alternative source, other than designated fuel supply agreement, shifting of fixed cost recovery from annual cumulative availability basis to a lower periodicity, such as monthly or quarterly or half yearly;

Transit & Handling losses

26.3.16 The Commission had specified norm of 0.2% for the pit head station and 0.8% for the non- pit head stations as loss in transit & handling. The same may have to be reviewed based on the actual data of the past period.

26.3.17 There is often grade slippage of coal from the coal mines to generating stations. As per fuel supply agreement (FSA) signed by generating station with coal supplier, ownership of the coal get transferred at coal dispatch point i.e. at the mine. Therefore, it becomes the responsibility of the generating company to ensure that the grade that is billed to the generator is dispatched by the coal companies though generators have really no control over such dispatch. It is often reported that there are substantial loss in GCV of coal due to grade slippage and loss in quantity.

26.3.18 A regulatory option could be that the generating station shall only pay for coal "As Received" at the plant plus normative transmission loss of GCV and quantity as per CERC norms. This can be addressed in the Tariff Regulation by indicating GCV as "As Received at plant end" and customization of Form-15 regarding the GCV.

Comments/ Suggestions

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

26.4 Thermal Generation (Coal washery rejects based)

26.4.1 The Tariff Policy dated 28th January, 2016 provides as under:

> *"5.4 The Central Electricity Regulatory Commission in consultation with Central Electricity Authority and other stakeholders shall frame within six months, regulations for determination of tariff for generation of electricity from projects using coal washery rejects. These regulations shall also be followed by State Electricity Regulatory Commissions.*
>
> *Provided that procurement of power from coal washery rejects based projects developed by Central/State PSUs, Joint Venture between Government Company and Company other than Government Company in which shareholding of company other than Government Company either directly or through any of its subsidiary company or associate company shall not be more than 26% of the paid up share capital, can be done under Section 62 of the Act."*

26.4.2 The Tariff Regulations, 2014 provides operational norms for thermal power plant based on coal washery rejects. Coal rejects exhibit distinguished characteristics. Coal rejects cannot be stacked as it would require a substantial amount of land at the mine site and storing of rejects for prolonged period is hazardous as it may lead to combustion.

Comments/ Suggestions

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

26.5 Transmission System

Transmission Availability Factor

26.5.1 Availability of Transmission System/ elements is expected to increase with introduction of new technology like polymer insulators etc. Thus, the mechanism of payment of transmission tariff based on availability of transmission system may need review.

26.5.2 The methodology for computation of Transmission system availability in tariff period 2009-14 was changed from earlier tariff period. As per 2009-14 Regulations, computation of availability of transmission system, Transmission System Availability Factor for a month (TAFM) was computed as (100- 100X NAFM), where NAFM is the non-availability factor in per unit for the month. The procedure of computation of transmission system factor for a month was provided in Appendix-IV of Tariff Regulation, 2009. This methodology of availability factor(TAFM) was again revised in Tariff Regulations,2014 wherein the weightage factor was considered based on the individual group such as transmission line, ICTs and Reactors etc.

26.5.3 In 2009-14 Tariff Regulations, computation of NAFM for the transmission system, outage hours for transformer was multiplied by a weightage factor of 2.5 and outage hours of reactors was multiplied by a weightage factor of 4. Factors were applied such that a 315 MVA transformer would have the same weightage as a 200 km long D/C line with twin conductors, and a 50 MVAR switched reactor would have one-fourth the weightage of a 315 MVA transformer. In 2014-19 Regulations, the weightage factor has been worked out based on actual availability (net of non-availability period) and total availability of region separately for transmission lines, ICTs and Reactors etc. There is a need to validate the existing methodology of weightage factor by considering actual data/availability.

26.5.4 As per the existing regulations, the maximum incentive for AC system is around 1.27% (99.75/98.5) while for HVDC, it is around 3.91% (99.76/96). Further, in case of inter-regional links, the present framework requires certification as to whether it is export region or import region.

