Central Electricity Regulatory Commission

New Delhi

Explanatory Memorandum

to

Draft Terms and Conditions of Tariff for 2014-2019

6th December, 2013

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1 Introduction

1.1.1 The Central Electricity Regulatory Commission (CERC) was constituted under the erstwhile Electricity Regulatory Commissions Act (ERC), 1998 to discharge the duties and perform the functions specified under Section 13 of the ERC Act, 1998. Upon enactment of the Electricity Act, 2003, CERC was deemed to be constituted under the same.

1.1.2 The Central Commission has been vested with the functions under the Electricity Act, 2003 (the Act) to regulate the tariff of the generating companies owned or controlled by Central Government, generating companies having a composite scheme for generation and sale of electricity in more than one State, to regulate inter-State transmission of electricity and to determine the tariff for inter-State transmission in electricity among other functions.

1.1.3 Section 61 of the Electricity Act 2003 provides for the guiding principles for the Commission whilespecifying the terms and conditions for the determination of tariff as follow:

"Section 61 (Tariff regulations):

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

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

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

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

(d) Safeguarding 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 electricity and also, reduces cross-subsidies in the manner specified by the Appropriate Commission;

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

(i) The National Electricity Policy and tariff policy:

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

1.1.4 Section 178(2)(s) of the Act further empowers the Central Electricity Regulatory Commission (CERC) to make regulations on the terms and conditions for the determination of tariff under section 61.

1.2 Tariff Regulations issued by CERC

1.2.1 The CERC was constituted under the erstwhile Electricity Regulatory Commissions Act, 1998, and in exercise of powers under the 1998 Act. The Commission, since its inception, has been issuing regulations based on multi-year tariff principles over the period. In exercise of powers under the 1998 Act, the Commission had issued terms and conditions for determination of tariff for the period 2001-04. After the enactment of the Electricity Act 2003, the CERC framed regulations, in exercise of the powers under Section 178 of the Act, on the terms and conditions for the determination of tariff for the period 2004-09 in March 2004 and subsequently for the period 2009-14 in January, 2009. The present tariff period 2009-14 would end on 31st March 2014 and the Commission proposes to specify the terms and conditions of tariff for the next control period i.e. for 2014-19.

1.3 Approach Paper for Tariff Regulations, 2014-19

1.3.1 The Commission initiated the process of framing the tariff regulations for 2014-19 by issuing an approach paper and solicited comments of stakeholders on the basis and assumptions to be considered while framing the new terms and conditions of tariff regulations. The Commission, through this approach paper, sought views from the stakeholders to review the existing tariff principles and norms in view of the developments during the ongoing tariff period, current and perceived challenges in the Power sector and duly recognizing the need for sustainable market development based on the experiences over the years. The Commission, through approach paper, aimed at soliciting views of stakeholders on the different aspects of tariff setting during tariff period 2014-19.

1.3.2 The Commission received comments from various stakeholders including State Governments, SERCs, Central sector utilities, State sector utilities, private sector utilities, financial and other organizations, and individual experts. A copy of the approach paper issued by the Commission is attached as **Annexure I** and the comments received from the stakeholders on various issues are discussed in the relevant sections in this explanatory memorandum. A brief of the comments received from stakeholders on each aspect is attached as **Annexure II**.

1.3.3 The Commission also convened a meeting of the Central Advisory Committee on October 07, 2013to discuss the approach paper on terms and conditions of tariff for 2009-14. A brief of the comments received from the members of the Central Advisory Committee on various issues is attached as **Annexure III** (along with Minutes of meeting).

1.3.4 The Commission in subsequent sections has discussed in detail the various aspects of Tariff Regulations including existing provisions, issues raised in the approach paper, summary of comments received from stakeholders, analysis of actual performance with respect to performance parameters and the Commission's proposal for framing Tariff Regulations for 2014-19 period. While analysing these aspects for tariff regulations, the Commission has consciously considered to balance the interests of the investors and the beneficiaries/consumers with due regard to the guiding principles as enunciated in Section 61 of the Electricity Act, 2003.

2 Capital Cost

2.1 Background

2.1.1 The determination of capital cost of the project is perhaps the most important step for the cost based regulations. The capital cost corresponding to the capitalized assets of infrastructure and plant and machinery of the project is the starting point as the rate base for deciding the return on the investment made by the generating company or transmission licensee.

2.1.2 The tariff determination process was followed prior to inception of Electricity Regulatory Commission. The capital cost parameter was significant at that time and different approaches were followed for determination of tariff. Prior to 1992 and during the period 1992 to 1997 and 1997 to 2001, the capital cost of the project used to be based on gross book value as per the audited accounts. The changes in the Capital cost by the way of capitalization and FERV were also being accounted for and the Tariff was being adjusted retrospectively. This practice was even followed during FY 2004-09. During the control period 2004-09, the capital cost was determined based on the actual cost as per the balance sheet of the regulated entities. Based on the experience gained over a period of time and considering concerns of the stakeholders, the Commission switched over to the methodology of determination of capital cost based on the projected capital expenditure for the tariff period of 2009-14. This enabled the generating companies/transmission licensees to file their tariff application prior to commissioning of the project. The un-discharged liabilities were not included in the projected/actual capital expenditure for the purpose of capitalization up to date of commercial operation. Capital cost also included interest during construction, financing charges and foreign exchange rate variation up to the date of commercial operation of the project. Any revenue generated on account of injection of infirm power through unscheduled interchange in excess of fuel cost is being adjusted in the capital cost.

2.1.3 As regard to the Additional Capital Expenditure, the Commission in its previous Regulations i.e., Tariff Regulations, 2001 and Tariff Regulations, 2004 had specified that capital expenditure on account of certain components within the original scope of work actually incurred after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check. Further, the Commission in its previous Tariff Regulations did not specify any provisions with respect to the standardization of the construction period. However, the Commission in Tariff Regulations, 2009, in order to boost the construction efficiency and faster completion of the projects, established standard construction period for new projects. According to this regulation, if the construction of such project is completed on specified time, the project is entitled for additional RoE to the extent of 0.5% over and above base rate of return on equity. Such additional return on equity will continue over a useful life of the assets unless it is reviewed by the Commission for the projects already qualified for additional ROE.

2.1.4 Further, the Tariff Regulations, 2001 and Tariff Regulations, 2004 did not include any provisions with respect to benchmark capital cost for the projects. However, the Commission in its Tariff Regulations, 2009 stipulated that in case of the thermal generating stations and the transmission system, prudence check of capital cost may be carried out based on the benchmark norms to be specified by the Commission from time to time. The benchmark capital cost, as notified by the Commission, for coal based thermal generation and transmission projects is being used as a guiding parameter for allowing capital cost during 2009-14.

2.1.5 Another important aspect of the projects is the cost of initial spares. As regard to the initial spares, the Commission in its Tariff Regulations, 2001 and Tariff Regulations, 2004 stipulated that the initial spares are to be linked with Capital cost of the project on the ground that capital cost of the project was single firm/unique number known to the developer and beneficiaries. Furthermore, the Commission in its Tariff Regulations, 2004 had also specified a ceiling for the cost of initial spares as a percentage of Capital cost of the project. The Commission has been following the same regulations in the control period 2009-14 with the changes in the ceiling numbers. Over the period of time, the Commission, while fixation of tariff, observed the variation in actual cost of initial spares for different projects.

2.1.6 The commissioning of the generating stations and transmission systems and their commercial operation, is declared after a successful completion of the trial operation/run. The Commission in its Previous Regulations i.e., Tariff Regulations, 2001 and Tariff Regulations, 2004 had stipulated that the Commercial Operation Date (COD) in relation to a unit is the date declared by the generator after demonstrating the Maximum Continuous Rating (MCR) or Installed Capacity (IC) through a successful trial run, after notice to the beneficiaries. The Commission had also stipulated that in relation to the generating station the date of commercial operation means the date of commercial operation of the last unit of the generating station. For the Control Period 2009-14, the Commission established separate definitions for the thermal generating stations, hydro generating stations and transmission projects.

2.1.7 The date of commercial operation has specific significance in tariff fixation as the capitalization of the assets and its usage has been accounted from this date. The developer has a specific significance of this milestone of COD as the project start fetching main revenue stream from this point. It is well understood that the developers would not like to compromise on this milestone, but while doing so, it is equally important that project developer would not compromise the quality and standards duly complying requirements of commercial operation. The Commission in past experienced the various issues on declaration of commercial operation of the project.

2.1.8 In a bid to improve the operational efficiency of the thermal generating stations, the Government of India introduced Perform Achieve and Trade scheme (PAT). The PAT scheme is a trading scheme aimed to reduce energy consumption in industries across India using market oriented mechanisms. The scheme is being designed and implemented by the Bureau of Energy Efficiency (BEE), under the Ministry of Power, Government of India. Since, Perform, Achieve and Trade scheme came into existence in the recent years, the Commission in its Previous Regulations i.e., Tariff Regulations, 2001 and Tariff Regulations, 2004 did not specify any provisions with respect to the capital expenditure made by the generators to achieve targets of the efficiency improvement under the Perform, Achieve and Trade (PAT) scheme.

2.2 Issues brought out in Approach Paper

2.2.1 With this background, the Commission in the Approach Paper observed that projected capital cost as on COD and subsequent additional capital expenditure up to cut-off date may change on account of various reasons like deferment in commissioning of projects, non-placement of orders due to limited vendor responses etc. Further, the Commission also contemplated on having a standardized construction period for projects and International Competitive Bidding for procurement of main plant packages.

2.2.2 The Commission in its Approach Paper also discussed the possibilities of the benchmark capital cost being specified as the normative Capital cost for the project and the need to address the additional Capital expenditure incurred by the generators to meet the efficiency improvement targets set up under the Perform, Achieve and Trade scheme (PAT).

2.2.3 The Commission in its Approach Paper brought out the following issue inviting comments/suggestions from the stakeholders:

a) *Whether the tariff claim based on projected capital expenditure needs to be continued or replaced. If replacement is to be made, what would be the alternatives? Can we rely on earlier approach of 2001-04 or 2004-09 period of allowing tariff claim based on actual expenditure incurred due to considerable variations in projected capital cost vis-à-vis actual capital cost as on COD? Alternative or suggestions, if any*

b) *Whether to standardize the construction period? If so, what should be the period? Should the existing provision of allowing IDC on equity infusion above desired level be continued? Is there a need to relook at the existing provision based on experience of considerable delays resulting into higher IDC* *on actual basis compounded by allowance of IDC on equity infusion above threshold limit?*

Should IDC for equity infusion above desired level be allowed till the date of capitalization (COD) along with actual IDC in case of allowance of time over run OR should such IDC be capped up to scheduled construction time period decided upfront?

c) *Can the benchmark capital cost as specified by Commission be considered for the purpose of normative capital cost or it requires further strengthening? Suggestions/comments on periodical review of benchmark capital cost.*

d) *Whether to review the permissible limit of initial spares for transmission projects? Whether permissible initial spares can be specified as percentage of original project cost or plant and machinery cost and what should be the methodology to determine it? Suggestion on separate initial norms for the ICT, switchable line and bus reactors, switchable variable capacitor (SVC) , Bay equipment, transmission line and Fixed Series Compensation (FSC) & fixed line reactors.*

e) *Whether to make ICB mandatory for the procurement of main plant packages/ major packages and competitive bidding for the other packages to ensure competitiveness of prices?*

f) *Suggestions/comments on the existing methodology followed for the trial xoperation of generating station and transmission system. Furnish alternative methodologies followed by State generating stations, Central generating stations and others, if any. Suggestions on addressing the 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. Similarly, suggestion on the issue of acceptance of COD of transmission line if the generating projects are not commissioned or the work under the scope of Generating agency was not completed.*

g) *Suggestions on the pre-requisite for completion of data telemetry and communication facilities for declaring COD of transmission system and operationalisation of RGMO for declaring COD of generating station.*

h) Suggestions to deal with capital expenditures made by generator to achieve targets of the efficiency improvement under the Perform, Achieve & Trade (PAT) scheme. Comments on type of expenditure to be considered as necessary for successful operation and efficient operation in case of hydro and transmission system

i) Suggestions/comments are invited on aspects to be covered in truing up of capital cost.

2.3 Existing Provisions of Tariff Regulations, 2009

7. <u>Capital Cost</u>. *(1) Capital cost for a project shall include:*

(a) the expenditure incurred or projected to be incurred, including interest during construction and financing charges, any gain or loss on account of foreign exchange risk variation during construction on the loan - (i) being equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event of the actual equity less than 30% of the funds deployed, - up to the date of commercial operation of the project, as admitted by the Commission, after prudence check;

(b) capitalised initial spares subject to the ceiling rates specified in regulation 8; and

(c) additional capital expenditure determined under regulation 9:

Provided that the assets forming part of the project, but not in use shall be taken out of the capital cost.

(2)The capital cost admitted by the Commission after prudence check shall form the basis for determination of tariff:

Provided that in case of the thermal generating station and the transmission system, prudence check of capital cost may be carried out based on the benchmark norms to be specified by the Commission from time to time:

Provided further that in cases where benchmark norms have not been specified, prudence check may include scrutiny of the reasonableness of the capital expenditure, financing plan, interest during construction, use of efficient technology, cost over-run and time over-run, and such other matters as may be considered appropriate by the Commission for determination of tariff:

Provided also that the Commission may issue guidelines for vetting of capital cost of hydro-electric projects by independent agency or expert and in that event the capital cost as vetted by such agency or expert may be considered by the Commission while determining the tariff for the hydro generating station:

Provided also that the Commission may issue guidelines for scrutiny and commissioning schedule of the hydro-electric projects in accordance with the tariff policy issued by the Central Government under section 3 of the Act from time to time.

Provided also that in case the site of a hydro generating station is awarded to a developer (not being a State controlled or owned company), by a State Government by following a two stage transparent process of bidding, any expenditure incurred or committed to be incurred by the project developer for getting the project site allotted shall not be included in the capital cost:

Provided also that the capital cost in case of such hydro generating station shall include:

(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and

(b) cost of the developer's 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) project in the affected area:

Provided also that where the power purchase agreement entered into between the generating company and the beneficiaries or the implementation agreement and the transmission service agreement entered into between the transmission licensee and the long-term transmission the respective year of the tariff period 2009-14, , as the case may be, provide for ceiling of actual expenditure, the capital expenditure admitted by the Commission shall take into consideration such ceiling for determination of tariff:

Provided also that the capital cost of the generating station shall include the cost for creating infrastructure for supply of power to the rural households located within a radius of five kilometers of the power station if the generating company does not intend to meet such expenditure as part of its Corporate Social Responsibility:

Provided also that in case of the existing projects, the capital cost admitted by the Commission prior to 1.4.2009 duly trued up by excluding un-discharged liability, if any, as on 1.4.2009 and the additional capital expenditure projected to be incurred for the respective year of the tariff period 2009-14, as may be admitted by the Commission, shall form the basis for determination of tariff

8. Initial Spares. *Initial spares shall be capitalised as a percentage of the original project cost, subject to following ceiling norms:*

(i)	*Coal-based/lignite-fired thermal generating stations*	*- 2.5%*
(ii)	*Gas Turbine/Combined Cycle thermal generating stations*	*- 4.0%*
(iii)	*Hydro generating stations including pumped storage hydro-electric generating station*	*- 1.5%*
(iv)	*Transmission system*	
	(a) Transmission line	*- 0.75%*
	(b) Transmission Sub-station	*- 2.5%*
	(c) Series Compensation devices and HVDC Station	*- 3.5%*
	(d) Gas Insulated sub-station	*- 3.5%*

Provided that where the benchmark norms for initial spares have been published as part of the benchmark norms for capital cost under first proviso to clause (2) of regulation 7, such norms shall apply to the exclusion of the norms specified herein.

9. Additional Capitalisation. *(1) The capital expenditure incurred or projected to be incurred, on the following counts within the original scope of work, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check:*

(i) Un-discharged liabilities;
(ii) Works deferred for execution;

(iii) Procurement of initial capital spares within the original scope of work, subject to the provisions of regulation 8;

(iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court; and

(v) Change in law

Provided that the details of works included in the original scope of work along with estimates of expenditure, undischarged liabilities and the works deferred for execution shall be submitted along with the application for determination of tariff.

(2) The capital expenditure incurred or projected to be incurred on the following counts after the cut-off date may, in its discretion, be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court;

(ii) Change in law;

(iii) Deferred works relating to ash pond or ash handling system in the original scope of work;

(iv) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) including due to geological reasons after adjusting for proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation; and

(v) In case of transmission system any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement of switchyard equipment due to increase of fault level, emergency restoration system, insulators cleaning infrastructure, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system:

(vi) In case of gas/ liquid fuel based open/ combined cycle thermal generating stations, any expenditure which has become necessary on renovation of gas turbines after 15 year of operation from its COD and the expenditure necessary due to obsolescence or non-availability of spares for successful and efficient operation of the stations.

Provided that any expenditure included in the R&M on consumables and cost of components and spares which is generally covered in the O&M expenses during the major overhaul of gas turbine shall be suitably deducted after due prudence from the R&M expenditure to be allowed.

(vii) Any capital expenditure found justified after prudence check necessitated on account of modifications required or done in fuel receipt system arising due to non-materialisation of full coal linkage in respect of thermal generating station as result of circumstances not within the control of the generating station.

(viii) Any undischarged liability towards final payment/withheld payment due to contractual exigencies for works executed within the cut-off date, after prudence check of the details of such deferred liability, total estimated cost of package, reason for such withholding of payment and release of such payments etc.

(ix) Expenditure on account of creation of infrastructure for supply of reliable power to rural households within a radius of five kilometers of the power station if, the generating company does not intend to meet such expenditure as part of its Corporate Social Responsibility.

Provided that in respect sub-clauses (iv) and (v) above, any expenditure on acquiring the minor items or the assets like tools and tackles, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, fans, washing machines, heat convectors, mattresses, carpets etc. brought after the cut-off date shall not be considered for additional capitalization for determination of tariff w.e.f. 1.4.2009.

6. Truing up of Capital Expenditure and Tariff.

(1) The Commission shall carry out truing up exercise along with the tariff petition filed for the next tariff period, with respect to the capital expenditure including

additional capital expenditure incurred up to 31.3.2014, as admitted by the Commission after prudence check at the time of truing up.

Provided that the generating company or the transmission licensee, as the case may be, may in its discretion make an application before the Commission one more time prior to 2013-14 for revision of tariff.

(2) The generating company or the transmission licensee, as the case may be, shall make an application, as per Annexure I to these regulations, for carrying out truing up exercise in respect of the generating station a unit or block thereof or the transmission system or the transmission lines or sub-stations thereof by 31.10.2014;

(3) The generating company or the transmission licensee, as the case may be, shall submit for the purpose of truing up, details of capital expenditure and additional capital expenditure incurred for the period from 1.4.2009 to 31.3.2014, duly audited and certified by the auditors;

(4) Where after the truing up, the tariff recovered exceeds the tariff approved by the Commission under these regulations, the generating company or the transmission licensee, as the case may be, shall refund to the beneficiaries or the transmission customers, as the case may be, the excess amount so recovered along with simple interest at the rates specified in the proviso to this regulation;

(5) Where after the truing up, the tariff recovered is less than the tariff approved by the Commission under these regulations, the generating company or the transmission licensee, as the case may be, shall recover from the beneficiaries or the transmission customers, as the case may be, the under-recovered amount along with simple interest at the rates specified in the proviso to this regulation;

(6) The amount under-recovered or over-recovered, along with simple interest at the rates specified in the proviso to this regulation, shall be recovered or refunded by the generating company or the transmission licensee, as the case may be, in six equal monthly installments starting within three months from the date of the tariff order issued by the Commission after the truing up exercise.

Provided that the rate of interest, for clauses (4), (5) and (6) of this regulation, for calculation of simple interest shall be considered as under:

(i) SBI short-term Prime Lending Rate as on 01.04.2009 for the year 2009-10.

(ii) SBI Base Rate as on 01.07.2010 plus 350 basis points for the year 2010-11.
(iii) Monthly average SBI Base Rate from 01.07.2010 to 31.3.2011 plus 350 basis points for the year 2011-12.
(iv) Monthly average SBI Base Rate during previous year plus 350 basis points for the year 2012-13 & 2013-14.

Further, under the existing Regulations, in order to boost the construction efficiency of the projects, incentives in form of additional Return on Equity to the extent of 0.5% is provided if the construction of the power plant is completed within a time limit specified by the Commission.

2.4 Stakeholders Responses

2.4.1 In response to the issues brought out in the Approach Paper by the Commission, the stakeholders submitted their comments/suggestions on various issues. The summary of comments/suggestions as submitted by the stakeholders is as follows:

(i) Projected Vs. Actual Capital Expenditure

(a) Some of the State Electricity Regulatory Commissions submitted that the Capital cost shall be based on the actual expenditure i.e., actual cash flow as on COD duly certified by the Auditor after prudence check by the Commission.

(b) Most of the Generating Companies and Licensees submitted that the existing methodology for determination of Tariff on the basis of the projected Capital expenditure may be continued.

(c) Some of the State distribution Utilities submitted that the Capital cost shall be based on the actual expenditure.

(ii) Additional Capital Expenditure

(a) Some of the Central Generating Companies submitted that projected additional Capital expenditure can be allowed as per the existing regulations.

(b) One of the State Generating Company submitted that Additional capitalization should be strictly scrutinized and the work pending for completion and the expenditure be disclosed during the prudence check of the capital cost.

(iii) Standardization of Construction Period

(a) One of the State Electricity Regulatory Commission submitted that the Construction period may be standardized to avoid increase in capital cost on account of IDC, escalation in prices and increase in establishment charges.

(b) Most of the Generation and Transmission Utilities submitted that Construction period cannot be standardized more particularly in case of hydro projects.

(c) Some of the State Distribution Utilities submitted that the construction period for the Power project can be standardized.

(d) Some of the Central and State Generating Utilities submitted that the existing provision of allowing IDC on equity infusion above desired level should continue to be allowed till the COD of the project.

(iv) Benchmark Capital Cost

(a) Some of the Government Departments submitted that the Benchmark Capital cost can be used as the normative Capital cost and the revision of the Benchmark Capital cost should be done more frequently.

(b) Some of the Central Generating Companies submitted that the Benchmark Capital cost should not be used as the normative Capital cost and should only be used as the guiding factor for the prudence check of the Capital cost of the project.

(c) Some of the State Generation and Distribution Utilities submitted that Benchmark Capital cost can be used as the normative Capital cost. However, the true up has to be done finally on the basis of the actual capital expenditure.

(v) Initial Spares

(a) One of the State Electricity Regulatory Commission and some of the Central Generating Companies submitted that the cost of the initial spares forms the part of the supply contract and therefore, this should be continued to be allowed as an element of the Capital cost.

(b) Some of the State Government Departments and State Generation Utilities submitted that the cost of initial spares should be linked with the Plant and Machinery cost rather than the Capital cost of the project.

(c) One of the Central Generating Company submitted that various transmission equipments are installed in generating stations' switchyard for grid interface of the power plants. Provision of initial spares of these equipments permitted for transmission licensees should also be allowed in case of generating stations.

(vi) International Competitive Bidding

(a) Some of the State Electricity Regulatory Commissions, State Government Departments and State Generation and Transmission Utilities submitted that in order to boost the competitiveness under the cost plus tariff mechanism, the ICB should be made mandatory.

(b) Some of the Central Generating Companies submitted that ICB may not be made mandatory through Regulations as this may sometimes delay award of the projects and thus may increase cost, particularly when the entire project is not awarded through a single EPC contract.

(c) Some of the State Generation and Distribution Utilities submitted that considering the risk of exchange rate fluctuation as well as complexity of international transactions, price preference may be given to domestic supply and ICB should not be made compulsory.

(vii) Trial Run and Trial Operation

(a) Some stakeholders suggested that trial performance test at rated load should be considered prerequisite for declaring COD of the generating unit. In case of transmission lines – 72 hours with no fault or infringement of specified safety clearances to ground and grounded objects and no visible corona should be considered adequate.

(b) One of the stakeholder suggested that in case of mismatch between COD of generating station and its associated transmission system, commissioning of generation and its associated transmission may be dealt in accordance with the relevant agreements entered between the parties and may be excluded from the tariff regulations.

(viii) Perform, Achieve and Trade Scheme (PAT)

(a) One of the Central Generating Company submitted that Capital expenditure incurred to achieve the targets fixed under PAT scheme or any other scheme and towards compliance of statutory /regulatory requirement notified by MoEF or any other Government agency may be allowed to be recovered from tariff.

(b) Some of the State Generation and Distribution Utilities submitted that in case when the generator gets energy efficiency certificate for operating above the benchmark fixed by PAT scheme, the benefit may be shared in the ratio of 50:50 between the generator and the beneficiary. In other case of under achievement of the bench mark fixed by PAT the generator will solely bear its burden.

(ix) Truing Up of Capital Cost

(a) Some of the State Electricity Regulatory Commissions submitted the truing up of capital cost should be allowed for the fixation of reasonable tariff on the basis of audited accounts of the generating company.

(b) Some of the Central and State Generating Companies submitted that the existing mechanism may be continued for the Truing up of the capital cost

2.5 Commission's Proposal

2.5.1 The Commission has carefully examined the issues brought out in the Approach Paper in light of the stakeholders comments and suggestions and has analysed the issues accordingly.

2.5.2 As regard to the projected vs. actual capital expenditure, the Commission has again examined the issue and is of the view that apart from meeting the intended objective of certainty of tariff and minimal retrospective adjustments, the projected Capital expenditure would have following additional advantages:

(a) From beneficiaries' perspective, they would be aware of the intended additional capitalization in advance and be able to raise their observations before the Commission about the reasonableness and necessity of additional capitalisation before the actual expenditure is made by the generating companies/transmission licensees. As regards their concern about the expected expenditure being considered in capital base without putting assets to use, the Commission would like to clarify that anticipated expenditure would be considered only after it is found justified. In the absence of expenditure actually made, the same would be reduced from the capital cost at the time of truing up exercise with appropriate refund/adjustment with interest. Further, if the expenditure indeed materializes, the actual retrospective adjustment is expected to be bare minimum as a result of truing up exercise.

(b) From the prospective of the generating companies/transmission licensees, they would be assured of the expenditure to be admitted once accepted by the Commission in the capital cost before making the expenditure. Moreover, they would be more careful about the expenditure to be made as it would require to be justified before the Commission.

2.5.3 As per above discussions and with due regards to the views of the stakeholders, though the Commission has observed variation in projected capital expenditure, it is recognized that tariff fixation based on projected capital expenditure was commenced first time in 1.4.2009. The truing up of those projected capital expenditure is yet to be done for the most of the projects. The project owners has gained experience of projecting capital cost so far during the period of 2009-13 and it is expected to have a further improvement after completion of truing up of exercise under existing tariff regulations of 2009-14. The tariff fixation based on projected capital expenditure are important from the benefit of consumer's point of view as it avoids the retrospective revision of the tariff to the beneficiaries. The tariff determination on projected capital expenditure is advantageous for beneficiaries or long term transmission customer/DICs and generating or transmission company. The Commission is not inclined to discontinue with the existing provisions for determination of tariff based on the capital expenditure incurred duly certified by the auditors or projected to be incurred.

2.5.4 However, based on the analysis of actual data, the Commission observed the wide variation between the projected capital expenditure and actual capital expenditure as on COD for new projects as well in additional capital expenditure for new projects. In case the actual capital expenditure varies substantially with respect to the projected capital expenditure, the impact of same needs to be allowed at the time of truing up with interest. While continuing with the projected capital expenditure, the wide variation between projected and actual capital expenditure leads to incorrect representation of cost in tariff. Thus, it is important that the wide variation between projected and actual capital expenditure needs to be controlled.

2.5.5 For new projects, the Commission also observed that there was substantial delay in actual COD of new unit/station/transmission system as compared to scheduled COD mentioned in the application submitted for approval of tariff. Under such cases, due to delay in project, the Capital Cost as on COD varies substantially with respect to projected figures. In case of new projects, the Utilities are allowed to submit the tariff applications based on projected expenditure for the Project which are likely to complete within 6 months from the date of application. However, in case the Project gets delayed the Capital Cost as on COD varies substantially due to various reasons such as increase in price variation, IDC, IEDC, etc. and hence it becomes imperative to carry out the prudence check of the Capital Cost once again based on actual Capital Cost as on COD. Therefore, the Commission proposes that if the date of commercial operation is delayed beyond 180 days from the date of issue of tariff order, the generating company or transmission licensee shall file a fresh application for determination of tariff after the date of commercial operation of the project.

2.5.6 As regard to the standardization of the construction period, the existing Regulations provide for the incentives in form of additional ROE if the construction of project is completed within a specified time limit. The delay in commissioning of a project has a direct impact on the capital cost of project as in case of any delay in commissioning of the project, capital cost would increase on account of IDC, IEDC, etc.

2.5.7 The Commission agrees with the views of various stakeholders that it may not be appropriate to specify the standard construction period as the time schedule for executing the project varies substantially across the projects due to various reasons such as execution philosophy, site conditions, etc. However, the Commission feels under the cost plus regime, it is important to specify the appropriate mechanism towards treatment of increase in cost on account of delay in project in order to allow the prudent costs to be passed on to consumers.

2.5.8 The Hon'ble APTEL in its judgment dated April 27, 2011 in Appeal No. 72 of 2010 elaborated discussed the probable reasons for the delay in execution of a project. The relevant extract from the Judgment is reproduced below:

"7.4. the delay in execution of a generating project could occur due to following reasons:

i) Due to factors entirely attributable to the generating company, e.g., imprudence in selecting the contractors/suppliers and in executing contractual agreements including terms and conditions of the contracts, delay in award of contracts, delay in providing inputs like making land available to the contractors, delay in payments to contractors/suppliers as per the terms of contract, mismanagement of finances, slackness in project management like improper co-ordination between the various contractors, etc.

ii) Due to factors beyond the control of the generating company e.g. delay caused due to force majeure like natural calamity or any other reasons which clearly establish, beyond any doubt, that there has been no imprudence on the part of the generating company in executing the project.

iii) Situation not covered by (i) & (ii) above. "

2.5.9 The Hon'ble APTEL in its judgment further elaborated on sharing of the excess cost due to time over run as detailed below:

"In our opinion in the first case the entire cost due to time over run has to be borne by the generating company. However, the Liquidated Damages (LDs) and insurance proceeds on account of delay, if any, received by the generating company could be retained by the generating company. In the second case the generating company could be given benefit of the additional cost incurred due to time over-run. However, the consumers should get full benefit of the LDs recovered from the contractors/suppliers of the generating company and the insurance proceeds, if any, to reduce the capital cost. In the third case the additional cost due to time overrun including the LDs and insurance proceeds could be shared between the generating company and the consumer. It would also be prudent to consider the delay with respect to some benchmarks rather than depending on the provisions."

2.5.10 The Commission proposes that the IDC and IEDC upto scheduled commercial operation shall be included as part of Capital Cost. Further any increase in IDC and IEDC due to delay in completion of project only on account of uncontrollable factors shall only be allowed as a part of Capital Cost subject to prudence check. Accordingly, the Commission proposes to specify the controllable and uncontrollable factors leading to cost escalation impacting IDC and IEDC.

