Comments on the draft CERC Regulations on Terms and Conditions of Tariff for the control period 2019 to 2024.		
SL. No		
1.	**Introduction**	
1.1	The Central Electricity Regulatory Commission has been vested with theresponsibility of regulation of tariff of generating companies owned or controlled bythe Central Government, generating companies having composite scheme forgeneration and sale of electricity in more than one state and inter-State transmissionsystems under Section 79 of the Electricity Act, 2003 ("the Act"). The Section 61 ofthe Act provides the principles for determination of tariff. Relevant provisions of theAct 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 controlledby the Central Government;* *(b) to regulate the tariff of generating companies other than thoseowned 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 thanone 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 thisAct, 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 CentralCommission for determination of the tariff applicable to generatingcompanies and transmission licensees;* *(b) the generation, transmission, distribution and supply of electricityare conducted on commercial principles;* *(c) the factors which would encourage competition, efficiency,economical use of the resources, good performance and optimuminvestments;* *(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) multiyear tariff principles;* *(g) that the tariff progressively, reflects the cost of supply of electricityand also, reduces cross-subsidies in the manner specified by theAppropriate Commission;* *(h) the promotion of co-generation and generation of electricity fromrenewable sources of energy;* *(i) the National Electricity Policy and tariff policy:* *Provided that the terms and conditions for determination of tariff underthe Electricity (Supply) Act, 1948, the Electricity RegulatoryCommission Act, 1998 and the enactments specified in the Scheduleas they stood immediately before the appointed date, shall continue toapply for a period of one year or until the terms and conditions for tariffare specified under this*	

	section, whichever is earlier."	
1.2	The Ministry of Power, Government of India, in compliance with Section 3 of theAct, 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 ensuringavailability of electricity to different categories of consumers at reasonable rates forachieving the objectives of rapid economic development of the country and improvingthe living standards of the people. It also envisages adequate return on investment forthe developer to attract investment in the sector. It further envisages transparency,consistency and predictability in approach for tariff fixation. Section 4 lays down theobjectives of this Tariff Policy as under: *a) Ensure availability of electricity to consumers at reasonable andcompetitive rates;* *b) Ensure financial viability of the sector and attract investments;* *c) Promote transparency, consistency and predictability in regulatoryapproach across jurisdictions and minimise the perceptions ofregulatory 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 StorageProjects (PSP) to provide adequate peaking reserves, reliable gridoperation 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 allcategories of consumers;* *i) Ensure creation of adequate capacity including reserves ingeneration, transmission and distribution in advance, for reliability ofsupply of electricity to consumers.*	
1.3	The Commission has been regulating generation and transmission tariffs byspecifying terms and conditions of tariff since 1998. Multi-year tariff regulations havebeen issued for the tariff periods 2001-04, 2004-09, 2009-14 and 2014-19 fordetermination of tariff of the generating stations within its jurisdiction and for inter-Statetransmission of electricity.	-
1.4	This Commission regulates tariff of about 76 GW[1] capacity of generatingcompanies apart from tariff determination and regulation of inter-state transmission system under Section 62 of the Act. The principles of tariff determination specified bythe 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 tobalance 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, theCommission has endeavoured to balance the interest of consumers, generators	-

	andtransmission licensees. The terms and conditions of tariff specified by the Commissionare also aimed at providing direction to the power sector keeping in view the economicand financial scenario of the country. Regulatory certainty is an integral part of tariffapproach. The Tariff should also reflect the changing market condition and macroeconomicparameters. The multi-year tariff principle is followed to maintain certainty,both to the generators and the procurers. This paper analyses the power scenario interms of cost of supply and impact of various components of value chain on the cost ofelectricity. Based on the analysis, possible regulatory options for the next controlperiod have been discussed in subsequent chapters.	
1.7	With the above broad parameters, this paper is brought out with the aim togenerate discussion on existing scenario and / likely developments in the power sector having impact on tariff determination during next control period commencing on1.4.2019.	-
1.8	Views of the stakeholders are solicited on provisions of 2014-19 TariffRegulations, and issues raised in this consultation paper which can be used as inputfor formulating Terms and Conditions of Tariff commencing on 1.4.2019. The wordtariff 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, forpromoting competition and rationalisation of tariff. The provisions contained in[1] as on	-

	31.3.2017 Section 62 and Section 63 of the Act, provide for determination of tariff. Section 62 ofthe Act provides the determination of tariff which will act as a ceiling tariff and Section63 of the Act provides for determination of tariff through competitive bidding process.The factors that guide the Appropriate Commission while specifying the terms andconditions for determination of tariff have been prescribed under Section 61 of theAct. The statutory scheme provided under Section 61 to 63 of the Act is intended topromote competition in the sector.	
2.2	During 2001-04 period, the tariff was determined based on the cost of serviceapproach. 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 componentof annual transmission charges with incentive and disincentive linked to availability.While adopting the cost of service approach, the importance of the normativeapproach was also well recognized, as it promotes efficiency and performance. Overtime, the cost of service approach has been modified gradually towards normative byintroducing benchmark norms for determination of one or more components of thetariff. The normative approach has been introduced for operational parameters,operation and maintenance expenses, rate of return, working capital etc. The hybridapproach, consisting of actual cost of service and pre-specified	-

	normativeparameters have been followed during 2004-09, 2009-14 and 2014-19 tariff periodsto 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 andoptimum investments. In accordance with Section 61 of the Act, the AppropriateCommission has to strike a balance between the consumers' interest and theinvestors' (generating company, transmission licensee and distribution company)interest, with emphasis on the need for applying commercial principles in conductingthe activities of generation, transmission, distribution and supply of electricity. Theevolution of regulatory approach has been gradually shifting towards normativeapproach for inducing efficiency so that tariff becomes affordable and competitive. The approach for determination of tariff needs to be evolved continuously so thatobjectives 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 periodshave been considered.	-
	Availability	
3.2	A glance at peak demand (in MW) and energy demand (GWh) as depicted inTable 1 below along with availability over the years reflects that both of these haveincreased substantially between 2009-10 and 2016-17.	-

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) of3.45% (CAGR). For availability, however, the rate of growth was 5.65% during thisperiod on account of addition of substantial coal based capacity, especially by theprivate sector. As a result, all India deficit has reduced to 0.66 – 0.70% in 2016-17from about 10 – 11% about 10 years ago.	-
3.4	As per Central Electricity Authority, there has been a significant increase in theinstalled capacity in country from about 105 GW in 2003 to almost 326 GW as on31.3.2017 as may be seen in Table 2. During this period, the coal based capacitygrew 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 doubledfrom 559 units in 2002 to 1122 units in March, 2017.	-
3.5	The Average Cost of Supply (ACoS) of electricity for the period 2009-10 to2015-16 is as under:	-
3.6	For a distribution utility, the key factors impacting cost of supply of electricityare cost of purchase of power and efficiency in operations indicated broadly by AT&Closses. Generally, cost of purchase of power from generating stations constitutesabout 60-70% of the total cost of supply of electricity of a distribution licensee. Therehas 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.	-

3.7	It may be seen from Table 3 and Table 4 above that the cost of purchase ofpower that constituted about 71% (=341*100/476) of the cost of supply of electricityin 2009-10 has come down to 63% (=438*100/691) in 2015-16. This implies thatother 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 ofoperational cost of distribution licensees,have not reduced much to have anysubstantial impact on the cost of supplyof electricity. During 2009-10 to 2015-16,the AT&C losses have reduced onlymarginally from 25.39% to 21.81**%.**	-
4.	**Value chain of Electricity Generation & Supply**	
4.1	In order to appreciate the contributing factors responsible for increase in costof supply and to identify the areas which require attention to regulate the tariff, theentire value chain of electricity generation and supply need to be looked at.	-
4.2	The cost of electricity delivered at the consumer end reflects the cost added ateach step of the entire value chain i.e. generation (including fuel), transmission anddistribution. Each component of the value chain adds to the cost of supply at eachstage depending on the level of efficiency. Since the contribution of electricitygeneration from coal is higher compared to other sources, contributions of majorfactors in the value chain have been analyzed in subsequent paragraphs.	-

4.3	Figure 3 represents thevalue chain of electricity generation & supply from coal.The efficiency of the entire valuechain of energy charges can bedepicted as conversion ratio ofheat value (Kcal). It can berepresented by the heat valuerequired at ex-mine end to deliverone unit of electricity (equivalentto 860.42 Kcal) at consumer endi.e. the ratio of heat value at mineend and equivalent heat value ofone unit of electricity at consumerend. The conversion depends onseveral factors such asconversion efficiency ofgeneration technology (which isin the range of 2.82 - 2.76 forsub-critical to super-criticaltechnology), auxiliary consumption, transportation loss, heat loss due to coal gradeslippages, transmission (intra state and inter-state) losses and distribution losses. The conversion efficiency is dependent on technology over which there is limitedcontrol. At present, there are large capacities in the country with sub-criticaltechnology. However, over the years, trend has been towards installing more unitswith super-critical technology which will improve the efficiency over the years. ApartGeneration- 12from switch over to super-critical technology to improve conversion efficiency, controlling other factors such as auxiliary consumption, transportation losses, heatlosses and AT&C losses will help improving the conversion ratio.	-
4.4	The cost of electricity delivered to the end consumer comprises of costs ofvarious components of value chain - energy charges and fixed charges. The energy charges represent equivalent cost of fuel paid by the	-

	end consumer coupled withoperational efficiency. It comprises the ex-mine cost of coal, taxes & duties on coal,transportation cost, losses of transmission and distribution network. Fixed chargesinvolve equivalent cost of infrastructure paid by the end consumer comprising of thecost of generating station infrastructure, transmission network and distributionnetwork. The cost of electricity delivered at consumer end varies from station tostation due to variations of operational parameters of station, state transmissionlosses and distribution losses. Cost variations in some of the important componentsof the value chain between 2009-10 and 2016-17 are analysed below.	
4.5	It may be seen from the Table 5 and Figure 4 given below that during twocontrol periods i.e. between 2009-10 and 2016-17, the coal costs (including taxesand duties) increased by 81.83% whereas the coal transportation cost went up by59.67%. Additionally, basic price of coal increased by 35.71% and Taxes & duties oncoal increased by 218.67%. The pricing mechanism of coal was changed from UHVto GCV in 2011.	-
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 ofgeneration. For Example, Clean Energy Cess has been repealed, but has beenreplaced with GST Compensation Cess @ Rs 400/- per MT.	-
4.7	The increase of various components in the cost of	

	electricity (per unit) hasbeen worked out based on specific coal consumption, transmission charges anddistribution cost as under.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 ofincrease intransmission and distribution costs.	-
4.8	The Commission stipulated improved operational parameters during the tariffcontrol period 2014-19 as shown below. However, the increase in fuel cost, transportation cost, taxes and duties nullified thegains on account of improvements in operational efficiency (SHR from 2425 Kcal to2375 Kcal and auxiliary consumption from 6.0% to 5.25%) and reduction in AT&Closses.	-
4.9	**Value Chain of Electricity Generation and Supply from Hydro Source** The value chain of the electricitygenerated from hydro is given in Figure 3.The components involved in the valuechain of electricity from hydro sources arecomparatively less than those in electricitygenerated from coal. Despite the initialcost of the hydroelectricity projectcomparatively high, on the long run, itoffers economic advantages to thedistribution licensees and end consumers.	-
4.10	**Value Chain of Electricity Generation and Supply from Renewable Source** The value chain of theelectricity generated from renewablesources is given in Figure 5. The valuechain of electricity from renewablesources is comparatively smaller.However, on account of variability ofrenewable	-

	generation, balancingrequirement is to be met from existingthermal plants, Hydro Electric Project or Energy storage system adds to thecost of supply.	
4.11	Inter-State transmission tariff (Rs/KWh) ("transmission rates") has gone upduring last five years due to expansion in transmission infrastructure. Transmissionnetwork capacity is generally planned and needed to meet the peak demand withdesired reliability. The transmission charges as on Apr-2011 and Apr-2017 and increases are as under.	-
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 capitalcost per MW and Annual Fixed Charges (AFC) as a percentage of total capital costhave been worked out for different time periods in respect of thermal and hydro power projects**.**	-
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 costincrease, but at the same time, it leads to improvement in efficiency in terms of O&Mand 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	-

	asunder.	
B.	**Coal based Thermal Generation**	
5.2.1	On the supply side, rapid capacity addition has taken place during the last fiveyears and is being seen in the renewable energy. Due to rapid addition ofrenewable capacity & slow growth of demand for electricity, there has beendecreasing trend in plant load factor (PLF) of thermal power plants.	-
5.2.2	National Electricity Plan (NEP) of Central Electricity Authority (CEA) estimatesthat the PLF of coal based stations is likely to come down to around 56.50% by2021-22, taking into considerations likely demand growth of 6.34% (CAGR) and175 GW capacities from renewable energy sources.	-
5.2.3	As may be seen from the Table 11 above, the PLF of the thermal generatingstations is low and has been reducing over the years. Consequently, many ofthe generating stations are not dispatched for large parts of the year. Presentregulatory framework recognizes servicing the fixed charges based on targetavailability factor that is considered based on the possible dispatch scenario. Ifthe PLF reduces significantly, it would be a challenge, especially with regard toservicing of fixed charges.	-
5.2.4	Most of the coal is located in the eastern parts of the country and requirestransportation over long distances, which often results in supply constraints.The thermal plants have been facing the issue of mismatch in quality as well asquantity of coal supplied and received. There is a need for transparency in	-