Options for Regulatory Framework

26.5.5

a) Existing approach for computation of Transmission system availability and weightage factors to be applied for outage hours for transformer and reactors;

b) Review of the incentive formula for HVDC bi-pole and HVDC back-to-back stations at par with AC system;

c) Specify appropriate region (import or export) for certifying the availability of Inter-regional links (AC and HVDC line) for the purpose of incentive and recovery of annual fixed charges; and

d) Review of the existing methodology or procedure for computation of availability, monthly availability and cumulative availability;

Transmission Losses

26.5.6 Presently, there is no regulatory framework on specifying the norms for transmission losses. Transmission loss comprises primarily of technical losses, which consists mainly of power dissipation in electricity system components such as transmission line, transformers and measurement systems. The transmission losses are dependent on the best operational practices, efficient planning, level of power flow and avoidance of circular flow. The operational strategies and practices adopted by transmission network operator and system operator impact the transmission losses.

26.5.7 The transmission losses considered in the present scheduling framework is about 4.5-5% for inter-state transmission system and 4-4.5% for intra-state transmission system. As a result, the net power delivered to the distribution periphery is reduced by about 9-10%, which has an impact on the cost of supply. An option could be to introduce the norms for inter-state transmission losses based on factors within control and international benchmarks.

26.5.8 The existing approach for operational norms and level of Normative Annual Transmission Availability Factor (NATAF) may be reviewed. The weightage factor to be applied for arriving outage hours for calculating NAFM of transformer and switchable reactor of substation element may also be deliberated upon.

Comments/ Suggestions

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

26.6 Hydro Generation

26.6.1 The existing Operational norms of Hydro generation include norms for auxiliary consumption, transformation losses and normative annual plant availability factor. Capacity Index as a measure of plant availability was implemented by the Commission during tariff periods 2001-2004 and 2004-09. It was based on the concept that hydrology risk has to be borne by beneficiaries all the time. After consultation, capacity index concept was modified with the new concept of Normative Annual Plant availability Factor (NAPAF) during 2009-14 and continued during 2014-19 based on actual data. However, in case of a few hydro plants the same was revised. This is based on the premise that hydrology risk is to be shared by the generator & the beneficiary in the ratio of 50:50. There may be need for review of existing values of NAPAF based on actual PAF data for last 5 years.

26.6.2 The norms of auxiliary power consumption of hydro generating station vary from 0.7% to 1.2% based on rotational or static excitation system. The transformation losses are covered as a part of auxiliary consumption.

Comments/ Suggestions

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

27. Incentive

27.1 For generation, the incentive prior to 2009 was linked to normative PLF and 25 paise/kWh was paid for generation beyond normative PLF in case of thermal generating station. The incentive, in case of hydro generating station, prior to 2009 was linked to the capacity charges and capacity-index. The incentive during tariff period 2009-14 was linked to normative availability and generation beyond normative availability was payable at the fixed charge rate for the stations which are more than 10 years old or at 50% of the fixed charge for the stations up to 10 years old. In case of hydro generating stations incentive was linked to the capacity charges (50% of annual fixed charges) and normative availability. During the Tariff Period 2014-19, incentive for coal based generating plant was again linked to normative PLF of 85% @ 50 paise.

27.2 At present there is same incentive for availability during peak and off peak period. There may be a need for introducing differential incentive during peak and off peak periods. On the same consideration, there may also be a need for higher incentive for the storage and pondage type hydro generating station providing peaking support. At present, generation beyond the design energy is paid at 80 Paise/kWh in case of hydro generating station, which may also need review.

27.3 As regards transmission system, incentive is being recovered only through monthly formula of billing and collection of transmission charges.In the absence of clear provision regarding reconciliation of annual transmission charges and incentive with monthly billing, the concept of NATAF specified by the Commission in Tariff Regulations, 2014 requires review.

27.4 In view of the introduction of the compensation mechanism for operating plants below norms i.e.83-85%, there may be a need to review the incentive and disincentive mechanism with reference to operational norms.

Options for Regulatory Framework

27.5 (a) Review linking incentive to fixed charges in view of variation of fixed charges over the useful life and on vintage of asset - Need for different incentives for new and old stations;

(b) Different incentive may be provided for off peak and peak period for thermal and hydro generating stations. Differential incentive mechanism for storage and pondage type hydro generating stations may also be considered.

(c) Review the incentive and disincentive mechanism in view of the introduction of compensation for operating plant below norms.

(d) Review the norms for availability of transmission system.