2.5.11 Some of the Controllable factors shall include but not limited to the following:

i. Variations in capital expenditure on account of time and/or cost overruns on account of land acquisition issues.

ii. Efficiency in the implementation of a project not involving approved change in scope of such project, change in statutory levies or force majeure events;

iii. Delay in execution by contractors appointed.

2.5.12 The "uncontrollable factors" shall include but not limited to the following:

i. Force Majeure events, such as acts of war, fire, natural calamities, etc.;
ii. Change in law;

2.5.13 While discussing the standardisation of construction period, it is important to decide starting point or zero date of the project so as to maintain uniformity for determination of time over run. The different approaches are followed for start date or zero date. In some of the cases, start date is being discussed as date of investment approval where as in some of the cases, letter of award is discussed as project start date. In order to have uniform approach, the Commission also proposes to include the definitions of "Start date or Zero date" and "Scheduled Commercial Operation Date (SCOD)".

2.5.14 On the issue of allowing IDC for the equity infusion above the desired level, the Commission would like to refer to the Tariff Policy, issued by the Government of India, which states that all the new Power Projects would be financed in the debt-equity ratio of 70:30 and the investors are free to infuse equity more than the 30% level with a condition that equity infusion above the threshold limit of 30% would be considered as normative loan. The Commission is of the view that any investment deployed either in the form of equity or debt has a cost to be serviced. The investments made in the form of equity are risk capital carrying higher rate of return and have perpetual flow of return up to the end of the life of the plant. But the loan capital does not enjoy the aforesaid perpetual and higher rate of return. As the equity in excess of 30% of capital cost has been considered as notional loan for the purpose of tariff, the Commission proposes that the said capital shall also be entitled for interest during construction, financing charges and foreign exchange risk variation up to the date of commercial operation of the project. It is understood that maintaining debt:equity ratio during construction phase would be difficult and variation is bound to happen. However, while considering the equity in excess of 30% of capital cost as notional loan, it is contemplated that fund should be deployed on prudent basis by generating company or transmission company as the case may be. Accordingly, the Commission proposes to allow interest during construction, financing charges and foreign exchange risk variation up to the scheduled date of commercial operation of the project on the normative loan admitted by the Commission after prudence check and IDC on actual loan will be allowed beyond SCOD to the extent found beyond the control of petitioner taking into account prudent phasing of funds.

2.5.15 As regard to the benchmark capital cost, the Commission would like to reiterate that under the existing Tariff Regulations, benchmark capital cost is notified by the Commission for coal based thermal generating stations and transmission projects. This benchmark capital cost is considered by the Commission as the guiding parameter for allowing capital cost of the projects and not the normative capital cost. The Commission agrees with the views of the stakeholders that each project has unique features and its cost varies based on project specific or site specific features and hence it may not be appropriate to consider the benchmark capital costs as normative capital costs

2.5.16 In view of the above discussion and with due regard to the sentiment of the stakeholders, the Commission proposes to continue with considering the benchmark capital cost as guiding parameter while carrying out the prudence check of the capital cost. However, the benchmark capital cost would be used for prudence check by examining variation of actual cost with benchmark capital cost and the capital cost above benchmark level will be allowed only after detail justification to the satisfaction of the Commission.

2.5.17 On the issue of Initial Spares, the existing regulations specify that the cost of initial spares should be computed as the percentage of the capital cost of the project. The Commission is of the view that typically the initial spares are supplied by the OEM suppliers and it may not be appropriate to consider the cost of initial spares as percentage of the total capital cost. The Capital cost for the project in addition to Plant and Machinery includes various other components such as cost of land, site development, IDC, Financing Charges, establishment expenses etc. and cost towards these components depend upon various other factors. For two similar projects having same Plant and Machinery cost, the total Capital Cost may vary substantially because of other components of Capital Cost and if Initial Spares are allowed as percentage of Capital Cost, the amount allowed towards Initial Spares for two projects with identical plant and machinery may vary substantially for same quantity and quality of the spares.

2.5.18 The Commission in order to derive norms for quantum of initial spares has considered the initial spares as a percentage of Plant & Machinery Cost for the following recently commissioned units.

a) Sipat I
b) Simhadri II
c) Uno Sugen
d) Teesta Lower Dam

e) Chamera III

2.5.19 In view of the above discussions and considering the views of some of the stakeholders, the Commission proposes that the cost of initial spares should be linked to the plant and machinery cost and shall be capitalised as a percentage of the Plant and Machinery Cost, subject to the following ceiling norms:

(i) Coal-based/lignite-fired thermal generating stations - 3.00%

(ii) Gas Turbine/Combined Cycle thermal generating stations - 3.00%

(iii) Hydro generating stations including pumped storage hydro generating station - 4.00%

(iv) Transmission system

a. Transmission line – 1.00%

b. Transmission Sub-station – 3.00%

c. Series Compensation devices and HVDC Station- 4.50%

d. Gas insulated sub-station (GIS) – 4.00%

e. Communication System under ULD&C - 3.50%

2.5.20 International Competitive Bidding

The Commission understands that it would be impractical to consider ICB for award of all the packages particularly when the project is being executed by awarding multiple packages as for some packages, it may not be possible to attract international suppliers. However, in a cost plus tariff mechanism wherein the tariff is determined based on the cost incurred, it is necessary and essential that all the expenses are carried out in a prudent manner. This is only possible if competitive bidding is insisted upon. It is desired that major technology intensified packages of projects to be procured through international competitive bidding for efficient price discovery.

2.5.21 In view of the above discussion and with due regard to views of the stakeholders, the Commission proposes that the competitive bidding be made mandatory for all the packages and International Competitive Bidding will be an option available to the procurers depending upon the availability of technology and cost effectiveness. In all such cases, care need to be taken to get technology transfer in a prescribed period as in case of defence procurements. The procurers will also take important care to safeguards the foreign exchange variations in the import of equipments thereby avoiding unnecessary burden on the consumers.

2.5.22 As regard the issue of trial run and trial operations, the Commission proposes to include the specific provisions in the Regulations.

2.5.23 As regard the issue of capital expenditure incurred by the generators to meet the targets under PAT, the Commission felt that the details of the Cost Benefit analysis and sharing of benefit are to be examined for any additional expenditure incurred by the generators in order to meet the efficiency improvement targets under the Perform, Achieve and Trade scheme. The Commission has tightened the norms during previous tariff periods to reflect maximum efficiency. It is contemplated that the present CERC norms are quite efficient and thus, the targets under PAT are to be examined in comparison with CERC norms to justify additional capital expenditure. The case to case base examination enables the Commission to decide the admissibility of additional capital expenditure. In view of above, the Commission felt that, it will appropriate to take decisions on allowing additional capital expenditure on case to case basis after analysing the following aspects:

a) Cost of plan proposed by developer in conformity with norms of Perform, Achieve and Trade Scheme,

Sharing of the benefit accrued on account the Perform, Achieve and Trade Scheme.In order to simplify the admission of capital cost in transparent manner, the specific provision has been made to exclude the cost of the asset forming part of project but not in use, assets created from the grant and de-capitalization of assets.

2.5.24 In the tariff regulations of tariff period 2004-09, the concept of cut off date was introduced and it was expected that all the necessary works and equipments would be in place by the cut off date within the original scope of work. The cut off date was defined as first financial year closing after one year of the COD in 2004-09. The definition of cut off date was further modified during the tariff period 2009-14 which provides that in case the date of commercial operation falls in the last quarter of the financial year, the cut off date shall be the financial year closing after two years of the date of commercial operation of the generating station or the transmission. This provision provides sufficient time to project developer for completion of balance works and for payment of liabilities after achieving COD in the last quarter. We are not inclined to change the provision of cut off date.

2.5.25 As regards the provision for additional capital expenditure, the Commission has specified the separate provision to limit the admission of capital expenditure before and after the cut off date. It is observed that the project achieving COD during last year of control period, the cut off date will spill over to next control period. Such projects would be treated as existing project in the next control period and the provision for additional capital expenditure would require some changes to accommodate the additional capital expenditure upto cut off date.

2.5.26 Thus in the draft regulation, separate provisions for the additional capital expenditure beyond the cut off date and after the cut off date corresponding to the existing and new projects have been proposed. The provision of additional capital expenditure is further limited on the basis of whether it is covered under original scope of work or not. While allowing the additional capitalization, the need is also felt to address the treatment of de-capitalization.

2.6 Proposed Provisions

The Commission accordingly proposes to specify the following provisions in the Regulations as regards to the Capital Cost:

Capital Cost :(1)The Capital cost determined by the Commission after prudence check in accordance with this Regulation shall form the basis of determination of tariff for existing and new projects.

(2) The Capital cost of a new project shall include the following:

(a) the expenditure incurred or projected to be incurred up to the date of commercial operation of the project;

(b) Interest during construction, financing charges and any gain or loss on account of foreign exchange risk variation during construction period, on the loans (i) being equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event of the actual equity less than 30% of the funds deployed;

(c) Interest during construction and incidental expenditure during construction as computed in accordance with Regulation 11 of these regulations;

(d) capitalised Initial spares subject to the ceiling rates specified in Regulation 13 of these regulations;

(e) expenditure on account of additional capitalization and de-capitalisation determined in accordance with Regulation 14 of these regulations; and

(f) adjustment of revenue due to sale of infirm power prior to the schedule commissioning as specified under regulation 18 of this Regulation.

(3) The Capital cost of an existing project shall include the following:

(a) the capital cost admitted by the Commission prior to 1.4.2014 duly trued up by excluding liability, if any, as on 1.4.2014;
(b) additional capitalization and de-capitalization for the respective year of tariff as determined in accordance with Regulation 14; and
(c) expenditure on account of renovation and modernisation as admitted by this Commission in accordance with Regulation 15.

(4) The capital cost in case of existing/new hydro generating station shall also include:

(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and
(b) cost of the developer's 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) project in the affected area.

(5) The capital cost with respect to thermal generating station, incurred or projected to be incurred on account of the Perform, Achieve and Trade (PAT) scheme of Government of India will be considered by the Commission on case to case basis and shall include :

a) Cost of plan proposed by developer in conformity with norms of PAT Scheme; and
b) Sharing of the benefits accrued on account the PAT Scheme.

(6) The following shall be excluded or removed from the capital cost of the existing and new project:
(a) The assets forming part of the project, but not in use;
(b) Any grant received from the Central or State Government or any statutory body or authority for the execution of the project which does not carry any liability of repayment;
(c) Decapitalisation of Asset; and
(d) Any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State government by following a two stage transparent process of bidding.

10. Prudence Check of Capital Expenditure: The following principles shall be adopted for prudence check of capital cost of the existing or new projects:

(1) In case of the thermal generating station and the transmission system, prudence check of capital cost may be carried out taking into consideration the benchmark norms specified/to be specified by the Commission from time to

time:

Provided that in cases where benchmark norms have not been specified, prudence check may include scrutiny of the reasonableness of the capital expenditure, financing plan, interest during construction, incidental expenditure during construction, use of efficient technology, cost over-run and time over-run, competitive bidding for procurement and such other matters as may be considered appropriate by the Commission for determination of tariff.

Provided further that in cases where benchmark norms have specified, the variation of capital cost from benchmark norms, the generating company or transmission licensee shall submit the reason for exceeding the capital cost from benchmark norms to the satisfaction of the Commission for allowing cost above benchmark norms.

(2) The Commission may issue new guidelines or revise the existing guidelines for vetting of capital cost of hydro-electric projects by an independent agency or an expert and in that event the capital cost as vetted by such agency or expert may be considered by the Commission while determining the tariff for the hydro generating station.

(3) The Commission may issue new guidelines or revise the existing guidelines for scrutiny and commissioning schedule of the hydro-electric projects in accordance with the tariff policy issued by the Central Government under section 3 of the Act from time to time which shall be considered for prudence check.

(4) Where the power purchase agreement entered into between the generating company and the beneficiaries provides for ceiling of actual capital expenditure, the Commission shall take into consideration such ceiling for determination of tariff for prudence check of capital cost.

11. Interest during construction (IDC), Incidental Expenditure during Construction (IEDC)

(A) Interest during Construction (IDC):

(1) Interest during construction, shall be computed corresponding to the loan

from the date of infusion of fund or date of financial closure, whichever is later, and after taking into account the prudent phasing of funds upto SCOD.

(2) In case of additional costs on account of IDC due to delays in achieving the date of commercial operation on SCOD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds:

Provided that if the delay is not attributable to the generating company or the transmission licensee as the case may be, and is due to uncontrollable factors as specified in Regulation 12 of these regulations, IDC may be allowed after due prudence check:

Provided further that only IDC on actual loan may be allowed beyond the SCOD to the extent found beyond the control of petitioner after due prudence and taking into account prudent phasing of funds.

(B) Incidental Expenditure during Construction (IEDC):

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

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

(2) In case of additional costs on account of IEDC due to delay in achieving the date of commercial operation on SCOD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justification with supporting documents for such delay including the details of incidental expenditure during delay period and liquidated damages recovered or recoverable corresponding to the delay:

Provided that if the delay is not attributable to the generating company or the transmission licensee, as the case may be, and is due to uncontrollable factors as specified in Regulation 12, IEDC may be allowed after due prudence check.

Provided further in case of delay on account of any agency or contractor or supplier of generating company or transmission licensee, the generating company or transmission licensee shall take into account the liquidated damages to the extent of the damages caused to generating company or transmission licensee on account of the delay.

(3) In case the time overrun beyond SCOD is not admissible after due prudence, the increase of capital cost on account of cost variation corresponding to the period of time over run may be excluded from capitalization irrespective of price variation provisions in the contracts with supplier or contractor, if any.

12. Controllable and Uncontrollable factors: The following shall be considered as controllable and uncontrollable factors leading to cost escalation impacting IDC and IEDC:

(1) The "controllable factors" shall include but shall not be limited to the following:

i. Variations in capital expenditure on account of time and/or cost overruns on account of land acquisition issues;
ii. Efficiency in the implementation of the project not involving approved change in scope of such project, change in statutory levies or force majeure events; and
iii. Delay in execution of the project on account of contractor, supplier or agency of the generating company or transmission licensee.

(**2**) The "uncontrollable factors" shall include but not limited to the following:

i. Force Majeure events, such as acts of war, fire, natural calamities, etc.; and
ii. Change in law.

Provided further that no additional impact of time overrun or cost overrun shall be allowed on account of non-commissioning of the generating station or associated transmission system by SCOD, as the same should be recovered through Indemnification Agreement between the generating company and the transmission licensee:

Provided further that if the generating station is not commissioned on the SCOD of the associated transmission system, the generating company shall bear the IDC or transmission charges if the transmission system is declared under commercial operation by the Commission in accordance with second proviso of regulation 4(3) of these regulations till the generating station is commissioned;

Provided also that if the transmission system is not commissioned on SCOD of the generating station, the transmission licensee shall arrange the evacuation from the generating station at its own arrangement and cost till the associated transmission system is commissioned

13. Initial Spares: Initial spares shall be capitalised as a percentage of the Plant and Machinery cost upto cut-off date, subject to following ceiling norms:

(i)	Coal-based/lignite-fired thermal generating stations	-	3.0%
(ii)	Gas Turbine/Combined Cycle thermal generating stations	-	3.0%
(iii)	Hydro generating stations including pumped storage hydro generating station.	-	4.0%
(iv)	Transmission system		
	(a) Transmission line	-	1.00%
	(b) Transmission Sub-station	-	3.00%
	(c) Series Compensation devices and HVDC Station	-	4.50%
	(d) Gas insulated sub-station (GIS)	-	4.0%
	(e) Communication system	-	3.5%

Provided that where the benchmark norms for initial spares have been published as part of the benchmark norms for capital cost by the Commission, such norms shall apply to the exclusion of the norms specified above:

Provided further that where the generating station has any transmission equipment forming part of the generation project, the ceiling norms for initial spares for such equipments shall be as per the ceiling norms specified for transmission system under this regulations.

14. Additional Capitalisation and De-capitalisation:

(1) The capital expenditure in respect of the new project or an existing project incurred or projected to be incurred, on the following counts within the original scope of work, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Undischarged Liabilities recognized to be payable at a future date;

(ii) Works deferred for execution;

(iii) Procurement of initial capital spares within the original scope of work, in accordance with the provisions of regulation 13;

(iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law; and

(v) Change in law or compliance of any existing law:

Provided that the details of works asset wise/work wise included in the original scope of work along with estimates of expenditure, liabilities recognized to be payable at a future date and the works deferred for execution shall be submitted along with the application for determination of tariff.

(2) The capital expenditure incurred or projected to be incurred in respect of the new project on the following counts within the original scope of work after the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;

(ii) Change in law and Force Majeure events;

(iii) Deferred works relating to ash pond or ash handling system in the original scope of work;

(iv) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.

(3) The capital expenditure, in respect of existing generating station or the transmission system including communication system, incurred or projected to be incurred on the following counts after the cut-off date may, in its discretion, be admitted by the Commission, subject to technical scrutiny and prudence check:

(i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;

(ii) Change in law;

(iii) Deferred works relating to ash pond or ash handling system in the original scope of work;

(iv) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.;

(v) For any capital expenditure other than that of the nature specified above in (i) to (iv) in case of coal/lignite based station shall be met out of compensation allowance;

(vi) Any additional capital expenditure which has become necessary for efficient operation of thermal generating plant other than coal/lignite based stations or transmission system as the case may be. The claim shall be substantiated with the technical justification duly supported by the documentary evidence like test results carried out by an Independent agency in case of deterioration of assets, report of Independent agency in case of damage caused by natural calamities, upgradation of capacity for the technical reason such as increase in fault level;

(vii) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) including due to geological reasons after adjusting for proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation;

(viii) In case of transmission system any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement due to obsolesce of technology, replacement of switchyard equipment due to increase of fault level, emergency restoration system, insulators cleaning infrastructure, replacement of porcelain insulator with polymer insulators, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system; and

(ix) Any capital expenditure found justified after prudence check necessitated on account of modifications required or done in fuel receiving system arising due to non-materialisation of coal supply corresponding to full coal linkage in respect of thermal generating station as result of circumstances not within the control of the generating station:

Provided that any expenditure on acquiring the minor items or the assets including tools and tackles, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, fans, washing machines, heat convectors, mattresses, carpets etc. brought after the cut-off date shall not be considered for additional capitalization for determination of tariff w.e.f. 1.4.2014:

Provided that if any expenditure has been claimed under Renovation and Modernisation (R&M), Repairs and maintenance under (O&M) expenses and Compensation Allowance, same expenditure cannot be claimed under this regulation;

(4) In case of de-capitalisation of assets of generating company or a transmission licensee, as the case may be, the original cost of such asset as on the date of de-capitalisation shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place.

3 Renovation and Modernization

3.1 Background

3.1.1 The Commission in 2009-14 Regulations made a separate provision for making application by the generating company or the transmission licensee for meeting expenditure on Renovation & Modernisation (R&M) for the purpose of extension of useful life beyond the useful life. An alternative provision was made in Tariff Regulations, 2009 in the form of special allowance to be allowed in lieu of R&M for Coal/lignite based thermal power stations.

3.2 Issues brought out in Approach Paper

3.2.1 The provision was made in Tariff Regulations, 2009 in the form of special allowance to be allowed in lieu of R&M for Coal/lignite based thermal power stations. This provision enabled generating Companies to meet the requirement of expenses including R&M on completion of 25 years of useful life to a unit /station without any need for seeking for resetting of capital base. The Commission in its Approach Paper has observed that the generating companies had been filing their application for meeting expenditure on Renovation and Modernisation without giving life extension period. The Commission in the Approach Paper has brought the following issue:

"Whether there is a need to address the above issues & review the provision relating to Renovation & Modernisation and Special allowance to make it more responsive to the requirement of generating stations and transmission assets?"

3.3 Stakeholder's Views

a) Some of the Government Departments and the State Electricity Regulatory Commissions have suggested that there is a strong need to encourage the schemes of R&M of existing generating stations with few modifications like revision of useful life of power plants to 30 years.

b) Some of the Central Generating Companies have submitted that the existing Regulations providing a special allowance in lieu of R&M of thermal power stations and the same may be continued.

c) Some of the State Generation and Distribution Utilities submitted that provision relating to the R&M and special allowance requires review.

3.4 Existing Regulations of Tariff Regulations, 2009

Renovation and Modernisation.*(1) The generating company or the transmission licensee, as the case may be, for meeting the expenditure on renovation and modernization (R&M) for the purpose of extension of life beyond the useful life of the generating station or a unit thereof or the transmission system, shall make an application before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, record of consultation with beneficiaries and any other information considered to be relevant by the generating company or the transmission licensee:*

Provided that in case of coal-based/lignite fired thermal generating station, the generating company, may, in its discretion, avail of a 'special allowance' in accordance with the norms specified in clause (4), as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof, and in such an event revision of the capital cost shall not be considered and the applicable operational norms shall not be relaxed but the special allowance shall be included in the annual fixed cost:

Provided also that such option shall not be available for a generating station or unit for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.

(2) Where the generating company or the transmission licensee, as the case may be, makes an application for approval of its proposal for renovation and modernisation, the approval

shall be granted after due consideration of reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.

(3) Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

(4) A generating company on opting for the alternative in the first proviso to clause (1) of this regulation, for a coal-based/lignite fired thermal generating station, shall be allowed special allowance @ Rs. 5 lakh/MW/year in 2009-10 and thereafter escalated @ 5.72% every year during the tariff period 2009-14, unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:

Provided that in respect of a generating unit in commercial operation for more than 25 years as on 1.4.2009, this allowance shall be admissible from the year 2009-10.

3.5 Commission's Proposal

3.5.1 The Commission is of the view that the Special Allowance in lieu of R&M introduced in 2009-14 Regulations will incentivise the plant owner to maintain the plant and achieve the normative performance parameters even after the useful life of the asset by continuous and progressive maintenance dozing subsequent to useful life on year to year basis. Further, Special Allowance is in lieu of Renovation & Modernisation Expenditure and if the Generating Station/Unit opts for Special Allowance, the recovery of Capital Expenditure on Renovation & Modernisation is not to be provided separately as part of tariff.

3.5.2 The Commission considering the suggestions of stakeholders proposes to continue with the provision of Special Allowance in lieu of R&M. However, the Commission feels that the Generating Company shall maintain the records of expenditure incurred or utilized from special allowance to ensure that the Special Allowance is being used for the intended purpose.

3.5.3 Considering the increase in R&M cost over a period of time, the Commission proposes to increase the Special Allowance to Rs. 7.5 Lakh/MW for the units, which will opt for Special Allowance during the tariff period 2014-19. The units, which have already opted for Special Allowance during 2009-14 tariff period, special allowance shall be allowed by escalating the special allowance applicable for 2013-14 @ 6.35% every year during the tariff period 2014-19.

3.5.4 The admission of capital expenditure on account of R&M will be limited through prudence check which will involve the prudence check of estimates, capital expenditure incurred and life extension. The capital cost will be re-determined after deducting the accumulated depreciation already recovered from the original project cost.

3.6 Proposed Provisions

Renovation and Modernisation: (1) The generating company or the transmission licensee, as the case may be, for meeting the expenditure on renovation and modernization (R&M) for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff of the generating station or a unit thereof or the transmission system or an element thereof, shall make an application before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee.

(2) Where the generating company or the transmission licensee, as the case may be, makes an application for approval of its proposal for renovation and

modernisation, the approval shall be granted after due consideration of reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.

(2) In case of gas/ liquid fuel based open/ combined cycle thermal generating station, any expenditure which has become necessary for renovation of gas turbines after 25 years of operation from its COD and an expenditure necessary due to obsolesce or non-availability of spares for efficient operation of the stations shall be allowed :

Provided that any expenditure included in the R&M on consumables and cost of components and spares which is generally covered in the O&M expenses during the major overhaul of gas turbine shall be suitably deducted after due prudence from the R&M expenditure to be allowed.

(3) Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

Special Allowance for Coal-based/Lignite fired Thermal Generating station:

(1) In case of coal-based/lignite fired thermal generating station, the generating company, instead of R&M may opt to, avail of a 'special allowance' in accordance with the norms specified in this regulation, as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof, and in such an event, revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the special allowance shall be included in the annual fixed cost:

Provided also that such option shall not be available for a generating station or unit for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.

(2) The Special Allowance shall be @ Rs. 7.5 lakh/MW/year for the year 2014-15 and thereafter escalated @ 6.35% every year during the tariff period 2014-19, unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:

Provided that in respect of a unit in commercial operation for more than 25 years as on1.4.2014, this allowance shall be admissible from the year 2014-15:

Provided also that the special allowance for the generating stations, who, in its discretion, has already availed of a 'special allowance' in accordance with the norms specified in clause (4) of Regulations 10 of Central Electricity Regulatory Commission (Terms and Conditions of Tariff Determination) Regulations, 2009, shall be allowed by escalating the special allowance allowed for 2013-14 @ 6.35% every year during the tariff period 2014-19.

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

4 Tariff Application Methodology

4.1 Background

4.1.1 The existing approach of tariff application based on projected capital expenditure and anticipated date of commissioning of project is within six months was specified as any generating station for the purpose of billing shall require a tariff approved by the Commission.

4.2 Issues brought out in Approach Paper

4.2.1 The Commission in its Approach paper flagged key issues to be addressed with regard to Tariff Application Methodology. The issues presented in the approach paper inviting suggestions from various stakeholders were as follows:

a) Can existing practice of allowing filing of petition six months prior to the date of commercial operation be continued or requires further change? Can provisional tariff requirement be done away? Any other suggestions/comments for simplification of tariff filing methodology.

b) In respect of tariff petitions, can provisional tariff be granted based on declaration by the Companies as against detailed petition? This may save time on account of frequent changes in proformas due to change in DOCO, other events etc. At the time of determining final tariff, detailed examination of all aspects can be undertaken. Can variations to the projected cost v/s actual cost be restricted to a pre-specified range/limit along with interest penalty provision?

c) Can the tariff for transmission system be determined on the regional basis for each inter- state transmission licensee? What could be the difficulties foreseen in this process?

4.3 Stakeholders Responses

4.3.1 The issues wise extracts of suggestions received from various stakeholders are as follows:

i. Some of the stakeholders suggested that the tariff claims based on actual capital expenditure as per the Balance Sheet as was followed earlier during the tariff period 2004-09 should be reintroduced.

ii. Some of the stakeholders suggested that in the existing system, petitions for tariff determination can be filed for the projects completed or projected to be completed within six months from the date of application. However, if provisional tariff is awarded based on a mere declaration by the Companies as against detailed petition, then the six months time can be dispensed with.

iii. Some of the stakeholders suggested that determination of final tariff involves submission of detailed formats which is followed by Technical Validation Sessions, Public hearings etc. which takes a lot of time. Under such circumstances, it is desirable to have an approval on the Provisional tariff of the transmission elements at least one month prior to the commencement of next billing cycle of POC. Further, for determination of provisional tariff 95% of proposed tariff may be considered as provisional tariff and any difference in the provisional tariff and final tariff should be allowed to be recovered or refunded with interest cost.

iv. Some of the stakeholders' submitted that the Provisional tariff may be granted based on declaration by the companies and thereafter final tariff determined against detailed petition. Provisional tariff may be allowed at the beginning of the tariff period, in order to minimize the tariff arrears and ease recovery/ refund of tariff revision arrears. The difference between projected cost and actual cost may be refunded/recovered to/from beneficiaries along with interest till date of payment.

v. In respect of tariff petitions, provisional tariff should not be granted based on declaration by the Companies as against detailed petition. It should be based on the tariff petition filed by the petitioner for determination of tariff and allowed as per existing regulations.

vi. POWERGRID submitted that in order to understand the impact of clubbing the petitions for all regional elements, a detailed exercise would be required to analyze the impact on tariff. The basic expectation of the licensees would be that the overall returns on the projects continue to be the same for the life of the projects under either of the regulatory approaches. Further, the impact of having a regional tariff and the requirement to specify POC charges needs to be analysed.

vii. Some of the stakeholders submitted that the tariff should be based on actual expenditure incurred, and, hence, there is no need for such provision. Provisional tariff may be granted only to the extent of actual expenditures incurred. With the PoC method in place this is not going to affect beneficiaries.

4.4 Commission's Proposal

4.4.1 The Commission after going through suggestions and comments received from the stakeholders is of the view that any utility should have an approved tariff before the date of commercial operations of the project. This can be achieved by filing petition prior to actual date of commercial operation. The Commission has proposed to continue tariff determination on projected capital expenditure basis. This will enable the generating company or transmission licensee to file application on anticipated commercial operation basis. Thus it is proposed to continue with the existing approach of filing petition prior to commercial operation based on anticipated COD with certain modifications. However, the existing provision of filing petition prior to six months from anticipated commercial operation date has been modified to120 days (four months).

4.4.2 In case of transmission system, filing of petition prior to 120 days does not appear to be feasible in view of the requirement of tariff for computation of tariff under CERC (sharing of transmission charges and losses) Regulations, 2010 (hereafter referred as 'sharing regulations'). As per the sharing regulations, the transmission charges and losses have been determined on quarterly basis by Nodal agency in advance. Thus, the tariff of the assets to be commissioned to that quarter is to be determined prior to the process of computation under sharing regulations. In view of above, the dispensation given to the transmission licensee to file a petition prior to 180 days from anticipated commercial operation date.

4.4.3 If the generating company or the transmission licensee continues to file a separate unit/element wise petition for unit/elements commissioned prior to 1.4.2014, the number of petitions will increase leading to avoidable regulatory burden. In view of above, it is proposed that the tariff of the units or elements commissioned prior to 1.4.2014 shall be determined on consolidated basis only and accordingly, the generating company or transmission licensee shall have to file a petition. Further, for the new projects, if the commercial operation of units or elements falls within the span of six months, the generating company or transmission licensee shall have to file consolidated petitions from the notional DOCO. It is expected that this will reduce number of hearings, petitions and simplify the tariff determination.

4.4.4 The commission observed that the generating companies are entering into power purchase contract through different modes i.e. competitive bidding route and MoU route. Thus, the tariff for the part capacity is to be determined by the Commission as per the Terms and conditions specified by the Commission under sections 62 of the Act read with sections 79 of the Act. In such a case the issue of determination of capital cost for the part capacity will be difficult. Thus, the Commission proposes to determine the capital cost for such project as a whole but the tariff determination will be limited to the extent of contracted capacity.

4.4.5 Further, the Commission observed that some of the companies are exercising the option of converting their dedicated line into inter-state transmission line and operating as a part of inter-state transmission system. The tariff for these transmission assets is also to be determined by the Commission. In order to address these requirements, the Commission proposes to determine the tariff for these assets from the date of utilization as a part of inter-state transmission system as indicated in transmission license or date of transmission license, whichever is later.

4.4.6 The Commission proposes to continue with provision of truing up with respect to capital expenditure and additional capital expenditure at the end of tariff period. However, in order to limit the impact on consumer in terms of carrying cost of under recovered or over recovered tariff on account of variation of projected and actual capital expenditure, the Commission proposes to reduce the burden of carrying cost on consumers. In the event of excess recovery of tariff in case the capital cost considered in the tariff exceeds the actual capital cost by more than 5%, the generating company or transmission licensee will refund the excess tariff recovered corresponding to excess capital cost, as approved by the Commission along with interest at 1.20 times of the bank rate as prevalent on April 1 of respective year. On the other hand, in case of under recovery of tariff in case the capital cost considered in the tariff falls short of the actual capital cost by more than 5%, the generating company or transmission licensee will recover the shortfall in tariff, as approved by the Commission alongwith interest at 0.80 times of the bank rate as prevalent on April 1 of respective year. It is expected that this provision will make the projections more accurate and at the same time, the interest of the beneficiaries or long term transmission customers/DICs are also protected.