	coalquality assessment of the coal supplied. The third party sampling mechanismmay need strengthening along with a mechanism for quick resolution of disputeand settlement of account.	
5.2.5	In line with the notification of the Ministry of Environment and Forest, revisedenvironmental and emission norms require installation of flue gasdesulphurization (FGD) systems and other control systems such as ESP etc. inboth new and old thermal power plants. This would have impact on the tariff asnot only additional capital cost would be required but O&M cost would alsoincrease.	-
5.2.6	As per estimates of Central Electricity Authority, thermal plants are likely to runat low plant load factor (capacity utilisation) and many plants may get partial orno schedule of generation. As per the present regulatory framework, thedistribution companies will continue to pay the fixed cost. Therefore,optimization of the power generation and rationalization of tariff structure arerequired.	-
5.2.7	There are concerns of the generating companies in respect of ensuringperformance of the power purchase agreement. Some of the State utilities haveinitiated actions for cancellation of concluded Power Purchase Agreements withpower producers, including surrender of power from centrally owned generatingstations on the ground of changes in market conditions.	-
5.2.8	Significant portion of the installed capacity are based on fossil fuels like coaland natural gas. Environmental concerns demand application of technology	-

	forreducing CO_2 emission. Though focus is on non-conventional energy sources,power generation is likely to continue to rely on fossil fuel in the coming fewyears. Decarbonising thermal power plants pose technological challenge andwill 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 notified17the Environment (Protection) Amendment Rules, 2015 (Amendment Rules,2015) introducing revised standards for emission of environmental pollutants tobe followed by the Thermal Power Plants. All existing Thermal Power Plants arerequired to meet the revised emission standards within the stipulated period.Large scale installation and up gradation of various emission control systemswould 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 additionalcapitalization and re-designing in plants for complying with the newenvironmental 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 theAppropriate Commission. The additional capital expenditure would depend onthe existing emissions at specific project and selection of proposed technology.The retrofitting would also impact OM	-

	expenses and auxiliary consumption.	
5.2.11	Presently, there is no benchmarking of capital or operational cost for pollutioncontrol system available which poses a challenge to develop a regulatoryframework. Central Electricity Authority (CEA) is working towards developingbenchmarking and normative parameters in this regard.	-
5.2.12	The Government of India has set a target of 175 GW of renewable capacity by2022. 100 GW is envisaged from solar projects, of which 60 GW is targetedfrom ground-mounted, grid-connected projects and remaining 40 GW isexpected to come from solar rooftop projects. Further, 60 GW is targeted fromwind projects, 5GW from Small Hydro projects and 10GW from Biomass. Therenewable energy sources offer competitive advantages due to low generationcost and thus predictability and certainty of the cost. However, the nature ofvariability and intermittency pose challenge for balancing of grid.	-
5.2.13	Presently, thermal generation is being used for balancing requirements of thegrid. The variability of renewable energy generation causes frequent regulationsof thermal generation which adversely affect the plant & machinery in terms ofreduced life, higher maintenance expenditure, higher down time and lowerefficiency (Heat Rate, Auxiliary Power Consumption and Specific OilConsumption).	-
C.	**Gas based Thermal Generation**	
5.3.1	The gas based thermal generating stations offer greater capability of rampingup and ramping down. Thus, gas	-

	based generating station can providealternative source for balancing power to address the intermittency ofrenewable generation. However, the gas based generating stations havingconcluded PPA are facing problem due to shortage of supply of gas fromdomestic source. The alternative may be to source costlier gas either from spotmarket or R-LNG.	
D.	**Integrated Power Project with Coal Mine**	
5.4.1	Coal Mines have been allocated to the NTPC Ltd. and Damodar ValleyCorporation (DVC). The present regulatory framework allows pass through ofthe fuel (coal) cost as determined by the Coal India Ltd. However, in case ofcoal supplied from the integrated mine or mine owned by the generatingcompany, 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 totalinstalled capacity.	-
5.5.2	Hydro projects are highly capital intensive and have long gestation period. Withmajority of the plants located at remote and inaccessible regions, hydro projectsgenerally get delayed due to various factors which, inter alia, include geologicalsurprises, natural calamities, lengthy clearance time, law & order problems anddelay in implementation of R&R Plans. These factors result in time and costoverrun 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 economic andenvironmental friendly power resource in	-

	the long run. However, the cost ofelectricity of hydro power is comparatively expensive vis a vis coal based powerplants in the short-run. In view of this, the hydro projects find it difficult to attractinvestment 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 powergeneration will have a significant role in future especially in view of large scaleadditions of renewable energy sources in the grid that has inherent intermittency. Therefore, there is a need to address factors that currently drivehydropower costs up.	
5.5.4	The pumped storage hydropower stations have generally been integrated as apart of the generation project. In present regulatory framework, additional returnhas been provided for pumped storage plants.	-
5.5.5	Flexibility of hydro power helps in the grid balancing required due to therenewable generation. The challenge is to evolve a suitable regulatoryframework to make the hydro operation flexible.	-
F.	**Inter-State Transmission**	
5.6.1	The transmission system has undergone change after introduction of CentralElectricity Regulatory Commission (Grant of Connectivity, Long Term Accessand Medium Term Access in inter-State transmission and related matters)Regulations, 2009 & Central Electricity Regulatory Commission (Sharing ofInter-State Transmission Charges and Losses) Regulations, 2010.	-
5.6.2	However, issues have emerged in development of the	-

	transmission system thatrelate to planning and co-ordination like matching with generation project and19 readiness of downstream network; delay due to Forest & Wildlife clearance,right of way (RoW) issues; relinquishment of LTA by IPPs and consequentrecovery 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 levelto encourage the renewable penetration, the electricity generation fromintermittent energy sources (wind, solar, tides) is gaining momentum. Now therenewable sources coupled with storage or suitable balancing powermechanism are seen as potential substitute to the conventional sources. Thefeed-in-tariff structure seems suitable when the contribution of renewablesources in the grid was lower as it would not create distortion. But withincreasing penetration of renewable energy, this may not be the case and evenfeed-in tariff structure may even lead to economic inefficiency.	-
5.7.2	When the share of renewable generation is low in the grid, the renewablegeneration may get exemption from scheduling and regulations, as thevariations can be met from other source of generation. But as the share ofrenewable generation increases in the grid, the distribution companies mayrequire to regulate its supply. In case of likely regulation of supply of therenewable generation, the entire tariff of the	-

	renewable generation (which is ofthe nature of fixed cost) is compared with the marginal cost of the othergeneration (excluding the fixed cost component), for merit order. Therefore, thetariff structure of renewable generation poses specific challenges in operationand for merit order considerations.	
H.	**Coal** **Gross Calorific Value (GCV)**	
5.8.1	Gross Calorific Value (GCV) in relation to thermal generation has been definedin successive tariff regulations issued by the Commission since 2001 as "the heat produced in kCal by complete combustion of one kilogram of solid fuel orone litre of liquid fuel or one standard cubic meter of gaseous fuel, as the casemay be". GCV is used to compute the Energy Charge payable by theDistribution Companies/Power Utilities to the generating companies.	-
5.8.2	In the entire value chain from mine end to generating station end, the loss ofGCV can take place on account of grade slippage at mine end, duringtransportation (transit with railway) and during storage (at generating stations).The generating companies generally have no control over the grade/GCV ofcoal received at their generating stations. There are several cases of gradeslippages 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 bythe 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 thesite of generating station is ultimately passed on to the beneficiaries, this issue20needs to be looked at in terms of risk allocation between the coal company,railways and the generating stations. The issue of grade slippage is significantin case of domestic coal as the GCV measurement is being done at Free onBoard (FOB) through acceptable practice. This poses specific challenges withrespect to the measurement point and method/ procedure for measurement ofGross Calorific Value (GCV).	-
	Alternative Source of Coal	
5.8.4	The power plants in the country face shortage of fuel (coal/gas) due to shortageof supply from the supplier or transportation constraints. Coal India Ltd. has notbeen 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 andprice. In the above circumstances, the generating stations are either forced toprocure fuel from spot market (in case of gas and coal) or to procure importedcoal at higher prices.	-
5.8.5	If power plants rely heavily on coal from alternative sources, the energy chargesmay increase substantially or the plant may have to be operated at lower PLF ifthe price restriction on blending as per the regulations triggers. Therefore, theuse of coal from a source other than designated under Fuel Supply Agreementposes a	-

	specific challenge as it has significant impact on energy charges.	
5.8.6	The present regulatory framework provides the computation of energy chargesbased on landed cost of fuel. The landed cost of fuel includes the costcomponents up to the delivery point of the generating stations. Further, as perthe present regulations, the energy charges are directly pass through based onthe formula specified for Energy Charge Rate (ECR) in the Tariff Regulations. The beneficiaries verify the bills or claims of the energy charge rate whilemaking payment.	-
5.8.7	The approach for allowing pass through of the landed cost of fuel was evolvedon the premise that the fuel cost is beyond the control of the generatingcompanies as these were administered prices. After 2012, there have beenseveral developments. The Government has opened the coal mine to privatecompanies. The generating company now has many alternatives forprocurement of coal viz. through Coal India Ltd, Open market, e-auction mode,captive mine etc. Further, the Government has also specified the flexibleutilization of coal under the existing fuel supply agreement. The generatingcompany has options to optimize the landed cost of fuel based on differentprocurement and transportation modes, considering the quality, source specificexpenses etc. The challenge is to optimize the landed cost of fuel, as there aredifferent components involved in the fuel cost.	-
5.8.8		-

	As the landed fuel cost involves various components of the fuel cost, there areconcerns regarding verification of these components. Further, there is widevariation in terms of cost and number of cost components involved in the landed21fuel cost, changes in which cause corresponding fluctuation in the tariff. Thechallenge 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 TariffPolicy, 2016, will have impact on the Tariff Regulations. a) Clause 5.2 provides exemption to the existing generating companies fromcompetitive bidding to carry out onetime expansion of 100% of the existingcapacity with a view that the benefit of the infrastructure cost of existing projectshould be passed on to consumers through tariff. While allowing expansion asper the provision of the Tariff Policy, the Commission has to ensure that thebenefit in reduction of costs due to sharing of infrastructure of existing projectshould be passed on to the consumers. The regulation will need to incorporateprovisions of regulatory oversight: b) Clause 5.4 introduced tariff determination for generation of electricity fromprojects using coal washery rejects. The operational norms and approach fordetermination of fuel cost need to be worked out for such projects whilespecifying terms and conditions of	-

	tariff: c) Clause 5.5 provides that the Appropriate Commission shall fix time period forcommissioning of Hydro Electric Project. The Commission will be required toconsider this while determination of commercial operation date of HEPs for tariffpurpose: d) 2nd Proviso to the Clause (c) of clause 5.11 has mandated to specify upperceiling of the rate of depreciation and an option to the developer to seek lowerrate of depreciation. The implementation of the above provision would requiremodification 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 coalwasheries, coal beneficiation system and dry ash handling & disposal system inthe cost of the project. The definition of generating station under the Act andthe project as considered in the tariff regulations so far do not include capitalcost associated with fuel mine or port handling etc. which is required to beaddressed in the regulations: f) Sub-Clause 5 of Clause 6.2 provides for mandatory use of water from sewagewater treatment plant. Since the existing approach provides specific treatmentof water charges, same is required to be reviewed in light of the aboveprovision.	
6.	**Some Relevant Factors**	
6.1	In view of the challenges and the developments that have taken place in theElectricity Sector over time, factors highly relevant while specifying the terms andconditions 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 ofeach party and their rights & obligations; e) Ensuring optimum utilization of the generation and transmission capacityand 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 anoptimal manner to meet the growing demand. For this, performance-based costof service was evolved and implemented during the previous control periods.Further, in order to induce efficiency, some of the components of tariff were prespecifiedon normative basis. Following tariff design has been adopted forgeneration (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 chargesrepresenting variable component with incentive and disincentivemechanism; andb) For hydro power plants, the recovery of fixed charges is through twocomponents i.e. “capacity charges” & “energy charges”, each componentrepresenting 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 availabilityof the transmission system.	-
III.	Feed-in Tariff structure for Renewable Generation: - a) Feed-in Tariff structure comprising fixed charges of the renewablegeneration project. **Thermal Generating Stations –Tariff Structure**	-
7.2.1	Possible three part tariff structure for thermal generating stations is discussed insubsequent 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 infollowing paragraphs, inter alia, one option may be to introduce three-part tariffstructure. The two-part tariff structure for generating station provides the right touse the infrastructure on payment of fixed component irrespective of quantumof electricity generated and the payment of energy cost for procuring each unitof electricity. However, with this tariff structure, following issues emerge. Thetwo-part tariff system structure is suitable when the demand for power ensuresutilization of capacity up to or around the target availability. It allows theprocurer to get electricity at reasonable per unit cost through optimum utilisationof asset. Two part tariff operates well in power deficit scenario. Due to low	**Acceptable**