Comments/ Suggestions

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

28. Implementation of Operational Norms

28.1 The new tariff regulations take effect from 1st April of the tariff period. The Tariff Regulations require the generating company or transmission licensee to file the petitions within 180 days from the date of notification of the regulations. Since the tariff determination is quasi-judicial function, there is a time lag between filing the petition and finalization/ issuance of tariff order. Till the issuance of final order, the generating company or the transmission licenses keep charging the tariff based on previous tariff order including operational norms. The operational norms notified by the Commission in new tariff regulations take effect much after the date of coming into force of new tariff regulations. Consequently, the benefits of the improved operational norms are passed to beneficiaries only after time lag of few months.

Comments/ Suggestions

28.2 Comments and suggestions of stakeholders are invited whether the operational norms of the new tariff period should be implemented from the effective date of control period irrespective of issuance of the tariff order for new tariff period.

29. Sharing of gains in case of Controllable Parameters

29.1 The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement in controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil consumption, refinancing of loan and the true up of primary fuel cost. Subsequent to above, the compensation mechanism has been introduced for operation in CERC (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016. The compensation mechanism aims to provide compensation if generating plant is operated at improved norms than ones specified in the amended IEGC Regulations of 2016. In view of the compensation mechanism, it needs to be considered as to whether the ratio of sharing of benefit may be reviewed.

29.2 The compensation mechanism introduced through IEGC entails the hedging of the risk of operating at low PLF. The compensation coupled with normative controllable parameters creates a buffer for generating companies. In view of this, the merit order operation can be linked with the PLF in such a way that the plants under Section 62 may be encouraged to compete for maximum PLF.

29.3 Further, different generators adopt different methodology for sharing of gain, say on monthly or annual basis. Thus, procedure for the monthly reconciliation or annual reconciliation mechanism may need to be prescribed.

30. Late Payment Surcharge & Rebate

30.1 The present regulatory framework provides for late payment surcharge at the rate of 1.50% per month for delay in payment beyond a period of 60 days from the date of billing. In view of the introduction of MCLR, the rate of late payment surcharge may need to be reviewed. One option is to add some premium over and above MCLR.

30.2 Further, as per the existing regulations, the rebate is provided if payment is made within 2 days of presentation of the bill. Valid mode of presentation of bill, (email, physical copy etc.), authorised signatory, definition of two days (working days or including holidays) may need elaboration.

31. Non-Tariff income

31.1 The tariff determination under Section 62 of the Act follows the principle of cost of recovery which inter-alia provides the reimbursement of cost incurred by the generating company or the transmission licensee. The income on account of sale of fly ash, disposal of old assets, interest on advances and revenue derived from telecom business may be taken into account for reducing O&M expenses. Present regulatory framework does not account for other income for reduction of operation & maintenance expenses. However, in case of transmission licensee, the income earned from telecom business are adjusted in the billing separately. The principle of treatment of other income as applicable in case of transmission can be extended for the generation business.

31.2 Presently, the revenue from telecom business is adjusted at the rate of Rs 3000/- per KM, which was fixed in 2007. It may need review.

32. Standardization of Billing Process

32.1 Presently, generating companies and the transmission licensees are following different practice for raising bills on the basis of tariff order. In order to avoid possible disputes in billing, it need to be consider as to whether standardization of billing process including formats, verification and timeline etc. may be done.

32.2 Some of the States are imposing electricity duty on the actual auxiliary consumption which may be higher or lower than the normative auxiliary consumption. Such electricity duty is passed on to the beneficiaries along with the monthly bill. Whether electricity duty is to be linked with actual auxiliary consumption or normative consumption or lower of the two, may need to be specified.

33. Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants)

33.1 As per the new Environment norms notified by Ministry of Environment, Forest and Climate Change, the TPPs would be required to install or upgrade various emission control systems like Flue-Gas desulfurization ("FGD") system, electrostatic precipitators ("ESP") system etc. to meet the revised standards. Recovery of the investment made during operation period in the form of additional capitalization through redesigning or retrofitting of plant and related operational costs require a mechanism in the tariff regulations.