4.4.7 Further, in order to limit the impact on account of variation of projected capital cost from actual capital cost, the Commission proposes interim true up. In the event of determining tariff on projected capital cost basis and from anticipated commercial operation date, the Commission proposes that the generating company or transmission licensee shall file an application for interim true up of capital cost within 180 days (six months) from commercial operation date.

4.4.8 It is observed that the apart from the variation of capital cost, there will be a variation in other parameters like station heat rate, auxiliary consumption and secondary fuel oil consumption (in case of generating station) which has an impact on tariff. The Commission felt that the variation which is within the control of generating company or transmission licensee shall also be trued up duly taking into account the reasons and gains are to be shared with consumers. It is, therefore, proposes that scope of truing up will be further expanded to controllable parameters and shall take into account the variation on account of controllable and uncontrollable parameters.

4.5 Proposed provisions

6. <u>Tariff determination</u>

(1) Tariff in respect of a generating station may be determined for the whole of the generating station or stage or generating unit or block thereof, and tariff in respect of a transmission system may be determined for the whole of the transmission system or transmission line or sub-station or communication system forming part of transmission system:

Provided that where all the generating units of a stage of generating station or all elements of a transmission system have been declared under commercial operation prior to 1.4.2014, the generating company or the transmission licensee, as the case may be, shall file consolidated petition in respect of the entire generating station or transmissions system for the purpose of determination of tariff for the period 2014-19:

Provided further that in case of commercial operation of the generating station or transmission system including communication system on or after 1.4.2014, the generating company or transmission licensee shall file a consolidated petition combining all the units of generating station or all elements of transmission system which are likely to be commissioned during next six months from the date of application:

Provided also that the tariff of the existing communication used for inter-state transmission system shall be as per the methodology followed by the Commission prior to 1.4.2014.

(2) For the purpose of determination of tariff, the capital cost of a project may be broken up into stages, distinct blocks, units, transmission lines and sub-systems forming part of the project, if required:

Provided that where the cost incurred on common facilities have not been proportionately apportioned between the units or elements of the project, the cost in respect of such common facilities shall be apportioned on the basis of the installed capacity of the units or line length and number of bays, as the case may be:

Provided further that where all the units of a generating station or elements of a transmission system including communication system or element thereof have not been declared under commercial operation as on the date of filing of the petition, the proportionate cost of common facilities shall be apportioned among the units of the generating station on the basis of their installed capacity or among the elements of the transmission system on the basis of line length and number of bays which have been declared under commercial operation as on the date of filing of the Petition.

(3) Where an existing transmission project has been granted licence under section 14 of the Act read with Regulation 6(c) of the Central Electricity Regulatory Commission (Terms and Conditions of grant of Transmission Licence for inter-State Transmission of electricity and related matters) Regulations, 2009, the tariff of such project shall be applicable from the date of grant of transmission licence or from the date as indicated in the transmission licence, as the case may be. In such cases, the applicant shall file petition as per **Annexure-I,** clearly demarcating the assets which form the part of regulated business of generation and transmission, the value of such assets, source of funding etc. duly certified by an auditor.

(4) In case of multi-purpose hydro generation scheme with irrigation, flood control and power components, the capital cost chargeable to the power component of the scheme only shall be considered for determination of tariff.

(5) Where only a part of the generation capacity of a generating station is tied up for supplying power to the beneficiaries through long term power purchase agreement and the generating units or stages for that part of the generation capacity have not been identified by the generating company, the tariff of the generating station shall be determined with reference to the capital cost of the

entire project, but the tariff so determined shall be applicable corresponding to capacity contracted for supply to the distribution licensees.

7. <u>Application for determination of tariff:</u>

(1) The generating company may make an application for determination of tariff for new generating station or unit thereof in accordance with Procedure Regulation, in respect of the generating station or generating units thereof within 120 days of the anticipated date of commercial operation.

(2) The transmission licensee may make an application for determination of tariff for new transmission system including communication system or element thereof as the case may be in accordance with the Procedure Regulations, in respect of the transmission system or elements thereof anticipated to be commissioned minimum 180 days from the date of filing the petition;

(3) In case of an existing generating station or transmission system including communication system or element thereof, the application shall be made not later than 120 days from the date of notification of these regulations based on admitted capital cost including any additional capital expenditure already admitted up to 31.3.2014 (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure for the respective years of the tariff period 2014-19:

(4) The generating company or the transmission licensee, as the case may be, shall make an application as per **Annexure-I** of these regulations, for determination of tariff based on capital expenditure incurred duly certified by the auditors or projected to be incurred up to the date of commercial operation and additional capital expenditure incurred duly certified by the auditors or projected to be incurred during the tariff period of the generating station or the transmission system as the case may be:

Provided further that the petition shall contain details of underlying assumptions for the projected capital cost and additional capital expenditure, wherever applicable.

(5) If the petition is inadequate in any respect as required under **Annexure-I** of these regulations, the application shall be returned to the generating company or transmission licensee as the case may be, for resubmission of the petition within one month after rectifying the deficiencies as may be pointed out by the staff of the Commission.

(6) If the information furnished in the petition is in accordance with the regulations and is adequate for carrying out prudence check of the claims made, the Commission shall consider the suggestions and objections, if any, received from the respondents within one month from the date of filing of the petition or any other person including the consumers or consumer association. The Commission shall issue the tariff order after hearing the petitioner, the respondents or any other person specifically permitted by the Commission.

(7) In case of the new projects, the generating company or the transmission licensee, as the case may be, may be allowed tariff by the Commission based on the projected capital expenditure from the anticipated COD in accordance with the Regulation 6 of these regulations:

Provided that if the date of commercial operation is delayed beyond 180 days from the date of issue of tariff order in terms of clause (6) of this regulation, the tariff granted shall be deemed to have been withdrawn and the generating company or the transmission licensee shall be required to file a fresh application for determination of tariff after the date of commercial operation of the project:

Provided further that where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure exceeds the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term transmission customers /DICs as the case may be, the excess tariff recovered corresponding to excess capital cost, as approved by the Commission alongwith interest at 1.20 times of the bank rate as prevalent on April 1 of respective year:

Provided also that where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure falls short of the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall be entitled to recover from the beneficiaries or the long term transmission customers /DICs as the case may be , the shortfall in tariff corresponding to reduction in capital cost, as approved by the Commission alongwith interest at 0.80 times of bank rate as prevalent on April 1 of respective year.

(8) In case of the existing projects, the generating company or the transmission licensee, as the case may be, may be allowed tariff by the Commission based on the admitted capital cost as on 1.4.2014 and projected additional capital expenditure in accordance with the Regulation 6:

Provided that the generating company or the transmission licensee, as the case may be, shall continue to bill the beneficiaries or the transmission customers / DICs at the tariff approved by the Commission and applicable as on 31.3.2014 for the period starting from 1.4.2014 till approval of tariff by the Commission in accordance with these regulations:

Provided further that where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure submitted by the generating company or the transmission licensee, as the case may be, exceeds the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term transmission customers /DICs as the case may be, the excess tariff recovered corresponding to excess capital cost, as approved by the Commission alongwith interest at 1.20 times of the bank rate as prevalent on April 1 of respective year:

Provided also that where the capital cost considered in tariff by the Commission on the basis of projected capital cost as on COD or the projected additional capital expenditure submitted by the generating company or the transmission licensee, as the case may be, falls short of the actual capital cost incurred on year to year basis by more than 5%, the generating company or the transmission licensee shall be entitled to recover from the beneficiaries or the long term transmission customers /DICs as the case may be ,the shortfall in tariff corresponding to reduction in capital cost, as approved by the Commission along with interest at 0.80 times of bank rate as prevalent on April 1 of respective year.

Truing up

(1) The Commission shall carry out truing up exercise along with the tariff petition filed for the next control period, with respect to the capital expenditure including additional capital expenditure incurred upto 31.03.2019, as admitted by the Commission after prudence check at the time of truing up:

Provided that where the tariff of a new project has been approved by the Commission based on anticipated COD, the generating Company or the transmission licensee, as the case may be, shall file an application for interim true up of capital expenditure within 180 days of the commercial operation of the new project:

Provided further that the generating company or the transmission licensee, as the case may be, may at its discretion make an application before the Commission one more time prior to 31st March, 2019 for revision of tariff.

(2) The Commission shall further carry out truing up of tariff of generating station based on the performance of following parameters:

a) Controllable Parameters
   i) Station Heat Rate ;
   ii) Secondary Fuel Oil Consumption ; and
   iii) Auxiliary Energy Consumption.

b) Uncontrollable Parameters
   i) Force Majeure ;
   ii) Change in Law; and
   iii) Primary Fuel Cost.

(3) The Commission shall further carry out truing up of tariff of transmission system based on the performance of following uncontrollable parameters:

(a) Force Majeure; and

(b) Change in Law.

(4) The financial gains by a generating company on account of controllable parameters shall be shared between generating company and the beneficiaries on monthly basis, in the ratio of 3:1 as per the following formulae:

Net Gain = (ECR_N - ECR_A) x Scheduled Generation

Where,

ECR_N – Normative Energy Charge Rate computed on the basis of norms specified for Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption.

ECR_A – Actual Energy Charge Rate computed on the basis of actual SHR, Auxiliary Consumption and Secondary Fuel Oil Consumption for the month.

(5) The financial gains and losses by a generating company or the transmission licensee, as the case may be, on account of uncontrollable parameters shall be passed on to beneficiaries of the generating company or long term transmission customer/DICs of transmission system, as the case may be.

5 Depreciation

5.1 Background

5.1.1 The Commission in its Tariff Regulations, 2001 allowed depreciation on the basis of straight line method on the historical cost of the asset including additional capitalisation and FERV by applying the depreciation rates notified by the Commission and considering salvage value of 10%.The Commission in addition to depreciation also allowed advance against depreciation to provide cash flow to the utilities to meet the loan repayment obligations subject to certain conditions. The same principle of allowing depreciation continued in the next Tariff Regulations, 2004. However, in Tariff Regulations, 2009 the Commission discontinued with the concept of advance against depreciation and to address the issues related to cash flow to meet the repayment obligations specified the higher rate of depreciation during the initial 12 years of useful life of the Projects with remaining depreciable value at the end of 12 years to be spread over the balance life of the assets.

5.2 Issues brought out in Approach Paper

5.2.1 The Commission in its approach paper discussed on the issues arising out by combining the units of a generating station for computing depreciation which can lead to a mismatch in respect of completion of 12 years of individual units. Further, the Commission also discussed about the treatment of depreciation for assets added during the fag end of the useful life of the project and the impact of special allowance approved in lieu of Renovation and Modernisation of the station on the recovery of the depreciation.

"a) Whether the treatment of weighted average useful life in case of combination, due to gradual commissioning of units, shall continue or alternatives if any? Can additional expenditure during fag end of life be considered for the re-assessment of useful life? Can additional expenditure after Renovation and modernization (or special allowance) be restricted to limited items/equipments? Can a regulatory method be derived wherein life gets reassessed at the start of every tariff period or

every additional capital expenditure through a provision in the same way it is prescribed in accounting standard?

b) In case of re-assessment of useful life, can depreciation be charged over the balance life of the assets along with the original written down value up to 90% value OR Add cap and original amount depreciate over revised/reassessed useful life of asset. ?

c) Can unrecovered depreciation due to disincentive be allowed to be recovered particularly when incentive is being separately allowed on exceeding target availability? Does incentive allowed includes any portion of depreciation in it?

d) Whether there is a need to revise the useful life of transmission assets?"

5.3 Existing Provisions of Tariff Regulations, 2009

1) *The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission.*

2) *The salvage value of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the capital cost of the asset.*

Provided that in case of hydro generating stations, the salvage value shall be as provided in the agreement signed by the developers with the State Government for creation of the site:

Provided further that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciable value shall correspond to the percentage of sale of electricity under long-term power purchase agreement at regulated tariff.

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

4) *Depreciation shall be calculated annually based on Straight Line Method and at rates specified in Appendix-III to these regulations for the assets of the generating station and transmission system:*

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

5) *In case of the existing projects, the balance depreciable value as on 1.4.2009 shall be worked out by deducting the cumulative depreciation as admitted by the Commission up to 31.3.2009 from the gross depreciable value of the assets.*

6) *Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the year, depreciation shall be charged on pro rata basis.*

5.4 Stakeholders Responses

i. Most of the Generating Companies and Licensees submitted that the existing treatment of weighted average useful life in case of combination of units, due to gradual commissioning of units, should be allowed to continue provided all the units are commissioned within a reasonable span of time.

ii. Some of the Beneficiaries submitted that in case of R&M, the depreciation shall be up to extended life of asset. Moreover, the project which are availing Special Compensatory Allowance in lieu of R&M should not be allowed depreciation, alternatively, Special Compensatory Allowance should be discontinued.

iii. Some of the Generating Companies suggested that a uniform rate of depreciation for entire project assets should be linked to repayment of debt. Accordingly, rate of depreciation may be kept at 5.83% (70% of debt/12 years of normative loan repayment period) for the initial period of 12 years. The balance value of the asset could be allowed to be depreciated over the residual life, duly considering the salvage value.

iv. Stakeholders submitted that there should be a Regulatory method to reassess useful life at the start of every tariff period and for every additional capital expenditure as prescribed in accounting standard.

v. One of the stakeholder submitted that as per the accounting Standard, there are two types of capitalization, one is new asset capitalization and other one is value addition to the existing asset. In the case of new addition, the depreciation is charged based on the life of that asset and in the case of value addition to the existing asset, it has to be depreciated within the life of the main asset. However, both the types of capital expenditure may be allowed to be depreciated over the balance useful life of the plant.

vi. Some of the Generating Companies and Licensees submitted that the rate of depreciation for the various assets may be continued as per Annexure III of current CERC Tariff Regulations. Reassessment of useful life of such assets should be done at the time of scrapping of the plant and due credit to be given to the salvage value.

vii. Some of the Generating Companies and Licensees suggested of reintroducing the concept of AAD to meet their debt service obligations.

viii. Some of the stakeholders suggested that in case of re-assessment of useful life depreciation should be allowed over the revised/re-assessed life of the project considering the salvage value of plant and the additional capitalization allowed.

ix. Some of the Beneficiaries suggested that unrecovered depreciation on account of non recovery of full fixed charges due to lower availability should not be allowed to be recovered later.

x. Some of the stakeholders suggested that any un-recovered depreciation should continue to be allowed to be recovered after useful life. Further, the depreciation provided presently to the developer is not sufficient for repayment of loans since the present loan tenure available is around 12 years only including construction period - leaving only 8-9 years for repayment after COD.

xi. Some of the stakeholders suggested that for review of useful life of transmission assets, component wise approach for substation, lines, and transformers may be considered in one group and the other items such as breaker / CT PT/ relays may be treated in a differential manner. In this regard, CEA opinion (including study of state distribution network) in the matter may be helpful.

xii. Some of the stakeholders suggested Useful life of the transmission assets may be revised upwards without reducing the recovery of depreciation in first twelve years equivalent to loan component.

5.5 Commission's Proposal

5.5.1 The Commission, after going through the suggestions received from various stakeholders and the issues faced in the current Tariff Period as regards whether to consider the weighted average useful life in case of combinations of Units, proposes to continue the same. This has also been the suggestion of most of the stakeholders. In such an event, the depreciation shall be computed from the effective date of commercial operation. In case of combination of units of generating station or combination of transmission elements of transmission system, the effective date of commercial operation shall be worked out by considering the date of commercial operation and installed capacity of all the units of generating station or capital cost of all elements of transmission system, for which single tariff needs to be determined.

5.5.2 The Commission after detailed deliberations in its previous Tariff Regulations discontinued the concept of advance against depreciation and to address the issues related to cash flow to meet the repayment obligations, specified a higher rate of depreciation during the initial 12 years of useful life of the Projects, with remaining depreciable value at the end of 12 years to be spread over the balance life of the assets. Considering the suggestions of various stakeholders, the Commission does not intend to re-introduce the concept of advance against depreciation and proposes to continue with the same approach of providing higher rates of depreciation during initial 12 years of useful life of the Projects with remaining depreciable value at the end of 12 years to be spread over the balance useful life of the assets.

5.5.3 The depreciation rates shall be as specified in the Appendix II of the draft Regulations.

5.5.4 For the assets that get added during the fag end of the life of the project, i.e., after 20 years of operation for thermal power stations and 30 years of operation for hydro generating stations and transmission projects, the Commission proposes that the generating company or transmission licensee, as the case may be, shall submit the details of proposed capital expenditure during the fag end of the project. The Commission based on prudence check of such submissions shall approve the depreciation on capital expenditure during the fag end of the project.

5.5.5 As regards recovery of unrecovered depreciation due to lower availability, the Commission is of the view that the same may not be allowed to be recovered later as the same is due to reduction in recovery of fixed charges on account of non-achievement of normative parameters, which is intended to discourage inefficient operations. If the costs disallowed in particular years due to non-achievement of performance parameters are allowed to be recovered in subsequent years, then the entire purpose of specifying the normative performance parameters for recovery of costs will get defeated and will be against the principle of Regulations. Thus, there is no rationale for allowing the unrecovered depreciation in case the project has not been able to deliver the normative levels of performance and in such cases the Utility should be accountable and bear the losses on account of performance below the normative levels. The Commission therefore, proposes to not allow the recovery of such unrecovered depreciation at the end of the life cycle of the project.

5.5.6 The useful life of AC and DC sub-station and for transmission lines, as specified in Tariff Regulations, 2009 is of 25 years and 35 years respectively. However, it is observed that certain equipment's within substation may operate satisfactorily even after 25 years. Accordingly, it is proposed that useful life of AC and DC sub-station (including GIS) shall be of 35 years.

5.5.7 As regards to the de-capitalization of the assets, the treatment of depreciation is to be specified in the regulation to bring more clarity and simplification in implementation.

5.6 Proposed Provisions

Depreciation: (1) Depreciation shall be computed from the date of commercial operation of generating station or unit thereof or transmissions system including communication system or element thereof. In case of the tariff of all the units of generating station or all elements of transmission system including communication system for which a single tariff needs to be determined, the depreciation shall be computed from the effective date of commercial operation taking into consideration the depreciation of individual units or elements thereof.

Provided that effective date of commercial operation shall be worked out by considering the date of commercial operation and installed capacity of all the units of generating station or capital cost of all elements of transmission system, for which single tariff needs to be determined.

(2) The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission. In case of multiple units in a generating station, weighted average life for the station shall be applied. Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the year, depreciation shall be charged on *pro rata* basis.

(3) The salvage value of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the capital cost of the asset:

Provided that in case of hydro generating stations, the salvage value shall be as provided in the agreement signed by the developers with the State Government for development of the Plant:

Provided further that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciated value shall correspond to the percentage of sale of electricity under long-term power purchase agreement at regulated tariff:

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

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

(5) Depreciation shall be calculated annually based on Straight Line Method and at rates specified in **Appendix-II** to these regulations for the assets of the generating station and transmission system:

Provided that, the remaining depreciable value as on 31st March of the year closing after a period of 12 years from effective date of commercial operation of the station shall be spread over the balance useful life of the assets.

(6) In case of the existing projects, the balance depreciable value as on 1.4.2014 shall be worked out by deducting the cumulative depreciation as admitted by the Commission upto 31.3.2014 from the gross depreciable value of the assets.

(7) The generating company or the transmission license, as the case may be, shall

submit the details of proposed capital expenditure during the fag end of the project (beyond 20 years from COD for thermal generating station and beyond 30 years for hydro generating station and transmission system) along with justification and proposed life extension. The Commission based on prudence check of such submissions shall approve the depreciation on capital expenditure during the fag end of the project.

(8) In case of de-capitalization of assets in respect of generating station or unit thereof or transmission system or element thereof, the depreciation shall be adjusted by taking into account of cumulative depreciation to the extent of de-capitalization.

6 Net Fixed Asset v/s Gross Fixed Asset Approach

6.1 Background

6.1.1 The Commission in the previous Tariff Regulations has adopted Gross Fixed Asset approach on the premise that it provides internal resources for capacity replacement/addition through return on equity base of 30%. Further stated that GFA approach provides incentive to the investors for creating its internal resources required for capacity addition and to maintain efficient operation of the Plant. The other advantage of GFA approach is that it ensures the predictability of returns and thus provides the consistency under uncertain market scenario on long term basis.

6.2 Issues brought out in Approach Paper

6.2.1 The Commission in its Approach Paper discussed the various approaches whether liability side approach of Gross Capital cost be continued or need to shift to Net Fixed Asset (NFA) or existing GFA approach be partially modified where gross capital may be divided in the ratio of loans and equity. Accordingly the Commission brought out the following issues on which it sought suggestions and comments:

"a) Whether liability side approach of Gross Capital cost be continued or there is a need to shift to Net Fixed Asset (NFA) Model where the NFA shall be arrived at by deducting the accumulated depreciation from the Gross Capital Cost admitted for tariff purposes ? Also this needs to be commented in context with ROCE approach.

b) Alternative to NFA approach, can existing GFA approach be partially modified where gross capital may be divided in the ratio of loans and equity and the loan amount may be reduced to the extent of depreciation accrued. Once the loan amount is fully repaid and reduced to zero, further depreciation would be allowed to reduce the equity component.

c) Suggestion if any on continuation of existing approach of Gross Fixed Asset base tariff determination."

6.3 Existing Provisions of Tariff Regulations, 2009

6.3.1 The Commission in the existing provisions has considered GFA approach in which the returns are provided on the normative equity base .i.e.30% on a perpetual basis over the entire life of the assets. The interest on loan is being computed duly taking into account the loan repayment equivalent to the depreciation and considering weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project.

6.4 Stakeholders Responses

6.4.1 The extracts of the suggestions received from various stakeholders on the issues flagged above are as follows:

i. Most of the generation and transmission companies have supported the GFA approach.

ii. Power Grid suggested that approach which lead to reduction in the returns on equity has already been set aside in Judgment dated 16th May 2006 in Appeal no 121 of 2005 by Appellate Tribunal for Electricity (ATE) in case of POWERGRID Vs CERC regarding the depletion of equity. Accordingly, the current approach of GFA as the base should be continued.

iii. One stakeholder suggested that the K.P Rao Committee recommended that once the loan is reduced to zero, the equity component will be reduced progressively to the extent of further depreciation recovered. Thus, it is equitable for the Central Commission to hold that the normative equity be reduced to the extent of depreciation charged after notional loan is repaid and hence accept the modified GFA approach which would be in accordance with the provision contained in Section 61(d) of the Electricity Act, 2003.

iv. Most of the generation and transmission companies submitted that hybrid method is not rational. Generating company is not permitted any return on the equity invested during the long gestation period, when a project is under construction. The existing GFA approach belatedly compensates the generating company for the lost revenue of which it was deprived upfront.

v. Association of Power Producers (APP) submitted that NFA will have substantial adverse impact on the sector and investment. This can be adopted only if depreciation/AAD is allowed on high rate to recover the whole investment (equity and debt both) and the legal framework allows redemption of equity every year in the same manner as repayment of debt.

vi. Most of the generation and transmission companies submitted that existing approach be continued.

6.5 Commission's Proposal

6.5.1 Taking into cognizance of the views and suggestions of various stakeholders and also taking into consideration the market conditions, the Commission proposes that existing GFA approach for providing the returns on investments may be continued as the sector is fraught with various challenges such as fuel availability, availability of land and water, etc, and change in approach at this stage may have detrimental effect on the investments in the sector.

7 Debt/Equity Ratio

7.1 Background

7.1.1 Financing plan of the project plays a predominant role in the determination of tariff. The Commission in its 2009-14 Regulations simplified the Debt:Equity provisions and specified the uniform debt-equity ratio of 70:30 for all the power projects i.e., whether it is initial project cost, additional capital expenditure or renovation & modernisation case.

7.1.2 However, the Commission intended that the investors should be free to invest fund in the form of equity as per their own investment plans, even beyond 30%. If the equity actually invested in a project is more than 30%, than equity in excess of 30% is considered as normative loan. However, where equity deployed is less than 30%, the actual equity is considered for determination of tariff.

7.1.3 Further in keeping with the requirement of National Tariff Policy, the Commission considered it appropriate to include a provision to the effect that equity invested in foreign currency should be designated in Indian rupees on the date of investment. The purpose was to make debt-equity ratio unaffected by the foreign exchange rate variation and provide regulatory certainty.

7.2 Issues brought out in Approach Paper

7.2.1 The Commission in its Approach Paper obtained the views of the stakeholders whether there is a need to revisit the existing approach for debt-equity ratio in the wake of the recent developments of debt markets which may have lead to higher reliance/availability of debt to corporate. Accordingly the Commission brought out the following issues on which it sought suggestions and comments:

"a) Whether there is a need to revisit the existing approach for debt: equity ratio or to continue with the existing composition?"

7.3 Existing Provisions of Tariff Regulations, 2009

In the existing provisions Debt: Equity ratio of 70:30 has been followed for financing new projects commissioning after 1.4.2009 and for additional capitalization. The equity in excess of normative level is treated as normative loan and in case of equity below the normative level, actual equity is being used for determination of Return on Equity in tariff computations. The existing provisions in this regard are as follows:

(1) For a project declared under commercial operation on or after 1.4.2009, if the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan:

Provided that where equity actually deployed is less than 30% of the capital cost, the actual equity shall be considered for determination of tariff:

Provided further that the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment.

Explanation:-*The premium, if any, raised by the generating company or the transmission licensee, as the case may be, while issuing share capital and investment of internal resources created out of its free reserve, for the funding of the project, shall be reckoned as paid up capital for the purpose of computing return on equity, provided such premium amount and internal resources are actually utilised for meeting the capital expenditure of the generating station or the transmission system.*

(2) In case of the generating station and the transmission system declared under commercial operation prior to 1.4.2009, debt-equity ratio allowed by the Commission for determination of tariff for the period ending 31.3.2009 shall be considered.

(3) Any expenditure incurred or projected to be incurred on or after 1.4.2009 as may be admitted by the Commission as additional capital expenditure for determination of tariff, and renovation and modernisation expenditure for life extension shall be serviced in the manner specified in clause (1) of this regulation.

7.4 Stakeholders Responses

7.4.1 The extracts of the suggestions received from various stakeholders on the issues flagged above are as follows:

i. Regulatory Commissions and Govt. Departments have suggested that existing approach of debt: equity ratio of 70:30 should be modified to 80:20.

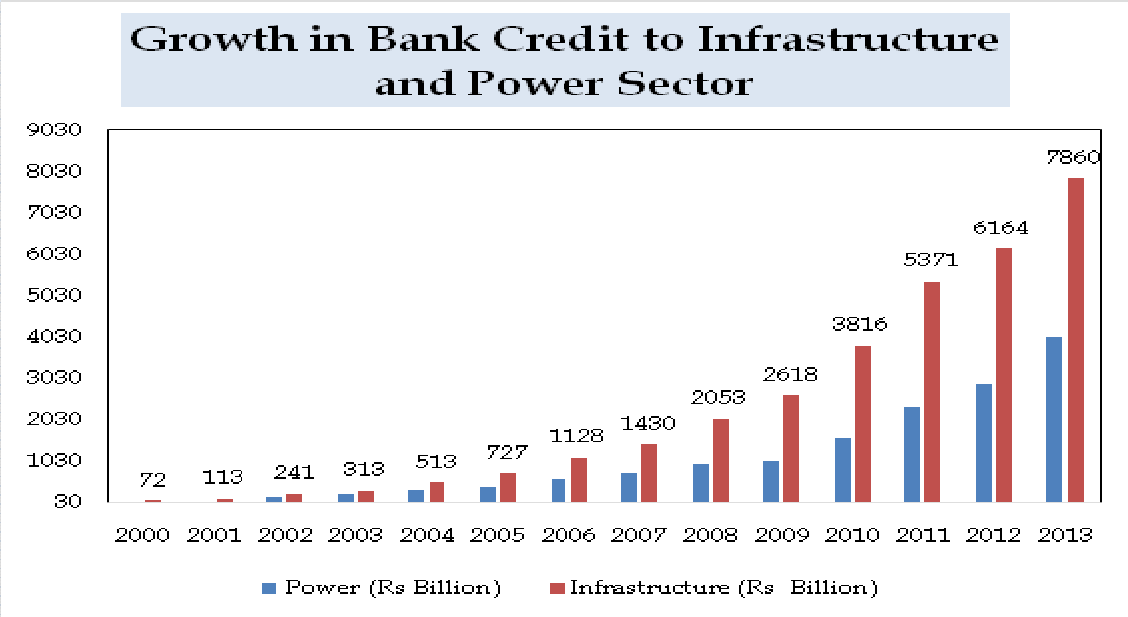
ii. Most of the generation and transmission companies have supported the existing debt: equity ratio. However, NTPC has suggested that in order to provide regulatory certainty, the existing approach should continue with the same Debt: Equity ratio of 70:30 for new investments and Debt Equity ratio of 50:50 for existing projects (i.e. projects where investment approval was made before 1992)

iii. Some stakeholders have also suggested that there is a need to revisit the existing approach for debt: equity ratio. In respect of the projects developed under Competitive Bid Routes the debt equity ratio is lower than the 70:30. Hence for all new projects the debt equity ratio of 75:25 may be proposed and even the lower value is acceptable. Further, repayment of debt may be extended to 15 years.

iv. One stakeholder submitted that debt- equity ratio should be revised to 80:20 ratio as most generators and the transmission licensees under the cost plus regime are in public sector and the anticipated risk in lowering the equity is much lower. The debt equity ratio in respect of old assets wherein the Commission had adopted the 50:50 ratio needed proper structuring as the debt-equity ratio in large number of power schemes was notionally presumed as 50:50 by the Commission.

7.5 Commission's Proposal

7.5.1 The Commission is of the view that keeping in mind the existing uncertainties of debt market such as rising trend of increase interest rate and uncertainties in debt market it would not be prudent to revise the existing debt: equity ratio. Further it has been observed from the data published by RBI, power sector alone deploys 9.3% of the gross bank credit as of March 31, 2013. Further, the working group for XII plan estimates a total requirement of power sector from scheduled commercial banks as Rs. 2705 billion. The Growth in Bank Credit to Infrastructure and Power sector from FY 2000 to FY 2013 is shown in the chart below.



Source: RBI Database

7.5.2 It can be observed from the above chart that there has been significant growth in bank credit to infrastructure projects and in which the power sector shares a major contribution of the Bank Credit. On the other hand the Commission is not oblivious of the fact that the primary reason for significant growth in bank credit to power sector that most of the IPPs are operating at a higher debt equity ratio. However, keeping in mind the financial health of Govt. Utilities it would be difficult for Govt. Utilities to enjoy a higher debt equity ratio as same as IPPs. Further, the existing debt:equity ratio of 70:30 has got wide acceptance. Given these realities and with due regard to the sentiment of the stakeholders, the Commission proposes to continue with existing debt: equity ratio of 70:30 for the next Tariff period.