	demand, coal based power plants are running at a PLF of around 60%.Consequently, States have not been coming forward for long term powerpurchase to avoid fixed cost liability and rather they have been resorting toshort term power purchase to meet their demand.	
7.2.3	As stated above, the two-part tariff structure works well when the gap betweenavailable 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 generatingcompany or many. This situation has undergone change. As the gap betweenplant availability factor and plant load factor has widened due to low PLF, theprocurers are no longer placed in similar position. AFC per unit would be onhigher side for the procurers having low demand. When two procurers are notplaced on similar positions, the present two-part tariff structure does not providefor charging differential fixed charges from different procurer. Though the tariffdetermined by the Commission acts as ceiling, there is no mechanism specifiedto charge the tariff lower than ceiling.	-
7.2.4	The possible options for tariff structure could be to offer to the procurers havinglow demand a menu of options for ensuring dispatch by linking a portion of fixedcharges with the actual dispatch and balance of AFC to availability. This willensure optimum utilization of	**Acceptable**

	the infrastructure, as procurers will continue toprocure power from the generating stations and the generator will getreasonable return without losing the demand.	
7.2.5	The tariff for supply of electricity from a thermal generating station couldcomprise of three parts, namely, fixed charge (for recovery of fixed costconsisting of the components of debt service obligations allowing depreciationfor repayment, interest on loan and guaranteed return to the extent of risk freereturn and part of operation and maintenance expenses), variable charge(incremental return above guaranteed return and balance operation andmaintenance expenses) and energy charges (fuel cost, transportation cost andtaxes, duties of fuel).	-
7.2.6	The recovery of fixed component could be linked to target availability, whereasvariable component could be linked to the difference between availability anddispatch. Fuel charges could be linked with dispatch.	**Acceptable**
7.3.1	**Thermal Generating Stations – Older than 25 years** As on 31st March 2016, as per CEA total thermal installed capacity in thecountry 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 plantscontribute 34,950 MW, which is about 19 % of total coal based generationcapacity. The coal based thermal power plants more than 25 years old areabout 37,453 MW, out of which around 35,506 MW capacity	**No Comments**

	pertain to State /Central sector.	
7.3.2	Present basket of thermal generating stations comprises of several old thermalgenerating stations which have completed 25 years. These generating stationshave completed useful life, whereas some others have completed 10-12 yearsof life. Such generating stations are placed differently as they were conceivedbased on the policy/regulatory environment and technology available at thattime. They are not comparable with the new generating stations in terms ofoperational norms and capital cost.	**No Comments**
7.3.3	As most of these have already recovered depreciation and completed loanrepayments, they may have advantage from financial consideration. But theiroperational cost could be higher due to less efficiency, such as highconsumption of coal due to higher station heat rate (SHR). Further, their O&M cost could be high.	**No Comments**
7.3.4	A clear policy/ **regulatory decision**is required in view of a number of thermalstations 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 necessarilydeteriorate much with age, if proper O&M practices are followed.	The plant which are commissioned before the year 2000, the useful life may be fixed to 25 years for phasing out the units.In place of phased out units, super critical units may be proposed. The plants which are commissioned later than the year 2000, the useful life may be fixed as 35 years with conforming to the latest international environmental norms. Required R&M shall be carried for the units which are commissioned after 2000 to 2010 to suit the latest international environmental norms, provided they continue to be financially viable.

7.4.1	**Hydro Generating Stations - Tariff Structure** The two part tariff structure of hydro generating stations seems adequate inpresent scenario. However, in view of large capital cost, hydro generatingstations often find it difficult to get dispatched due to resultant higher energycharges. In order to address this issue, for the hydro generating stations, thefixed charges and variable charges may need to be reformulated.	This should be made applicable only to new hydro generating stations built at high capital cost.
7.4.2	Options for Regulatory framework The fixed component may include debt service obligations, interest on loan andrisk free return while the variable component may include incremental returnabove guaranteed return, operation and maintenance expenses and interest onworking capital. The annual fixed cost can consist of the components of returnon equity, interest on loan capital, depreciation, interest on working capital; andoperation and maintenance expenses.	**Acceptable**
7.5.1	**Inter-State Transmission System - Tariff Structure** Presently, single part tariff structure is followed for determination of annualtransmission tariff of a particular element of the transmission system or entiretransmission system covered in the project. This single part tariff structure oftransmission consolidates all the costs of	The present POC charges are not equitable as the intervening States Network with Loads are not properly modelled resulting in very high transmission charges being collected from intervening States like Karnataka, Rajasthan and Andhra Pradesh. Recovery of Transmission charges for Inter-State Transmission lines shall be based on capacity contracted under Long Term

	providing access to the generatingstation or the distribution licensee and transmission service. This cost isallocated as per CERC (Sharing of inter-state transmission charges)Regulations, 2010 and subsequent amendment thereto which is based on theprinciple of usage. The present regulatory framework recognizes thetransmission cost as long term access charges, essentially injection and drawcharges irrespective of their actual transactions or transmission service.	Agreements (LTA).
7.5.2	At present, there is no distinction between access service and transmissionservice. The cost associated with the access has been combined with thetransmission 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 transmissionsystem but may not necessarily avail the transmission service unless there isactual transaction.	As suggested distinction between access service and transmissionservice for short term and medium term open access is desirable.
7.5.3	The emerging requirement is to recognize the access service separatelyindependent of the quantity for which transmission service is availed. Thetransmission access may be treated as right to access the transmission systemand transmission service may be treated as the right to transfer the electricitythrough the transmission system. The present tariff structure of transmissionsystem does not meet this emerging requirement.	-
7.5.4	Transmission tariff can be on two-part basis, wherein the first part can be linkedwith the access service and second part can be linked with the transmissionservice.	-

7.5.5	The tariff for transmission of electricity on inter-State transmission system canconsist of fixed components and variable components. a) The fixed components may consist of either (i) annual fixed cost of some offixed transmission system designated for access and immediateevacuation, (ii) annual fixed cost of the evacuation transmission system or(iii) part of annual fixed cost of the entire transmission system consisting ofdebt service obligations, interest on loan, guaranteed return;b) The variable components may consist of either (i) common transmissionsystem or system strengthening scheme excluding immediate evacuationtransmission system, (ii) common transmission system excludingevacuation transmission system or (iii) sum of incremental return aboveguaranteed return, operation and maintenance expenses and interest onworking capital.	**Acceptable**
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 theextent of use, to be recovered in proportion to the power flow (TransmissionService Charge). The fixed component may be linked to evacuation system oron normative basis based on aggregate transmission charges of the identifiedtransmission system under the contract. The variable component may be linkedwith yearly transmission charges based on actual flow or actual dispatchagainst long term access.	**Acceptable**
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 bepossible 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 marginalcost of the other generation (excluding the fixed cost component). c) In case of bundling renewable generation with conventional powergeneration at the ex-bus of generating station, it may be difficult to combinethe tariff as feed-in-tariff structure is a single part tariff and conventionalgeneration has two part tariff structure.	**No Comments**
7.6.2	The tariff structure of the renewable generation may be rationalized	Only in case of Bagasse based Co Generation and Bio mass based renewables Two part tariff is desirable
7.6.3	There can be Two part tariff structure for renewable generation covered underSection 62 of the Act, which comprises fixed component (debt serviceobligations and depreciation) and variable component (equal to marginal costive O&M expenses and return on equity) - fixed component as feed-in-tariff (FIT)and variable component equal to capacity augmentation such as storage orback up supply tariff.	**Acceptable**
7.6.4	In case of integration of the renewable generation with the coal/ lignite basedthermal power plant, the following may the alternatives. a) The renewable generation may be supplied through the existing tariff forthe contracted capacity of thermal power plant under PPA. In thisalternative, the tariff of	Option (b) is desirable.

	renewable generation may replace the energycharges; b) Tariff of renewable generation may be combined with the fixed and variablecomponents of the thermal generation to the extent of contracted capacityunder PPA. The operational norms of conventional plants may requirerevision 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 thermalpower generation may be recovered separately. The operational norms forrecovery of tariff may have to be specified separately.	
7.7.1	Comments and suggestions are invited from the stakeholders on the possibleregulatory options discussed above and alternatives, if any.	-
8.	**Deviation from Norms**	
8.1	Regulation 48 for deviations of norms as below.***"48. Deviation from norms:*** *(1) Tariff for sale of electricity by thegenerating company or for transmission charges of the transmissionlicensee, as the case may be,may also be determined in deviation ofthe norms specified in these regulations subject to the conditionsthat:* *(a) The levellised tariff over the useful life of the project on the basisof the norms in deviation does not exceed the levellised tariffcalculated on the basis of the norms specified in these regulationsand upon submission of complete workings with assumptions to beprovided by the generator or the transmission licensee at the time*	Acceptable

	offiling of the application; and *(b) Any deviation shall come into effect only after approval by theCommission, for which an application shall be made by thegenerating company or the transmission licensee, as the case maybe...”*	
8.2	Section 61 of the Act provides that the Commission shall be guided by thefactors which would encourage competition and recovery of the cost of electricity in areasonable manner. The present market framework involves the competition for powerprocurement for securing power purchase agreement. Once the power purchaseagreement is secured, there is no framework for competition of dispatch. Thedistribution licensees follow merit order based on the tariff agreed under PPA underSection 63 of the Act or the tariff determined by the Commission under section 62 ofthe Act.	**-**
8.3	For various reasons, out of tied up capacity by the distribution licensee, some ofthe capacity often remains undispatched over large part of the year. Since the tariffdetermined by the Commission acts as ceiling, there is no embargo on the generatingstations or the transmission licensee to charge lower tariff. This provides a scope forcreating some competition.	**-**
8.4	Possible option could be to develop for incentive and disincentive mechanismfor different levels of dispatch and specifying the target dispatch expanding the scopeof Regulation 48 above.	**Acceptable**
8.5	Comments and suggestions are invited from the stakeholders on the possibleregulatory 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 suchcase, part capacity may have been tied up under Section 63 and/or Section 62 of theAct and balance may have remained as merchant capacity.	**No Comments**
9.2	Section 62 of the Act provides that the Appropriate Commission shall determine thetariff for (a) supply of electricity by a generating company to a distribution Licensee, (b)transmission of electricity, (c) wheeling of electricity and (d) retail sale of electricity. Section61(b) of the Act provides that the Appropriate Commission shall specify the terms andconditions of tariff for generation, transmission, distribution and supply of electricity areconducted on commercial principles. The commercial principles inter-alia emphasize the riskallocation through contractual arrangement such as power purchase agreement in case ofgeneration and transmission service agreement or long term access agreement in case of transmission service.	**No Comments**
9.3	The question is whether the annual fixed charges and energy charges are tobe determined to the extent of the capacity tied up under Section 62 of the Act or forthe entire capacity. One approach could be to determine the tariff of the generatingstation for entire capacity and restrict the tariff for recovery to the extent of powerpurchase agreement on pro-rata basis and balance capacity will be merchant capacityor tied up under Section 63, as the case may be.	**Acceptable.**
9.4	Comments and suggestions are invited from the	-

	stakeholders on the possibleregulatory options discussed above and alternate options, if any.	
10.	**Optimum utilization of Capacity**	
10.1	The unutilized capacity due to partial or less demand has impact on therecovery of the cost by the generating plant. At the same time, the distribution licenseemay be impacted by way of liability of fixed charges without availing dispatch from thegenerating station.	-
10.2	If the unutilized capacity of the generating station is allowed to be utilized byother distribution companies or through open market, the obligations of the distributioncompanies may reduce to the extent of utilization.	Acceptable.
10.3	(a) Flexibility may be provided to the generating company and thedistribution licensee to redefine the Annual Contracted Capacity (ACC) onyearly basis out of total Contracted Capacity (CC), which may be based on theanticipated reduction of utilization. Annual Contracted Capacity (ACC) may betreated as guaranteed contracted capacity during the year for the generatingcompany and the distribution licensee and the capacity beyond the ACC maybe treated as Unutilized Capacity (UC). The distribution licensee will have a right to recall Unutilized Capacity during next year and for securing such rights,some part of fixed cost, say 10-20% or to the extent of debt service obligations,may be paid; (b) Such unutilized Capacity may be aggregated and bided out todiscover the market price of surplus	-

	capacity. The surplus capacity may be reallocatedto the distribution licensee at market discovered price.	
10.4	The present commercial framework under PPA allows the use of hydro powerto 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. Inother words, there is a need for a framework for flexible operation of the hydroelectricproject. Further, as the scheduling of cascade hydro power station i.e. reservoiroperations 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;	Balancing incentive may be determined for such hydro generators, the benefitthereon hasto be passed on to the PPA holders.
10.5	(a) Extend the useful life of the project up to 50 years from existing 35 yearsand the loan repayment period up to 18-20 years from existing 10-12 years formoderating upfront loading of the tariff. (b) Assign responsibility of operation of the hydro power stations and pumpedmode operations at regional level with the primary objective for balancing. Forthis purpose, the scheduling of the hydro power operation (generation andpumped mode operation) may have to be delinked from the requirements ofdesignated beneficiaries with whom agreement exists. The power scheduledto the hydro generation can be dispatched to designated beneficiaries throughbanking facility so that flexibility in scheduling can be achieved for balancingpurpose and to address the difficulties of cascade hydro power station. Somepart of fixed charge liability to the extent of 10-20% against the use	Acceptable.