33.2 Several generating companies have filed petition for approval of additional capital expenditure under "change in law" for complying the revised standards of emission for thermal power projects. CEA may be required to specify and benchmark appropriate technology and costing norms, apart from preparing phasing plan for shutdown during installation of emission related retrofits/ equipment. The generating companies would be required to select suitable technology at competitive rates through the process of transparent competitive bidding to minimize the impact on tariff in the power supply agreement.

<u>Option for Regulatory framework</u>

33.3 There is likelihood of significant impact on tariff on account of compliance with these norms. Supplementary tariff could be determined considering the followings.

a) The principle of bringing the generator to the same economic condition if it is considered as change in Law.

b) Technical specifications based on the difference in actual emission and revised emission, proposed technology, construction period, phasing plan for shutdown during the construction period;

c) Feasibility of undertaking implementation of new norms with R&M proposal for plants having low residual life, say, less than 10 years.

d) Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipments.

<u>Comments/ Suggestions</u>

33.4 Comments and suggestions are invited from stakeholders on

a) Possibility of reducing funding cost through suitable change in debt:equity requirements. Relaxation in funding from equity may be introduced and the rate of return on equity may be aligned with the interest on debt;

b) “Debt Service obligation during construction period and recovery of depreciation” may be provided with the condition that such depreciation may be adjusted during the remaining period;

c) As the level of emission is linked to actual generation, it would be appropriate to link recovery of supplementary tariff with the actual generation or availability or combination of both.

34. Renewable Generation by existing Thermal Generation Stations

34.1 The Revised Tariff Policy dated 28th January,2016 provides for setting up of renewable energy generation capacity by existing coal based thermal power generating station. The policy provides that in case any existing coal and lignite based thermal power generating station chooses to set up additional renewable energy generating capacity with the concurrence of power procurers under the existing Power Purchase Agreements, the power from such plant shall be allowed to be bundled and tariff of such renewable energy shall be allowed as pass through by the Appropriate Commission. The Obligated Entities who finally buy such power would account this power towards their renewable purchase obligations(RPOs). Scheduling and dispatch of such conventional and renewable generating plants shall be done separately.

34.2 One of the options is to install renewable project at the same location using the common facilities and land and bundle RE power with the conventional power prior to delivery point i.e. before ex-bus bar. Other option is to establish the renewable project at different location and pool the generation capacity on external basis beyond the delivery point. In both the cases, the annual fixed charges for thermal project and renewable project may be determined separately, based on separate set of tariff principles.

34.3 The scheduling and dispatch mechanism of renewable generation canbe as per the thermal power generation. The target availability and dispatch level, in this case, maybe pre-specified which may be 2% higher for every 10% renewable capacity addition and the annual fixed charges for the thermal project and renewable project maybe combined for deciding the tariff. The rate of return, land cost, operation and maintenance cost for such renewable capacity canbe specified separately.

Comments/ Suggestions

34.4 Comments and suggestions are invited from the stakeholders on the possible options for bundling tariff, and alternative options, if any.

35. Commercial Operation or Service Start date

35.1 The commissioning of the generating stations and transmission systems and their commercial operation is declared after successful completion of the trial operation/run. In case of transmission system, it is ensured that an element of the transmission system is in regular service after successful charging and trial operation to ensure grid security. In some cases, non-availability of evacuation system and/or adequate load has delayed the trial operation and commissioning of the plants. There is also an issue of mismatch between the commercial operation of a generating station and the associated transmission systems which has had an impact on specifying COD and consequently, on the IDC of the generating station or the transmission system.

35.2 There may be a need to specify a methodology of trial operation for generating station and transmission system and ensuring regular use of service in case of transmission system. Similarly, the methodology of trial operation for bay equipment, Inter-connecting transformer, Reactors, Fixed Series Compensation, and transmission lines may need to be specified.

35.3 Data telemetry, communication and restricted governing mode of operation are requirements of system operator to monitor real time grid operation and for grid stability. There is a need to ensure completion of data telemetry and communication by RLDCs/ NLDC/ SLDCs for declaring COD of transmission system/ generating station and operationalization of Restricted Governing mode of Operation (RGMO) in case of generating station.

35.4 Delay can occur in the commercial operation due to factors beyond control or non-commissioning of associated transmission system. In case of the transmission system, the delay on account of non-commissioning of downstream or upstream system is more relevant. Since the declaration of commercial operation date attracts the liability of fixed charges or the transmission charges, as the case may be, the parties dispute the commercial operation date. In order to stream line the process of the declaring commercial operation date in case of the delay and to make aware the parties upfront about the consequences of delay, provisions could be made for demarcation of responsibilities or for Indemnification Agreement.