7.6 Proposed Provisions

Debt-Equity Ratio: (1) For a project declared under commercial operation on or after 1.4.2014, if the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan:

Provided that where equity actually deployed is less than 30% of the capital cost, actual equity shall be considered for determination of tariff:

Provided further that the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment:

Provided also that any grant obtained for the execution of the project shall not be considered as a part of capital structure for the purpose of tariff determination.

Explanation.-The premium, if any, raised by the generating company or the transmission licensee, as the case may be, while issuing share capital and investment of internal resources created out of its free reserve, for the funding of the project, shall be reckoned as paid up capital for the purpose of computing return on equity:

Provided that such premium amount and internal resources are actually utilised for meeting the capital expenditure of the generating station or the transmission system.

(2) The generating company or the transmission licensee shall submit the resolution of the Board of the company for infusion of fund from internal resources in support of the utilization being made to meet the capital expenditure of the generating station or the transmission system as the case may be.

(3) In case of the generating station and the transmission system including communication system declared under commercial operation prior to 1.4.2014, debt-equity ratio allowed by the Commission for determination of tariff for the period ending 31.3.2014 shall be considered.

(4) In case of the generating station and the transmission system including communication system declared under commercial operation prior to 1.4.2014, but where debt: equity ratio has not been determined by the Commission for determination of tariff for the period ending 31.3.2014, the Commission shall approve the debt::equity ratio based on actual information provided by the

generating company or the transmission licensee as the case may be.

8 Return on Investment (RoI)

8.1 Background

8.1.1 The Commission in the Tariff Regulations for the period FY 2004-09 after considering views of the stakeholders, came to the conclusion that the Return on Capital Employed is a better approach and the change over to ROCE could be brought out after the interest rates are stabilised and benchmarking of debt/equity is perfected.

8.1.2 Further, while framing the Tariff Regulations for FY 2009-14 on the issue regarding change over to ROCE approach, majority of the stakeholders as well as the view of the members of the Central Advisory Committee was in favour of continuing with the existing ROE approach as the situation especially in regard to interest rate fluctuation and debt market in India had not yet stabilized to enable projection of a firm normative interest rate for the purpose of arriving at return on capital employed. Further, the Commission was of the view that due to existence of significant disparity in the nature of entities under the purview of the Commission, implementation of ROCE approach would raise a large number of issues as it requires computation of annual Weighted Average Cost of Capital (WACC) due to progressive change and reduction in the capital employed.

8.1.3 Further as per Section 61 of the Electricity Act, 2003, the State Commissions are to be guided by the terms and conditions of tariff notified by CERC for generation and transmission. It would have been more difficult for the State Commissions to adopt the normative interest rate notified by CERC for the utilities regulated by the State Commissions, since such utilities in some cases were not be in a position to bargain interest rate for loans equivalent to that availed by the large entities regulated by CERC. Accordingly, the Commission while framing the Tariff Regulations for FY 2009-14 has preferred RoE approach of over RoCE approach for providing return on investments to the investors.

8.2 Issues brought out in Approach Paper

8.2.1 The Commission in its Approach Paper obtained the views of the stakeholders whether the existing return on equity approach be continued or return on capital employed approach may be adopted, methodology to be adopted for benchmarking the cost of debt and cost of equity. Accordingly the Commission brought out the following issues on which it sought suggestions and comments:

a) *Whether the Return on Equity approach may be continued or ROCE approach be adopted. If ROCE, approach is adopted what could be the methodology to arrive at return on capital employed? Whether it would be WACC or any other methodology?*

b) *Comments/suggestions are also invited on the methodology of benchmarking of cost of debt and cost of equity for working out WACC.*

c) *Comments/suggestions are also invited on the feasibility to implement the ROCE approach for individual project/transmission element/unit wise v/s feasibility to implement for the whole Company? What would be the treatment of existing and new projects in the context of ROCE?*

d) *On departing from existing ROE approach, can significant impact on investment be expected? Stakeholder may comment on expected benefit of switchover to ROCE and demerits of departing from existing ROE approach?*

e) *Suggestion and benefits on continuation of existing approach of Return on Equity if any*

8.3 Existing Provisions of Tariff Regulations, 2009

8.3.1 The Commission in the existing provisions has considered Return on Equity approach in which the returns are provided on the normative equity base .i.e.30% on a perpetual basis over the entire life of the assets. The interest on loan is provided separately duly taking into account the loan repayment equivalent to the depreciation and considering weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project.

8.4 Stakeholders Responses

8.4.1 The extracts of the suggestions received from various stakeholders on the issues flagged above are as follows:

i. Most of the generation and transmission companies have suggested that in the absence of benchmarking data of debt and equity, Return on Equity (RoE) approach may be considered which may be determined through evaluation of risk by using Capital Asset Pricing Model (CAPM) to arrive at Market expected Rate of Return.

ii. Few stakeholders have suggested that in case ROCE approach to be adopted, WACC method should be preferred, as WACC approach assumes that each project has equal financing priorities. Hence, the WACC method is appropriate for decision making process amongst the competing projects within the organization. However, the WACC approach is not appropriate for old projects due to the fact that there is a different financial leverage of the company and changed risk taking scenario.

iii. Most of the generation and transmission companies have suggested that as the benchmarking of Cost of Debt for power sector is very complicated and the existing approach of actual interest rate may be continued and no normative rate of interest may be fixed.

iv. Few of the developers have suggested that benchmarking Cost of Debt with Government Securities Yield might also not to be feasible as there has been no correlation between SBI Base Rate and Government Securities Yield in the past. The financial market is expected to be turbulent for next few years and benchmarking debt-equity ratio and cost of debt will not only be difficult but may be unrealistic as well.

v. Most of the generation and transmission companies have suggested the existing ROE approach may be followed.

vi. Power Grid suggested that it may not be feasible to implement the ROCE approach for the company as a whole on account of the following:

a. By virtue of age of assets, additional capitalisation in schemes, varying debt, equity ratio of projects, it may not be possible to club all such schemes into a single tariff petition under the RoCE approach.
b. On account of different time of acquiring the loans, it would be difficult to fit everything under the WACC approach at this moment.
c. Determination of individual ROCE rates for the individual projects/transmission elements would be a very difficult.

vii. Most of the generation and transmission companies have suggested that significant impact on the investments in the power sector can be expected in case of departure from the ROE approach on account of the following:

- Under the existing ROE approach, the equity invested into the project continues to fetch ROE till the assets remain operational and continue to serve the consumers.
- Under the ROCE approach the capital invested into the projects continues to diminish as the eligible asset base for allowing the returns is the NFA.
- Any shortfall in generation of such internal resources would ultimately mean reduction in the investing capabilities of the company.

viii. Most of the generation and transmission companies have suggested that the following are the benefits on continuation of RoE approach:

a. There will not be any Regulatory uncertainty

b. The profit is transparently known in terms of pre-tax return on equity in RoE approach.
c. Income Tax calculation/grossing up will be transparent
d. The developer will know clearly that its investment has been fully pre-paid through depreciation and salvage value.

8.5 Commission's Proposal

8.5.1 While framing the previous Tariff Regulations the Commission has accepted the fact that theoretically Return on Capital Employed (ROCE) approach is better than Return on Equity (ROE) approach. However, implementation of ROCE approach requires benchmarking of cost of debt and debt: equity ratio.

8.5.2 The merits and de-merits of both the approaches are discussed below:

<u>Merits and De-merits of RoE Approach</u>

The merits of RoE approach are:

i) It is easy to compute and simple to implement and is hence, easily understood by all stakeholders.
ii) From the investor's view-point, he gets assured returns on equity investment for ever, once the investment is done.
iii) The Utility is protected against the risk of fluctuation in interest rates, since interest expense is allowed as a pass through expense at actuals.

The demerits of RoE approach are:

i) No incentives for regulated entities to bring down cost of capital, as return on equity invested is guaranteed and actual interest expense incurred is also passed through at actuals in the ARR and tariff.
ii) Regulated entities are not encouraged to practice financial engineering and optimise the financing mix by restructuring debt and equity, since the debt: equity ratio is allowed on normative basis (usually 70:30)
iii) Even if fixed assets are depreciated fully or assets are retired or replaced, Utilities get assured returns on the equity invested, unless

specific provisions are built-in to ensure that the corresponding equity is also reduced.

iv) In case the equity invested in the regulated business is low or nil, then the resultant claim for RoE is also reduced or will be nil, which may hamper the Utility's efforts to invest in future capital expenditure.

8.5.3 **<u>Merits and De-merits of RoCE Approach</u>**

The merits of RoCE approach are:

i) The RoCE approach incentivises financial planning to optimize the debt-equity mix and bring down the cost of capital.

ii) The consumers are insulated from changes in debt-equity mix and changing interest rates, etc. However, if variation in interest rate above a certain level is allowed to be passed through in tariff, then the consumers will not remain insulated from the changing interest rates.

iii) It also makes it easier for the Regulators as they do not have to monitor debt and equity component separately. However, if variation in interest rate above a certain level is allowed to be passed through in tariff, then the Commission will have to keep track of the quantum of the debt availed by licensee for investment in licensed business.

iv) Since the returns are linked to the investment in the business, once the asset is fully depreciated, then the Utility does not earn any return on its investment, and hence, the tariffs would also reduce to that extent.

v) The Utilities, which may have a lower equity base, would not be adversely affected, since the Returns would be given on the total capital employed, rather than the equity invested in the business.

The demerits of RoCE approach are:

i) The RoCE approach requires an estimation of the normative cost of debt and benchmarking of the debt-equity ratio, making it more complicated to understand and implement.

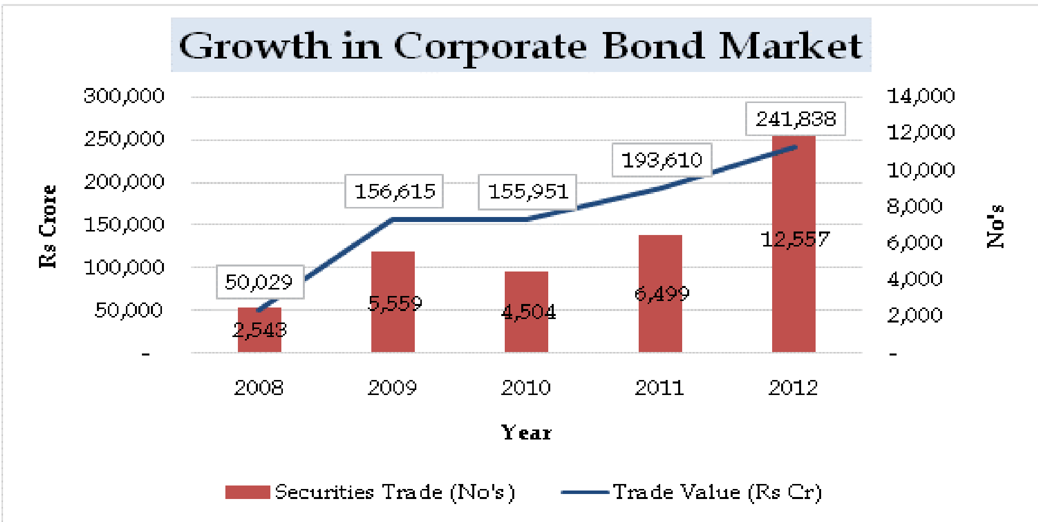
ii) The RoCE approach could lead to windfall profits or abnormal losses depending on the ability of the Utility to undertake financial engineering to restructure its debt and equity.

iii) The RoCE approach may also pose an entry barrier for new entrants as they may not be able to achieve the desired debt: equity mix and also may not be able to source cheaper loans, as compared to existing Utilities with stronger Balance Sheets.

iv) Utilities and ERCs across the country have generally been averse to adopting the RoCE approach, on account of the higher risk perception of this approach, as well as the comfort with the existing RoE approach, which is less complicated.

8.5.4 On this assumption if a higher benchmark cost of debt is taken this will lead to unnecessary burden to consumers and undue benefit to generating and transmission utilities in case of actual cost of debt is less.

8.5.5 Further in contrast to a mature equity market, the bond market in India is relatively under-developed as compared to other Asian economies and developed nations. The corporate bond market in India is only 3.3% of GDP whereas the share of corporate bonds to GDP is 10.6% in China, 41.7% in Japan & 49.3% in Korea. However, the Corporate bond market has witnessed significant growth in last five years as shown in the chart below:



Source: BSE Database

8.5.6 In case of stringent benchmarking of cost of debt, financial planning for small companies or new entrants shall be difficult as the cost of debt will be a higher as compared to large size companies. This shall be detrimental for new entrants creating an entry barrier for new companies.

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

8.6 Proposed Provisions

8.6.1 The Commission has decided to continue with the Return on Equity approach in which the returns are provided on the normative equity base .i.e.30%. The interest on loan is provided separately duly taking into account the loan repayment equivalent to the depreciation and considering weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project.

9 Return on Equity (RoE)

9.1 Background

9.1.1 The Commission in the Tariff Regulations for FY 2001-04 had specified a post-tax ROE of 16% based on the recommendations of the study requisitioned to study the cost of capital. Further in the Tariff Regulations for FY 2004-09 the Commission had reduced the ROE as 14%. However, while framing the FY 2009-14 Regulations, the Commission had decided to revise the ROE on post-tax basis as 15.5% considering the rise in the PLR of the public sector banks, 10-year G-Sec, etc and also in order to help the entities to build up sufficient internal accruals for the purpose of investment in capacity addition. Further, w.e.f. December 31, 2012, ROE for storage type generating stations including pumped storage hydro stations and run of river generating station with pondage has been increased to 16.5%. Further, to incentivise the timely completion of projects, the Commission in its 2009-14 Regulations allowed an additional return on equity at the rate of 0.5% to those projects that are completed within time.

9.1.2 Under the National Tariff Policy as well as section 61(d) of the Electricity Act 2003 the Commission has clear mandate to fix a rate of return for equity that will not only attract investment but generate sufficient resources for further growth in the sector.

9.1.3 As regards the post tax vs. pre tax return, the Commission for the tariff period 2001-04 and 2004-09 specified post-tax return of equity and allowed income tax, in respect of income from core businesses only, as pass through to be recovered separately on actual. However, in the 2009-14 Regulations considering the views of various stakeholders, the Commission allowed pre-tax return on equity to the utilities. The Commission in 2009-14 Regulations specified that the rate of return on equity shall be computed by grossing up the base rate with the normal tax rate for the year 2008-09 applicable to the concerned generating company or the transmission licensee, as the case may be.

9.2 Issues brought out in Approach Paper

9.2.1 The Commission in its Approach Paper obtained view from the stakeholders that whether there is a need to review the existing level of return on equity keeping in view the existing market conditions and expected returns by regulated entity, fixed rate of return over the entire tariff period or provision for mid-term review can be introduced, differential rate of return for generation projects (hydro and thermal) or transmission projects, factors to be considered for arriving at differential rate of return, pre tax and post tax Return on Equity. Accordingly the Commission brought out the following issues on which it sought suggestions and comments:

a) *Whether there is a need to review the existing level of return on equity keeping in view of the existing market condition and expected return by regulated entity? What should be the return on equity?*

b) *The fixed rate of return over the entire tariff period as per the existing practice should be adopted or provision for mid-term review can be introduced. If the fixed rate of return is adopted, then what could be the rate of return?*

c) *Whether return should be linked to market conditions considering the risk factor? If the Return on Equity is to be linked to market conditions, criteria to be adopted for arriving at the rate of return need to be addressed.*

d) *Can the component of risk premium be defined and quantified based on available financial information which needs to be added in the overall return?*

e) *Whether there is a need for differential rate of return for generation projects (hydro and thermal) or transmission projects? What are the factors to be considered for arriving at differential rate of return?*

f) *Whether the working out of pre-tax return on equity by grossing up of tax rate should be reviewed? In case of grossing up of tax rate, what should the treatment of 80IA benefit? Should the base rate be grossed up by actual tax paid in respect of a project and not the corporate tax of the company? Should separate reporting of the tax liability calculated by developers of* *generators/transmission service providers be insisted for each quarter, so as to ensure that the ROE is not excessive than intended?*

g) *Is there a case for reduction of ROE level in view of the profit of the regulated entities and risk premium in operation of project?*

9.3 Existing Provisions of Tariff Regulations, 2009

The Commission in the 2009-14 Regulations has specified ROE of 15.5% on post-tax basis Further, to incentivise the timely completion of projects, the Commission decided to allow an additional return on equity at the rate of 0.5% to those projects that are completed within time. Further, w.e.f. December 31, 2012, ROE for storage type generating stations including pumped storage hydro stations and run of river generating station with pondage has been increased to 16.5%. The existing provisions in this regard are as follows:

(1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with regulation 12.

(2) Return on Equity shall be computed on pre-tax basis at the base rate of 15.5% for thermal generating stations, transmission system and run of the river generating station, and 16.5% for the storage type generating stations including pumped storage hydro generating stations and run of river generating station with pondage and shall be grossed up as per clause (3) of this regulation:

Provided that in case of projects commissioned on or after 1st April, 2009, an additional return of 0.5% shall be allowed if such projects are completed within the timeline specified in ***Appendix-II****:*

Provided further that the additional return of 0.5% shall not be admissible if the project is not completed within the timeline specified above for reasons whatsoever.

3) The rate of return on equity shall be computed by grossing up the base rate with the Minimum Alternate/Corporate Income Tax Rate for the year 2008-09, as per the Income Tax Act, 1961, as applicable to the concerned generating company or the transmission licensee, as the case may be.

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

Rate of pre-tax return on equity = Base rate / (1-t)
Where "t" is the applicable tax rate in accordance with clause (3) of this regulation.

(5) The generating company or the transmission licensee, as the case may be, shall recover the shortfall or refund the excess Annual Fixed Charge on account of Return on Equity due to change in applicable Minimum Alternate/Corporate Income Tax Rate as per the Income Tax Act, 1961 (as amended from time to time) of the respective financial year directly without making any application before the Commission:

Provided further that Annual Fixed Charge with respect to the tax rate applicable to the generating company or the transmission licensee, as the case may be, in line with the provisions of the relevant Finance Acts of the respective year during the tariff period shall be trued up in accordance with Regulation 6 of these regulations.

9.4 Stakeholders Responses

9.4.1 The extracts of the suggestions received from various stakeholders on the issues flagged above are as follows:

i. Most of the hydro power generation companies have submitted the 18%to 18.5% ROE should be provided to hydro projects taking into consideration the long gestation periods and blocking of equity during construction stage in form of CWIP, besides risk involved due to geological surprises and tough/ remote locations.

ii. NTPC submitted that considering the increasing interest rates, CERC should allow at least 18% ROE. Further, to take care of loss of ROE during the construction period, a 2% margin should be provided.

iii. Power Grid submitted that in accordance with CAPM, the expected ROE is in the range of 19.37% to 20.46% (post tax)]

iv. National Institute of Public Finance & Policy submitted that ROE should be determined based on standard Capital Asset Pricing Model (CAPM). Since very few power companies are listed it would be appropriate to list a large number of comparable firms from other countries, calculate Beta values for them, and take their median as a global estimate for beta. This can be then adjusted based on factors relevant for India.

v. NTPC submitted that Return on equity should be revised periodically taking into account the current developments in the industry's risk-return profile and changing market conditions.

vi. THDC, NHDC, Power Grid submitted that fixed rate of return should be provided as per the existing practice

vii. National Institute of Public Finance & Policy submitted that CAPM can be applied on a real time basis, it need not be used in a manner that requires frequent tariff revisions. The method can be used to estimate reasonable return on equity for a regulatory period. After that, the tariff needs to be revised only if there is a significant shift in one of the components.

viii. THDC, NHDC submitted that existing uniform ROE should be continued throughout the Tariff period in order to have regulatory certainty.

ix. Power Grid submitted that the Commission may consider the scientific methods such as the CAPM for estimation of the Return on equity

x. Most of the generation and transmission companies have submitted that CAPM is an accepted method for factoring risk and arriving at the approximate ROE which is scientific. However, Risk Profile of all Power sector companies is not the same. Risk varies on the basis of customer of the Generator (some DISCOMS are still healthy while others are in distressed financial conditions). In that case, Return on Equity must be linked to an index that needs to be absolutely transparent and practical.

xi. NTPC submitted that thermal power stations encounter certain operational risk which are unique and not faced by other segments of power sector. Hence, there is a case for thermal power generators to be compensated for the higher operational risks by increasing the ROE further by at least 2.0% to 2.5%.

xii. NHPC, NHDC submitted that keeping into consideration the location, construction methodology, time period required for construction, compliance requirements etc, the differential rate of returns should be decided and hydro Power Projects should have more rate of return in comparison to the Thermal Power stations. The hydro Projects located in N.E. Region should be allowed with better rate of return in comparison to rest of the country.

xiii. Some of the Generating Companies and Transmission Licensees submitted that the existing approach of Pre-Tax Return may be continued.

xiv. One stakeholder submitted if Pre-tax rate of Return is allowed to be continued than either approach can be used i.e., Grossing up the base rate of return on equity at the maximum applicable rate of tax or tax expenses (including Deferred Tax), irrespective of the tax rate applicable to the utilities or if the base rate of return on equity is allowed to be grossed up at the applicable tax rate say, MAT rate, the Deferred Tax liabilities as and when it materializes needs to be reimbursed.

xv. Some of the Beneficiaries suggested that income tax should not be grossed up otherwise working capital will increase. Actual, income tax should be passed through.

xvi. National Institute of Public Finance & Policy suggested that deduction under 80IA is a benefit given by the government to firms investing in certain sectors. The money saved by this reduction in tax liability should eventually accrue to the investors or owners of the firm. If the post-tax return on equity is grossed up based on actual tax paid, it would nullify the benefit given by the government. So, to ensure the benefit is not nullified, and the benefit given by the government is maintained, it would be advisable to use the corporate tax rate to gross up the post-tax return on equity.

xvii. Some of the Discoms suggested that as a matter of principle, no utility should make profit from taxation and certain proportion of actual tax should be allowed as pass through. Only actual tax should be a pass through and Procurers should pay tax only on the return on equity and not on super-normal returns due to incentive or efficiency or merchant sales or other businesses.

xviii. Association of Power Producers suggested that the practice of working out pre-tax return on equity by grossing up the tax rate should be continued. During the period when 80IA benefit is available to a project, the grossing up could be done by using the MAT rate instead of corporate tax rate. In other words, the base rate should be grossed up by actual tax paid in respect of a project and not the corporate tax of the company as a whole. This is more equitable and avoids mismatches. Alternatively, taxes may be reimbursed at actuals on a quarterly basis in addition to the RoE. However the additional tax liability of the Generator due to efficiency gains etc should also be reimbursed by the beneficiaries.

xix. NTPC submitted that the sector is currently fraught with several risks such as non-availability of fuel, chances of default of the customers, delay in project clearances, despatch of power etc. Hence there is a greater need to encourage investment in the power sector to ensure its growth, which would be beneficial for the entire economy. Reducing ROE would certainly give a wrong signal to the investors. Therefore, the Return on Equity should be estimated following the CAPM approach, which is estimated to be around 20.11%.

xx. UPPCL and Rajasthan Discom Power Procurement Centre suggested that base rate of return on ROE may be reduced if some SERCs have allowed it below 15.5% or 14.5% whichever is lower.

xxi. Government of Tripura, Dept. of Power submitted that ROE should be 14%.

xxii. Some of the stakeholders suggested that ROE should be reduced considering existing financial downturn.

9.5 Commission's Proposal

9.5.1 The power sector in India has been able to create a lot of enthusiasm amongst the investors during the last decade, and has witnessed significant increase in capacity addition. During the 11^{th} Five Year Plan, actual capacity addition was around 54,000 MW, which is around 200% of the achievement during the 10^{th} Plan and highest ever since independence. The sector is in transition stage from a controlled environment to a competitive market driven regime, which endeavours to provide affordable, reliable and quality power to various categories of consumers.

9.5.2 The rate of return on equity can be fixed by using scientific models like dividend growth model, price/earning ratio, capital asset pricing model, risk premium model, etc. However, the limitation of using any of these scientific models is the availability of sufficient volume of historical data. Thus, scientific method of determining cost of equity is still not practicable, as adequate number of entities operating in the power sector have not entered the primary market for providing a decent representative sample of the companies operating in the power sector. Accordingly, the

Commission does not favour determination of the cost of equity using any of the scientific models.

9.5.3 The movement of yields of 10-year Government of India bonds, which are considered as risk free securities, over the past four years have been given below, and show that the yields have varied between 6% to 9%, with the average yield being around 8%.

Government Bond Generic Bid Yield 10 Year

***Source**: Bloomberg*

9.5.4 The Commission also explored the option of fixing the rate of return on equity by linking to an appropriate benchmark like RBI Bank Rate, SBI Base Rate, 10 year G-Securities Rate, etc., with an appropriate mark up. However, it is observed that the debt market is not mature enough and interest rates have also witnessed significant fluctuation in the recent past. Hence, the Commission proposes that unless the debt market stabilises, it may not be appropriate to link the rate of return to any benchmark rate with mark up.

9.5.5 Thus, after detailed deliberations and considering the views of Central Advisory Committee and the stakeholders, the Commission proposes to continue with the existing base rate of return on equity of 15.5% with the additional 0.5% return on equity for timely completion of projects. The Commission again impresses upon the importance of timely completion of projects, which has a direct impact of the growth of the economy. On the other hand, if the project is not completed within the stipulated timeline for any reasons whatsoever, the additional return of 1% shall not be admissible.

9.5.6 The Commission also proposes to incorporate a provision of reduction of 1% in the rate of return on equity in case generation station or transmission system declares COD without commissioning of RGMO/FGMO, data telemetry and communication system to respective load dispatch centre, and protection system.

9.5.7 Pre-tax v/s Post Tax Return on Equity

On the issue of pre-tax vs. post tax return on equity with tax to be allowed as pass through on actual basis, the Commission has received mixed responses from different stakeholders.

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

9.5.9 Under the regulated business, when the Utilities are allowed specified post tax rate of return on equity in addition to prudently incurred expenses, the recovery of tax on specified Return on Equity by the Utilities needs to be allowed based on actual tax paid on Return on Equity on no profit and no loss basis, as tax on Return on Equity is a sort of reimbursement to ensure the recovery of the specified RoE. Therefore, the Commission proposes to modify the existing provision of pre-tax RoE being grossed up with the Tax Rate, to post tax RoE with income tax to be recovered on actual basis to the extent of return on equity only.

9.6 Proposed Provisions

(1) **Return on Equity**. (1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with regulation 19.

(2) Return on equity shall be computed at the base rate of 15.50% for thermal generating stations, transmission system including communication system and run of the river hydro generating station, and at the base rate of **16.50%** for the storage type generating stations including pumped storage hydro generating stations and run of river generating station with pondage:

Provided that in case of projects commissioned on or after 1st April, 2014, an additional return of **0.50 %** shall be allowed if such projects are completed within the timeline specified in **Appendix-I**:

Provided further that the additional return of 0.5% shall not be admissible if the project is not completed within the timeline specified above for reasons whatsoever:

Provided further that the rate of return of new project shall be reduced by 1% if the generating station or transmission system is declared commercial operation without commissioning of RGMO/FGMO, data telemetry and communication system up to load dispatch centre and protection system.

Tax on Return on Equity:

(1) Tax on the income corresponding to Return on Equity approved by the Commission for the generating company or the transmission licensee, as the case may be, shall be directly recovered from the beneficiaries or the long term transmission customers /DICs, as the case may be. Tax on the income shall be computed with reference to the total actual income tax paid by the generating company or the transmission licensee as the case may be, on pro-rata basis with respect to return on equity. The tax on any other income stream (including

efficiency gains, incentive, etc) other than Return on Equity shall not be recovered from beneficiaries or the long term transmission customers /DICs, as the case may be, and tax on such other income shall be payable by the generating company or transmission licensee, as the case may be.

(2) In case the profit before tax for a particular year is higher than the effective income tax on Return on Equity as approved by the Commission for any year, the Income Tax on Return on Equity to be recovered from the beneficiaries or the long term transmission customers /DICs, as the case may be on pro-rata basis in the following manner:

Income Tax to be recovered = Total Income Tax Paid x RoE approved by the Commission/Profit before Tax

In case the Profit before Tax for a particular year is lower than the tax on Return on Equity as approved by the Commission for any year, the actual Income Tax paid by the Generating Company or Transmission Licensee shall be recovered from beneficiaries or the long term transmission customers /DICs, as the case may be.

(3) Any under-recovery or over-recovery of tax on income shall be adjusted every year on the basis of income-tax assessment under the Income-Tax Act, 1961, as certified by the auditor:

Provided that income-tax allocated to the thermal generating station shall be charged to the beneficiaries in the same proportion as annual fixed charges, and the income-tax allocated to the hydro generating station shall be charged to the beneficiaries in the same proportion as annual capacity charges, and in case of inter-State transmission system, the sharing of income-tax shall be in the same proportion as annual transmission charges:

Provided further that the generating company and transmission licensee shall bill the Income Tax under a separate head called 'Income Tax Reimbursement' in their respective bills.

(4) The tax computation on ROE as approved by the Commission may be made based on advance tax assessed or deposited subject to adjustment on actual at the end of the year. The recovery or refund of tax, if any, in comparison with actual

tax shall be made along with interest as determined by the assessing officer of Income Tax department. The penalty, if any, arising on account of delay in deposit of tax or short deposit of tax amount shall not be claimed by the generating company or the transmission licensee as the case may be.

Provided that the deferred tax liability before 1.4.2009 shall be recovered from the beneficiaries as and when same gets finalized. No claim on account of deferred tax liability arising after 1.4.2009 shall be made from the beneficiaries.

10 Interest on Loan

10.1 Background

10.1.1 In the Tariff Regulations for FY 2001-04 and 2004-09 the Commission has adopted the approach that the loan arrived on the basis of debt-equity ratio is considered as gross normative loan for the purpose of calculation of interest on loan and the normative loan outstanding at the beginning of Tariff period is arrived by deducting the cumulative repayment admitted by the Commission upto the preceding Tariff period.

10.1.2 While framing the Tariff Regulations for the period FY 2009-14, the Commission in order to simplify the approach departed from the existing approach and considered the repayment for the tariff period as equal to the depreciation allowed. Also to encourage the entities to make every effort to re-finance the loan as long as it results in net benefit to the beneficiaries, the Commission allowed sharing of the net benefit of re-financing between the beneficiaries and the utilities in the ratio of 2:1.

10.2 Issues brought out in Approach Paper

10.2.1 The Commission in its Approach Paper obtained view from the stakeholder whether to continue with the existing method of working out cost of debt or switchover to normative cost of debt calculated on the basis of present debt market condition, how to address the variation of cost of debt among different rating companies, linking of cost of debt to benchmark yield on comparable bonds or Government Securities. Accordingly the Commission brought out the following issues on which it sought suggestions and comments:

a) Can we continue the existing method of working out cost of debt by considering weighted average rate of interest, calculated on the basis of actual loan, actual interest rate and scheduled loan repayment, or switchover to normative cost of debt calculated on the basis of present debt market condition? What should be the criteria for working out normative cost of debt?

b) *How can we address the variation of cost of debt among different rating Companies? Can allowable cost of debt be linked to a benchmark yield on comparable bonds or Government securities? Can ceiling be specified linking with benchmark yield? Any other alternatives*

10.3 Existing Provisions of Tariff Regulations, 2009

The Commission in the existing Regulations has considered repayment for the tariff period as equal to the depreciation allowed. Also to encourage the entities to make effort to re-finance the loan as long as it results net benefit to the beneficiaries, the Commission allowed sharing of the net benefit between the beneficiaries and the utilities in the ratio of 2:1. Any cost incurred in such refinancing is to be reimbursed by the beneficiaries and the net savings are be shared. Existing provisions in this regard are as follows:

(1) The loans arrived at in the manner indicated in regulation 12 shall be considered as gross normative loan for calculation of interest on loan.