	of flexibleoperation and pumped operations may be apportioned to the regionalbeneficiaries as reliability charges.	
10.6	The use of gas based generating station is important because of possibility ofimmediate ramp up and ramp down for balancing the variations of renewable generation.	-
10.7	Scheduling and dispatch of gas based generating station may be shifted toregional level with the primary objective of balancing. After meeting the requirement ofdesignated beneficiaries, the regional level system operator can use it for balancingpower at the rate specified by the generating companies. Alternatively, all the gasbased generating station capacities may be pooled at regional level. After meeting therequirement of designated beneficiaries, the balance generation may be offered forbalancing purpose as and when required.	All the gasbased generating station capacities may be pooled at regional level. After meeting therequirement of designated beneficiaries, the balance generation may be offered forbalancing purpose as and when required.
10.8	Comments and suggestions are invited from the stakeholders on the possibleregulatory 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 thecontrol 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 Isconsidered along with additional capitalization during the control period after duediligence.	
11.2	During the control period 2004-09, the capital cost was determined based onthe actual cost as per the balance sheet of the regulated entities. From the controlperiod 2009-14, the Commission switched over to the methodology of determination ofcapital cost based on the projected capital expenditure. This enabled the generatingcompanies or transmission licensees to file their tariff application prior tocommissioning of the project. The undischarged liabilities were not included in theprojected/actual capital expenditure for the purpose of capitalization.	**No Comments**
11.3	Capital cost includes interest during construction, financing charges and foreignexchange rate variation up to the date of commercial operation of the project. Anyrevenue generated on account of injection of infirm power through unscheduledinterchange in excess of fuel cost is used to reduce capital cost.	**No Comments**
11.4	The principles of tariff determination as per the Act mandate balancing ofconsumer's interest while allowing reasonable cost to the generator. The capital costhas a direct correlation with the cost of value chain of fixed charges and therefore theCommission always endeavour's to allow capital cost after prudence check. The TariffPolicy, 2016 stipulates that the Appropriate Commission would evolve benchmark of31capital cost as reference to allow reasonable	-

	capital cost to the generators ortransmission licensees.	
11.5	There are several issues and challenges with respect to the capital cost for thetransmission system, thermal generating stations and hydro generating stationsi) Variation between actual project cost vis-a-vis projected capital cost.ii) Additional capital expenditure estimated up to cut-off date on account ofreasons like deferment in commissioning of projects, non-placement of ordersdue to limited vendor responses etc.iii) Delay in project execution is due to various reasons such as delay in landacquisition, delay in getting statutory approvals/clearances, delay due togeographical location of the site, delay on the part of contractor /supplier ofmaterial, execution philosophy etc., leading to increase in IDC, overheadexpenses etc.iv) Absence of benchmark capital cost, leading to use of the estimated capital costas per investment approval for reference purpose. Estimated capital cost asper investment approval may not truly reflect the efficiency in procurement andexecution of the project when compared to market rates.v) Use of the audited annual accounts to ascertain the claim of the capitalexpenses. The tariff filing forms have been prescribed for filing regulatoryinformation to facilitate reconciliation with financial statements prepared as peraccounting standards. The financial statements of power companies have beenchanged w.e.f.1st April, 2016 due to introduction of the Indian AccountingStandards Rules, 2015. The formats for filing regulatory information may needto be reviewed in this	-

	context.vi) On the basis of indicative location, fuel and estimated cost of the generatingstation (investment approval), the beneficiaries enter into power purchaseagreement and undertake the obligations to off-take the power on commercialoperation of the project. Often, on declaring commercial operation, thegenerating companies revise the investment based on revised cost andbeneficiaries may not be aware of the revised estimated cost. Similarly, thetransmission licensees also revise the costs, which the customers may not beaware of.	
11.6	There are specific issues and challenges in respect of thermal generatingstations. i) The claims of deferred works were allowed to be capitalised up to the cut-offdate under the head "works deferred for execution/deferred works" but there isno provision for allowing such expenses after cut-off date. In some of thecases, expenditure was allowed even after cut-off date; ii) The Tariff Regulations, 2014 provides for specific treatment of expenses ofcapital nature at the fag-end of project life and allows allowances which had32consequential impact on tariff as entire depreciation would have to be chargedwithin balance useful life. This provision may need review in view of the policyof phasing out of old plants and expected benefit for getting dispatch aftercompletion of useful life; iii) Additional capitalization by thermal generators to meet the efficiencyimprovement targets under the	-

	Perform, Achieve & Trade (PAT) scheme, waterfrom Sewage Thermal Plant (STP), Pollution Control System to meet revisedstandards of emission norms, adoption of storage facility and combiningrenewable generation with thermal power project. iv) The efficacy of normative compensation allowance and special allowance mayneed to be reviewed vis-à-vis actual expenditure. The regulatory oversight maybe required to address overlapping of expenditure under compensationallowance and O&M allowance. v) Provisions to handle capital expenditure to comply with new environmentalnorms, expenditure due to change in law (whether it is possible to specifyevents), servicing of expenditure relating to rail infrastructure, availability ofwagons etc. to tackle major breakdowns and expenditure relating to gridsecurity.	
11.7	There are also specific issues and challenges in respect of hydro generatingstations. i) The trend of capital cost of hydro generating stations indicates that the hydrostations are becoming un-viable due to higher tariff. The present approach mayneed to be reviewed in view of sustainable benefits offered by hydro generationin terms of clean power and high ramping rates.	-
11.8	One of the options is to move away from investment approval as reference costand shift to benchmark/reference cost for prudence check of capital cost. However,the challenge is absence of credible benchmarking of technology and capital cost.	Benchmarking of capital cost is not practicable, as the cost varies from State to State depending upon the geographical conditions and local laws.
11.9	Higher capital cost allows the developer return on	Acceptable.

	higher base of equitydeployed. In the cost plus pricing regime, the developer envisages return on equity asper the original project cost estimation. The regulations allow compensation towardsincrease in cost due to uncontrollable factor so as to place the developer to the sameeconomic position had this uncontrollable event not occurred. Therefore, in newprojects, the fixed rate of return may be restricted to the base corresponding to thenormative equity as envisaged in the investment approval or on benchmark cost. Thereturn on additional equity may be restricted to the extent of weighted average ofinterest rate of loan portfolio or rate of risk free return. Further, incentive for earlycompletion and disincentive for slippage from scheduled commissioning can also beintroduced.	
11.10	Comments and suggestions are invited from the stakeholders on the possibleregulatory options discussed above and alternatives, if any.	-
12.	**Renovation & Modernisation**	
12.1	The generating companies and the transmission licensees are allowed toundertake renovation & modernisation for the purpose of extension of life beyond theuseful life of the generating station or a unit thereof or a transmission system. Theadmissibility of the renovation & modernisation claim are required to be supported byProject 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.	Acceptable.

12.2	At times the generating companies file their petitions for renovation andmodernisation without giving estimated life extension period, which makes it difficult tocarry out cost benefit analysis. In old plants, R&M nature of works are sometimesclaimed without specific life extension. Servicing of such R&M expenditure at the endof useful life of the station without extension of useful life may be difficult to justify.	**No Comments**
12.3	An alternative provision was made in the Tariff Regulations, 2009 in the form ofspecial allowance to be allowed in lieu of R&M for coal/lignite based thermal powerstations. This provision enabled generating companies to meet the requirement ofexpenses including R&M on completion of 25 years of useful life to a unit /stationwithout any need for seeking resetting of capital base.	-
12.4	The old transmission lines and substations are sometimes inadequate to caterto the new demand due to capacity degradation and obsolesce of technology.However, construction of new transmission lines and sub-stations require high initialcapital investment and substantial time towards seeking approvals, tackling right ofway (ROW) issues and environmental clearances. R&M with and without up-gradationof existing projects is one of the cost effective alternatives to increase the powertransmission capabilities. The upgradation of transmission line and substation tohigher voltages has emerged as a viable alternative to cater to the load growth ortransmission requirements. It also offers commercial advantages as	-

	some of theoriginal foundations, structure, or equipment can be re-used with minimalmodifications.	
12.5	In coastal areas, line structures/ towers, hardware's, conductors etc. get rusteddue to saline atmosphere. Lines passing through chemical zones also require to be strengthened by stub strengthening, replacement of conductors, hardware's,insulators, earth wire etc. The transmission lines which are in service for more than 25years are affected due to atmospheric conditions and aging.	-
12.6	The R&M of transmission system could include Residual Life Assessment ofSub-Station and Transmission Lines, Upgradation of sub-station and transmissionline, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow Renovation & Modernisation (R&M) for the purpose ofextension of life beyond the useful life of transmission assets. Alternatively, theCommission may allow special allowance for R&M of transmission assets. Suchprovision will enable the transmission companies to meet the required expensesincluding R&M on completion of 25/35 years of useful life of sub-station/transmissionline without any need for seeking resetting of capital base.	Acceptable.
12.7	Comments and suggestions are invited from the stakeholders on the optionsdiscussed above and alternatives, if any.	-
13.	**Financial Parameters**	
13.1	The performance based cost of service approach, a combination of actual costand normative parameters has been evolved for the Tariff regulations.	Acceptable.

	Componentslike return on equity, operation & maintenance expenses and interest on workingcapital have been specified on normative basis whereas cost of debt has beenallowed based on actual rate of interest on normative debt. The normative parametersare expected to induce operational and financial efficiency. While continuing with thehybrid approach, more weightage may be provided for normative parameters toinduce greater efficiency during operation as well as in development phase.	
13.2	Comments and suggestions are invited from the stakeholders for continuationof 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 theNational Electricity Policy, 2006 provided that "depreciation reserve is created so as tofully meet the debt service obligation." The regulatory principle evolved over timestipulates that there should be enough cash flow available to meet the repayment obligations of the generating company or transmission licensee during first 12 years ofoperation. The depreciation rate has been considered based on the above principle.The Tariff Policy, 2016 stipulates that the Central Commission may notify the rates ofdepreciation in respect of generation and transmission assets and the rates sonotified would be applicable for the purpose of tariffs as well as accounting.	Acceptable.
14.2	The depreciation depends on three factors viz. rate base which includessubsequent additions also, method	Acceptable.

	of depreciation and useful life. The followingfactors are relevant for determination of depreciation: i) The tariff setting approach, ROE based or ROCE based, has a bearing ondepreciation. Presently Historical cost (HC) based approach for determining therate 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 gasbased stations, have remained the same in all the tariff periods. For gas basedstations, life of 15 years was used in tariff period 2001-04 & 2004-09. It wasenhanced to 25 years in tariff period 2009-14 and continued in 2014-19 period; iii) With passage of time, the regulatory definition of depreciation, as pronounced in2009-14 tariff regulations viz. enough cash flow to meet the repaymentobligations of the generator during first 12 years of operation, has gainedprecedence in tariff setting. Accordingly, depreciation rate is arrived at byconsidering normative repayment period of 12 years to repay the loan (70% ofthe 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 haveuniformity in depreciation rates for accounting as well as tariff setting, the aspectof fair life got delinked in 2009-14 and 2014-19 at least for first 12 years ofoperation, while setting the depreciation rates. v) There are two sets of assets viz. those coming under	

	cost plus (section 62) andothers through competitive bidding (section 63). Further, within the subset ofcost plus assets, many of existing units/stations have already outlived or willoutlive their originally envisaged useful life of 25 years in the tariff setting periodof 2019-24. Renovation and Modernization is allowed based on two approachesi.e. actual expenditure incurred and normative special allowance for coalbased/lignite fired thermal generating station. In case of former approach,proposal includes estimated life extension wherein the calculation of allowabledepreciation is feasible. However, in case where special allowance is allowed, itis not feasible to workout depreciation in absence of life extension.	
14.3	In the following circumstances, treatment of depreciation is contingent uponperiod 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 inlieu of renovation and modernisation have consequential impact on the tariff dueto recovery of depreciation over balance useful life; ii) Additional capital expenditure after allowing the special allowance has an impacton recovery of depreciation. iii) The useful life of Hydro Stations, as specified in Tariff Regulation, 2009, is 35years. However, the actual life of these Hydro stations may be much more than35 years. For hydro stations allowing higher depreciation rates	-

	during first 12years results in front loaded tariff. To keep the tariff on lower side, thedepreciation 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 andthe International experience in this regard needs to be looked into to bring furtherimprovements.	
14.4	Section 123 of the Companies Act 2013, under Schedule II- provides life ofSpecial Plant and Machinery, as 40 years for generation, transmission and distributionof power whereas Part B of the same has linked useful life to be as specified byregulatory authority. The relevant portion of Part B is extracted under:"The useful life or residual value of any specific asset, as notified foraccounting purposes by a Regulatory Authority constituted under an Act ofParliament or by the Central Government shall be applied in calculating thedepreciation to be provided for such asset irrespective of the requirements ofthis Schedule".	Acceptable.
14.5	Books of Accounts are required to be prepared as per Ind AS (Ind AccountingStandard) for generators whose tariff is determined based on regulations notified byCommission. RBI's notification dated July 15, 2014 regarding flexible structuring oflong term project loans to infrastructure and core industries covers power industry.Stipulations relating to depreciation have been laid down in Tariff policy notified on 28January 2016.	-
14.6	Options for Regulatory Framework a) Increase the useful life of well-maintained plants for	Acceptable.