Comments/ Suggestions

35.5 Comments and suggestions are invited from the stakeholders on possible options for dispute-free and practical mechanism for declaring commercial operation date. Comments and suggestions are also invited on the following.

a. Addressing the shortcomings in existing methodology for the trial run of generating station and trial operation for transmission element through appropriate regulatory mechanism;

b. Issue of trial operation and commissioning of the project when a generating station is ready but cannot be operated due to non-availability of load or evacuation system;

c. Issue of acceptance of COD of transmission line if the generating project or upstream/ downstream transmission assets are not commissioned;

d. Pre-requisite of completion of data telemetry and communication facilities for declaring COD of transmission system and operationalization of RGMO for declaring COD of generating station;

e. Linking of commercial operation date with schedule commercial operation or schedule commencement date of the Power Purchase Agreement or Long Term Access Agreement respectively;

f. Linking the commercial operation date of the transmission system with the commissioning of the generating units or stations;

g. Separation of the commercial operation date of the unit or stations, the transmission element or system from the service start date under the contract.

36. Energy Storage System

36.1 Deployment of grid storage is at a nascent stage and there is no policy or regulatory framework as regards storage. However, its importance is well recognized. The need of grid level battery storage cannot be undermined in areas such as frequency regulation, renewable generation, generation shift etc. In this respect, a staff paper was circulated on 4th January, 2017 underlining the need of energy storage system and various options for its uses.

36.2 In the paper, two different uses of energy storage for regulatory framework were considered, one as a part of the inter-state transmission system and other as a part of inter-state generation station. The grid level storage system established by the transmission system owner has similar characteristics to that of transmission because it acts as intermediary for conveyance of the electricity from generator to the procurer covered within the Section 79 (c) of the Act. When the storage facility is used by generator to optimize the value of generation output and hedging purpose, it can be construed as a primary generator covered under Section 79 (a) and (b) of the Act.

36.3 The regulatory options available for implementation of the energy storage system for use are to combine the tariff with transmission and generation projects. Storage facility as a part of inter-state transmission system may be subjected to regulatory approval while storage facility as a part of the generating capacity may be as per the consent of the procurer for availing storage facilities.

36.4 The annual fixed charges of energy storage system may be determined separately as per the pre-specified operational and financial norms by the Commission and may be recovered from the beneficiaries of the region as supplementary to the transmission charges. Energy storage at transmission level can be used for overall optimization of power from the grid, irrespective of the owner of storage capacity and may be dispatched when needed. Such dispatch can be added in the drawl schedule of all beneficiaries of the region on ex-post basis. Alternatively, the energy storage at transmission level can be used as ancillary support services. The specific operational procedure can be devised for transmission level grid storage.

36.5 The annual fixed charges of energy storage system may be determined separately as per pre-specified operational and financial norms by the Commission. The energy storage at generation level would be used for storage of generation output. The supplier may use it for optimization of the generation dispatch specific to their designated beneficiaries within the power purchase agreement. The generating stations may use it to avoid the flexible operations due to frequent regulations. The specific operational procedure can be devised for generation level grid storage.

36.6 The annual fixed charges of the storage facility can be determined based on ramping rate, auxiliary consumption, Return on Equity (ROE), Interest on Loan, Depreciation, Operation & Maintenance cost and Interest on Working Capital.

Comments/ Suggestions

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

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.6.30 Crore/MW. However, the standard deviation for the above distribution was as high as

Rs.2.44 crore/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 a larger database facilitating bigger cluster-wise sample sizes and a more rigorous exercise, which could possibly facilitate drawing conclusions about whether AFC could 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?