(2) The normative loan outstanding as on 1.4.2009 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2009 from the gross normative loan.

(3) The repayment for the year of the tariff period 2009-14 shall be deemed to be equal to the depreciation allowed for that year:

(4) Notwithstanding any moratorium period availed by the generating company or the transmission licensee, as the case may be the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the annual depreciation allowed,.

(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project:

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

Provided further that if the generating station or the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered.

(6) The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest.

(7) The generating company or the transmission licensee, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and the generating company or the transmission licensee, as the case may be, in the ratio of 2:1.

(8) The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

(9) In case of dispute, any of the parties may make an application in accordance with the Central Electricity Regulatory Commission (Conduct of Business) Regulations, 1999, as amended from time to time, including statutory re-enactment thereof for settlement of the dispute:

Provided that the beneficiary or the transmission customers shall not withhold any payment on account of the interest claimed by the generating company or the transmission licensee during the pendency of any dispute arising out of re-financing of loan.

10.4 Stakeholders Responses

10.4.1 The extracts of the suggestions received from various stakeholders on the issues flagged above are as follows:

i. Most of the power generation and transmission companies have suggested that the existing approach should be continued.

ii. One of the IPP Developer submitted that if interest rate on debt is to be normalized then it should additionally be classified credit rating wise. Foreign exchange rate risk should be allowed at actual as the fluctuations in INR to US $ are so volatile that hedging has become costly and uncertain. Actual interest cost, actual forex variation cost and hedging expenses should be allowed pass through as cost of overseas debt separately.

i. Most of the power generation and transmission companies have suggested that the existing approach should be continued.

ii. Beneficiaries suggested that Ceiling limit of cost of debt needs to be linked to long term Government Securities.

iii. One of the private sector Utility submitted that benchmarking of cost of debt will be difficult since the debt market in India is still to be fully developed. Further, benchmarking of the cost of debt is not currently possible due to following reasons:

    (a) Interest rate is dependent on (i) Project specific, risk profile and/or (ii) credit rating of entities

    (b) Presently, the interest rate is on an increasing trend. Assuming the requirement of the debt with long tenure, such debt would involve the clause for reset of ROI for a couple of times during the tenure of the debt, which makes the benchmarking of cost of debt inappropriate and impossible.

10.5 Commission's Proposal

10.5.1 With the adoption of GFA approach, it is imperative to determine the outstanding loan at the beginning of each year of the tariff period.

10.5.2 The Commission is of the view that while determining cost of debt, an appropriate balancing of the interest of the consumers and regulated entities needs to be maintained as debt component has significantly higher share in the normative capital structure. Further, as discussed earlier in the past few years significant volatility has been witnessed in the interest rate. Accordingly, at this stage it may not be appropriate at this stage to benchmark the interest rate with Prime Lending Rate and G- Sec rate.

10.5.3 The other challenge in benchmarking the interest rate is the interest on loan financed by the Financial Institutions/Banks varies depending on the financial strength and other operational conditions of the entity. This also varies between public sector and private sector status of the borrowing entities and even between the Central Sector companies and State Level companies. Thus, it would not be appropriate to specify the same benchmark interest rate for all the entities as the same may result in wind fall gains for some entities and substantial losses for other entities.

10.5.4 Accordingly, it is proposed to continue the existing methodology of weighted average rate of interest calculated on the basis of the actual loan portfolio and consider repayment of loan equivalent to the depreciation.

10.6 Proposed Provisions

Interest on loan capital: (1) The loans arrived at in the manner indicated in regulation 19 shall be considered as gross normative loan for calculation of interest on loan.

(2) The normative loan outstanding as on 1.4.2014 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2014 from the gross normative loan.

(3) The repayment for each of the year of the tariff period 2014-19 shall be deemed to be equal to the depreciation allowed for the corresponding year. In case of de-capitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment made to the extent of de-capitalization.

(4) Notwithstanding any moratorium period availed by the generating company or the transmission licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the depreciation allowed for the year or part of the year .

(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after accounting for interest capitalized:

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

Provided further that if the generating station or the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered.

(6) The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest.

(7) The generating company or the transmission licensee, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and the generating company or the transmission licensee, as the case may be, in the ratio of 2:1.

(8) The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

(9) In case of dispute, any of the parties may make an application in accordance with the Central Electricity Regulatory Commission (Conduct of Business) Regulations, 1999, as amended from time to time, including statutory re-enactment thereof for settlement of the dispute:

Provided that the beneficiaries or the long term transmission customers /DICs shall not withhold any payment on account of the interest claimed by the generating company or the transmission licensee during the pendency of any dispute arising out of re-financing of loan.

11 Interest on Working Capital

11.1 Background

11.1.1 The Commission in its Tariff Regulations, 2001 and Tariff Regulations, 2004 approved 45 days of coal cost for pit head and 60 days of coal cost for non pit head stations, one month O&M expenses, two months receivable and maintenance spares at 1% of historical capital cost as working capital. The Commission in its subsequent Tariff Regulations, 2009 approved separate norms for coal and lignite fired stations, gas based stations and hydro generating stations. For coal and lignite based station the fuel stock norm was different for pit head and non pit head stations. Further the norm for computing maintenance spares for considering it as working capital for both thermal and hydro generating station was revised and the same was liked to O&M expenses and not to historical capital cost of the generating station.

11.2 Issues brought out in Approach Paper

11.2.1 The Commission in its Approach paper discussed on the issue of allowable stock of fuel presently considered for working capital in view of actual fuel stock maintained by these stations. The Commission further discussed on reviewing the inclusion of depreciation and Return on Equity as a part of receivables for computing working capital requirement. Further, the Commission also discussed on the inclusion on tax component in the working capital as the Return on Equity was being allowed on pre tax basis. The Commission also discussed on the present methodology of allowing maintenance spares separately as the same is included in O&M expenses. The Commission in view of the above invited suggestions and comments on the following issues:

"a) Whether amount and stock of fuel oil/O&M expenses/maintenance spares/receivables specified in the existing regulations should continue or, any change is required? Whether maintenance spares should form a part of the working capital along with O&M expenses in the existing methodology?

b) Whether stores and spares / repairs & maintenance / employees cost, insurance, security and most of the sub-elements under administrative expenses and most of *the sub-elements under corporate office expenses included in O&M expenses should form a part of the working capital?*

c) In case ROCE approach is applied, whether net working capital can be a part of the Regulatory Asset Base instead of providing it separately?

d) In this regard it is to be deliberated whether the Depreciation and Return of equity should be considered as part of annual fixed costs while working out two months receivable for working capital as no working capital is required to fund the depreciation and return on equity."

11.3 Existing Provisions of Tariff Regulations, 2009

(1) The working capital shall cover:

(a) Coal-based/lignite-fired thermal generating stations

i. *Cost of coal or lignite and limestone, if applicable, for 1½ months for pithead generating stations and two months for non-pit-head generating stations, for generation corresponding to the normative annual plant availability factor;*
ii. *Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil.*
iii. *Maintenance spares @ 20% of operation and maintenance expenses specified in regulation 19.*
iv. *Receivables equivalent to two months of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor, and*
v. *Operation and maintenance expenses for one month.*

(b) Open-cycle Gas Turbine/Combined Cycle thermal generating stations

i. *Fuel cost for one month corresponding to the normative annual plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel;*

ii. *Liquid fuel stock for ½ month corresponding to the normative annual plant availability factor, duly taking in to account mode of operation of the generating stations of gas fuel and liquid fuel and in case of use of more than one liquid fuel, cost of main liquid fuel.*

iii. *Maintenance spares @ 30% of operation and maintenance expenses specified in regulation 19.*

iv. *Receivables equivalent to two months of capacity charge and energy charge for sale of electricity calculated on normative plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel, and*

v. *Operation and maintenance expenses for one month.*

(c) In case of Hydro generating stations including pumped storage hydro-electric generating station and transmission system

i. *Receivables equivalent to two months of fixed cost.*

ii. *Maintenance spares @ 15% of operation and maintenance expenses specified in regulation 19;*

iii. *Operation and maintenance expenses for one month.*

(2) The cost of fuel in cases covered under sub-clauses (a) and (b) of clause (1) shall be based on the landed cost incurred (taking into account normative transit and handling losses) by the generating company and gross calorific value of the fuel as per actual for the three months preceding the first month for which tariff is to be determined and no fuel price escalation shall be provided during the tariff period.

(3) Rate of interest on working capital shall be on normative basis and shall be considered as follows:

(i) SBI short-term Prime Lending Rate as on 01.04.2009 or on 1st April of the year in which the generating station or a unit thereof or the transmission system, as the case may be, is declared under commercial operation, whichever is later, for the unit or station whose date of commercial operation falls on or before 30.6.2010.

(ii) SBI Base Rate plus 350 basis points as on 1.7.2010 or as on 1st April of the year in which the generating station or a unit thereof or the transmission system, as the case may be, is declared under commercial operation, whichever is later, for

the units or station whose date of commercial operation lies between the period 1.7.2010 to 31.3.2014:

Provided that in cases where tariff has already been determined on the date of issue of this notification, the above provisions shall be given effect to at the time of truing up.

(4) Interest on working capital shall be payable on normative basis notwithstanding that the generating company or the transmission licensee has not taken loan for working capital from any outside agency.

11.4 Stakeholders Responses

11.4.1 The extracts of the suggestions received from various stakeholders on the issues flagged above are as follows:

i. Some of the stakeholders submitted that the current methodology of computing working capital should be continued.

ii. Some of the stakeholders suggested following changes in the current methodology:

a. Fuel Stock including secondary oil to be considered for working capital requirement should be for one month with some stakeholders suggesting 15 days.

b. O&M cost should not be considered separately as this is included in receivables.

c. Maintenance spares should not be considered in working capital as this is already included in O&M expenses.

d. Secondary fuel oil charges being included in the AFC the same should not form a part of working capital.

e. Generators are not maintaining normative stock of fuel/oil/maintenance spares as specified in existing regulations. There are several cases of less availability of coal to NTPC. While declaring less availability during off-peak hours, they are allowed to earn interest on working capital which includes the normative cost of fuel equivalent to 1.5 to 2 months of coal/oil. Thus, based on the actual level of inventory maintained by various generators, stock of fuel to be considered for working capital may be reviewed.

f. Receivables considered for working capital may be reduced from 60 days to 45 days. However, due date of payment of NTPC for Delhi

Discoms is last date of the same month in which the bill is raised. Therefore, for such Discoms, either payment due date shall be raised to 60 days or receivables equivalent to one month of capacity charge and energy charge for sale electricity on the normative annual plant availability factor shall be allowed to the generator.

iii. Some of the stakeholders submitted that the interest rate should be linked to SBI Base Rate prevailing on a monthly basis so that the generators are in position to recover the actual interest.

iv. Some of the stakeholders suggested that the expenses viz. stores and spares / repairs & maintenance/employees cost, insurance, security and most of the sub-elements under administrative expenses and most of the sub-elements under corporate office expenses included in O&M expenses are incidental to the transmission business and are essential for providing reliability and efficiency to the system. Such expenses are recurring in nature and must be considered as part of the working capital requirement.

v. Some of the stakeholders suggested that the items specified above should not be included in O&M expenses and it should not form a part of working capital. Stakeholders also submitted that grossing of income tax is allowed on return on equity, which in turn ROE forms a significant portion of working capital. Accordingly, income tax also becomes a part of working capital which should not be the case. Hence, while calculating the amount of working capital, the ROE should be considered without grossing up of tax. Since specific fuel oil consumption is also part of AFC, it also burdens on the beneficiaries being element of receivables

vi. There are certain expenses such as insurance expenses, etc which are paid in advance. Hence, it is essential to factor some of these costs as part of working capital instead of the entire O&M costs.

vii. Some of the stakeholders suggested that under the ROCE approach, only long-term debt, equity and reserves should be used for calculating the capital employed. Working capital need not be a part of capital employed. Average working capital requirement should be separately computed, and return on it should be provided for.

viii. One of the stakeholder submitted that irrespective of ROCE or ROE approach, the working capital may be calculated by taking into account both the normative Current Assets and normative Current Liabilities While arriving at the Capital Employed, CERC may exclude the Current Liabilities (i.e., Credit period provided by the fuel supplier, employee cost, etc.). The Commission may not provide the separate Interest on Working Capital, if the same is considered as part of Capital Employed. Further, the Commission may provide additional mark up in terms of percentage for Interest on Working Capital while determining the Rate of Return on Capital Employed.

ix. Some of the stakeholders submitted that the amount of Depreciation is employed for repayment of loans and the Return of Equity is shareholders' funds and further these expense are cashless expenses and need no funding therefore these may not be considered as part of annual fixed costs while working out two months receivables for working capital

x. Some of the stakeholders submitted that the Depreciation is considered as deemed repayment of loan for tariff purposes. In case depreciation is not provided as part of receivables in working capital, cash flow for repayment of debt would be inadequate. Return on equity has been fixed based on the present dispensation of receivables. Therefore, depreciation and return on equity being part of receivables need to be considered in the working capital. Further Depreciation cannot be termed as non cash item. Return on Equity can't be considered as item payable only at the end of year. Hence, equity investors are entitled to ROE on daily/monthly basis.

11.5 Commission's Proposal

11.5.1 The Commission has gone through the suggestions and comments received from various stakeholders. In the existing Regulations, the cost of coal or lignite for thermal generating stations includes one month fuel cost and cost of fuel towards 15 days of stock for pit head stations and 30 days of stock for non pit head stations. The Commission in this regard had sought information with regards to actual annual average fuel stock maintained by the generating stations and the maximum fuel storage capacity these generating stations have. In this regard the generating stations submitted their actual average fuel stock maintained for FY 2008-09 to FY 2012-13 and maximum fuel storage capacity which is as summarised below:

Table: Actual Average Fuel Stock and Maximum Fuel Storage Capacity

S. No	Stations	Fuel Type	Units	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Five Year Average
1	Singrauli Super Thermal Power Station	Primary Fuel	Days	7.04	18.28	5.83	12.72	11.01	10.98
		Storage Capacity (Primary)	**Days**			**27**			
2	Rihand Super Thermal Power Station	Primary Fuel	Days	6.83	18.08	12.63	13.50	10.97	12.40
		Storage Capacity (Primary)	**Days**			**20**			
3	Tanda Thermal Power Station	Primary Fuel	Days	15.30	23.52	37.99	24.94	32.00	26.75
		Storage Capacity (Primary)	**Days**			**50**			
4	Unchahar FGUTPP	Primary Fuel	Days	7.20	10.78	20.67	9.27	5.15	10.62
		Storage Capacity (Primary)	**Days**			**35**			
5	Korba Super Thermal Power Station	Primary Fuel	Days	9.72	17.68	17.17	8.06	3.99	11.32
		Storage Capacity (Primary)	**Days**			**15**			
6	Vindhyachal Super Thermal Power Station	Primary Fuel	Days	4.74	12.71	5.33	8.47	7.59	7.77
		Storage Capacity (Primary)	**Days**			**18**			
7	Sipat Super Thermal Power Station	Primary Fuel	Days	7.89	8.24	21.30	17.98	5.82	12.25
		Storage Capacity (Primary)	**Days**			**18**			
8	Ramgundam Super Thermal Power Station	Primary Fuel	Days	6.86	14.15	11.24	6.27	6.19	8.94
		Storage Capacity (Primary)	**Days**			**15**			
9	Simhadri Super Thermal Power Station	Primary Fuel	Days	4.92	9.49	9.54	10.74	3.78	7.70
		Storage Capacity (Primary)	**Days**			**30**			
10	Farakka Super Thermal Power Station	Primary Fuel	Days	2.96	2.51	6.07	8.80	1.39	4.35
		Storage Capacity (Primary)	**Days**			**15**			
11	Kahalgaon Super Thermal Power Station	Primary Fuel	Days	2.79	2.32	1.43	1.66	2.35	2.11
		Storage Capacity (Primary)	**Days**			**16**			
12	TTPS Thermal Power Station	Primary Fuel	Days	13.05	18.14	27.47	16.64	17.10	18.48
		Storage Capacity (Primary)	**Days**			**25**			
13	Tal kaniha Super Thermal Power Station	Primary Fuel	Days	2.78	1.76	3.43	4.25	2.62	2.97
		Storage Capacity (Primary)	**Days**			**15**			

S. No	Stations	Fuel Type	Units	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Five Year Average
14	Badarpur Thermal Power Station	Primary Fuel	Days	12.39	8.34	31.45	10.48	7.92	14.12
		Storage Capacity (Primary)	**Days**			**30**			
15	Dadri Thermal Power Station	Primary Fuel	Days	10.14	14.15	15.48	5.33	3.35	9.69
		Storage Capacity (Primary)	**Days**			**30**			

Note: Average coal stock in days have been computed based on the basis of daily coal requirement on the basis of actual generation for that year.

11.5.2 As shown above, in almost all the stations the average fuel stock maintained was well below the normative 15 days for pit head stations and 30 days for non pit head stations allowed. Except in case of Tanda TPS wherein the actual average fuel stock maintained was close to 30 days, the average coal stock at most of the generating stations was in the range of around 10-15 days. Further, it is observed that very few generating stations even have the coal storage capacity of more than 30 days and in most of the cases the maximum storage capacity of fuel is around 15-30 days.

11.5.3 The Commission therefore proposes that the cost of fuel towards fuel stock shall be considered as 15 days for pits head stations and 30 days for non pit-head stations subject to maximum storage capacity.

11.5.4 In case of gas based stations, the Commission proposes to retain the current norm for primary fuel cost of 30 days.

11.5.5 As regards to components of two months receivables as part of working capital, the Commission is of the view that though depreciation is not a cash expense but depreciation is utilised to meet the repayment obligations and hence it will not be appropriate to not include the depreciation as part of receivables for arriving at normative working capital. The Commission proposes to not include RoE as the component of receivables for arriving at normative working capital as no working capital is required to fund the Return on Equity.

11.6 Proposed Provisions

Interest on Working Capital:(1) The working capital shall cover:

(a) Coal-based/lignite-fired thermal generating stations

(i) Cost of coal or lignite and limestone towards stock, if applicable, for 15 days for pit-head generating stations and 30 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower;

(ii) Cost of coal or lignite and limestone for 30 days for generation corresponding to the normative annual plant availability factor;

(iii) Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil;

(iv) Maintenance spares @ 20% of operation and maintenance expenses specified in regulation 29;

(v) Receivables equivalent to two months of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor; and

(vi) Operation and maintenance expenses for one month.

(b) Open-cycle Gas Turbine/Combined Cycle thermal generating stations

(i) Fuel cost for 30 days corresponding to the normative annual plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel;

(ii) Liquid fuel stock for 15 days corresponding to the normative annual plant availability factor, and in case of use of more than one liquid fuel, cost of main liquid fuel duly taking in to account mode of operation of the generating stations of gas fuel and liquid fuel and in case of use of more than one liquid fuel, cost of main liquid fuel;

(iii)Maintenance spares @ 30% of operation and maintenance expenses specified in Regulation 29;

(iv) Receivables equivalent to two months of capacity charge and energy charge for sale of electricity calculated on normative plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel; and

(v) Operation and maintenance expenses for one month.

(c) Hydro generating station including pumped storage hydro electric generating station and transmission system including communication system.

(i) Receivables equivalent to two months of fixed cost;

(ii) Maintenance spares @ 15% of operation and maintenance expenses specified in regulation 29;

(iii) Operation and maintenance expenses for one month;

(2) The cost of fuel in cases covered under sub-clauses (a) and (b) of clause (1) of this regulation shall be based on the landed cost incurred (taking into account normative transit and handling losses) by the generating company and gross calorific value of the fuel as per actual for the three months preceding the first month for which tariff is to be determined and no fuel price escalation shall be provided during the tariff period.

(3) Rate of interest on working capital shall be on normative basis and shall be considered as the bank rate as on 1.4.2014 or as on 1st April of the year during the tariff period 2014-19 in which the generating station or a unit thereof or the transmission system including communication system or element thereof, as the case may be, is declared under commercial operation, whichever is later.

(4) Interest on working capital shall be payable on normative basis notwithstanding that the generating company or the transmission licensee has not taken loan for working capital from any outside agency.

12 Operations and Maintenance Expenses

12.1 Background

12.1.1 The Commission in its Tariff Regulations, 2001 specified that the O&M Expenses for stations in operation for five or more than five years shall be derived on the basis of past five year actual O&M expenses excluding the abnormal O&M expenses. For new stations as well as stations, which have not completed less than five years of operation, the Commission specified norm for O&M expenses for first year as 2.50% of the actual capital cost. The Commission in its subsequent Tariff Regulations, 2004 approved normative O&M expenses for thermal stations on the basis of unit sizes of 200/210/250 MW units. The Commission also approved O&M norms for 500 MW and above units. For deriving such norms the Commission relied upon the past years' actual data. For Hydro stations, new generating stations and the stations that had not completed five years of operations, the Commission retained its earlier approach of approving O&M expenses based on past five year actual O&M expenses. The Commission in its subsequent Tariff Regulations, 2009 continued with its earlier approach of approving O&M norms on the basis of unit sizes in case of coal based generating stations and on the basis of actual O&M expenses for past years for hydro new generating stations and the stations that had not completed five years of operations. However, the Commission in this Tariff Regulations, 2009 with regard to coal based stations specified norms for supercritical units and added another class of unit size of 300/330/350 MW. The Commission in its Tariff Regulations, 2004 and Tariff Regulations, 2009 also approved separate norms for some of the stations of NTPC and DVC.

12.2 Issues Brought Out in the Approach Paper

12.2.1 The Commission in its approach paper discussed on the issues related to the use of fixed escalation rate that needs to be considered for escalating base O&M expenses. The Approach paper also invited suggestion on introduction of RPI-X concept for determining escalation rates. The Commission with regard to Hydro generating station, in its approach paper discussed on introducing norms for hydro generating stations similar to thermal generating stations/transmission system. Accordingly the Commission invited suggestions on following issues;

a) *Comments on adequacy of the existing O&M norms with regard to the O&M requirement and resultant cash flows. Whether to review the existing O&M norms? (To be viewed in the context of availability of margins).*

b) *Comments on CERC O&M norms as compared to similar norms set by SERCs. Is the variation in CERC norms justified for reasons like better performance in terms of higher availability etc.?*

c) *Comments on the requirement of mid-term review of normative O&M cost. How to deal with variations in O&M cost during the tariff period? Is there a need for introduction of truing up after specifying normative parameters?*

d) *Methodologies to determine escalation factor for determining O&M cost. In case escalation factor is determined based on WPI & CPI indexation, the weightage of WPI & CPI to determine the escalation rate. What would be the escalation rate for normative O&M on year on year basis methodologies suggested?*

e) *Efficacy of the method of determining O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects. Alternatives to develop O&M Cost norms for the Hydro generating stations?*

f) *Suggestions on development of a model for specifying the O&M norms which reflects optimum operational efficiency? Whether to introduce the concept of RPI-X for the limited purpose of O&M as discussed in above para 3.10.2(ii).*

g) *Treatment of income from other business and other income like interest on deposits, advances etc. while arriving at the O&M cost? Further, treatment of offsetting revenues generated out of telecom business (by way of laying optical fibre composite overhead ground wire) from annual transmission charges. Suggestion on treatment of license fees, taxes and duties.*

12.3 Stakeholders Responses

1) Some of the stakeholders submitted that the O&M costs needs to be reviewed as the existing norms are higher in comparison with that allowed to State Utilities operating at higher efficiency.

2) Some of the stakeholders submitted that the existing O&M norm is not sufficient to cover the actual O&M expenditure. The actual O&M expenses incurred is more than the normative expenses allowed by CERC. Restricting employee cost to certain extent is not reasonable and requires a review.

3) Some of the stakeholders submitted that it is normal tendency with the generating companies and the transmission licensee to economize on the O&M expenses which is not a good trend. The Commission may true up the O&M expenses within the overall limits of the norms and any saving on O&M expenses should be shared equally with the beneficiaries.

4) Some of the stakeholders suggested that the SERCs of UP, MP, Chhattisgarh, Gujarat, etc., are allowing water charge as a separate pass through element, over and above the O&M expenses.

5) Some of the stakeholders suggested that the review of O&M expenses should be considered during the Tariff Period. However, if O&M expenses have risen due to extra ordinary condition like rise in wages, etc., and their cumulative impact at commencement of Tariff Period exceeds such cumulative normative O&M expenses by say 10 %, then mid-term reviews may be considered.

6) Some of the stakeholders suggested that the provision of mid-term review of normative O&M expenses may be adopted if there is a need on account of very high inflation only. However, there should not be truing up of the O&M cost else it would shift the methodology from normative to actual.

7) Some of the stakeholders suggested that the mid-term review of O&M norms during the tariff period may result in revision of AFC as well as bills raised to the beneficiaries. Frequent revision of bills is not in favour of beneficiaries too, since they cannot recover the same from the consumers retrospectively.

8) Some of the stakeholders suggested that the biggest share in O&M cost is of Employee cost which relates to CPI. Further, R&M has one component related to labour cost (which is more closely related to CPI than WPI). Thus, the WPI:CPI mix may be reviewed and more weightage (say 50%) may be assigned to CPI.

9) Some of the stakeholders suggested that the O&M costs may be benchmarked to WPI and CPI percentages and may be set every year.

10) Some of the stakeholders suggested that while determining the escalation factor for determining O&M cost, the rate of annual increase in actual normalised O&M expenses may be worked out. The same may be compared with the WPI and CPI and a realistic approach may be adopted to determine the escalation factor.

11) Some of the stakeholders suggested that the present provision is fine as generalised norms for hydro project based on their capacity (as thermal plants) will not be practically possible owing to different size/design of project components for projects having similar capacity (tunnel, dam, etc.) whereas some suggested that the O&M cost need to be assessed under separate components. Only R&M has a direct linkage with Capital Cost. Thus, O&M cost should not be based on the percentage of capital expenditure.

12) Some of the stakeholders suggested that the RPI-X methodology should be considered so that high O&M expenses due to over staffing, inefficiency in operation, etc., are reduced.

13) Some of the stakeholders suggested that the O&M norms need to have operational efficiency factor similar to the model applicable to distribution licensees. Based on the past norms and actual expenses, efficiency factor needs to be developed for future Tariff Period.

14) Some of the stakeholders suggested that while arriving at the O&M cost, the income from the other sources should be deducted and for the

subsequent period the escalation factor should be determined based on WPI and CPI indexation in line with escalation considered in the bid route for the existing projects.

Some of the stakeholders submitted that the O&M expenses should be determined on the basis of the audited accounts of the individual stations. Other incomes such as interest on deposits are not part of income of the stations; therefore such incomes do not go into the base O&M cost decided for the generating stations.

12.4 Existing Norms vis-à-vis Actual O&M Expenses

12.4.1 Existing norms

Normative operation and maintenance expenses shall be as follows, namely:

(a) Coal based and lignite fired (including those based on CFBC technology) generating stations, other than the generating stations referred to in clauses (b) and (d):

(Rs. in lakh/MW)

Year	*200/210/250 MW Sets*	*300/330/350 MW Sets*	*500 MW Sets*	*600 MW Sets and above*
2009-10	*18.20*	*16.00*	*13.00*	*11.70*
2010-11	*19.24*	*16.92*	*13.74*	*12.37*
2011-12	*20.34*	*17.88*	*14.53*	*13.08*
2012-13	*21.51*	*18.91*	*15.36*	*13.82*
2013-14	*22.74*	*19.99*	*16.24*	*14.62*

Provided that the above norms shall be multiplied by the following factors for additional units in respective unit sizes for the units whose COD occurs on or after 1.4.2009 in the same station:

200/210/250 MW	*Additional 5th and 6th units*	*0.9*
	Additional 7th and more units	*0.85*
300/330/350 MW	*Additional 4th and 5th units*	*0.9*
	Additional 6th and more units	*0.85*
500 MW and above	*Additional 3rd and 4th units*	*0.9*
	Additional 5th and above units	*0.85*

(b) Talcher Thermal Power Station(TPS), Tanda TPS, Badarpur TPS of NTPC and Bokaro TPS, Chandrapura TPS and Durgapur TPS of DVC

(Rs. in lakh/MW)

Year	***Talcher TPS***	***Tanda and Chandrapura TPS***	***Badarpur, Bokaro and Durgapur TPS***
2009-10	*32.75*	*26.25*	*31.35*
2010-11	*34.62*	*27.75*	*32.25*
2011-12	*36.60*	*29.34*	*33.17*
2012-13	*38.70*	*31.02*	*34.12*
2013-14	*40.91*	*32.79*	*35.09*

(c) Open Cycle Gas Turbine/Combined Cycle generating stations

(Rs. in lakh/MW)

Year	***Gas Turbine/ Combined Cycle generating stations other than small gas turbine power generating stations***	***Small gas turbine power generating stations***	***Agartala GPS***
2009-10	*14.80*	*22.90*	*31.75*
2010-11	*15.65*	*24.21*	*33.57*
2011-12	*16.54*	*25.59*	*35.49*
2012-13	*17.49*	*27.06*	*37.52*
2013-14	*18.49*	*28.61*	*39.66*

(d) Lignite-fired generating stations

(Rs. in lakh/MW)

Year	***125 MW Sets***	***TPS-I of NLC***
2009-10	*24.00*	*27.00*
2010-11	*25.37*	*28.54*
2011-12	*26.82*	*30.18*
2012-13	*28.36*	*31.90*
2013-14	*29.98*	*33.73*

(e) In case of coal-based or lignite-fired thermal generating station a separate compensation allowance unit-wise shall be admissible to meet expenses on new assets of capital nature including in the nature of minor assets, in the

following manner from the year following the year of completion of 10,15, or 20 years of useful life:

Years of Operation	*Compensation Allowance (Rs lakh/MW/year)*
0-10	*Nil*
11-15	*0.15*
16-20	*0.35*
21-25	*0.65*

(f) Hydro generating station

(i) Operation and maintenance expenses, for the existing generating stations which have been in operation for 5 years or more in the base year of 2007-08, shall be derived on the basis of actual operation and maintenance expenses for the years 2003-04 to 2007-08, based on the audited balance sheets, excluding abnormal operation and maintenance expenses, if any, after prudence check by the Commission.

(ii) The normalised operation and maintenance expenses after prudence check, for the years 2003-04 to 2007-08, shall be escalated at the rate of 5.17% to arrive at the normalized operation and maintenance expenses at the 2007-08 price level respectively and then averaged to arrive at normalised average operation and maintenance expenses for the 2003-04 to 2007-08 at 2007-08 price level. The average normalised operation and maintenance expenses at 2007-08 price level shall be escalated at the rate of 5.72% to arrive at the operation and maintenance expenses for year 2009-10:

Provided that operation and maintenance expenses for the year 2009-10 shall be further rationalised considering 50% increase in employee cost on account of pay revision of the employees of the Public Sector Undertakings to arrive at the permissible operation and maintenance expenses for the year 2009-10.