	the purpose ofdetermination of depreciation for tariff; b) Continue the present approach of weighted average useful life in case ofcombination, due to gradual commissioning of units; c) Consider additional expenditure during the end of life with or without reassessmentof useful life. Admissibility of additional expenditure after renovationand modernization (or special allowance) to be restricted to limiteditems/equipment; d) Reassess life at the start of every tariff period or every additional capitalexpenditure through a provision in the same way as is prescribed in Ind AS andcorresponding treatment of depreciation thereof; e) Extend useful life of the transmission assets and hydro station to 50 years andthat of thermal (coal) assets to 35 years and bring in corresponding changes intreatment of depreciation. f) Reduce rates which will act as a ceiling. g) Continue with the existing policy of charging depreciation. However, the TariffPolicy allows developer to opt for lower depreciation rate subject to ceiling limitas set by notified Regulation which causes difficulty in setting floor rate,including zero rate as depreciation in some of the year(s).	
14.7	Comments and suggestions are invited from the stakeholders on the possibleregulatory 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 approachas it incentivizes the equity investors to efficiently operate and maintain theinfrastructure, even after the plant has been fully depreciated. The internal resourcesgenerated by way of depreciation are reutilized for further capacity addition. CEA hasestimated that in view of present demand growth rate and availability ofcommissioned and under construction capacity, no new coal based capacity may berequired till 2027.	
15.2	An option could be to base the returns on the modified gross fixed assetsarrived at by reducing the balance depreciation after repayment of loan in respect oforiginal project cost.	Acceptable.
15.3	Comments and suggestions are invited from the stakeholders on any otherpossible regulatory options or to continue with the existing mechanism.	-
16.	**Debt:Equity Ratio**	
16.1	The capital cost for generation and transmission projects commissioned after1.4.2019 is considered to be financed through a debt equity ratio of 70:30. Further, itis provided that if the actual equity deployed is more than 30% of the capital cost, theequity in excess of 30% shall be treated as normative loan whereas if the equitydeployed is less than 30% of the capital cost, the actual equity shall be considered fordetermination of tariff. The above provision in Tariff Regulations is consistent with theprinciples laid down in the Revised Tariff Policy 2016.	Acceptable.
16.2	Some of the utilities in private sector operate with a very high financialleverage. Also, it is observed that financial	Acceptable .

	institutions are willing to extend finance up todebt equity ratio of 80:20 depending on the credit appraisal of the utilities. Whendemand for capacity addition is low, maintaining debt:equity of 70:30 may needreview.	
16.3	Further, for some of the old plants, the equity base has been maintainedbeyond 30% (upto50%) for the purpose of fixed return to enable the developer togenerate internal resource for further capacity addition. In view of availability ofsufficient capacity in the market, there is a need for review of the same.	Acceptable.
16.4	For future investments, modify the normative debt-equity ratio of 80:20 inrespect of new plants, where financial closure is yet to be achieved.	Acceptable.
16.5	Comments and suggestions are invited from the stakeholders on the possibleregulatory 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 areasonable return on their investments besides recovering all other costs incurredthrough tariff. The return on investment is allowed as a compensation to the investorsfor assuming the investment related risks. It is based on opportunity cost principle andrisk 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 Policy2016 have laid down broad guiding	The present ROE approach may be continued.

	principles for determination of rate of return.These have mandated to maintain a balance between the interests of consumers andneed for investments while laying down the rate of return. It is stipulated that the rateof return should be determined based on the assessment of overall risk and prevalentcost of capital. Further, it should lead to generation of reasonable surplus and attractinvestment for the growth of the sector. As per the Tariff Policy, the Commission mayadopt either Return on Equity (RoE) or Return on Capital Employed (RoCE) approachfor providing the return to the investors.	
17.3	Over a period of time, allowing fixed rate of return on equity has evolved as anacceptable approach and the same has been followed by most of the State ElectricityRegulatory Commissions. The RoE approach has been widely accepted by investorsin the sector. The large scale investment in the power sector is attributable to theapproach of fixed rate of return. The Commission had compared both the approachesviz. RoE and RoCE while framing the Tariff Regulations for 2014-19 and decided tocontinue with RoE approach with the following observations in the ExplanatoryMemorandum; *"As the tariff is determined on multiyear principles, it is important tomaintain certainty in approach over each control period to maintain theconfidence of investors and regulated entities. In view of thefluctuating interest rate, shallow debt market and considering thefinancial*	-

	health of Utilities and the other serious issues faced byDevelopers in sector such as fuel shortages etc., it appears that it I snot the desirable to switch to ROCE approach and thus theCommission proposes to continue with the ROE approach for nextTariff Period. Further most of the stakeholders have suggested forcontinuing the existing ROE approach."	
17.4	Comment and suggestions are invited from the Stakeholders on the continuation offixed 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 theirequity investment ingeneration/transmission projects. To ensure that it is fair to boththe investors and the consumers, the return allowed should be commensurate withthe 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 ofequity/RoE. However, the Commission has been largely depending on the CAPMmodel for arriving at RoE during previous tariff periods.	-
18.2	The Commission had specified a post-taxRoE of 16% and 14% respectivelyfor 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 begrossed up by the applicable tax rate. An incentive of 0.5% was also allowed for	Considering the present borrowing rate, the RoE of 14 % instead of current 15.5%, is desirable.

	thegeneration/transmission projects completed within the prescribed timeline. For thetariff 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 forstorage type hydro generating stations.	
18.3	As per the present regulatory framework, the additional return on equity isallowed for all the units or the transmission elements irrespective of their size orlength of line if such assets have been commissioned as per the timeline specified bythe Commission. The timeline applied is same irrespective of size of the project-lengthof 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 projectdeveloper for timely completion. However, there is no disincentive for delay incompletion of the project.	In present surplus energy situation, allowing incentive for completion of project before the timeline may not be desirable.
18.5	Following key trends have been observed during recent times: -	
18.6	According to CEA, the capacity addition is no more a major challenge andadequate installed capacity (along with currently under installation) exists to meet thedemand for the next 8-10 years. Further, the rate of interest has also come down inrecent times. Therefore, there is market dynamics which favours reduction of rate ofreturn. However, any such reduction will have negative impact on the equity alreadyinvested in the existing and under construction projects, creating further financialstress on such projects. Different rate of	-

	return for new projects (where financialclosure is yet to be achieved), may be thought of, with different rates for generationand transmission projects.	
18.7	(a) Review the rate of return on equity considering the present marketexpectations and risk perception of power sector for new projects; (b) Have different rates of return for generation and transmission sector andwithin the generation and transmission segment, have different rates ofreturn for existing and new projects; (c) Have different rates of return for thermal and hydro projects with additionalincentives to storage based hydro generating projects; (d) In respect of Hydro sector, as it experiences geological surprises leading todelays, the rate of return can be bifurcated into two parts. The firstcomponent can be assured whereas the second component is linked totimely completion of the project; (e) Continue with pre-tax return on equity or switch to post tax Return onequity; (f) Have differential additional return on equity for different unit size forgenerating station, different line length in case of the transmission systemand different size of substation; (g) Reduction of return on equity in case of delay of the project;	Acceptable.
18.8	Comments and suggestions are invited from the stakeholders on the possibleoptions 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 paymentsand upfront fee for raising finances through debt. As per the prevailing TariffRegulations, the weighted average interest rate calculated on the basis of actual loanportfolio of the utility is considered as the cost of debt. The cost of debt thus arrived atis applied on the normative outstanding loan to compute the annual interest expensesof the utility which is given a pass through in the tariff. This approach does not provideincentive to the utility to lower the cost of borrowings, as even higher rates are givenas pass through in tariff.	-
19.2	Clause (d) of para 5.11 of Tariff Policy, 2016 has stipulated that the utilitiesshould be encouraged and suitably incentivized to restructure their debt for bringingdown the tariff. The Tariff Regulations for 2014-19 has provided that the regulatedentities shall make every effort to refinance the loan to lower the interest costs. Andfor this purpose, while the costs associated with refinancing shall be borne by thebeneficiaries, the savings on interest shall be shared between the beneficiaries andthe utilities in the ratio of 2:1.	Acceptable.
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 ofdebt including the interest rate varies across sources depending upon several factorsviz. quantum, tenor, type, timing, etc. As of now utilities are predominantly borrowingfrom banks and other financial	-

	institutions for capital expenditure through nonstandardizedand negotiated bank loans in the form of corporate loan, project loans,syndicated loans etc. Long term credit rating of utilities varies across utilities. Theinterest rates at which funds are borrowed from banks/financial institutions/debtmarket depend upon the credit rating of the utilities. As per RBI database, thesize of the Indian corporate bondmarket vis-a-vis GDP is still low incomparison to developed andeven several developingcountries. However, corporatebonds outstanding as a % of GDPhave grown from around 5% in2012 to 23% during 2017-18.Further, amount of corporate loanraised through issuing bonds inprimary market during last 7 yearshas grown at a CAGR of around15%. Historically, the corporatebond market has been dominatedby PSU's AAA and AA ratedbonds. However, the trend seemsto be changing with a number ofmutual funds investing in debtportfolio with low rated bonds. As of now except the better ratedutilities like NTPC Ltd. and PGCIL, othersutilities are primarily dependent upon banks & financial institutions for meetingtheir loan requirement. However, with thestrengthening of corporate bond market, itwill provide an alternative for thecompanies to raise their finances.RBI has gradually revised its repo rate downward from 8% during 2014 to6% in August, 2017. Since August 2017RBI has maintained status quo in the policy rates based on the	

	recommendationsgiven 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 transmissionof policy rates into the money market. As a result, the bank lending rates have alsoreduced during this period.	
19.4	While allowing the cost of debt as pass through, options available for regulatoryframework are either to consider normative cost of debt based on market parametersor actual cost of debt based on loan portfolio. As the tariff is determined for multi-yearperiod and cost of debt varies based on changing market conditions, linking cost ofdebt to market parameters such as MCLR & G-sec will bring a degree ofunpredictability. The regulatory approach evolved so far has been to allow the cost ofdebt based on actual loan portfolio. This does not incentivize the developers torestructure the loan portfolio to reduce the cost of debt. The current incentive structuremay need review to encourage developers to go for reduction of cost of debt.	Acceptable.
19.5	(a) Continue with existing approach of allowing cost of debt based on actualweighted average rate of interest and normative loan, or to switch to normativecost of debt and differential cost of debt for the new transmission andgeneration projects; b) Review of the existing incentives for restructuring or refinancing of debt; c) Link reasonableness of cost of debt with reference to	For the old loans, the weighted average interest rate and for new loans the interest rate as per MCLR plus certain basis points to cover the future risk is desirable. Acceptable.

	certain benchmark viz. RBIpolicy repo rate or 10-year Government Bond yield and have frequency of resettingnormative cost of debt;	
19.6	Comment and suggestions are invited from the stakeholders on the possibleregulatory 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-basedor lignite-fired thermal generating station, open-cycle gas turbine/combined Cyclethermal generating stations and hydrogenerating station & transmission system. Theworking capital is determined based on fuel stock, inventory of maintenance spares,one month operation and maintenance cost and two months receivables dependingon the type of thermal generating station, hydro and transmission projects.	
20.2	The existing Tariff Regulations provides the definition of bank rate as the BaseRate of interest specified by the State Bank of India (SBI) from time to time or anyreplacement thereof for the time being in effect, plus 350 basis points. The ReserveBank of India (RBI), vide ref. RBI/2015-16/273 DBR.No.Dir.BC.67/13.03.00/2015-16dated 17.12.2015, introduced Marginal Cost of funds-based Lending Rate (MCLR).The new methodology for computing benchmark lending rates came into effect fromApril 1, 2016. The objective of MCLR is to get response of bank faster to policy raterevisions. As per the reference of RBI, MCLR will automatically apply to new loans.However,	Acceptable.