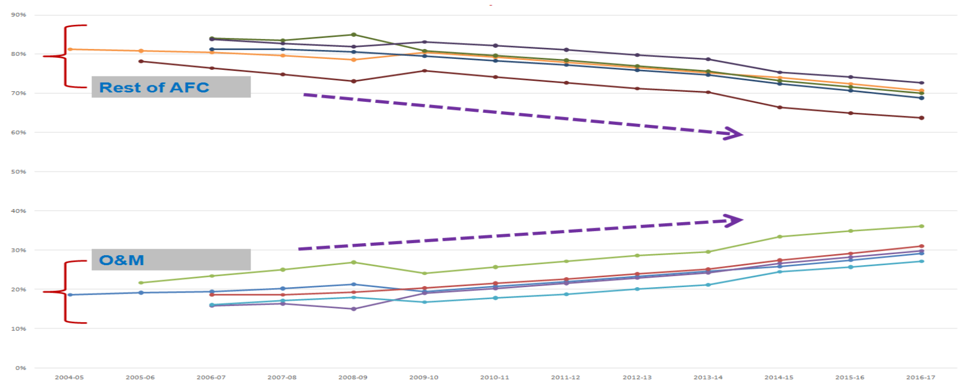
b. What could be the possible methodology to establish the relation between AFC and Capital Cost so that it meets the interests of both buyers and sellers?

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 AFC Components which escalate / increase over the period" and "Group of AFC Components 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 upto 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 31st March 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 in realistic terms?

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 on AFC 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 utilisation 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, the changing 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% upto 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 declared 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 AFC tariffs?

37.22 The flow process for determination of normative tariff is summarised 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 and AFC 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 of AFC on a normative basis.
2	Components of AFC be segregated into "escalable / increasing" and "non-escalable/ decreasing" segments a. Segment -1 (Non-Escalable/ decreasing) comprising of RoE, IoL, IoWC, Depreciation b. Segment -2 (Escalable) comprising O&M	
3	Current Regulations provide for "Add. Cap." as permissible for a period from CoD upto Cut-Off date	
4	"Cut-off Date" means 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 31st March of the year closing after three years of the year of commercial operation	
5	Add. Cap be isolated and the components of AFC be derived without giving effect to Add. Cap. (from Cut-Off Date onwards)	Add. Cap be allowed till Cut-Off Date ("Capital Base" may vary during the period). However, upon reaching the Cut-Off Date, the Capital Cost be freezed.

	"Existing" Generating Stations	"New" Generating Stations
7	For each year the "CAGR" or the de-escalation / de-escalation factors, as the case may be, for the two segments of AFC (namely "O&M" & "RoE+IoL+IoWC+Dep") (without Add. Cap) are determined by the Commission.	For each year the escalation / de-escalation factors, as the case may be, for the two segments of AFC (namely "O&M" & "RoE+IoL+IoWC+Dep") (without Add. Cap) are determined by the Commission.
8	No "Additional Capital", Compensation Allowance, Special Allowance be provided from the current control period	
9	Uncontrollable/ unavoidable expenditure beyond the Cut Off Date, if any, which is considered reasonable and permitted by the Commission, be allowed as a separate stream on annuity basis	
10	Add. Cap. availed, be liquidated before the plant completes its useful life	
11	From FY 2019-20 onwards till completion of useful life of plant the trajectory of AFC (including the trajectory for liquidation of Add. Cap) be derived	
12	AFC be recovered by the Generating Company from the beneficiaries in two parts, i.e. Peak AFC and Off-Peak AFC	
13	As part of this, 80% of AFC be paid (guaranteed), upon declaration of 80% PAF during the year. Remaining 20% of AFC be paid upon achieving 95% PAF during the peak period of 4 months, as declared by the concerned RLDC	
14	AFC Recovery (peak and off peak shares) be arrived at by considering the following • Peak price over off peak price • PAF (Off Peak & Peak) (%) • No. of Months (Off Peak & Peak) • Weightage Factors for Peak and Off Peak components	
15	Month-wise trajectory AFC recovery for the rest of the useful life of the plant is arrived at	
16	The operating and financial norms for any new control period need not 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 framework could 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.

Comments/ Suggestions

37.24 Comments and suggestions are invited from the stakeholders on this alternate approach of tariff determination.

38 Transparency in Billing and Accounting of Fuel

38.1 The regulatory approach of pass through of coal cost to the procurer directly on the basis of certification has been well adopted. Comments and Suggestions are invited for further strengthening the existing system.