(iii) The operation and maintenance expenses for the year 2009-10 shall be escalated further at the rate of 5.72% per annum to arrive at permissible operation and maintenance expenses for the subsequent years of the tariff period.

(iv)In case of the hydro generating stations, which have not been in commercial operation for a period of five years as on 1.4.2009, operation and maintenance expenses shall be fixed at 2% of the original project cost (excluding cost of rehabilitation & resettlement works). Further, in such case, operation and maintenance expenses in first year of commercial operation shall be escalated @5.17% per annum up to the year 2007-08 and then averaged to arrive at the O&M expenses at 2007-08 price level. It shall be thereafter escalated @ 5.72% per annum to arrive at operation and maintenance expenses in respective year of the tariff period.

(v) In case of the hydro generating stations declared under commercial operation on or after 1.4.2009, operation and maintenance expenses shall be fixed at 2% of the original project cost (excluding cost of rehabilitation & resettlement works) and shall be subject to annual escalation of 5.72% per annum for the subsequent years.

12.4.2 **Actual O&M Expenses**

12.4.2.1 The Commission through its Order dated June 07, 2013 directed various Central Generating Stations to submit details of actual annual O&M expenses incurred for FY 2008-09 to FY 2012-13. In response the generating stations submitted the O&M expenses which has been analysed as discussed below.

12.4.2.2 The Central Generating Stations submitted the O&M expenses for FY 2008-09 to FY 2012-13 in the prescribed format with actual break up of expenses incurred for the above mentioned period under various sub heads. The O&M expenses incurred by these generating stations can be broadly classified into three heads as shown below:

a) Repair and Maintenance Expenses
b) Administrative and General Expenses
c) Employee Expenses

12.4.2.3 The Commission has analysed sub head wise expenses incurred by various generating stations and has following broad observations on the data submitted by various generating stations along with the approach followed.

1) Some of the expenses like prior period expenses, arrears etc., booked under the head O&M expenses were non recurring expenses. Since these expenses are onetime expenses the same has not been considered as a part of O&M expenses for arriving at norms.
2) Some of the expenses like Ex-gratia, incentives, productivity linked incentives and Performance related pay are expenses that are linked to efficient operation of generating station and are payable only in case the plant achieves normative operational levels or overachieves them. The Commission proposes that incentives and performance related pay are supposed to be made only if the plant benefits from efficient O&M and therefore the same should be paid by the generating company from the increase in revenue due to reduced down time and efficient plant operations.

3) Some of the expenses such as Donations, Provisions, Community Development Expenses, Loss of Store are expenses that cannot form a part of O&M expenses for determination of norms.

4) For most of the stations, few instances were observed where there was steep year on year increase in expenses incurred. In such cases where there has been abrupt increase in any sub head the Commission in order to normalise the same has escalated the previous year O&M expenses by the average escalation rate determined for FY 2008-09 to FY 2012-13 which works out to be 7.01% (WPI) and 10.30% (CPI).

5) Most of the generating stations including NHPC and NTPC stations submitted bookings under the head electricity charges. The Commission has considered these charges however the abnormal increase in such expenses have been normalised.

6) For NTPC stations it was generally observed that the employee expenses for FY 2008-09 was higher than the employee expenses for FY 2009-10. The same was left unexplained by the generating company in its submissions. The Commission in such cases has derived the actual O&M expenses for FY 2008-09 by discounting the normalised O&M expenses for FY 2009-10 by 10.30%.

7) In case of NLC stations it was observed that the allocation of corporate expenses on the generating stations especially in case of NLC TPS I was abnormally high and was working out to be around 8 lakh/MW/Year for FY 2011-12 and FY 2012-13. The Commission has therefore restricted the corporate allocation to these stations to 50% of the actual for TPS-I and 60% of the actual for the rest of the stations of NLC.

8) In case of NTPC stations there has been abrupt increase in security expenses in FY 2009-10 due to introduction of service tax, however, the increase observed in most of the stations was much more than the rate of service tax. The Commission has therefore considered the net impact of introduction of service tax and has accordingly normalised the same.

9) For NEEPCO stations there was huge increase of around 100% in employee expenses in FY 2011-12 and FY 2012-13.

10) Further Since water charges are to be approved and allowed separately the same has not been considered as a part of O&M expenses for thermal and Hydro Generating stations.

11) Some of the Central Generating Stations including NTPC and NHPC have booked expenses under the head "Expenditure of Capital nature as per accounting practice not claimed/disallowed in capital cost". The Commission had asked the generating stations to submit the breakup of such expenses incurred which the

generating stations failed to submit. The Commission has therefore not considered such expenses as a part of O&M expenses.

12.4.2.4 The Commission has accordingly derived normalised O&M expenses actually incurred by the generating stations for approving the norms for thermal and hydro generating stations.

A. Thermal Generating Stations

As discussed earlier the Commission in its Tariff Regulations, 2009 approved norms of O&M expenses based on the unit sizes. These units sizes were 200/210/250 MW, 300/330/350 MW, 500 MW and above (sub-critical) units and 600 MW and above super critical units. As discussed above the Commission has analysed the actual O&M expenses for these stations. Most of the stations for which O&M data have been submitted are combination of different unit sizes therefore for determining the norms only stations with single unit type configuration have been considered. For 200/210/250 MW units the Commission have considered the O&M expenses for following stations:

a) Unchahar TPS
b) Bokaro TPS
c) NLC TPS – I Expansion
d) NLC TPS-II
e) NSPCL – Bhilai Extension Plant

The actual O&M expenses for these stations for FY 2008-09 to FY 2012-13 are as shown below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Unchahar FGUTPP	17.98	18.71	22.42	22.60	24.44
NLC TPS I Exp	13.49	16.47	15.59	19.94	23.23
NLC TPS II	17.46	20.20	20.39	21.56	23.95
Bokaro TPS	17.82	20.43	22.75	26.50	NA
NSPCL Bhilai Ext			14.44	13.06	17.25

NA- DVC accounts for FY 2012-13 has not been audited hence four year data considered

Similarly stations with only 500 MW sized units are as stated below:

a) Simhadri TPS
b) Tal Kaniha TPS
c) Rihand TPS

The actual O&M expenses for these stations for FY 2008-09 to FY 2012-13 are as shown below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Simhadri TPS	13.76	12.09	14.42	11.04	13.43
Tal Kaniha TPS	9.25	9.83	12.86	14.99	13.07
Rihand TPS	12.79	13.03	15.42	14.47	14.59

In case of supercritical units of 600 MW and above, as such units were not operational before, therefore for such units five year data is not available.

Apart from these, separate norms were provided for following stations:

a) Talcher TPS
b) Tanda and Chandrapura TPS
c) Badarpur and Durgapur TPS

The actual O&M expenses for these stations are as shown in the table below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Talcher TPS	30.03	32.16	36.62	36.57	42.19
Tanda TPS	27.03	27.91	31.01	27.92	32.20
Badarpur TPS	32.31	35.99	40.75	34.92	39.79
Chandrapura TPS	29.65	28.67	37.50	30.00	NA
Durgapur TPS	26.79	32.64	34.38	37.25	NA

NA- DVC accounts for FY 2012-13 not audited hence four year data considered

All the above stations have smaller sized units and therefore separate norms were provided for them however, most of these station have part of its installed capacity with units size of 210 MW.

Out of the above stations, only Tanda TPS has all small sized units of 110 MW each.

For lignite fired stations the Commission had approved separate norms for NLC TPS-I. The actual expenses are as shown in the table below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
NLC TPS I	26.33	28.25	31.67	31.42	34.73

For Gas based stations other than small gas turbines, the actual O&M expenses are as shown in the table below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Anta	14.63	12.72	16.45	13.79	18.72
Auraiya	10.06	13.71	13.34	12.72	16.65
Kawas	12.28	13.36	14.49	13.44	16.27
Gandhar	11.20	11.86	13.30	15.41	12.33
Faridabad	11.82	10.39	20.35	22.72	14.63
Dadri	9.23	10.41	9.97	10.82	10.06
Kayamkulam	22.52	14.48	26.08	19.45	18.36

For advance class gas power stations, actual normalised O&M expenses of Sugen is as shown below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Sugen	NA	23.48	21.11	21.94	21.53
Ratangiri	12.89	32.01	26.94	19.49	14.43

NA- Plant Commissioned in FY 2009-10

For small gas turbine power generating station and Agartala GPS the actual normalised O&M expenses are as shown in the table below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Assam GPS	20.08	20.86	30.82	29.09	31.39
Agartala GPS	23.61	26.58	32.07	39.51	42.44

B. Hydro Generating Stations

The Commission in its Tariff Regulations, 2009 specified the methodology for approving the O&M norms for hydro generating stations considering the actual O&M expenses based on the audited balance sheet for FY 2003-04 to FY 2007-08. The Commission however, in its Tariff Regulations, 2009 did not specify station wise norms. The Commission however, in this Tariff Regulations proposes to specify the station wise O&M norms for these stations based on the actual normalised O&M expenses. The actual normalised O&M expenses for hydro generating station are as shown below:

Name of Station	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
NHPC Stations					
Bairasul Power Station	35.01	34.13	40.32	43.77	40.84
Loktak Power Station	64.36	69.76	81.14	84.39	68.87
Salal Power Station	14.31	14.72	17.14	18.12	19.48
Tanakpur Power Station	39.76	41.83	51.76	56.07	59.12
Chamera - I Power Station	14.85	14.39	15.40	19.86	18.24
Uri Power Station	9.91	11.16	13.33	16.14	17.25
Rangit Power Station	58.60	55.13	68.37	59.06	66.21
Chamera - II Power Station	14.52	17.31	23.35	28.49	26.51
Dhauliganga Power Station	16.91	19.13	21.94	22.31	22.31
Dulhasti Power Station	15.99	28.24	30.10	35.52	36.38
Teesta- V Power Station	11.42	11.24	13.05	13.75	15.93
Sewa-II Power Station	-	-	35.71	54.84	49.19
Chamera -III Power	-	-	-		

Station				-	24.13
Chutak Power Station	-	-	-	-	24.68
NEEPCO Stations					
KHEP	18.60	23.27	21.21	26.75	28.16
RHEP	10.34	10.92	13.22	14.21	17.47
DHEP	33.97	36.75	42.26	51.77	57.89
Khadong HEP	Data not submitted				
NHDC Stations					
Omkareshwar	5.52	5.69	8.99	9.62	10.71
Indira Sagar	5.46	6.73	7.72	6.66	7.38
SJVNL	11.88	11.87	13.44	15.67	14.81
Tehri	13.47	12.87	20.61	17.56	19.45

12.5 Commission's Proposal

12.5.1 Escalation Rate

The Escalation rate computed based on the five year average WPI and CPI indices for FY 2008-09 to FY 2012-13 considering 60% WPI and 40% CPI works out to 8.35%. The Commission observed that after normalisation the increase in O&M expenses for the period FY 2008-09 to FY 2012-13 was around 5.71% for coal based generating stations of NTPC and around 6.19% for gas based generating stations (excluding Kayamkulam station). In case of Hydro generating station the average increase in normalised O&M expenses for the period FY 2008-09 to FY 2012-13 has been around 6.04% excluding Uri, Chamera II and Dulhasti as the increase in these stations have been considerably higher. Further in some of the stations the escalation factor has been even lesser and in some cases the same is higher. The Commission is therefore of the view that average CPI and WPI indices are an indicator of inflation, however, the average increase in actual normalised O&M expenses for most of the stations is lower than the escalation rate of 8.35%. Therefore, for the purpose of escalation till FY 2013-14 the Commission proposes to consider the escalation rate of 5.72%, 6.19% and 6.04% for coal, gas and hydro generating stations respectively.

12.5.2 The average increase in actual normalised O&M expenses for generating stations is around 6% which is approximately 2.35% lower than the prevailing rate of inflation during the same period. The Commission for the purpose of escalating the norm during the next Tariff Period proposes to consider 2% lesser inflation rate as 6.35% for all generating stations.

a) Determination of Norms

12.5.3 The Commission based on the actual O&M expenses for FY 2008-09 to FY 2012-13 has re-computed the O&M expenses for FY 2012-13 by taking average of five year O&M expenses after escalating annual normalised O&M expenses by 6.35% per annum. O&M expenses thus computed for FY 2012-13 has been escalated further considering 6.35% to arrive at the O&M expenses for FY 2014-15 to FY 2018-19.

12.5.4 The Commission proposes to approve the norms based on the actual O&M expenses incurred after normalisation. The Commission for the purpose of determining norms for 200/210/250 MW unit has considered the O&M expenses for following stations:

a) Unchahar TPS
b) Bokaro TPS
c) NLC TPS – I Expansion
d) NSPCL – Bhilai Extension Plant

12.5.5 The O&M expenses for the above stations are as shown below:

Generating Stations	**FY 2008-09**	**FY 2009-10**	**FY 2010-11**	**FY 2011-12**	**FY 2012-13**	**FY 2012-13**	**FY 2014-15**	**FY 2015-16**	**FY 2016-17**	**FY 2017-18**	**FY 2018-19**
	Actual					**Derived**	**Projected**				
Unchachar TPP	17.98	18.71	22.42	22.60	24.44	23.59	26.53	28.21	30.00	31.91	33.93
NLC TPS I Exp.	13.49	16.47	15.59	19.94	23.23	19.61	22.05	23.45	24.94	26.52	28.20
NLC TPS II	17.46	20.20	20.39	21.56	23.95	23.04	25.91	27.55	29.30	31.16	33.14
Bokaro TPS	17.82	20.43	22.75	26.50	NA	24.96	28.07	29.85	31.74	33.76	35.90
NSPCL Bhilai Ext			14.44	13.06	17.25	15.73	17.79	18.92	20.12	21.40	22.76
Average (200/210/250 MW)	**16.69**	**18.95**	**19.12**	**20.73**	**22.22**	**21.39**	**24.07**	**25.60**	**27.22**	**28.95**	**30.79**

12.5.6 For determining the norms for 500 MW units based on sub critical technology the Commission has considered the following stations:

a) Simhadri STPS
b) Tal Kaniha STPS
c) Rihand TPS

12.5.7 The O&M expenses for the above stations are as shown below:

Generating Stations	FY 2008-09	FY 2009- 10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2012-13	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
	Actual					Derived	Projected				
Simhadri TPS	13.76	12.09	14.42	11.04	13.43	14.54	16.35	17.38	18.49	19.66	20.91
Tal Kaniha TPS	9.25	9.83	12.86	14.99	13.07	13.30	14.95	15.90	16.91	17.98	19.12
Rihand TPS	12.79	13.03	15.42	14.47	14.59	15.70	17.65	18.77	19.97	21.23	22.58
Average (500 MW Sets)	**11.94**	**11.65**	**14.23**	**13.50**	**13.70**	**14.51**	**16.32**	**17.35**	**18.45**	**19.63**	**20.87**

12.5.8 The Commission for determining the O&M expenses for 300/330/350 MW units, in continuation with its earlier approach proposes to consider the average O&M expenses norm for 200/210/250 MW and 500 MW units.

12.5.9 Since historical actual O&M data for super critical technology is not available, the Commission proposes to specify the norms for these stations at slightly lower levels as compared to 500 MW units.

12.5.10 Apart from the above stations the Commission proposes to approve norms for stations having smaller sized units. The Commission based on the actual normalised O&M expenses has determined the O&M expenses.

12.5.11 For stations with 100/110/130/140 MW units the Commission proposes to approve norm based on the actual performance of the plant. Since Tanda TPS comprises of only 110 MW units the actual normalised O&M expenses has been considered for approving norms for similar sized units.

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2012-13	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
	Actual					Derived	Projected				
Talcher TPS	30.03	32.16	36.62	36.57	42.19	39.46	44.37	47.18	50.18	53.37	56.75
Tanda TPS	27.03	27.91	31.01	27.92	32.20	32.62	36.68	39.01	41.49	44.12	46.92

12.5.12The norms for Tanda TPS shall be applicable for smaller sized units of Badarpur TPS, Chandrapura TPS, Durgapur TPS.

12.5.13For NLC TPS I the Commission proposes to approve the norms based on the actual O&M expenses incurred and for 125 MW lignite fired station the Commission proposes to approve the norm based on the actual O&M expenses incurred for Barsingsar TPS for FY 2012-13 which is as shown below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2012-13	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
	Actual					Derived	Projected				
NLC TPS I	26.33	28.25	31.67	31.42	34.73	33.92	38.14	40.56	43.14	45.88	48.79
125 MW sets					25.90	25.90	29.12	30.97	32.94	35.03	37.25

12.5.14The Commission for generating stations based on coal rejects proposes to approve the norm for O&M expenses as approved for 125 MW lignite fired stations.

12.5.15The Commission for determining norms for gas based stations has considered all the gas based generating stations of NTPC for determination of O&M expenses for FY 2014-15 to FY 2018-19 except for Kayamkulam Station as the O&M expenses for the same is considerably higher than the other stations.

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2012-13	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
	Actual					Derived	Projected				
Anta GPS	14.63	12.72	16.45	13.79	18.72	17.15	19.37	20.60	21.91	23.30	24.78
Auraiya	10.06	13.71	13.34	12.72	16.65	14.88	16.81	17.88	19.01	20.22	21.50
Kawas	12.28	13.36	14.49	13.44	16.27	15.70	17.73	18.86	20.05	21.33	22.68
Gandhar	11.20	11.86	13.30	15.41	12.33	14.43	16.29	17.33	18.43	19.60	20.84
Faridabad	11.82	10.39	20.35	22.72	14.63	17.83	20.14	21.42	22.78	24.22	25.76
Dadri GPS	9.23	10.41	9.97	10.82	10.06	11.40	12.87	13.69	14.56	15.49	16.47
Kayamkulam	22.52	14.48	26.08	19.45	18.36	22.88	25.84	27.48	29.22	31.08	33.05

12.5.16 For determining the norms for gas based advance F Class machines the Commission has considered the O&M expenses for Sugen power plant which is as shown below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2012-13	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
	Actual					Derived	Projected				
Sugen	NA	23.48	21.11	21.94	21.53	24.19	25.72	27.36	29.09	30.94	32.91
Ratnagiri	12.89	32.01	26.94	19.49	14.43	24.04	27.15	28.88	30.71	32.66	34.73

12.5.17 For small gas turbine stations the Commission has considered Assam GPS for determination of O&M norms and for Agartala Gas based stations the Commission has considered the actual normalised O&M expenses for FY 2008-09 to FY 2012-13.

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2012-13	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
	Actual					Derived	Projected				
Assam GPS	20.08	20.86	30.82	29.09	31.39	29.51	33.33	35.44	37.69	40.09	42.63
Agartala GPS	23.61	26.58	32.07	39.51	42.44	36.48	41.20	43.82	46.60	49.56	52.70

For the Hydro Generating Station which has completed more than three years of operation after COD as on 01.04.2013 the O&M expenses is as shown below:

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2012-13	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
	Actual					Derived	Projected				
NHPC Stations											
Bairasul	35.01	34.13	40.32	43.77	40.84	43.51	48.97	52.08	55.39	58.90	62.64
Loktak	64.36	69.76	85.25	89.50	68.87	82.83	93.25	99.17	105.47	112.17	119.29
Salal	14.31	14.72	17.14	18.12	19.48	18.72	21.08	22.41	23.84	25.35	26.96
Tanakpur	39.76	41.83	51.76	56.07	59.12	55.38	62.35	66.31	70.52	75.00	79.76
Chamera - I	14.85	14.39	15.40	19.86	18.24	18.51	20.83	22.16	23.56	25.06	26.65
Uri	9.91	11.16	13.33	16.14	17.25	15.04	16.93	18.01	19.15	20.37	21.66

Generating Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2012-13	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
	Actual					Derived	Projected				
Rangit	58.60	55.13	68.37	59.06	66.21	69.11	77.77	82.71	87.97	93.55	99.49
Chamera - II	14.52	17.31	23.35	28.49	26.51	24.39	27.47	29.22	31.07	33.05	35.15
Dhauliganga	16.91	19.13	21.94	22.31	22.31	22.97	25.86	27.50	29.24	31.10	33.08
Dulhasti	15.99	28.24	30.10	35.52	36.38	31.29	35.26	37.50	39.88	42.41	45.11
Teesta- V	11.42	11.24	13.05	13.75	15.93	14.60	16.44	17.48	18.59	19.77	21.03
Sewa-II	-	-	35.71	54.84	49.19	49.17	55.43	58.95	62.69	66.67	70.91
KHEP	18.60	23.27	21.21	26.75	28.16	26.33	29.69	31.58	33.58	35.71	37.65
RHEP	10.34	10.92	13.22	14.21	17.47	14.70	16.58	17.63	18.75	19.94	21.03
DHEP	33.97	36.75	42.26	51.77	57.89	49.41	55.72	59.26	63.03	67.03	71.28
Khadong	Data not submitted considered for DHEP as both have same size turbines.						55.72	59.26	63.03	67.03	71.28
NHDC Stations											
Omkareshwar	5.52	5.69	8.99	9.62	10.71	8.96	10.10	10.74	11.42	12.15	12.92
Indira Sagar	5.46	6.73	7.72	6.66	7.38	13.13	14.81	15.75	16.75	17.82	18.95
SJVNL	11.88	11.87	13.44	15.67	14.81	15.14	17.08	18.16	19.32	20.54	21.85
Tehri	13.47	12.87	20.61	17.56	19.45	18.73	21.12	22.46	23.88	25.40	27.01

12.5.18The Commission with regards to the O&M expenses incurred by some of the Hydro generating stations observed that the Man/MW ratio of these generating stations is very high as compared to the rest of the generating stations. The Man/MW ratio of various hydro generating stations for comparison purpose is as shown below:

Station	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Bairasul Power Station	3.01	2.85	2.72	2.60	2.48
Loktak Power Station	6.35	6.14	5.41	4.89	4.41
Salal Power Station	1.30	1.29	1.31	1.28	1.25
Tanakpur Power Station	4.11	4.15	4.09	4.29	4.29
Chamera - I Power Station	0.96	0.88	0.84	0.80	0.72
Uri Power Station	0.62	0.61	0.60	0.55	0.55
Rangit Power Station	3.48	3.27	3.20	3.17	2.90

Station	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Chamera - II Power Station	1.24	1.25	1.24	1.13	1.10
Dahuliganga Power Station	1.28	1.24	1.21	1.20	1.03
Dulhasti Power Station	1.40	1.34	1.30	1.30	1.23
Teesta- V Power Station	0.80	0.64	0.61	0.58	0.58
SJVNL	0.56	0.54	0.54	0.54	0.52
DHEP	4.13	4.24	4.12	4.06	4.05
Khandong Kopili Kopili II	1.64	1.57	1.49	1.40	1.36
RHEP	1.04	1.04	1.02	0.98	0.92
Omkareshwar	0.38	0.37	0.37	0.38	0.38
Indirasagar	0.32	0.31	0.33	0.33	0.32

12.5.19 As seen from above in some of the stations the Man/MW ratio is even higher than 2. The Commission though for the next tariff period proposes to approve the norm for these stations on the basis of actual incurred during FY 2008-09 to FY 2012-13. However, the Commission directs the generating companies to reduce the man/mw ratio to 2.5/MW for all the generating station having man/mw ratio above 2.5.

12.5.20 For new generating stations the Commission proposes to continue with the current norms prescribed in Tariff Regulations, 2009.

12.5.21 The Commission with regards to compensatory allowance proposes to revise the norms by escalating the current norms by an escalation factor of 8.35%.

12.6 Proposed Norms

(1) Normative Operation and Maintenance expenses of thermal generating station shall be as follows:

(a) Coal based and lignite fired (including those based on CFBC technology) generating stations, other than the generating stations/units referred to in clauses(b) and (d):

(Rs. lakh/MW)

Year	200/210/250 MW Sets	300/330/350 MW Sets	500 MW Sets	600 MW Sets and above
FY 2014-15	24.07	20.19	16.32	14.68
FY 2015-16	25.60	21.47	17.35	15.61
FY 2016-17	27.22	22.84	18.45	16.60
FY 2017-18	28.95	24.29	19.63	17.66
FY 2018-19	30.79	25.83	20.87	18.78

Provided that the norms shall be multiplied by the following factors for arriving at norms of O&M expenses for additional units in respective unit sizes for the units whose COD occurs on or after 1.4.2014 in the same station:

200/210/250 MW	Additional 5th& 6th units	0.90
	Additional 7th& more units	0.85
300/330/350 MW	Additional 4th& 5th units	0.90
	Additional 6th& more units	0.85
500 MW and above	Additional 3rd& 4th units	0.90
	Additional 5th& above units	0.85

(b) Talcher Thermal Power Station(TPS), Tanda TPS, Badarpur TPS Unit 1 to 3of NTPC and, Chandrapura TPS Unit 1 to 3and Durgapur TPS Unit 1 of DVC:

(Rs. lakh/MW)

Year	**Talcher TPS**	**Chandrapura TPS (Units 1 to 3), Tanda TPS, Badarpur (Unit 1 to 3) , Durgapur TPS (Unit 1)**
2014-15	44.37	36.68
2015-16	47.18	39.01
2016-17	50.18	41.49
2017-18	53.37	44.12
2018-19	56.75	46.92

(c) Open Cycle Gas Turbine/Combined Cycle generating stations.

(Rs. lakh/MW)

Year	Gas Turbine/ Combined Cycle generating stations other than small gas turbine power generating stations	Small gas turbine power generating stations	Agartala GPS	Advance F Class Machines
2014-15	16.77	33.33	41.20	25.72
2015-16	17.83	35.44	43.82	27.36
2016-17	18.97	37.69	46.60	29.09
2017-18	20.17	40.09	49.56	30.94
2018-19	21.45	42.63	52.70	32.91

(d) Lignite-fired generating stations

(Rs. lakh/MW)

Year	125 MW Sets	TPS-I of NLC
2014-15	29.12	38.14
2015-16	30.97	40.56
2016-17	32.94	43.14
2017-18	35.03	45.88
2018-19	37.25	48.79

(e) Generating Stations based on coal rejects

Year	O&M Expenses (Rs Lakh/MW)
2014-15	29.12
2015-16	30.97
2016-17	32.94
2017-18	35.03
2018-19	37.25

(2) Hydro Generating Station

(a) Following operations and maintenance norms shall be applicable for hydro generating stations which have been operational for three or more years as on

March 31, 2013.

Sr. No	Name of Station	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
A.	**NHPC**					
1	Bairasul Power Station	49.07	52.18	55.50	59.02	62.77
2	Loktak Power Station	93.41	99.34	105.65	112.36	119.49
3	Salal Power Station	21.12	22.46	23.88	25.40	27.01
4	Tanakpur Power Station	62.46	66.43	70.64	75.13	79.90
5	Chamera - I Power Station	20.88	22.20	23.61	25.11	26.70
6	Uri Power Station	16.96	18.04	19.18	20.40	21.70
7	Rangit Power Station	77.94	82.89	88.15	93.75	99.70
8	Chamera - II Power Station	27.51	29.26	31.12	33.09	35.19
9	Dhauliganga Power Station	25.90	27.54	29.29	31.15	33.13
10	Dulhasti Power Station	35.29	37.53	39.91	42.45	45.14
11	Teesta- V Power Station	16.47	17.52	18.63	19.81	21.07
12	Sewa-II Power Station	55.45	58.97	62.71	66.69	70.93
B.	**THDC**	21.12	22.46	23.88	25.40	27.01
C.	**SJVNL**	17.08	18.16	19.32	20.54	21.85
D.	**NHDC**					
1	Indira Sagar Power Station	14.81	15.75	16.75	17.82	18.95
2	Omkareshwar Power Station	10.10	10.74	11.42	12.15	12.92
E.	**NEEPCO**					
1	KHEP	29.69	31.58	33.58	35.71	37.98
2	Rangadi HEP	16.58	17.63	18.75	19.94	21.21
3	Doyang HEP	55.72	59.26	63.03	67.03	71.28
4	Khadong	55.72	59.26	63.03	67.03	71.28

(b) In case of the hydro generating stations, which have not been in commercial operation for a period of three years as on 1.4.2013, operation and maintenance expenses shall be fixed at 2% of the original project cost (excluding cost of rehabilitation & resettlement works) for the first year of commercial operation. Further, in such case, operation and maintenance expenses in first year of commercial operation shall be escalated @ 6.04% per annum up to the year 2013-14 and then averaged to arrive at the O&M expenses at 2013-14 price level. It shall be thereafter escalated @ 6.35 %per annum to arrive at operation and maintenance expenses in respective year of the tariff period.

(c) In case of the hydro generating stations declared under commercial operation on or after 1.4.2014, operation and maintenance expenses shall be fixed at 2% of the original project cost (excluding cost of rehabilitation & resettlement works) for first year of commercial operation and shall be subject to annual escalation of 6.35% per annum for the subsequent years.

The above norms of O&M expenses for thermal and hydro generating stations are excluding Water Charges. Water charges as applicable shall be allowed separately.

13 O&M Expenses for Transmission

13.1 Background

13.1.1 In order to facilitate the process of finalization of terms and conditions of tariff, the Commission vide its Order dated 7 June, 2013 directed the transmission licensees namely POWERGRID, Powerlinks Transmission Ltd., Torrent Powergrid Pvt. Ltd., Jindal Power Ltd. and other transmission licensees to furnish details of actual performance/operational data and O&M expenses for the period from FY 2008-09 to FY 2012-13 in respect of their transmission systems as per the prescribed formats. In response, the POWERGRID, Powerlinks Transmission Limited, Torrent Power Grid Limited, Jindal Power Ltd., Rajasthan Rajya Vidyut Prasaran Nigam Limited and Delhi Transco Limited have submitted the information.

13.1.2 During finalization of the norms for O&M expenses for the transmission system for the Tariff Period 2009-14, in view of the comments from the stakeholders, the Commission reconsidered the methodology proposed in the Explanatory Memorandum for draft Regulations and adopted revised methodology. As per the said revised methodology, the gradation of O&M expenses was done on the basis of the voltage for sub-stations and on per km basis with additional gradation based on circuit configuration for AC and HVDC lines. For lines, gradation was done on the basis of sub-conductor.

13.1.3 CEA is yet to make recommendations relating to operating norms and analysis of existing operational norms for transmission system. In the absence of CEA recommendations, the Commission is proceeding on its own based on the data available with the Commission. Necessary corrections, if considered necessary, could be effected as and when recommendations of CEA are received.

13.2 Existing provisions

13.2.1 After following due regulatory process, the Commission finalized the norms for O&M expenses for the transmission system for the Tariff Period 2009-14. The relevant extract of CERC (Terms and Conditions of Tariff) Regulations, 2009 is reproduced below:

"19. Operation and Maintenance Expenses: Normative operation and maintenance expenses shall be as follows:

….