	the existing borrowings linked to the Base Rate may continue till repaymentor renewal, as the case may. Alignment of Regulations to above development maytherefore, be required.	
20.3	(a) Assuming that internal resources will not be available for meeting workingcapital requirement and short-term funding has to be obtained from bankinginstitutions for working capital, whose interest liability has to be borne by theregulated entity, IWC based on the cash credit was followed during previoustariff 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 befixed or actual stock of fuel may be taken. (c) While working out requirement of working capital, maintenance spares arealso accounted for. Since O&M expenses also cover a part of maintenancespares expenditure, a view may be taken as regards some percentage, say,15% maintenance spares being made part of working capital or O&Mexpenses. (d) Maintenance spares in IWC which is also a part of O&M expenses results inhigher IWC for new hydro plants with time and cost overrun. For old hydrostations, the higher O&M expenses due to higher number of employees alsoyield higher cost for "Maintenance Spares" in IWC. Therefore, option couldbe to de-link "Maintenance Spares" in IWC from O&M expenses. (e) In view of increasing renewable penetration and continued low demand, theplant load factor of thermal	Acceptable.

	generating stations is expected to be low. As perthe present regulatory framework, the normative working capital has beenprovided considering target availability. In case of wide variation between theplant load factor and the plant availability factor, the normative approach oflinking working capital with "target availability" can be reviewed.	
20.4	Comments and suggestions are invited from the stakeholders on the regulatoryoptions 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 generatingstations and transmission system in the existing tariff regulations based on the data of2009-10 to 2013-14. Presently O&M expenses have been specified on per MW basisfor 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 intoaccount WPI and CPI indexation. However, variations in WPI & CPI indexpose challenge in specifying the fixed escalation rate for the entire tariff period. Further, the fixed escalation rate does not capture the variation due tounexpected expenses such as wage revision etc. For new hydro stations whose COD was declared during the tariff period2014-19, the first year normative O&M has been specified as 4% and 2.5% oforiginal project cost (excluding cost of R&R works) for stations less than 200MW projects and for stations more than 200 MW	-

	respectively. But O&Mexpenses could vary depending on the type of plant and number of units.O&M expense of hydro stations is given as a percentage of capital cost,which is inclusive of IDC & IEDC. Thus, projects with substantial time & costoverrun get higher O&M.There could be overlapping of the O&M expenses and the compensationallowance, due to overlapping of items covered under these two.	
21.3	O&M expenses vary if the dispatch of the generating station is continuouslylow, as in the case of gas/ naphtha based generating stations. In such cases,specifying recovery of O&M expenses based on installed capacity may need review.	Acceptable.
21.4	The O&M expenses of transmission substation comprises O&M expenses fortransformer, reactors, bays, compensation devices, transmission lines, control room switchgears, DC system, switchyard etc. When the number of bays increases, therewill 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 thesubstations. As an alternative, the O&M expenses may need to worked out on thebasis of MVA capacity instead of individual components else some weightage may beaccorded to different components.	The O&M expenses may need to worked out on thebasis of MVA capacity instead of individual components else some weightage may beaccorded to different components.
21.5	In case of expansion of capacity in existing generating station or existingtransmission substation, the O&M expenses may vary on account of economies ofscale. The O&M expenses have been rationalized by multiplying factor of 0.90, 0.85and 0.80 to O&M	Implementation is difficult.

	expenses per MW depending on the size of the units. Rationalization similar to generating stations could be considered for the transmissionsystem where the generating stations receive lower amount towards O&M expensesin case of addition of units in same generating stations as stated above. At the sametime, different multiplying factor can be prescribed for different unit sizes even in caseof the generating stations.	
21.6	The O&M expenses of a generating station generally increase with increase inthe life completed by it. That is to say, the new plants require less O&M expenseswhereas old plants require higher O&M expenses. Specifying generic norms forO&M expenses for all plants irrespective of its life may need a relook.	Vintage multiplier may be explored.
21.7	(a) Review the escalation factor for determining O&M cost based on WPI & CPIindexation as they do not capture unexpected expenditure; (b) Address the impact of installation of pollution control system and mandatoryuse 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 newhydro 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 likethe bays or transformer or transmission lines of transmission system andreview of the multiplying factor in case of addition of units in	-

	existingstations; (f) Have separate norms for O&M expenses on the basis of vintage ofgenerating station and the transmission system. (g) Treatment of income from other business (e.g. telecom business) whilearriving at the O&M cost.	
21.8	Comments and suggestions are invited from the stakeholders on the possibleregulatory 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 definedin successive tariff regulations issued by the Commission since 2001 as "the heatproduced in kCal by complete combustion of one kilogram of solid fuel or one litre ofliquid fuel or one standard cubic meter of gaseous fuel, as the case may be". GCV issued to compute the Energy Charge payable by the distribution company's/powerutilities to the generating companies. The normative energy consumption admissibleper unit of electricity generated has been specified by the Commission in the tariffregulations as normative Station Heat Rate (SHR) in terms of kcal/kWh. The ratio ofSHR and GCV gives the quantity of coal used per unit of electricity generated.Therefore, GCV being used for the computation of energy input becomes extremelyimportant as any increase/reduction in GCVdecreases/increases the admissible coalconsumption affecting the cost of power.	No Comments
22.2	Energy Charge constituting about 60-70% of the total	No Comments

	cost of generation tariffhas major impact on cost to end consumers. In order to balance the interest of boththe generating companies as well as the distribution companies (and ultimately theend consumers), the measurement of GCV of coal used needs to be as accurate asthe true representative of the coal consumption is required.	
22.3	GCV of coal is measured at different points and accordingly, various GCVterminologies are used namely "GCV as Billed", "GCV as Received" and "GCV asFired". "GCV as Billed", also called as "Invoice GCV" is indicated by the supplier's inthe dispatch invoice and payment for the coal is made to the suppliers on the basis of"GCV As Billed". However, "GCV as Billed" is based on GCV measured in acontrolled environment. "GCV as Received" is GCV measured at the generating station upon receipt of coal in the station. "GCV As Fired" is computed before feedingcoal into coal bunkers of the generating unit for power generation.	-
22.4	The "GCV As Billed" is indicative of total energy content dispatched by thesuppliers and normally paid for by the recipient stations. The "GCV Has Received" isexpected to be same as "GCV as Billed" barring minor transit losses. "GCV asFired "is computed at the time of actual use of coal in the generating unit for powergeneration. For a coal consignment, "GCV As Fired" would be equal to "GCV AsReceived" minus the heat loss due to storage, as coal may undergo certain qualitychanges/degradation over the storage periods.	-
22.5	In the entire value chain from mine end to generating	-

	station end, the loss ofGCV can take place on account of grade slippage at mine end, during transportation(transit with railway) and during storage (at generating stations). The generatingcompanies generally have no control over the grade/GCV of coal received at theirgenerating stations. There are several cases of grade slippages between the minemouth and at the site of generating stations. Further, there is loss in GCV duringtransport of coal through Railway. Therefore, the generator may receive lower energythan what was billed by the coal companies. These are beyond the control of thegenerating companies.	
22.6	Since the cost of slippage in grade of coal between the loading point and thesite of generating station is ultimately passed on to the beneficiaries, this issue needsto be looked at in terms of risk allocation between the coal company, railways and thegenerating stations.	-
22.7	In case of imported coal, sampling and proximate analysis are being done atFree on Board (FOB) and at Cost Insurance Freight (CIF). The coal is transported byrail from port to the generating stations. Since the existing regulatory frameworkprovides that the GCV is to be measured as on received basis at generating end, thesame is followed for imported coal too. In case of imported coal, the GCVmeasurement is followed on Air Dried basis at CIF for billing purpose, whereas incase of domestic coal, the same is measured at the mine end.	-
22.8	**(a) Take actual GCV and quantity at the generating**	Option (c) is desirable. However, the GCV as per Fuel Supply

	station end and addnormative transportation losses for GCV and quantity for each mode oftransport and distance between the mine and plant for payment purpose bythe generating companies. In other words, specify normative GCV lossbetween "As Billed" and "As Received" at the generating station end andidentify losses to be booked to Coal supplier or Railways. **b) Similarly, specify normative GCV loss between "As Received" and "As Fired" in thegenerating stations.** **c) Standardize GCV computation method on "As Received' and "Air-Dry basis'' forprocurement of coal both from domestic and international suppliers**.	Agreement (FSA) needs to be ensured.
22.9	Comments and suggestions are invited from the stakeholders on the possibleregulatory 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 toshortage of supply from the supplier or due to transportation constraints. Coal IndiaLtd. has not been able to supply committed quantity of coal as per Fuel SupplyAgreement. Coal supply also gets affected due to Rail transportation relatedconstraints. Uncertainty about supply of gas continues, both in terms of availabilityand price. In the above circumstances, the generating stations are either forced toprocure fuel from spot market (in case of gas and coal) or to procure imported coal athigher prices.	-
23.2	The Tariff Regulations, 2014 allowed procurement of balance coal fromalternate sources like import/e-auction for blending. Under restrictions prescribed inthe	-

	regulations relating to quantum/price of alternate coal, the generating companiesmeet shortfall in supply of coal under FSA through alternate sources (which aregenerally costlier). If power plants rely heavily on coal from alternative sources, theenergy charges may increase substantially or the plant may have to be operated atlower PLF if distribution licensees do not give consent to blend higher percentage ofimported coal than the threshold prescribed in the regulations.	
23.3	There is difficulty in verification of GCV of blended coal, due to unavailability ofseparate value of GCV of domestic and imported coal on "As Fired Basis". It maytherefore, be necessary to provide for payment of energy charges based on" As Received" GCV of domestic and imported coal with suitable margin and adjustmentfor arriving at "As Fired" GCV. This would require development of norms for suchadjustment.	-
23.4	Alternatively, normative blending ratio may be decided in advance inconsultation with the beneficiaries in terms of technical limitation of steam generator.The blending ratio in the domestic coal based plants may vary depending upon thequality of coal, the quality of actual coal being received, age of plant, unit loading etc.	-
23.5	The Central Commission, vide Third Amendment to Tariff Regulations, dated30.12.2012, has already incorporated the regulation for maintaining transparency infuel procurement by generator and sharing of fuel prices including, fuel procurementthrough e-auction and imported coal.	-

23.6	**Normative blending ratio may be specified for existing plant as well as newplants separately in consultation with the beneficiaries.**	Acceptable.
24.	**Fuel - Landed Cost** 24.1 The present regulatory framework provides for the computation of energycharges based on landed cost of fuel. The landed cost of fuel includes the costcomponents up to the delivery point of the generating stations. Further, as per thepresent regulations, the energy charges are directly pass through based on the formula specified for Energy Charge Rate (ECR) in the Tariff Regulations. Thebeneficiaries verify the bills or claims of the energy charge rate while makingpayment.	-
24.2	The generating company has to provide the necessary details of the costincluded in the landed cost of fuel. Different generating companies follow differentpractices for supplying such information. Further, asymmetry of information fordifferent fuel sources creates ambiguity for billing energy charges. There may be aneed to specify the required information to be supplied and the standard procedure tobe followed while claiming bills for energy charges.	-
24.3	The approach for allowing pass through of the landed cost of fuel was evolvedon the premise that the fuel cost is beyond the control of the generating companies asprices were administered. Subsequently, there have been several developments. TheGovernment has opened the coal mine to private companies. Today,	-

	the generatingcompany may procure coal either through Coal India Ltd, Open market, e-auctionmode, captive mine etc. Further, the Government has also specified the flexibleutilization of coal under the existing fuel supply agreement. The generating companyhas options to optimize the landed cost of fuel based on different procurement andtransportation modes, considering the quality, source specific expenses etc.	
24.4	The landed cost of fuel constitutes differentcomponents such as basic run ofmine (ROM) price, sizing charges, surface transportation charges, royalty, stowingexcise duty, fuel surcharge, cess etc. Further, the components may vary dependingupon the source of coal. In case of railway transport, it involves basic freight, terminalcharges, busy season surcharges etc. In case of imported coal, it includes the FOBprice, over sea transportation, port handling charges, rail transportation, roadtransportation etc. As a result, there is wide variations in terms of cost and number ofcost components involved in the landed fuel cost, changes in which causecorresponding fluctuations in the tariff. The energy charges largely depend on the fuelcost which is determined by the cost components allowable as part of tariff.	-
24.5	**(a) All cost components of the landed fuel cost may be allowed as part of tariff. Oraltentatively, specify the list of standard cost components.** **(b) The source of coal, distance (rail and road transportation) and quality of coalmay be fixed or specified for a minimum period, so that the distribution**	Option(b) is acceptable.