39 Relaxation of Norms

39.1 The present regulatory framework provides for specifying normative operational parameters. However, there may be situations where the normative level due to the site specific features such as FGD, Desalination plant, increase in length of water conductor system etc may lead to power consumption in excess of the norms. In such situations, the present regulatory framework provides for relaxation of norms.

Comments/ Suggestions

39.2 Comments and suggestions are invited on whether to continue with the practice or change the parameters during the intervening stage.

40 Merit Order Operation

40.1 Though merit order is a dispatch issue, scheduling/ non-scheduling has its impact on purchase cost. It is seen that in respect of certain old plants having low fixed costs, their power may not get dispatched as the merit order is based on variable cost, which may be high.

40.2 The merit order operation is important for economic operation of the plants and optimum despatch of economic resources. The consideration of other factors such as distance of transportation, secondary fuel oil consumption may provide the option to distribution utility to optimize the despatch. Present merit order is based on the fuel cost of the past data, with time lag of up to two-three months in billing cycle.

Comments/ Suggestions

40.3 Comments and Suggestions are invited from the stakeholders for alternative approach, if any, for economic operation of merit order.

41 Application 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 in transmission 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 of relevant 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.

Comments/ Suggestions

41.4 Comments and suggestions of the stakeholders are invited on simplification of the process for disposal of tariff petitions.

42 Goods and Service Tax (GST)

42.1 Goods and Services Tax (GST) has been introduced which has replaced various Central and State level taxes. Accordingly, prudence check of impact of pre-GST and post-GST taxation regime on the costs may be required for determination of tariff in the next control period.

-// Annexure 1(A) //-

Cost of Coal (2009-10)

Cost of Coal As On 31.3.2009 (Price notification No.CIL/SCM/GM(F)/PRICING/1125 DTD.12th December,2007)		Rs per Unit
Grade	**E Grade**	
GCV Range (Kcal/ kg)	**>3360 <=4200**	
Unit	**Rs/Tonne**	
Source	**MCL**	
Basic Price	560.00	
Sizing / Crushing Chg. -100 mm	55.00	
Surface Trpt. Chg.(vary as per distance)	30.00	
Sub Total (for calculation of Excise Duty) (A)	**645.00**	**0.42**
Central Excise Duty (Introduced w.e.f 1.3.2011)		
Education Cess	-	
Higher Secondary Education Cess	-	
Royalty 5% + 70 (E-Grade)(w.e.f. 1.8.2007)	98.00	
Stowing Excise Duty	10.00	
Niryat Kar (0.20% on Basic Price + Sizing Chg.)	1.23	
Sales Tax (5% of Royalty+SED+A)	37.65	
Vikas Upkar	-	
Clean Energy Cess	-	
Sub Total (B)	**146.88**	
Sub Total (C=B+A)	**791.88**	
CST @2% of **C** (applicable based on location)	15.84	
VAT @ 5% of **C** (applicable based on location)	39.59	
Cost of Coal (ex- Mine)	**847.31**	
Contribution of Taxes & Duties	**202.31**	**0.13**

Railway Distance	**500**	
Road Distance	**-**	
Basic Freight	488.40	
Busy season surcharge (Oct. - June) @5%	24.42	
Sub Total	**512.82**	
Development Surcharge @2%	10.26	
Terminal Charges	10.00	
Road freight (Rs/tonne) (12.36% service tax on 25% of	23.99	
Final Railway Freight (Rs/ tonne)	**557.06**	**0.33**

Operational Parameter		
Station Heat Rate	Kcal/KWh	2425
Auxiliary	(%)	6.00%
Specific Coal Consumption	Kg/KWh	0.645

Per Unit Cost (Rs/Unit)	2009-10
Coal Price (ROM)	0.42
Taxes and Duties	0.13
Coal Transportation	0.33
Taxes & Duties on Transportation	0.03
Total	**0.91**

-// Annexure 1(B) //-

Cost of Coal (2016-17)