(g) Transmission System

(i) Norms for operation and maintenance expenses shall be as under:

Norms for O&M expenditure for Transmission System

Norms for sub-station (Rs Lakh per bay)	***2009-10***	***2010-11***	***2011-12***	***2012-13***	***2013-14***
765 kV	*73.36*	*77.56*	*81.99*	*86.68*	*91.64*
400 kV	*52.40*	*55.40*	*58.57*	*61.92*	*65.46*
220 kV	*36.68*	*38.78*	*41.00*	*43.34*	*45.82*
132 kV and below	*26.20*	*27.70*	*29.28*	*30.96*	*32.73*
Norms for AC and HVDC lines (Rs Lakh per km)					
Single Circuit (Bundled Conductor with four or more sub-conductors)	*0.537*	*0.568*	*0.600*	*0.635*	*0.671*
Single Circuit (Twin & Triple Conductor)	*0.358*	*0.378*	*0.400*	*0.423*	*0.447*
Single Circuit (Single Conductor)	*0.179*	*0.189*	*0.200*	*0.212*	*0.224*
Double Circuit (Bundled conductor with four or more sub-conductors)	*0.940*	*0.994*	*1.051*	*1.111*	*1.174*
Double Circuit (Twin & Triple Conductor)	*0.627*	*0.663*	*0.701*	*0.741*	*0.783*
Double Circuit (Single Conductor)	*0.269*	*0.284*	*0.301*	*0.318*	*0.336*
Norms for HVDC Stations					

HVDC Back–to-back stations (Rs Lakh per 500 MW)	*443.00*	*468.00*	*495.00*	*523.00*	*553.00*
Rihand-Dadri HVDC bipole scheme (Rs Lakh)	*1450.00*	*1533.00*	*1621.00*	*1713.00*	*1811.00*
Talcher- Kolar HVDC bipole scheme (Rs. Lakh)	*1699.00*	*1796.00*	*1899.00*	*2008.00*	*2122.00*

(ii)The total allowable operation and maintenance expenses for the transmission system shall be calculated by multiplying the number of bays and kms of line length with the applicable norms for the operation and maintenance expenses per bay and per km respectively."

13.3 Issues brought out in Approach Paper

13.3.1 The Commission in its Approach Paper invited comments and suggestions from the stakeholders on the following issues:

a) *Comments on adequacy of the existing O&M norms with regard to the O&M requirement and resultant cash flows. Whether to review the existing O&M norms? (To be viewed in the context of availability of margins.)*

b) *Comments on CERC O&M norms as compared to similar norms set by SERCs. Is the variation in CERC norms justified for reasons like better performance in terms of higher availability etc.?*

c) *Comments on the requirement of mid-term review of normative O&M cost. How to deal with variations in O&M cost during the tariff period? Is there a need for introduction of truing up after specifying normative parameters?*

d) *Methodologies to determine escalation factor for determining O&M cost. In case escalation factor is determined based on WPI & CPI indexation, the weightage of WPI & CPI to determine the escalation rate. What would be the escalation rate for normative O&M on year on year basis based on the methodologies suggested?*

e) *Suggestions on development of a model for specifying the O&M norms which reflects optimum operational efficiency? Whether to introduce the concept of RPI-X for the limited purpose of O&M as discussed in above para 3.10.2(ii).*

f) *Treatment of income from other business and other income like interest on deposits, advances etc. while arriving at the O&M cost? Further, treatment of offsetting revenues generated out of telecom business (by way of laying optical fibre composite overhead ground wire) from annual transmission charges. Suggestion on treatment of license fees, taxes and duties.*

13.4 Stakeholders Responses (Transmission)

13.4.1 The extracts of the suggestions pertaining to O&M Expenses in respect of transmission system received from various stakeholders on the issues flagged above are as follows:

1. POWERGRID submitted that:
   a. The existing methodology for working out the normative O&M expenses appears to be appropriate and there is no need of mid-term review of normative O&M expenses. However, the Regulations should be flexible to allow the Utilities to approach the Commission for consideration of any one time/recurring expense that was/could not be envisaged at the start of the Tariff Period.
   b. As regards norms for different transmission elements, POWERGRID submitted that
      - The O&M norms for D/C transmission lines should be double as compared to that for S/C transmission lines.
      - The O&M norms for HVDC substation are station-specific in the existing Regulations. In the absence of norms for newly added sub-stations, difficulties are being faced in claiming O&M expenses. It proposed that the Commission may specify O&M norms for generic nature of HVDC sub-stations based on sub-station capacities and voltage class.

- AC lines with Hexagonal/Octagonal conductor configuration are likely to be commissioned during the Tariff Period 2014-19. O&M expenses for the same needs to be discussed while deciding the tariff norms.

c. The geographies and the voltage level of POWERGRID assets and State Transmission Utilities (STU) assets grossly differ. Therefore, O&M norms specified by SERC for STU's cannot be compared with those issued by CERC.

d. Regulations should provide for pass through of pay revision impact at the time of truing up in the subsequent year as and when the decision of a pay revision is finalized. Pay revision impact should be considered retrospectively from the year from which such an increase is proposed.

e. As regards concept of RPI-X, given the nature of CPSUs, it may be difficult to reduce the normative O&M expenses and it may be imprudent to make such framework, which increases the risks towards recovery of legitimate expenses despite the fact that the Utilities have been able to achieve the performance parameters set by the Commission.

f. As regards treatment of income from other business and other income while arriving at the O&M cost, POWERGRID submitted that these should be allowed as pass through. Further, the licensees should be allowed to retain the non-tariff income.

2. Electrical Power Transmission Association submitted that normative O&M expenses need to be reviewed on a regular or annual basis. Further, the same should be determined and reviewed on the basis of data obtained for all projects in the country and not solely on the basis of estimates provided by PGCIL.
3. One Discom submitted that the concept of offsetting of revenues of telecom business from annual transmission charges needs to be reviewed, if the investment in telecom business is made out of depreciation recovered in excess of loan amount.

13.5 Analysis of Actual O&M Expenses and Commission's Proposal

13.5.1 The actual regional O&M expenses as submitted by POWERGRID are given in the following table:

Table: Actual Regional O&M expenses as submitted by POWERGRID

(Rs. Lakh)

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
NR	31187.19	39971.82	40047.58	49267.90	54647.73
WR	14332.39	20262.91	22843.77	27753.97	35435.51
ER	14510.68	19324.65	20376.71	24768.76	27605.50
SR	20562.71	25526.93	29642.30	31990.07	30409.75
NER	7990.22	10418.91	10757.64	11734.02	13856.36
Total	**88,583.18**	**11,5505.22**	**1,23,667.99**	**1,45,514.72**	**1,61,954.85**

Table: HVDC- Actual Regional O&M expenses as submitted by POWERGRID

(Rs. Lakh)

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Rihand	319.11	2956.51	394.68	476.69	595.07
Dadri	656.32	735.00	527.97	992.63	948.97
Bhiwadi Balia	0.00	0.97	759.73	1308.48	1426.16
Vindhyachal BTB	241.85	370.95	438.51	540.03	553.76
Chandrapur BTB	771.98	782.23	2128.66	1620.23	1279.86
Sasaram BTB	422.24	538.38	443.73	724.84	692.79
Gazuwaka BTB	1560.59	1829.69	2222.79	2295.37	1918.20
Talcher	344.43	301.89	517.01	539.54	545.13
Kolar	424.87	309.87	623.43	578.93	539.75
Total	**4741.39**	**7825.48**	**8056.51**	**9076.73**	**8499.69**

13.5.2 The actual regional O&M expenses as submitted by **Powerlinks Transmission Limited (PTL)** are given in the following tables:

Table: Actual Regional O&M expenses as submitted by PTL (Rs. Lakh)

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
NR	542.63	532.32	621.09	610.19	812.47
ER	414.10	400.43	510.85	496.52	894.84
Total	956.73	932.75	1131.94	1106.71	1707.31

Table: Ckt-km of AC lines

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Quad ACSR	1318.02	1318.02	1318.02	1318.02	1318.02
Twin ACSR/AACSR	965.456	965.456	965.456	965.456	965.456
Single ACSR	48.10	48.10	48.10	48.10	48.10

13.5.3 Major part of the **Powerlinks Transmission Limited (PTL)** system is in the form of 400 kV D/C lines. Further, PTL is a single project company with a project which is unidirectional.

13.5.4 **Torrent Power Grid Limited (TPGL)** system consists of 400 kV transmission lines and 2 no. of 400 kV bays. The actual O&M expenses as submitted by TPGCL are given in the table below:

Table: Actual O&M expenses as submitted by TPGL (Rs. Lakh)

FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
72.68	26.65	86.96	241.05	181.98

Table: Number of AC sub-station bays

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
400 kV	-	-	-	2	2

Table: Ckt-km of AC lines

	01.04.09	01.04.10	01.04.11	01.04.12	01.04.13
Twin ACSR	28.80	188.40	479.25	479.25	479.25

13.5.5 **Jindal Power Limited** (JPL) system consists of 400 kV transmission lines and 4 no. of 400 kV bays and 2 no. of 220 kV bays. JPL has submitted details for FY 2011-12 and FY 2012-13. The actual O&M expenses as submitted by JPL are given in the table below:

Table: Actual Regional O&M expenses as submitted by JPL (Rs. Lakh)

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
WR	-	-	-	541.90	536.97

Table: Number of AC sub-station bays

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
400 kV	-	-	-	4	4
220 kV	-	-	-	2	2

Table: Ckt-km of AC lines

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Twin ACSR	-	-	-	516.80	516.80

13.5.6 Rajasthan Rajya Vidyut Prasaran Nigam Ltd. and Delhi Transco Ltd. (DTL) have also submitted the details of O&M expenses and certain transmission system parameters. The Commission appreciates the efforts undertaken by these Utilities for submitting the information. However, it is observed that information furnished is insufficient for carrying out the proper analysis, as the details such as length of transmission lines by conductor configuration and numbers of substation bays in commercial operation have not been provided.

13.5.7 For analysing the O&M expenses, the first step is normalization of O&M expenditure. The normalization has been done in the following manner:

(i) Electricity charges have been apportioned in the ratio of electricity consumption in the sub-station and that in the colony. Only the former has been considered for the process of normalization since colony consumption cannot be considered.

(ii) Donations, ex-gratia, productivity linked incentives and Performance Related Pay have been taken out, since such expenses are not allowable expenses.

(iii) Filing fees have not been considered since the same are being allowed separately.

(iv) Expenditure on Corporate Social Responsibility (CSR) has not been considered, since such expenses are not allowable expenses.

(v) Prior period adjustments have been taken out.

(vi) Abnormal security expenses separately furnished by POWERGRID on deployment of special security have not been considered.

(vii) Normalised O&M expenditure for HVDC stations have been obtained by applying the ratio of regional normalized expenditure to regional actual expenditure of the relevant region. In case of Rihand HVDC station, there was steep increase in O&M expenditure during FY 2009-10. Similar steep increase was observed in the expenses for Chandrapur BTB station during FY 2010-11 and FY 2011-12 and Sararam BTB for FY 2011-12. Since, it is not normal to have so much expenditure in a single year, for the process of normalization, the O&M expenses for these stations have been restricted to 120% of the previous year. This normalization at HVDC Station is reflected in the total O&M expense for respective regional O&M expenses as well.

13.5.8 The normalised expenditure in respect of transmission system of POWERGRID for various regions is given in the following table:

Normalised Regional O&M expenditure in respect of POWERGRID Transmission System

(Rs. Lakh)

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
NR	28739.86	36806.60	36865.97	45905.70	49730.28
WR	12843.35	16262.94	21022.49	25561.65	33173.74
ER	13000.83	16170.80	18741.62	22967.75	24520.08
SR	18435.61	22661.43	27590.70	29441.02	27880.88
NER	7094.24	9111.00	10215.50	10701.78	11945.80
Total	**80,113.89**	**1,01,012.78**	**1,14,436.27**	**1,34,577.89**	**1,47,250.78**

Normalised Regional O&M expenditure in respect of POWERGRID Transmission System (excluding HVDC stations)

(Rs. Lakh)

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
NR	27618.11	35434.45	34913.58	42814.29	46523.42
WR	12151.57	15635.13	20269.11	24657.59	31975.57
ER	12622.52	15720.29	18333.49	22477.99	23904.72
SR	16346.74	20494.05	24460.25	26299.20	25127.54
NER	7094.24	9111.00	10215.50	10701.78	11945.80
Total	**75,833.17**	**96,394.91**	**1,08,191.92**	**1,26,950.86**	**1,39,477.06**

13.5.9 As regards details of network parameters, since information for the period from 1st April, 2009 to 1st April, 2013 is available, average values for a year have been calculated by taking average of respective values as on 1st April of two consecutive years except for FY 2008-09, for which the values as on 1 April, 2009 have been used. The tables below give details of the average number of AC sub-station bays and average ckt-kms of AC and HVDC lines in commercial operation.

13.5.10 In case of transmission lines, the existing norms are based on per km basis with additional gradation based on circuit configuration. In continuation with the present approach, S/C twin conductor ckt-kms have been used as base and ckt-kms of all other circuit and conductor configuration have been converted to equivalent ckt-kms of S/C twin conductor ckt-km. Further, in continuation with the present approach no differentiation has been made between triple and twin conductor for same circuit configuration. Weightage factor for conversion have been used based on our estimate of ration of O&M expenditure for a particular conductor and circuit configuration vis-à-vis S/C twin conductor. The weightage factor for a bundled conductor with four or more conductors is taken as 1.5 and that for single conductor it is taken as 0.5. Additionally, ratio between O&M expenditure of 1 km of D/C line is estimated to be 1.5 time that of 1 km of S/C lime for single conductor and 1.75 time of 1 km of S/C for bundled conductor.

13.5.11 In line with existing Regulations, voltage has been retained as the basis for gradation of norms for O&M expenditure for sub-station. However, bays at various voltage levels have been converted to equivalent 400 kV bays. The weightage factors for such conversion are considered in line with the approach followed in the present regulations. Tables below give details of number of bays and ckt-kms based on the gradation and equivalent 400 kV bays and equivalent S/C twin conductor ckt-kms.

Table: Number of AC sub-station bays

	Actual average no. of bays in commercial operation					W.F.	Eq. No. of bays (400 KV) in commercial operation				
	FY 09	FY 10	FY 11	FY 12	FY 13		FY 09	FY 10	FY 11	FY 12	FY 13
765 kV	6	6	6	24.5	83.5	1.4	8.4	8.4	8.4	34.3	116.9
400 kV	870	901	987.5	1155.5	1368.5	1	870	901	987.5	1155.5	1368.5
220 kV	464	481	534	626.5	722.5	0.7	324.8	336.7	373.8	438.55	505.75
Upto 132 kV	106	109	119	128	144.5	0.5	53	54.5	59.5	64	72.25
Total	**1446**	**1497**	**1647**	**1935**	**2319**		**1256**	**1301**	**1429**	**1692**	**2063**

Table: Ckt-km of AC and HVDC lines

	Actual average ckt km in operation					Weightage	Equivalent ckt-km (twin conductor) in operation				
	FY 09	FY 10	FY 11	FY 12	FY 13	Factor	FY 09	FY 10	FY 11	FY 12	FY 13
S/C Quad	2460.57	2723.42	3047.32	4119.78	5498.17	1.500	3690.85	4085.12	4570.98	6179.68	8247.26
S/C Triple	0.00	0.00	2.81	3.98	2.35	1.000	0.00	0.00	2.81	3.98	2.35
S/C Twin	17503.93	17506.38	17609.95	17795.98	17858.51	1.000	17503.93	17506.38	17609.95	17795.98	17858.51
S/C Single	1184.07	1238.93	1254.56	1199.69	1184.07	0.500	592.03	619.47	627.28	599.85	592.03
D/C Quad	7359.38	7452.07	8737.17	10859.05	12898.93	1.313	9662.86	9784.57	11471.91	14257.94	16936.30
D/C Triple	1566.26	1566.26	1765.16	2757.43	3887.55	0.875	1370.48	1370.48	1544.52	2412.75	3401.60
D/C Twin	34154.13	35878.99	39331.30	43290.01	46919.81	0.875	29884.86	31394.12	34414.88	37878.76	41054.84
D/C Single	7215.15	7215.15	7323.89	7665.89	8058.31	0.375	2705.68	2705.68	2746.46	2874.71	3021.87
M/C Quad	0.00	6.75	17.24	20.99	20.99	1.152	0.00	7.77	19.86	24.18	24.18
M/C Twin	0.00	0.00	81.34	242.07	333.36	0.767	0.00	0.00	62.39	185.67	255.69
Total	**71443.47**	**73587.95**	**79170.73**	**87954.88**	**96662.05**		**65410.69**	**67473.60**	**73071.03**	**82213.49**	**91394.62**

13.5.12 The growth in the number of substation bays and transmission lines during the period from FY 2008-09 to FY 2012-13 is evident from Table above. The number of bays has increased from 1256 in FY 2008-09 to 2063 in FY 2012-13 and the CAGR of increase in bays works out to 13.21%. While, the transmission line length has increased from 65410 equivalent ckt-km in FY 2008-09 to 91394 equivalent ckt-km in FY 2012-13 and the CAGR of increase in transmission lines works out to around 8.72%. Thus, the number of bays has increased in higher proportion as compared to transmission lines.

13.5.13 The normalized O&M expenses for HVDC stations of the region concerned were deducted from the overall region-wise normalized expenses. The resulting values represent normalized expenses for AC sub-stations and transmission lines (AC as well as DC) for FY 2008-09 to FY 2012-13.

Table: CAGR of increase in O&M expenses for the period FY 2008-09 to FY 2012-13

		FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
A	Total **Normalized** O&M Expenses	75833.17	96394.91	108191.92	126950.86	139477.06
B	Normalized O&M expenses allocated to S/S (70% of A)	53083	67476	75734	88866	97634
C	Equivalent No. of sub-station bays	1256	1301	1429	1692	2063
D	**O&M expenditure per equivalent (400 kV) AC bay**	42.26	51.88	52.99	52.51	47.32
	CAGR (FY 2008-09 to FY 2012-13)					**2.87%**
E	Normalized O&M expenses allocated to AC and HVDC lines (30% of A)	22749.95	28918.47	32457.58	38085.26	41843.12
F	Equivalent ckt-km in commercial operation	65410.69	67473.60	73071.03	82213.49	91394.62
G	**O&M expenditure per equivalent (S/C. twin conductor) ckt-km**	0.348	0.429	0.444	0.463	0.458
	CAGR (FY 2008-09 to FY 2012-13)					**7.11%**

13.5.14Considering normalisation in O&M expenses and the apportioning of such normalised O&M expenses between sub-stations and transmission lines (AC and HVDC lines) in 70:30 ratio, CAGR of O&M expenses per equivalent (400 kV) AC bay for the period FY 2008-09 to FY 2012-13 works out to around 2.87% and CAGR of O&M expenses per equivalent (S/C twin conductor) for the period FY 2008-09 to FY 2012-13 works out to 7.11%. By applying the same ratio of 70:30 between sub-stations and transmission lines, the effective CAGR of increase in O&M expenses for the period FY 2008-09 to FY 2012-13 works out to 4.14%.

13.5.15As discussed in above para, though over the period there is increase in no. of substation bays and in transmission lines, the increase in substation bays is much higher than the increase in transmission lines. In order to capture such trend of increase in substation bays and lines in the composition of proposed O&M expenses norms, for the purpose of arriving at norms, it has been decided that total O&M expenses shall be apportioned between sub-stations and transmission lines (AC and HVDC lines) in the ratio of 75:25 instead of 70:30.

13.5.16POWERGRID has submitted the actual number of employees engaged in O&M of Sub-station and Transmission lines for various regions. In order to analyse trend of manpower per bay and manpower per km of line length, employees per equivalent (400 kV bay) and employees per equivalent (single ckt-Twin conductor) 100 ckt-km have been derived. Employees per equivalent (400 kV bay) has been reduced from 2.45 to 1.51 during FY 2008-09 to FY 2012-13. Further, employees per equivalent (single ckt-Twin conductor) 100 ckt-km has been reduced from 1.67 to 1.44. It is proposed that the O&M expenditure considered for formulating norms shall be arrived at from the normalised O&M expenditure by adjusting the employee cost for the period FY 2008-09 to FY 2011-12 by keeping manpower per ckt-km and per bay at the same level as in FY 2012-13.

Table: Number of employees engaged in O&M substation of as submitted by POWERGRID

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
NR	970	1036	1057	1103	1114
WR	400	420	441	519	521
ER	806	817	787	695	688
SR	540	551	592	608	536
NER	356	322	257	245	249
Total	**3072**	**3145**	**3133**	**3170**	**3107**
Equivalent (400 kV) no. of bays	1256.20	1300.60	1429.20	1692.35	2063.40
Employees per Equivalent (400 kV) bay	2.45	2.42	2.19	1.87	1.51
Ratio of Employees per Equivalent (400 kV) bay w.r.t. FY 2012-13	1.62	1.61	1.46	1.24	1.00
Factor for considering employees cost at the FY 2012-13 level	0.62	0.62	0.69	0.80	1.00

Table: Number of employees engaged in O&M of transmission lines as submitted by POWERGRID

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
NR	384	448	407	407	447
WR	214	243	266	315	343
ER	144	150	143	149	140
SR	260	254	273	312	287
NER	90	90	105	110	92
Total	**1092**	**1184**	**1193**	**1293**	**1308**
Equivalent (single ckt-	65410.69	67473.60	73071.03	82213.49	91394.62

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
twin conductor)					
Employees per equivalent (single ckt-Twin conductor) 100 ckt-km	**1.67**	**1.75**	**1.63**	**1.57**	**1.43**
Ratio of Employees per equivalent (single ckt-Twin conductor) 100 ckt-km w.r.t FY 2012-13	1.17	1.23	1.14	1.10	1.00
Factor for considering employees cost at the FY 2012-13 level	0.86	0.82	0.88	0.91	1.00

13.5.17Following table shows the process of arriving at the average O&M expenditure per equivalent 400 kV bay and average O&M expenditure per equivalent ckt-km of S/C twin at 2012-13 price level. Allocated O&M expenses have been adjusted for employee costs as discussed above. Such adjusted normalised O&M expenses for FY 2008-09 to FY 2011-12 have been escalated to FY 2012-13 level at the escalation rate of 4.14% per annum And O&M expenditure per equivalent (400 kV) AC bay and O&M expenditure per equivalent (S/C. twin conductor) ckt-km has been derived. Average of such values serves as the base at FY 2012-13 price level.

Table: O&M expenses per equivalent (400 kV) bay and per equivalent (single ckt-twin conductor) ckt-km

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Average
Total actual Normalized O&M Expenses (Rs. Lakh) (A)	75833.17	96394.91	108191.92	126950.86	139477.06	
Actual Normalized O&M expenses allocated to S/S (75% of A) (Rs. Lakh) (B)	56875	72296	81144	95213	104608	
Employee cost (Rs. Lakh) (C)	25925	31320	35378	38262	41425	
Factor (D)	0.62	0.62	0.69	0.80	1.00	
Employee cost - S/S x Factor (E=CxD)	15965	19503	24301	30763	41425	
Normalized O&M expenses after adjustment (Rs. Lakh) (F = B-C+E)	46916	60479	70067	87714	104608	
O&M expenses escalated to FY 2012-13 level @ 4.14% (Rs. Lakh) (G)	55181	68306	75989	91345	104608	
Equivalent No. of sub-station bays (H)	1256	1301	1429	1692	2063	
O&M expenditure per equivalent (400 kV) AC bay (Rs. Lakh/bay)	43.93	52.52	53.17	53.98	50.70	50.86

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Average
Actual Normalized O&M expenses allocated to AC and HVDC lines (25% of A) (Rs. Lakh) (B)	18958.29	24098.73	27047.98	31737.71	34869.26	
Employee cost (Rs. Lakh) (C)	9213	11791	13471	15603	17439	
Factor (D)	0.86	0.82	0.88	0.91	1.00	
Employee cost - S/S x Factor (E = C xD)	7926	9645	11832	14211	17439	
Normalized O&M expenses after adjustment (Rs. Lakh) (F= B-C+E)	17671	21953	25408	30346	34869	
O&M expenses escalated to FY 2012-13 level @ 4.14% (Rs. Lakh) (G)	20784	24794	27556	31602	34869	
Equivalent ckt-km in commercial operation (H)	65410.69	67473.60	73071.03	82213.49	91394.62	
O&M expenditure per equivalent (S/C. twin conductor) ckt-km (Rs. Lakh/ckt-	0.318	0.367	0.377	0.384	0.382	0.366

Note: Employee cost is allocated pro-rata to number of employees

13.5.18 The average O&M expenses for FY 2012-13 have been further escalated @ 4.14% per annum to reach FY 2014-15 level. The O&M expenses thus arrived for FY 2014-15 are given in Table below:

	Average FY 2012-13	**Escalated @ 4.14% to FY 2014-15 level**
O&M expenditure per equivalent (400 kV) AC bay	50.86	55.16
O&M expenditure per equivalent (S/C. twin conductor) ckt-km	0.366	0.397

13.5.19 The norms for AC sub-station and transmission lines (AC and HVDC) for equivalent 400 kV bay and for equivalent S/C twin conductor ckt-km so arrived are then converted to various voltage levels (for sub-stations) and various circuit and conductor configuration (for transmission lines) by applying weightage factors as contained in Tables 13 and 14. The escalation rate of 4.14% per annum is applied to the norms for FY 2014-15 to arrive at norms for each year of the Period 2015-19.

HVDC

13.5.20 The existing Regulations specify separate stand-alone norms for HVDC bipole projects namely Rihand-Dadri and Talcher-Kolar scheme. POWERGRID has also submitted details of actual O&M expenditure for Balia-Bhiwadi HVDC bipole scheme. As regardsTalcher-Kolar scheme and Rihand-Dadri scheme, it is observed that actual O&M expenses during FY 2008-09 to FY 2012-13 are lower as compared to the norms for O&M expenditure for transmission system. Therefore, normalised O&M expenses from FY 2008-09 to FY 2012-13 have been considered. However, an exception has been made in case of Rihand HVDC station in FY 2009-10, where normalized expenses have been restricted to 20% more than value for previous year in order to smoothen the spike. In order to arrive at norms for HVDC stations, normalized expenses during FY 2008-09 to FY 2012-13 have been escalated @ 4.14% per annum to reach FY 2012-13 level. The average O&M expenses for FY 2012-13 level is escalated @ 4.14% per annum to reach FY 2014-15 level.

13.5.21 As regards Balia-Bhiwadi HVDC bipole scheme, actual O&M expenditure has been submitted for the period from FY 2009-10 to FY 2012-13. For the purpose of arriving at norms, average O&M expenses from FY 2011-12 to FY 2012-13 have been escalated @ 4.14% per annum to reach FY 2014-15 level.

Table: Computation of base norms at FY 2012-13 price level for HVDC bipole schemes

(Rs. Lakh)

	Normalised O&M expenditure					Escalated to FY 2012-13 level @ 4.14%					Average at 2012-13 le	
HVDC Station	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Station wise	For Scheme
Rihand- Dadri Scheme												
Rihand	294.07	352.88	363.32	444.16	541.52	345.88	398.55	394.03	462.55	541.52	428.51	
Dadri	604.82	676.80	486.03	924.89	863.58	711.37	764.38	527.10	963.18	863.58	765.92	1194
Talcher-Kolar Scheme												
Talchar	308.80	268.00	481.23	496.55	499.80	363.20	302.68	521.90	517.11	499.80	440.94	
Kolar	380.92	275.09	580.28	532.80	494.86	448.03	310.69	629.32	554.86	494.86	487.55	928
Bhiwadi*												
Balia*	0.00	0.89	699.37	1219.19	1297.83	0.00	1.01	758.48	1269.66	1297.83	1283.74	1337

* Average from FY 2011-12 to FY 2012-13

13.5.22 Based on the above analysis, norms for existing HVDC bipole schemes work out as under:

Table: Norms for HVDC bipole scheme

(Rs. Lakh)

Norms for sub-station (Rs Lakh per bay)	2014-15	2015-16	2016-17	2017-18	2018-19
Rihand-Dadri HVDC bipole scheme (Rs. Lakh)	1295	1349	1405	1463	1524
Talcher- Kolar HVDC bipole scheme (Rs. Lakh)	1007	1049	1092	1137	1184
Balia-Bhiwadi HVDC bipole scheme (Rs. Lakh)	1450	1510	1572	1638	1705

13.5.23 Further, it is also felt necessary to have a norm for HVDC Bipole project of 2000 MW capacity. Talcher-Kolar HVDC system of 2000MW was put under commercial operation in 2002-03 and Rihand-Dadri HVDC system of 1500 MW was put under commercial operation in 1991-92. Considering the operational experience of Talcher-Kolar HVDC system of 2000 MW, the O&M expenses for new HVDC bipole scheme shall be calculated pro-rata on the normative rate of O&M expenses for 2000 MW Talcher- Kolar HVDC bi-pole scheme for the respective year. Accordingly, a suitable provision has been proposed in the draft tariff regulations.

13.5.24 The existing Regulations specify O&M expenses per 500 MW capacity of HVDC BTB stations. In case of BTB stations, expenses for Chandrapur BTB for FY 2010-11 and FY 2011-12 have been restricted to 20% more than for previous year in order to smoothen the spike. In order to arrive at norms for HVDC stations, normalized expenses during FY 2008-09 to FY 2012-13 have been escalated @ 4.14% per annum to reach FY 2012-13 level. The normalized O&M expenses at FY 2012-13 level have been divided by the Station capacity (for every 500 MW) to arrive at values in Rs. Lakh/500 MW. It is observed that O&M Expenses for Gazuwaka BTB for the period from FY 2008-09 to FY 2012-13 are not comparable with other BTB. Therefore, O&M expenses per 500 MW have been derived by taking average HVDC BTB stations (excluding Gazuwaka BTB) at FY 2012-13 level. The norms so arrived for FY 2014-15 are further escalated by 4.14%.

Table: Computation of base norms at FY 2012-13 price level for HVDC back to back schemes

(Rs. Lakh)

	Normalised O&M expenditure					Escalated to FY 2012-13 level @ 4.14%					Average at 2012-13 lev	
HVDC Station	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Station wise	per 500 MW
Vindhyachal BTB	222.87	341.58	403.67	503.18	503.93	262.13	385.78	437.79	524.01	503.93	422.73	422.73
Chandarpur BTB	691.78	627.82	753.38	904.05	1198.17	813.65	709.06	817.05	941.48	1198.17	895.88	447.94
Sasaram BTB	378.31	450.51	408.13	489.75	615.36	444.96	508.82	442.62	510.03	615.36	504.36	504.36
Gazuwaka BTB	1399.15	1624.30	2068.95	2112.47	1758.68	1645.64	1834.50	2243.80	2199.92	1758.68	1936.51	968.25
											Average	458.34

13.5.25 Based on the above analysis, norms for HVDC back-to-back stations works out as under:

Norms for sub-station (Rs Lakh per bay)	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
HVDC Back–to-back stations (Rs. Lakh per 500 MW)	497	518	539	561	585

13.5.26 Further, it is observed that certain region of POWERGRID has transmission lines with M/C twin conductor and M/C quad conductor. Therefore, norms for transmission lines with M/C twin conductor and M/C quad conductor have been added. As explained above, the proposed norms have been derived based on the prevalent norms which in turn assumed S/C twin conductor ckt-km as base and ckt-km of all other circuit and conductor configuration have been converted to equivalent ckt-km of S/C twin conductor ckt-km. Weightage factor for a conversion have been used based on our estimated ratio of O&M expenditure for a particular conductor vis-à-vis S/C twin conductor. The weightage factor for a bundled conductor with four or more sub-conductors is taken as 1.5. Additionally ratio between O&M expenditure of 1 km of M/C line is estimated to be 3.0625 time of 1 km of S/C bundled conductor.