	company will have reasonable predictability over variation of the energycharges.	
24.6	Comments and suggestions are invited from the stakeholders on the possibleregulatory options discussed above and alternate options, if any.	-
25.	**Fuel - Alternate Source**	
25.1	The present regulatory framework provides that the generators resorting thealternate source of fuel, other than designated fuel supply agreement, require priorconsultation only if the energy charge rate exceeds 30% of the base energy chargerate or 20% of energy charge rate of the previous month. These provisions wereintroduced w.e.f. 1.4.2014 in view of the shortage of fuel at that time.	-
25.2	**(a) Stipulate procedure for sourcing fuel from alternate source includingceiling rate;** **(b) Rationalize the formulation keeping in view the different level of energycharge rates, as the fuel cost has increased since 1.4.2014.**	Option (a) is acceptable.
25.3	Comments and suggestions are invited from the stakeholders on the possibleregulatory options discussed above and alternate options, if any.	-
26.	**Operational Norms**	
26.1	The Tariff Policy dated 28th January, 2016 provides the guiding principle forfixation of operational norms as under:Suitable performance norms of operations together with incentives and disincentiveswould need to be evolved along with appropriate arrangement forsharing the gains of efficient operations with the consumers. The operatingparameters in tariffs should be	--

	at "normative levels" and not at "lower ofnormative and actual".The norms should be efficient, relatable to past performance, capable ofachievement and progressively reflecting increased efficiencies and may alsotake into consideration the latest technological advancements, fuel, vintage ofequipment, nature of operations, level of service to be provided to consumersetc.	
26.2	The regulatory approach evolved for specifying operation norms was based onhistorical data analysis and consideration of efficiencies, technological advancement,vintage etc. However, in case of existing projects, where projects specific notificationsof Government of India existed or if there was a PPA entered between the parties, thenorms specified therein were applied. In so far, as the operational norms in respect ofPLF and Target Availability are concerned, these were separately laid down by theCommission.	-
26.3	**Thermal Generation (Coal based)**	
26.3.1	Station Heat rate (SHR) refers to the conversion efficiency of thermal heatenergy into electrical energy and used for computation of energy charges.The Commission while framing the Regulations for terms and conditions oftariff for different tariff periods has been considering the operational data ofthe generating stations for the past 5 years. The methodology of considering5 years' data ensures that the generator is able to recover the cost ofelectricity in a reasonable manner and covers the reduction in the generationlevel. The heat rate norm specified during	-

	previous tariff periods are as under:	
26.3.2	The GCV measurement of coal was shifted to "As Received" basis for thepurpose of energy charges computation in the Tariff Regulations for theperiod 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 powerplants are running at low utilization (PLF) levels due to various reasonsincluding shortage of coal/gas, lower demand etc. Machines working at lowerPLF have adverse impact on the operational norms and hence, the existingheat rate norms for the new and existing generating stations are required tobe reviewed along with the need for margin. The norms of heat rate will beover and above the heat rate guaranteed by the OEM based on actualperformance data during the last five years.	-
26.3.4	The heat rate is a crucial parameter as it has substantial impact on tariff. Thegain/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 allrelevant factors including shortage of domestic coal supply in the country. Theheat rate norms would also require to be seen in the light of efficiencyimprovement targets achieved by the generating stations under the PATscheme. The heat rate norms vary with the passage of useful life of theproject due to degradation and therefore, the norms specified based on therecently commissioned plants may not be attainable by older plants.	-

26.3.5	The existing regulations provides for calculation of Gross Station Heat rate fornew stations based on Designed Heat Rate with margin of 4.5%. This marginspecified for gross station heat rate is based on recommendation of theCentral Electricity Authority.	-
26.3.6	Approach for determination of station heat rate may need review including thecriteria for specifying heat rate of old plants, continuation of relaxed norms forspecific stations and possible changes required in the existing norms given inTariff Regulation 2014-19.	Acceptable.
26.3.7	**Specific Secondary Fuel Oil Consumption.** The existing norm for the Secondary Fuel Oil Consumption is 1.00 ml/KWh forlignite based CFBC technology with some exception in case of TPS-I and0.50 ml/KWh for Coal based project with the provision for sharing of savingswith the beneficiaries. Further reduction in specific secondary fuel oilconsumption norms may adversely affect the boiler operations under differentoperating conditions including partial loading of units due to fuel shortageconditions. With contribution from renewable generation increasing in the grid,thermal power plants are facing frequent regulations of supply and operationsat lower PLF up to technical minimum. The consumption of secondary fuel oilwould change on account of nature of operations.	--
26.3.8	**Auxiliary Energy Consumption.** The existing norms of auxiliary consumption of coal based generating stationvaries from 5.25% for unit size	-

	of 500 MW and above to 8.5% for 200 MWseries units with steam driven boiler feed pumps and electrically driven boilerfeed 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 ofauxiliary consumption of lignite based generating station is 0.5% more thancoal 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 constructionpower consumption.	
26.3.9	Presently, the auxiliary consumption of 800 MW is fixed based on 500MWsets. The auxiliary consumption of 800 MW sets may vary depending on thesize 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 differencebetween actual (lower) and normative auxiliary consumption. Further, colonyconsumption is not a part of auxiliary consumption w.e.f. 1.4.2014 andtherefore, the same cannot be accounted for against auxiliary consumptionwhile declaring availability. Methodology of declaring availability afterreduction of normative auxiliary consumption and colony consumption needelaboration. .	--
26.3.11	**Normative Annual Plant Availability.** In control period 2014-19, the target availability has	

	been determined basedon the data available for the past years. The recovery of fixed charges waslinked to availability. The availability of 85% is specified with exceptions ofspecific plant wise availability. The existing availability norms are uniform forall the generating stations. Now with the increase of private participation,access to imported fuel by private developers and technological improvementmay have improved the availability. The issue of different availability normsfor existing and new plants can be contemplated.	Acceptable
26.3.12	Shortage of domestic fuel affects availability of the plants and the scheduling. The existing norm for availability may therefore to be revisited. Inthe event of bridging gap through e-auction or imported coal (other than fuelarrangement agreed in purchaseagreement), the need of prior consent ofbeneficiary, maximum permissible limit of blending etc. also need to bedeliberated.	Acceptable
26.3.13	As per present regulatory framework, the recovery of annual fixed charges isbased on cumulative availability during the year. There may be a chances ofdeclaring lower availability during the peak demand period when thebeneficiaries may be required to resort to procurement from short termmarket to meet their demand. However, during low demand period, thegenerating station may declare higher availability so as to achieve the targetcumulative availability on annual basis to recover the full annual fixedcharges. In this process, the beneficiaries may not get the	Suitable mechanism needs to be put in place to verify the availability.

	electricity whenrequired at the time of high demand.	
26.3.14	In case of partly tied up capacity, the plant availability factor for whole plantmay not be relevant. Theconsideration of merchant capacity for the purpose of plant availability declaration is not relevant.	Acceptable.
26.3.15	The existing norms of annual plant availability may need review byconsidering fuel availability, procurement of coal from alternative source,other than designated fuel supply agreement, shifting of fixed cost recoveryfrom annual cumulative availability basis to a lower periodicity, such asmonthly or quarterly or half yearly;	Acceptable
26.3.16	**Transit and Handling Losses:** The Commission had specified norm of 0.2% for the pit head station and0.8% for the non- pit head stations as loss in transit & handling. The samemay have to be reviewed based on the actual data of the past period.	Acceptable
26.3.17	There is often grade slippage of coal from the coalmines to generatingstations. As per fuel supply agreement (FSA) signed by generating stationwith coal supplier, ownership of the coal gets transferred at coal dispatch pointi.e. at the mine. Therefore, it becomes the responsibility of the generatingcompany to ensure that the grade that is billed to the generator is dispatchedby the coal companies though generators have really no control over suchdispatch. It is often reported that there are substantial loss in GCV of coal dueto 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	Acceptable.

	andquantity as per CERC norms. This can be addressed in the Tariff Regulationby indicating GCV as "As Received at plant end" and customization of Form-15 regarding the GCV.	
26.3.19	Comments and suggestions are invited from the stakeholders on the possibleregulatory options discussed above and alternatives, if any.	-
26.4	**Thermal Generation (Coal washer rejects based)**	
26.4.1	The Tariff Policy dated 28th January, 2016 provides as under: *"5.4 The Central Electricity Regulatory Commission inconsultation with Central Electricity Authority and otherstakeholders shall frame within six months, regulations fordetermination of tariff for generation of electricity from projectsusing coal washer rejects. These regulations shall also befollowed by State Electricity Regulatory Commissions.Provided that procurement of power from coal washer rejectsbased projects developed by Central/State PSUs, Joint Venturebetween Government Company and Company other thanGovernment Company in which shareholding of company otherthanGovernment Company either directly or through any of itssubsidiary company or associate company shall not be morethan 26% of the paid up share capital, can be done underSection 62 of the Act."*	--
26.4.2	The Tariff Regulations, 2014 provides operational norms for thermal powerplant based on coal washer's rejects. Coal rejects exhibit distinguishedcharacteristics. Coal rejects cannot be stacked as it would require asubstantial amount of land at the mine site and storing	-

	of rejects for prolongedperiod is hazardous as it may lead to combustion.	
26.4.3	Comments and suggestions are invited from the stakeholders on the possibleregulatory 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 withintroduction of new technology like polymer insulators etc. Thus, themechanism of payment of transmission tariff based on availability oftransmission system may need review.	-
26.5.2	The methodology for computation of Transmission system availability in tariffperiod 2009-14 was changed from earlier tariff period. As per 2009-14Regulations, computation of availability of transmission system, TransmissionSystem Availability Factor for a month (TAFM) was computed as (100- 100XNAFM), where NAFM is the non-availability factor in per unit for the month. Theprocedure of computation of transmission system factor for a month wasprovided in Appendix-IV of Tariff Regulation, 2009. This methodology ofavailability factor(TAFM) was again revised in Tariff Regulations,2014 whereinthe weightage factor was considered based on the individual group such astransmission line, ICTs and Reactors etc.	Acceptable
26.5.3	In 2009-14 Tariff Regulations, computation of NAFM for the transmissionsystem, outage hours for transformer was multiplied by a weightage factor of2.5 and outage hours of reactors was multiplied by a weightage factor	Acceptable

	of Factors were applied such that a 315 MVA transformer would have the sameweightage as a 200 km long D/C line with twin conductors, and a 50 MVARswitched reactor would have one-fourth the weightage of a 315 MVAtransformer. In 2014-19 Regulations, the weightage factor has been workedout based on actual availability (net of non-availability period) and totalavailability of region separately for transmission lines, ICTs and Reactors etc.There is a need to validate the existing methodology of weightage factor byconsidering actual data/availability.	
26.5.4	As per the existing regulations, the maximum incentive for AC system isaround 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 requirescertification as to whether it is export region or import region.	The maximum rate of incentive needs to be reduced by refixing the minimum availability requirement from 98.5 to 99 for AC system and 96 to 98 for HVDC system, to reduce the burden on the end consumers.
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;**	Acceptable.
26.5.6	**Transmission Losses:**	

	Presently, there is no regulatory framework on specifying the norms fortransmission losses. Transmission loss comprises primarily of technical losses,which consists mainly of power dissipation in electricity system componentssuch as transmission line, transformers and measurement systems. Thetransmission losses are dependent on the best operational practices, efficient planning, level of power flow and avoidance of circular flow. The operationalstrategies and practices adopted by transmission network operator and systemoperator impact the transmission losses.	-
26.5.7	The transmission losses considered in the present scheduling framework isabout 4.5-5% for inter-state transmission system and 4-4.5% for intra-statetransmission system. As a result, the net power delivered to the distributionperiphery is reduced by about 9-10%, which has an impact on the cost ofsupply. An option could be to introduce the norms for inter-state transmissionlosses based on factors within control and international benchmarks.	Acceptable
26.5.8	The existing approach for operational norms and level of Normative AnnualTransmission Availability Factor (NATAF) may be reviewed. The weightagefactor to be applied for arriving outage hours for calculating NAFM oftransformer and switchable reactor of substation element may also bedeliberated upon.	Acceptable
26.5.9	Comments and suggestions are invited from the stakeholders on the possibleregulatory 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 auxiliaryconsumption, transformation losses and normative annual plant availabilityfactor. Capacity Index as a measure of plant availability was implemented bythe Commission during tariff periods 2001-2004 and 2004-09. It was based onthe 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 andcontinued during 2014-19 based on actual data. However, in case of a fewhydro plants the same was revised. This is based on the premise thathydrology risk is to be shared by the generator & the beneficiary in the ratio of50:50. There may be need for review of existing values of NAPAF based onactual PAF data for last 5 years.	Acceptable
26.6.2	The norms of auxiliary power consumption of hydro generating station varyfrom 0.7% to 1.2% based on rotational or static excitation system. Thetransformation losses are covered as a part of auxiliary consumption.	Acceptable
26.6.3	Comments and suggestions are invited from the stakeholders on the possibleregulatory options discussed above and alternate options, if any.	-
27.	**Incentive**	
27.1	For generation, the incentive prior to 2009 was linked to normative PLF and25 paisa/kWh was paid for generation beyond normative PLF in case of thermalgenerating station. The incentive, in case of hydro generating station, prior to 2009was linked to the	-