Cost of Coal As On 31.3.2017 (Notification No.CIL:S&M:GM(F)/Pricing 2016/294 dated 29th May,2016		Rs per Unit
Particulars	**G12**	
GCV Range (Kcal/ kg)	**3700-4000**	
Source	**MCL**	
Basic Price Sizing / Crushing Chg. -100 mm Surface Trpt. Chg.(vary as per distance)	760.00 79.00 57.00	
Sub Total (for calculation of Excise Duty) (A)	**896.00**	**0.56**
Central Excise Duty (Introduced w.e.f 1.3.2011) Education Cess Higher Secondary Education Cess Royalty 14% on BC DMF @ 30% of Royalty NMET @ 2% of Royalty Vikasupkar @7.5/- Clean Energy Cess Paryavaran @7.5/- Stowing Excise Duty	62.19 1.24 0.62 106.40 31.92 2.13 - 400.00 - 10.00	
Sub-total (B)		
Sub-total (C=B+A)	**1,510.50**	
CST@ 2% of C GST Compensation Cess	30.21 -	
Net Coal Cost (Rs/MT) (C)	**1,540.71**	
Contribution of Taxes & Duties (C-A)	**644.71**	0.40

Railway Distance (KM)	500	
Road Distance	-	
Basic Freight (Rs/MT)	712.0	
Busy season surcharge (Oct. - June) @15%	106.8	
Sub Total	**818.80**	
Development Surcharge @2%	40.94	
Originating Coal Terminal Charge	55.00	
Destination Coal Terminal Charge	55.00	
Service Tax 4.5%	43.64	
Sub-total		
Net Freight (Inclusive of Tax) (Rs/MT)	**1013.38**	**0.51**

Operational Parameter		
Station Heat Rate	Kcal/KWh	2375
Auxiliary	(%)	5.25%
Specific Coal Consumption	Kg/KWh	0.627

Per Unit Cost (Rs/Unit)	2016-17
Coal Price (ROM) Taxes and Duties Coal Transportation	0.56 0.40 0.51
Taxes & Duties on Transportation	0.12
Total (Per Unit Cost)	**1.59**

Note (1): Royalty is applicable as per Notification 3367 dated 1.8.2007-GSR 522(E). Subsequent to above, GoI, Ministry of Coal, vide Notification no. G.S.R. 349 (E) dated 10.05.2012, has increased the rate of Royalty on Coal to 14% ad-valorem on the price of coal.

(2) Central Excise Act, 1944, MoF, GoI issued a Notification No.1/2011-CE dated 01.03.2011 wherein Excise Duty was imposed on domestic coal classified under Chapter 27, serial No. 2701 of the First Schedule to the Central Excise Tariff Act, 1985.

(3) CST and VAT is applicable based on location of mines and hence considered as generic applications.

(4) Subsequently, vide Notification Nos. 1/2010 and 3/2010 dated 22.06.2010, Clean Energy Cess was levied under the Tenth Schedule to the Finance Act, 2010 @ Rs. 100 per tonne. Subsequently it is revised to Rs 400 per tonne from 2016-17 and repealed by GST compensation cess.

Comparative Analysis

	2009-10	2016-17
Generation Plant(Fixed Cost)[1]	2.01	1.66
Transmission Cost(Inter)[2]	0.23	0.39
Transmission Cost(Intra)[3]	0.12	0.14
Transmission losses[4]	0.29	0.33
	2.65	**2.52**
Distribution Cost[5]	0.48	1.39
Distribution Losses (AT&C)[6]	1.03	1.17
	1.51	**2.56**

[1] Per unit fixed cost has been worked out by applying the norms applicable in 2009-14 Tariff Regulations and 2014-19 Tariff Regulations by considering capital cost of Rs 6.3 Cr/MW (based on COD of stations during 2009-10 period).

[2] Transmission cost of 2009-10 has been worked out based on average of Zonal Annual Tariffs of major states (issued on February, 2010 along with Explanatory Memorandum to CERC (Sharing of Inter-state transmission charges and losses) Regulations, 2010. For 2016-17, the Point of connection charges have been considered.

[3]Intra-state transmission charges have been assumed as based on the then prevailing transmission charges of some of the states.

[4]Transmission losses have been considered as 5% in respect of inter-State transmission system and 4.5% in respect of intra-State transmission system. The inter-State transmission losses has been assumed on the basis of losses published by POSOCO and intra-State transmission losses is based on the available data on the website of some of the SLDCs.

[5]Distribution cost has been worked out on the basis of difference between total expenditure and power purchase cost divided by energy input as per the Report on performance of utilities published by PFC Ltd.

[6]AT&C losses are based on CEA report.