	capacity charges and capacity-index. The incentive during tariffperiod 2009-14 was linked to normative availability and generation beyond normativeavailability was payable at the fixed charge rate for the stations which are more than10 years old or at 50% of the fixed charge for the stations up to 10 years old. In caseof hydro generating stations incentive was linked to the capacity charges (50% ofannual 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 paisa.	
27.2	At present there is same incentive for availability during peak and off peakperiod. There may be a need for introducing differential incentive during peak and offpeak periods. On the same consideration, there may also be a need for higherincentive for the storage and pond age type hydro generating station providingpeaking support. At present, generation beyond the design energy is paid at 80Paise/kWh in case of hydro generating station, which may also need review.	-
27.3	As regards transmission system, incentive is being recovered only throughmonthly formula of billing and collection of transmission charges. In the absence ofclear provision regarding reconciliation of annual transmission charges and incentivewith monthly billing, the concept of NATAF specified by the Commission in TariffRegulations, 2014 requires review.	-
27.4	In view of the introduction of the compensation	-

	mechanism for operatingplants below norms i.e.83-85%, there may be a need to review the incentive anddisincentive mechanism with reference to operational norms.	
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 fornew 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 storageand pond age 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**.	Acceptable
27.6	Comments and suggestions are invited from the stakeholders on the possibleregulatory 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 TariffRegulations require the generating company or transmission licensee to file thepetitions within 180 days from the date of notification of the regulations. Since thetariff determination is quasi-judicial function, there is a time lag between filing thepetition and finalization/ issuance	-

	of tariff order. Till the issuance of final order, thegenerating company or the transmission licenses keep charging the tariff based onprevious tariff order including operational norms. The operational norms notified bythe Commission in new tariff regulations take effect much after the date of coming intoforce of new tariff regulations. Consequently, the benefits of the improved operational norms are passed to beneficiaries only after time lag of few months.	
28.2	Comments and suggestions of stakeholders are invited whether the operationalnorms of the new tariff period should be implemented from the effective date ofcontrol 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 betweengenerating company and beneficiaries in 60:40 ratios on account of improvement incontrollable factors such as Station Heat Rate, Auxiliary consumptions, secondaryfuel oil consumption, refinancing of loan and the true up of primary fuel cost. Subsequent to above, the compensation mechanism has been introduced foroperation in CERC (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016. The compensation mechanism aims to provide compensation if generatingplant is operated at improved norms than ones specified in the amended IEGCRegulations of 2016. In view of the compensation mechanism, it needs to beconsidered as to whether the	Acceptable

	ratio of sharing of benefit may be reviewed.	
29.2	The compensation mechanism introduced through IEGC entails the hedging ofthe risk of operating at low PLF. The compensation coupled with normativecontrollable parameters create a buffer for generating companies. In view of this, themerit order operation can be linked with the PLF in such a way that the plants underSection 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 orannual reconciliation mechanism may need to be prescribed.	Acceptable
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 thedate of billing. In view of the introduction of MCLR, the rate of late payment surchargemay need to be reviewed. One option is to add some premium over and aboveMCLR.	Acceptable To limit the rate to 1 %.
30.2	Further, as per the existing regulations, the rebate is provided if payment ismade 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 daysor including holidays) may need elaboration.	Two working days is acceptable.
31.	**Non-Tariff income**	
31.1	The tariff determination under Section 62 of the Act	Acceptable

	follows the principle of costof recovery which inter-alia provides the reimbursement of cost incurred by thegenerating 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. Presentregulatory framework does not account for other income for reduction of operation &maintenance expenses. However, in case of transmission licensee, the incomeearned from telecom business are adjusted in the billing separately. The principle oftreatment of other income as applicable in case of transmission can be extended forthe generation business.	
31.2	Presently, the revenue from telecom business is adjusted at the rate of Rs3000/- per KM, which was fixed in 2007. It may need review.	Acceptable.
32.	**Standardization of Billing Process**	
32.1	Presently, generating companies and the transmission licensees are followingdifferent practice for raising bills on the basis of tariff order. In order to avoid possibledisputes in billing, it need to be consider as to whether standardization of billingprocess including formats, verification and timeline etc. may be done.	Acceptable
32.2	Some of the States are imposing electricity duty on the actual auxiliaryconsumption 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	Acceptable

	linked with actual auxiliary consumption or normativeconsumption or lower of the two, may need to be specified.	
33.	**Tariff mechanism for Pollution Control System (New norms for ThermalPower Plants)**	
33.1	As per the new Environment norms notified by Ministry of Environment, forestand Climate Change, the TPPs would be required to install or upgrade variousemission control systems like Flue-Gas desulfurization ("FGD") system, electrostaticprecipitators ("ESP") system etc. to meet the revised standards. Recovery of theinvestment made during operation period in the form of additional capitalizationthrough redesigning or retrofitting of plant and related operational costs require amechanism in the tariff regulations.	Acceptable
33.2	Several generating companies have filed petition for approval of additionalcapital expenditure under "change in law" for complying the revised standards of emission for thermal power projects. CEA may be required to specify and benchmarkappropriate technology and costing norms, apart from preparing phasing plan forshutdown during installation of emission related retrofits/ equipment. The generatingcompanies would be required to select suitable technology at competitive ratesthrough the process of transparent competitive bidding to minimize the impact on tariffin the power supply agreement.	Acceptable
33.3	There is likelihood of significant impact on tariff on account of compliance withthese norms. Supplementary tariff could be determined considering	Acceptable

	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 andrevised emission, proposed technology, construction period, phasingplan for shutdown during the construction period; c) Feasibility of undertaking implementation of new norms with R&Mproposal for plants having low residual life, say, less than 10 years. d) Change in Auxiliary Consumption and operation and maintenanceexpenses due to implementation of pollution control equipment's.	
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 beintroduced and the rate of return on equity may be aligned with theinterest on debt; b) "Debt Service obligation during construction period and recovery ofdepreciation" may be provided with the condition that such depreciationmay be adjusted during the remaining period; c) As the level of emission is linked to actual generation, it would beappropriate to link recovery of supplementary tariff with the actualgeneration or availability or combination of both.	Acceptable
34.	**Renewable Generation by existing Thermal Generation**	

	Stations	
34.1	The Revised Tariff Policy dated 28th January,2016 provides for setting up ofrenewable energy generation capacity by existing coal based thermal powergenerating station. The policy provides that in case any existing coal and lignite basedthermal power generating station chooses to set up additional renewable energygenerating capacity with the concurrence of power procurers under the existing PowerPurchase Agreements, the power from such plant shall be allowed to be bundled andtariff of such renewable energy shall be allowed as pass through by the AppropriateCommission. The Obligated Entities who finally buy such power would account thispower towards their renewable purchase obligations(RPOs). Scheduling and dispatchof 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 thecommon facilities and land and bundle RE power with the conventional power prior todelivery point i.e. before ex-bus bar. Other option is to establish the renewable projectat different location and pool the generation capacity on external basis beyond thedelivery point. In both the cases, the annual fixed charges for thermal project andrenewable project may be determined separately, based on separate set of tariffprinciples.	Pricing shall be based on bundled power.
34.3	The scheduling and dispatch mechanism of renewable generation canbe asper the thermal power generation. The target availability and dispatch level, in thiscase,	-

	maybe pre-specified which may be 2% higher for every 10% renewablecapacity addition and the annual fixed charges for the thermal project and renewableproject maybe combined for deciding the tariff. The rate of return, land cost, operationand maintenance cost for such renewable capacity canbe specified separately.	
34.4	Comments and suggestions are invited from the stakeholders on the possibleoptions 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 andtheir commercial operation is declared after successful completion of the trialoperation/run. In case of transmission system, it is ensured that an element of thetransmission system is in regular service after successful charging and trial operationto ensure grid security. In some cases, non-availability of evacuation system and/oradequate load has delayed the trial operation and commissioning of the plants. Thereis also an issue of mismatch between the commercial operation of a generatingstation and the associated transmission systems which has had an impact onspecifying COD and consequently, on the IDC of the generating station or thetransmission 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 oftransmission system. Similarly, the methodology of trial operation for bay equipment, Inter-connecting transformer, Reactors, Fixed Series Compensation, and	Acceptable

	transmissionlines 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.	Acceptable
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 transmissionsystem, the delay on account of non-commissioning of downstream or upstream system is more relevant. Since the declaration of commercial operation date attractsthe 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 ofthe 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 fordemarcation of responsibilities or for Indemnification Agreement.	Acceptable
35.5	Comments and suggestions are invited from the stakeholders on possible options for dispute-free and practical mechanism for declaring commercial operationdate. 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 apart 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 storagesystem 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 toregulatory approval while storage facility as a part of the generating capacity may beas per the consent of the procurer for availing storage facilities.	-
36.4	The annual fixed charges of energy storage system may be determinedseparately as per the pre-specified operational and financial norms by theCommission and may be recovered from the beneficiaries of the region	Alternative is acceptable.

	assupplementary to the transmission charges. Energy storage at transmission level canbe used for overall optimization of power from the grid, irrespective of the owner ofstorage capacity and may be dispatched when needed. Such dispatch can be addedin 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 determinedseparately 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 totheir designated beneficiaries within the power purchase agreement. The generating stations may use it to avoid the flexible operations due to frequent regulations. Thespecific operational procedure can be devised for generation level grid storage.	Acceptable
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.	Acceptable
36.7	Comments and suggestions are invited from the stakeholders on the possible as 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.	-
37.3	Normative ……. Capital cost is the starting point for tariff	Existing practice of detailed cost component needs to be

	fixation. Therefore, the first question that arises is as to whether the capital cost could be determined on normative basisas against the existing practice of detailed cost component wise examination?	continued.
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 analysed. The NormativeValue of the capital cost per MW approved by the Commission during the year of Commissioning of respective sample plants was calculated by applying thenormalization 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 thedistribution 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 andduties 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?	Benchmarking of capital cost for Generation and transmission projects is not advisable.
37.7	Normative Tariff by fixing AFC as a percentage of Capital Cost: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 analyse the AFC of first year of operation as a percentage of the approved capital cost. It was observedthat correlation coefficient between AFC approved for the first year of operation and approved capital cost was around 0.84. Similarly, correlation coefficient betweenaverage 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 ofbenchmarking AFC as percentage of capital cost to save resources and time spent on conducting component wise prudence check. However, a further analysis showedMean 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 rigorousexercise, 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?	a) No b)Existingmethodology would address the issue.
37.10	Normative Tariff by fixing each component of AFC as a percentage of total AFC: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 wasconsidered. 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.	-
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 CoDup to the "Cut-Off Date". The Regulations indicate "Cut-Off Date" as 31st March of the year closing after two years of the year of commercial operation of whole or part of the project, and in case the whole or part of the project is declared under commercial operation in the last quarter of a year, the cut-off date shall be 31stMarch of the year closing after three years of the year of commercial operation.	
37.15	Hence, the generator has approximately three years' duration beyond CoD for additional capitalization. Therefore, in order to provide regulatory certainty, the"Additional Capitalization" could be strictly restricted to the period between "CoD" and the "Cut-Off Date". This would imply that the "Capital Cost" as on "Cut-Off Date" would remain unaltered for the rest of the useful life of the plant. However, any reasonable expenditure in future, such as cost towards meeting new environmental norms etc. if considered uncontrollable / unavoidable may be treated as a separate stream of revenue and recovery could be allowed as a separate component on annuity basis.	-
37.16	The next issue is surge/ dip owing to change of control	Acceptable

	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 Scalable (increasing)/ non-Scalable (decreasing) factors? c. Whether Scalable(increasing) / non-Scalable (decreasing) factors should remain same for all plants/transmission systems (or) they be separate foreach 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?	
37.18	Principle of Cost Recovery-Approach towards Multi-Part Tariff. 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 plantavailability factor as per the benchmark level specified by the Commission. All the generating stations regulated by CERC are required to follow the scheduling anddispatch 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,	**Acceptable.**

	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). Theproposition 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 inproportionate 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, adherenceto 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	**Acceptable.**

	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. "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 “Scalable / increasing” and “nonScalable/ decreasing” segments a. Segment -1 (Non-Scalable/ decreasing) comprising of RoE, IoL,IoWC, Depreciation.b. Segment -2 (Scalable) comprising O&M 3 Current Regulations provide for "Add. Cap." as permissible for a period from CoDupto 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 wholeor 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 threeyears 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 free zed. “Existing” Generating Stations “New” Generating Stations 7 For each year the “CAGR” or 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.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 pricePAF (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	
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. Itwould 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 isbenchmarked 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., "Scalable / Increasing" and "Non-Scalable / 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	Acceptable

	financial norms for any new control period need not apply on the existing plants (both thermal and hydro-stations). The mechanism also proposes to revisit the principles of cost recovery. It is proposed to split the "Fixed Charges payable to the Generator" into two components,viz., "Off-Peak Fixed Charge (OPFC)" and "Peak Fixed Charge (PFC)", linked to the availability of plant during off-peak and peak periods at specified levels. This frameworkcould also apply mutatis mutandis for transmission projects. In so far as the energy charges for the thermal stations are concerned, the proposition is that the operational norms as prevalent on their date of commercial operation (COD) will continue to beapplicable 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.	
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 leveldue	Acceptable.

	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.	
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.	-
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 individualelement 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 ofthe 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 existingassets 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.	Acceptable.
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	Acceptable.

	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.	
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 checks 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.	Acceptable.