13.5.27Further, it is also observed that POWERGRID is likely to commission AC lines with Hexagonal conductor configuration. Since, there is no historical data available regarding O&M expenses for Hexagonal conductor configuration. For arriving at O&M expenditure for a particular conductor configuration vis-à-vis S/C twin conductor, the weightage factor of 1.75 is taken.

13.5.28To arrive at norms for Gas Insulated Substation (GIS), POWEGRID submitted O&M expenses of 7 Gas Insulated Substations. It is further submitted that '*…the O&M expenditure of the GIS stations are not indicative of a trend as most of the stations other than Maharani Bagh have been completed in FY 2011-12 and FY 2012-13*'. For the comparison purpose the Commission has considered O&M expenses of 4 substations for FY 2012-13. Based on such details, it is observed that average no. of employees engaged per Gas Insulated Substation for FY 2012-13 works out around 18.5, whereas, the actual average O&M expenses are around Rs. 560.88 Lakh per Gas Insulated Substation. Based on information submitted by POWERGRID for AC substations, average no. of employees engaged for AC substation for FY 2012-13 works out around 21.58, say 22. Further, based on actual parameters (such as no. of bays for 765 kV, 400 kV, etc.) the normative O&M expenses per substation for FY 2012-13 work out to be around Rs. 887.24 Lakh. From the above it is observed that the number of employees engaged as well as O&M expenses in case of Gas Insulated Substations are less as compared to conventional AC substations. Out of total O&M expenses Employee, Administrative & General (A&G) and Repair & Maintenance (R&M) constitute around 43%, 40% and 17% respectively. The O&M expenditure per equivalent for 400 kV AC bay for FY 2012-13 is Rs. 50.70 Lakh per bay. The employee expenses for GIS shall be around 16% less than that required for AC substation, whereas R&M expenses shall be around45% less than with A&G expenses at same level. Accordingly, the norms for GIS bays for FY 2012-13 works out to Rs. 43.33

Lakh per bay which is escalated @ 4.14% per annum to reach FY 2014-15 level.

13.6 Proposed Norms

(a) The following normative operation and maintenance expenses shall be admissible for the transmission system :

Table: Proposed Norms for O&M Expenditure for Transmission System

(Rs. Lakh)

Norms for sub-stations (Rs. Lakh per bay)	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
765 kV	77.22	80.41	83.74	87.21	90.82
400 kV	55.16	57.44	59.82	62.29	64.87
220 kV	38.61	40.21	41.87	43.61	45.41
132 kV and below	27.58	28.72	29.91	31.15	32.44
400 kV Gas Insulated Substation	46.99	48.94	50.96	53.07	55.27
Norms for AC and HVDC lines (Rs Lakh per km)					
Single Circuit (Bundled Conductor with six or more sub-conductors)	0.694	0.723	0.753	0.784	0.816
Single Circuit (Bundled Conductor with four sub-conductors)	0.595	0.619	0.645	0.672	0.700
Single Circuit (Twin & Triple Conductor)	0.397	0.413	0.430	0.448	0.466
Single Circuit (Single Conductor)	0.198	0.206	0.215	0.224	0.233
Double Circuit (Bundled conductor with four or more sub-conductors)	1.041	1.084	1.129	1.176	1.225
Double Circuit (Twin & Triple	0.694	0.723	0.753	0.784	0.816

Norms for sub-stations (Rs. Lakh per bay)	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
Conductor)					
Double Circuit (Single Conductor)	0.297	0.310	0.323	0.336	0.350
Multi Circuit (Bundled conductor with four or more sub-conductors)	1.827	1.903	1.982	2.064	2.149
Multi Circuit (Twin & Triple Conductor)	1.217	1.267	1.319	1.374	1.431
Norms for HVDC Stations					
HVDC Back–to-back stations (Rs. Lakh per 500 MW)	497	518	539	561	585
Rihand-Dadri HVDC bi-pole scheme (Rs. Lakh)	1295	1349	1405	1463	1524
Talcher- Kolar HVDC bi-pole scheme (Rs. Lakh)	1007	1049	1092	1137	1184
Balia-Bhiwadi HVDC bi-pole scheme (Rs. Lakh)	1450	1510	1572	1638	1705

Provided that the O&M expenses for the new HVDC bi-pole scheme shall be calculated pro-rata on the basis of normative rate of O&M expenses for 2000 MW Talcher- Kolar HVDC bi-pole scheme for the respective year.

(b) The total allowable operation and maintenance expenses for the transmission system shall be calculated by multiplying the number of bays and kms of line length with the applicable norms for the operation and maintenance expenses per bay and per km respectively.

(c) The operation and maintenance expenses of communication system forming part of of inter-state transmission system shall be derived on the basis of the actual O&M expenses for the period of 2008-09 to 2012-13 based on audited accounts excluding abnormal variations if any after prudence check by the Commission.

13.7 Impact of Wage Revision

The impact of wage revision if any, during the tariff period shall be allowed in due consideration of Government of India, Department of Public Enterprise guidelines and considering following percentage of O&M as employee cost:

Coal/Lignite based Stations:	40%
Gas/liquid fuel based stations:	32%
Hydro Generating Stations:	46%
Transmission system:	40%

14 Norms of Operations

14.1 Norms of Operation for Thermal Generating Stations

14.1.1 The Commission initiated the process of framing the terms and conditions for tariff determination for the next Control Period starting April 01, 2014 and in order to reasonably frame the norms of operation directed various Central and State generating utilities to furnish the operational and performance data for the period FY 2008-09 to FY 2012-13 vide its order dated June 07, 2013. The operational and performance data for these years have submitted by all the Central Generating Stations and Inter State Generating Stations which have been considered while specifying the norms.

14.1.2 In addition to the coal, lignite and gas based generating stations, since some of the stations based on coal rejects have come up and few are under construction the Commission proposes to specify norms for such generating stations as well. The Commission has accordingly determined separate norms for such generating stations.

14.1.3 Further, the Commission also received suggestions form stakeholders for determination of separate norms for stations based on IC engines. The Commission in this regard proposes that generating stations based on IC engines are similar to gas based generating stations and therefore separate norms for the same is not required. However, the Commission proposes that any modification to the norms for the generating stations based on IC Engines shall be approved on case to case basis upon receipt of application in this regard.

14.1.4 The Commission also proposes to continue with its earlier approach to specify separate norms for Lignite Based Plants based on Circulating fluidized bed combustion (CFBC) boiler technology.

Para 5.3 f) of the Tariff Policy on operating Norms stipulates as follows:

*"**Suitable performance norms of operations together with incentives and dis-incentives would need be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers.** Except for the cases referred to in para 5.3(h)(2), the operating parameters in tariffs should be at "normative levels" only and not at "lower of normative and actuals." This is essential to encourage better operating performance. **The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipments, nature of operations, level of service to be provided to consumers etc. Continued and proven inefficiency must be controlled and penalized**.*

The Central Commission would, in consultation with the Central Electricity Authority, notify operating norms from time to time for generation and transmission. The SERC would adopt these norms. In cases where operations have been much below the norms for many previous years, the SERCs may fix relaxed norms suitably and draw a transition path over the time for achieving the norms notified by the Central Commission." ***(Emphasis Added)***

14.1.5 The Commission in accordance with the Tariff Policy proposes to specify the norms which reflects efficiency, is relatable to past performance and progressively reflects increased efficiency at the same time factoring the nature of operations, vintage of equipment, fuel and technological advancements. Further, the Commission in view of the Tariff Policy also proposes to specify a mechanism for sharing of gains with beneficiaries with regards to various operational parameters.

14.1.6 CEA was accordingly requested to provide its recommendations on the operational parameters for Inter State Generating Stations. CEA is yet to make any recommendations. In the absence of CEA recommendations, the Commission is proceeding on its own based on the data available with them. Since CERC terms and conditions of tariff shall act as guidelines for State Commissions, corrections, if considered necessary could be effected as and when CEA recommendations are received.

14.1.7 The various operational parameters namely Target Availability, Plant Load Factor (PLF), Station Heat Rate, Auxiliary Energy Consumption and Specific Fuel Oil Consumption are discussed in subsequent paragraphs based on actual operation and performance of coal/lignite based and Gas/Liquid fuel based generating stations of NTPC, NLC, DVC, & NEEPCO and some of the comparable generating stations of SEBs/IPPs.

14.1.8 The Commission has relied upon the data for FY 2008-09 to FY 2012-13 for specifying the operational norms for the Thermal Generating Stations.

14.1.9 In case of stations like Badarpur TPS, Tanda TPS and Talcher TPS, the Commission proposes to revise the norms for the generating stations based on the improved performance levels achieved during FY 2008-09 to FY 2012-13.

15 Target Availability for recovery of Full Annual Fixed Charges (AFC) and Target PLF for Incentive

15.1 Background

15.1.1 The Commission in its Previous Regulations i.e., Tariff Regulations, 2001 and Tariff Regulations, 2004 had specified separate norms to be achieved for recovery of entire annual fixed charges and to qualify to receive incentive in case the station performs above the specified norm. The Commission in the above said regulations specified that the entire full fixed charges shall be recoverable if the Station achieved target availability. However, in order to qualify for incentive a separate norm was prescribed as target Plant Load Factor (PLF). The generator was allowed incentive only in case when it generated power in excess of target PLF.

15.1.2 However, the Commission in its Tariff Regulations, 2009 changed the norm and specified single norm as target availability for recovery of full fixed charges and incentive.

15.2 Issues brought out in Approach Paper

15.2.1 The Commission in its Approach Paper contemplated to have separate norms for new generating stations and old generating stations on account of technological improvements. The Commission further with regard to impact of fuel shortage on availability of fuel invited suggestions by highlighting the following issue:

"Whether the existing norms of annual plant availability should be reviewed for thermal generating station considering the scenarios with and without fuel shortage? What should be the treatment of normative availability in the event of procuring alternative fuel in case of shortage condition?"

15.3 Existing Norm vis-à-vis Actual Availability

15.3.1 Existing Norms

The existing regulations for tariff period 2009-14 as amended provide following norms for the Target Availability for recovery of full Annual Fixed Charges (AFC) for the thermal generating stations:

(i) Normative Annual Plant Availability Factor (NAPAF)

(a) All thermal generating stations, except those covered under clauses (b), (c), (d), (e) & (f) - 85%

(b) Following Coal-Based Thermal Generating Stations of NTPC Ltd

Talcher TPS	82%
Badarpur TPS	82%

(c) Following Lignite-fired Thermal generating stations of Neyveli Lignite Corporation Ltd, other than specified in sub-clause (b)

TPS-I	75%
TPS-II Stage I & II	75%
TPS-I (Expansion)	80%

(d) Following Thermal Generating Stations of DVC

Mejia TPS Unit-I to IV	82%
Bokaro TPS	75%
Chandrapura TPS	60%
Durgapur TPS	74%

(e) Following Gas based Thermal Generating Stations of NEEPCO

Assam GPS	72%

(f) Lignite fired Generating Stations using Circulatory Fluidized Bed Combustion (CFBC) Technology

1. First Three years from COD – 75%
2. From next year after completion of three years of COD – 80%

The Commission vide its Order dated June 07, 2013 asked all the central generating stations to submit the actual data for FY 2008-09 to FY 2012-13. The purpose behind the same was to check the appropriateness of the current norms vis-à-vis actual performance. The next section deals with the actual availability achieved by the stations for the period FY 2008-09 to FY 2012-13.

15.3.2 Actual Availability of Central Generating Stations (Thermal)

15.3.2.1 The actual availability of the various coal, and lignite based thermal generating stations along with their five year average is as shown below:

S. No.	Stations	Plant Availability Factor (%)					
		2008-09	2009-10	2010-11	2011-12	2012-13	Five year Average
	NTPC Stations						
1	Singrauli	90.91	92.44	97.30	89.55	94.05	92.85
2	Rihand	95.17	100.94	91.05	97.17	82.05	93.28
3	Rihand II	101.95	91.79	100.45	92.2	100.08	97.29
4	Rihand III	NA	NA	NA	NA	62.65	62.65
5	Tanda	89.55	92.61	93.52	89.16	84.46	89.86
6	Unchahar	91.77	98.8	99.77	94.44	98.78	96.71
7	Unchahar II	98.41	95.81	100.38	92.96	100.07	97.53
8	Unchahar III	93.09	104.83	95.62	101.66	100.06	99.05
9	Korba	97.48	97.96	93.24	79.76	90.96	91.88
10	Korba III	NA	NA	81.38	76.76	94.76	84.30
11	Vindhyachal I	93.33	96.48	96.2	91.27	93.97	94.25
12	Vindhyachal II	95	97.06	97.02	89.65	94.17	94.58

S. No.	Stations	Plant Availability Factor (%)					
		2008-09	2009-10	2010-11	2011-12	2012-13	Five year Average
13	Vindhyachal III	96.93	99.7	99.39	97.19	98.96	98.43
14	Vindhyachal IV	NA	NA	NA	NA	24.39	24.39
15	Ramagundam Stage I and II	93.52	93.65	92.48	94.34	93.4	93.48
16	Ramagundam Stage III				94.84	87.03	90.94
17	Sipat	96.72	94.39	96.95	98.78	85.69	94.51
18	Sipat I	NA	NA	NA	70.99	80.54	75.77
19	Simhadri Stage II	94.54	94.38	94.09	89.79	75.41	89.64
20	Farakka	76.81	73.36	87.24	82.56	74.22	78.84
21	Farakka Stage III	NA	NA	NA	NA	70.65	70.65
22	Kahalgaon I	80.11	68.74	75.09	80.19	85.61	77.95
23	Kahalgaon II	72.86	65.08	68.73	64.77	75.05	69.30
24	Badarpur	94.48	86.46	90.17	76.7	90.23	87.61
25	Tal kaniha	85.54	90.49	87.79	85.52	82.12	86.29
26	Talcher Stage I	88.5	86.68	84.77	80.83	81.93	84.54
27	Talcher Stage II	91.67	97.4	92.5	88.55	82.87	90.60
28	Dadri Thermal	101.22	101.37	98.67	96.6	98.24	99.22
37	Jhajjar STPS	NA	NA	38.02	65.18	84.77	62.66
38	NSPCL – Bhilai Ext.	NA	45.88	74.97	73.50	76.13	67.62
	DVC Stations*						
1	Bokaro TPS	62.54	63.75	62.26	60.82	56.30	61.13
2	Chandrapura	73.26	62.84	75.04	60.87	76.49	69.70
3	Durgapur	62.68	66.57	49.07	63.79	67.02	61.82
4	Mejia	51.54	58.06	74.62	70.85	66.11	64.24
	NLC Stations						
1	NLC TPS – I	60.76	70.78	66.32	68.01	68.93	66.96

S. No.	Stations	Plant Availability Factor (%)					
		2008-09	2009-10	2010-11	2011-12	2012-13	Five year Average
2	NLC TPS II - Stg - I	66.41	77.26	82.16	84.91	86.35	79.42
3	NLC TPS II-Stg II	70.79	84.06	82.90	85.65	87.69	82.22
4	NLC TPS I Exp.	85.28	81.78	82.04	83.93	90.73	84.75
5	NLC Barsingsar	-	-	-	-	-	65.74

* For DVC stations PLF data considered.

15.3.2.2 Similarly the actual availability of the gas based thermal generating stations along with their five year average is as shown below:

S. No.	Stations	Plant Availability Factor (%)					
		2008-09	2009-10	2010-11	2011-12	2012-13	Five Year Average
1	Anta	83.17	89.38	89.7	94.09	93.61	89.99
2	Auraiya	86.19	91.33	96.05	92.47	91.55	91.52
3	Gandhar	84.24	89.74	92.41	94.05	93.58	90.80
4	Kawas	84.14	89.56	91.43	96.43	90.56	90.42
5	Faridabad	72.63	93.15	89.85	89.86	91.44	87.39
6	Dadri Gas	89.01	90.12	96.30	94.80	97.68	93.58
7	Kayamkulam	92.56	94.14	92.04	96.13	92.62	93.50
	NEEPCO						
1	Assam Gas	70.85	69.79	74.04	70.15	66.25	70.22
2	Agartala Gas	88.99	88.99	88.99	88.99	87.78	88.74

15.3.2.3 As evident from the actual data of coal and gas based generating stations, the average actual availability during FY 2008-09 to FY 2012-13 for most of the stations of NTPC was above 90% with few stations in the range of 85% to 90% and only some stations like Farakka and Kahalgaon having actual availability less than the norm of 85%. Even stations like Badarpur, Talcher for which relaxed norm of 82% were prescribed have a five year average availability of around 85%.

15.3.2.4 For DVC stations since the actual availability data is not available PLF has been computed on the basis of the actual generation submitted by the generating stations.

15.3.2.5 For NLC Stations the availability of the stations is more or less near to the norms except in case of NLC TPS – I wherein the station has slightly underperformed. The target availability for the station was 72% however the five year average suggests that it could achieve only 67%.

15.3.2.6 For gas based generating stations of NTPC almost all the stations have achieved target availability and have achieved much better availability with most of the generating stations having five year average actual availability of 90%.

15.3.3 Variance Analysis

15.3.3.1 Most of the gas and coal fired stations of NTPC have achieved the availability higher than the target norm specified in the Tariff Regulations, 2009 by a considerable margin. However, in case of some of the stations like Farakka and Kahalgaon the norms could not be achieved and the reasons stated for the underachievement was low coal quality. Further in case of stations like Rihand III, Sipat I and Jhajjar STPS which have achieved commercial operation during the Control Period FY 2009-14 the actual average availability is less than the norms however, as observed in case of stations like Jhajjar and Sipat –I the availability has improved considerably in the subsequent years post commercial operations.

15.3.3.2 For DVC stations, the actual generation suggests lower performance levels than the norms specified. For Mejia TPS (Unit 1-4) a norm of 82% was prescribed. The station as a whole achieved PAF of 64.24%. Even in case of Bokaro TPS and Durgapur TPS the actual performance levels have been lower than the norms. However, in case of Chandrapura TPS the actual five year average PLF was around 70% against the norm of 60%. There was capacity addition of around 500 MW wherein 2 units of 250 MW was added to the plant capacity. However, there has been no increase in the availability of the plant on overall basis. The first three units of the station was also performing at the same level as evident from the actual data for FY 2008-09 to FY 2010-11.

15.3.3.3 For gas based stations of NEEPCO in case of Assam Gas Stations the actual five year average availability is 70.22% when compared to the target availability of 72% and for Agartala Gas station the actual five year average availability is 88.74% which is well above the target norm of 85%.

15.3.3.4 With regards to availability of NLC stations the actual data suggests that the same is almost close to the norms specified in Tariff Regulations, 2009 except in case of TPS-I station where in the average availability is lower than the target norm by around 5%. With regards to Barsingsar TPP the units have achieved CoD in FY 2012-13 and only partial year data is available.

15.4 Stakeholders Responses

15.4.1 In response to the issues brought out in this regard in the approach paper some of the stakeholder suggested that relaxed norms for Talcher TPS should be withdrawn as it is operating well above the relaxed norm as massive R&M activities have been carried out. Further most of the stakeholders suggested to retain the present availability norms. Some of the stakeholders suggested if there is fuel shortage not enabling a generating station to achieve normative availability, then loss of availability may be added to determine fixed charges (and not incentive). In considerations to these, normative availability may not be reduced but deemed availability may be considered where it is affected by

(i) Specific instruction by RLDC or SLDC or beneficiary(ies) or

(ii) Where beneficiary decline to purchase electricity from available alternate/imported fuel at a price determined by FPA or where due to force majeure stock of fuel is exhausted.

15.4.2 With regard to shortage of coal, most of the stakeholders suggested that the same should not affect the availability of the station.

15.4.3 Some of the stakeholder suggested that the Pit-head Stations may not be allowed for blending of imported/e-auction coal with the linkage coal. However, the consent of the beneficiary may be made mandatory before carrying out any sort of blending of coal.

15.4.4 Some of the stakeholders with regard to the bridging of the gap through e-auction or imported coal, submitted that it should be limited to the extent of 15% increase in the variable cost. Further, if there is any increase beyond this limit, then the concurrence of the beneficiaries should be obtained.

15.5 Commission's Proposal

15.5.1 Considering the actual performance of the stations and the suggestions received by the stakeholders, the Commission is of the view that the present norm for Target Availability of 85% for coal based generating stations was achieved by almost all the stations of Central Generating Stations. Though most of the stations have even achieved availability of above 90%, the Commission proposes to keep the Target Availability norm of 85% for coal based thermal generating stations.

15.5.2 The Commission with regards to under performance of stations like Farakka and Kahalgaon which have cited coal quality as the reason for frequent breakdown is of the view that such anomaly in fuel supply and quality cannot be factored in the norms as the same shall imply acceptance of something which needs to be rectified and therefore the same cannot be considered as a ground for relaxed norm for stations. The Commission therefore proposes to keep the same norm of target availability for the two stations. Further, with regards to stations like Badarpur and Talcher stations for which relaxed norms were specified in Tariff Regulations, 2009 as these stations have achieved actual average five year availability of around 85%, the Commission proposes to keep the norm for such generating stations at the same level as applicable for other generating stations.

15.5.3 For DVC stations since the actual availability data is not available PLF has been computed on the basis of the actual generation submitted by the generating stations. The actual generation suggests lower performance levels than the norms specified. For Mejia TPS (Unit 1-4) a norm of 82% was prescribed. The station as a whole achieved PAF of 64.24%. Even in case of Bokaro TPS and Durgapur TPS the actual performance levels have been lower than the norms. However, in case of Chandrapura TPS (Unit 1-3) the actual five year average PLF as well as the average PLF for FY 2008—09 to FY 2010-11 was around 70% against the norm of 60%.

15.5.4 In view of the above the Commission is of the view that for stations like Mejia enough time has been allowed to improve their operational efficiencies and therefore, further relaxation of norms for these stations may not be in the interest of consumers and therefore the Commission proposes to approve a norm of 85% for Mejia TPS. As regards to Chandrapura TPS (Unit 1-3) the Commission taking cognisance of the improved performance and the time already allowed to improve the station efficiency proposes to approve an improved norm of 75%. The Commission with regards to Bokaro and Durgapur TPS proposes to retain the current norm of 75% and 74% respectively.

15.5.5 With regards to NLC stations the actual data for NLC TPS-I, NLC TPS-II stations suggests that the present norms for the stations are close to their actual performance achieved by these stations during FY 2008-09 to FY 2012-13. The Commission therefore proposes to keep these norms unchanged for the next Control Period.

15.5.6 For Gas based thermal generating stations of NTPC all the stations have achieved the availability norms. The target availability norms for the same are already 85% and therefore the Commission proposes to retain the same level of target availability for the next Control Period.

15.5.7 With regards to gas based stations of NEEPCO the actual five year average data suggests that the two stations have almost achieved the target norm and therefore the Commission proposes to the retain the same norms for these stations for the next Control Period.

15.5.8 Further, the Commission in this Regulation after taking into difficulties faced by various distribution utilities and issues arising out on account of payment of incentives without receiving power leading to increased average cost of power purchase, proposes to re-introduce separate norms for recovery of full fixed charges linked to the target availability and norms for target PLF above which the incentive shall be applicable.

15.5.9 With regard to thermal generating station, the Commission has proposed to fix the incentive rate of 50 paise/kWh.

15.5.10 With regards to the secondary energy charge in case of hydro generating station the Commission proposes that the rate should be slightly lower than the lowest variable cost of thermal generating station and therefore the Commission proposes to fix the secondary energy charge rate at 90 paisa/kWh which is slightly lower than the current variable charge for Korba thermal power station.

Scheduling of Power in case of Fuel Shortages

15.5.11 With regards to scheduling of power in case of fuel shortages the Commission is of the view that securing fuel is prime responsibility of generator and in case of non fulfilment of supply of committed quantity of coal the generator is free to procure either e-auction coal or imported coal and schedule power on the basis of the same. If the generator is not able to schedule power due to fuel shortage the same shall be considered as loss in availability of the unit or station as the case may be.

15.5.12 On the issue of obtaining beneficiaries consent before blending of coal, the Commission is of the view that the same may not be practically possible at all the instances and hence it is felt to fix some limit beyond which the generator should obtain beneficiaries consent before blending of coal. The Commission therefore proposes that in case the blending of coal leads to a price increase of blended coal in Rs/Kcal terms by over 30% of the base price of fuel or 20% of price of fuel for the previous month, whichever is lower, the generator must intimate beneficiaries three days in advance and take beneficiaries' consent before going for such blending.

15.5.13 The Commission through its specific tariff orders for each generating station shall approve the base price of fuel price for the FY 2014-15. The fuel price so approved shall be the base price of fuel and shall be applicable for the month of notification of such tariff orders. For subsequent months the base price of fuel shall be escalated by escalation rate applicable for domestic coal as notified by the Commission under "Notification of Escalation Factors and other Parameters for the Purpose of Bid Evaluation and Payment as per the Competitive Bidding Guidelines from time to time for bidding purpose.

15.6 Proposed Norms

The norms of operation as given hereunder shall apply to thermal generating station:

<u>(A) Normative Annual Plant Availability Factor (NAPAF)</u>

(a) All thermal generating stations, except those covered under clauses (b), (c), (d), &(e) - 85%

(b) Following Lignite-fired Thermal generating stations of Neyveli Lignite Corporation Ltd:

TPS-I	72%
TPS-II Stage I & II	75%
TPS-I (Expansion)	80%

(c) Following Thermal Generating Stations of DVC:

Bokaro TPS	75%
Chandrapura TPS	75%
Durgapur TPS	74%

(d) Following Gas based Thermal Generating Stations of NEEPCO:

Assam GPS	72%

(e) Lignite fired Generating Stations using Circulatory Fluidized Bed Combustion (CFBC) Technology and Generating stations based on coal rejects

1. First Three years from COD – 75%
2. For next year after completion of three years of COD – 80%

(B) Normative Annual Plant Load Factor (NAPLF) for Incentive

a) All thermal generating stations, except those covered under clauses (b), (c) - 85%

(b) Following Lignite-fired Thermal generating stations of Neyveli Lignite Corporation Ltd:

TPS –I	75%
TPS – II Stage I &II	80%
TPS- I (Expansion)	80%

(c) Following Thermal Generating Stations of Damodar Valley Corporation (DVC):

Bokaro TPS	80%
Chandrapur TPS	80%
Durgapur TPS	80%

16 Gross Station Heat Rate

16.1 Background

16.1.1 The Commission in its Tariff Regulations, 2001 had approved single norm for existing as well as new 200 MW and 500 MW units for all Central Generating Stations. The Commission however, specified relaxed norm for new stations during stabilisation period. Subsequently in Tariff Regulations, 2004 the Commission specified separate norms for 200 MW units and 500 MW units. The Commission with regards to 200 MW units retained the same norm as prescribed in the previous regulations however it slightly tightened the norms for 500 MW units as these units were more efficient resulting in lower SHR. The Commission further continued with specifying relaxed norms for new stations during stabilisation period. However, in Tariff Regulations, 2009 the Commission did not specify separate norms for stabilisation period. The Commission even in Tariff Regulations, 2009 retained the earlier heat rate norms for 200 MW units taking cognisance of the vintage of these units. The Commission however, slightly tightened the norms for 500 MW units.

16.2 Issues brought out in Approach Paper

16.2.1 The Commission in its Approach Paper brought out the following issue inviting suggestions.

"Whether the existing norms of station heat rate are required to be strengthened? Alternative methodology for arriving at revised norms, if any, and present level of station heat rate based on the technological improvement that may also be specified. What are the important criteria to be considered while specifying norms for station heat rate? The need for continuation of relaxed norms for specific stations? Changes required in the existing norms given in Tariff Regulation 2009-14 may be commented duly supported with authentic data if any.

16.3 Existing Norm vis-à-vis Actual Gross Station Heat Rate

16.3.1 Existing Norms

The existing regulations for tariff period 2009-14 as amended provide following norms for Gross Station Heat Rate for the thermal generating stations:

A. Existing Thermal Generating Station

(a) Existing Coal-based Thermal Generating Stations, other than those covered under clauses (b) and (c) below

200/210/250 MW Sets	*500 MW Sets (Sub-Critical)*
2500kCal/kWh	*2425kCal/kWh*

….

(b) Thermal generating stations of NTPC Ltd.:

Badarpur TPS	*2825 kCal/kWh*
Talcher TPS	*2950 kCal/kWh*
Tanda TPS	*2825 kCal/kWh*

(c) Thermal Generating Stations of Damodar Valley Corporation (DVC):

Bokaro TPS	*2700 kCal/kWh*
Chandrapur TPS	*3100 kCal/kWh*
Durgapur TPS	*2820 kCal/kWh*

(d) Lignite-fired Thermal Generating Stations

(1) For lignite-fired thermal generating stations, except for TPS-I and TPSII (Stage I & II) of Neyveli Lignite Corporation Ltd, the gross station heat rates specified under sub-clause (a) for coal-based thermal generating stations shall be applied with correction, using multiplying factors as given below:

(i) For lignite having 50% moisture: 1.10

(ii) For lignite having 40% moisture: 1.07

(iii) For lignite having 30% moisture: 1.04

(iv) For other values of moisture content, multiplying factor shall be pro-rated for moisture content between 30-40% and 40-50% depending upon the rated values of multiplying factor for the respective range given under sub-clauses (i) to (iii) above.

(2) TPS-I and TPS-II (Stage I & II) of Neyveli Lignite Corporation Ltd

TPS-I 4000 kCal/kWh

TPS-II 2900 kCal/kWh

(e) Open Cycle Gas Turbine/Combined Cycle generating stations

Existing generating stations of NTPC Ltd and NEEPCO

Name of generating station	**Combined cycle (kCal/kWh)**	**Open Cycle (kCal/kWh)**
Gandhar GPS	2040	2960
Kawas GPS	2075	3010
Anta GPS	2075	3010
Dadri GPS	2075	3010
Auraiya GPS	2100	3045
Faridabad GPS	2000	2900
Kayamkulam GPS	2000	2900
Assam GPS	2500	3440
Agartala GPS		3700

B. New Thermal Generating Station achieving COD on or after 1.4.2009

(a) Coal-based and lignite-fired Thermal Generating Stations

= 1.065 X Design Heat Rate (kCal/kWh)

Where the Design Heat Rate of a unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR, zero percent make up, design coal and design cooling water temperature/back pressure.

….

(b) Gas-based / Liquid-based thermal generating unit(s)/ block(s)

= 1.05 X Design Heat Rate of the unit/block for Natural Gas and RLNG (kCal/kWh)

= 1.071 X Design Heat Rate of the unit/block for Liquid Fuel (kCal/kWh)

Where the Design Heat Rate of a unit shall mean the guaranteed heat rate for a unit at 100% MCR and at site ambient conditions; and the Design Heat Rate of a block shall mean the guaranteed heat rate for a block at 100% MCR, site ambient conditions, zero percent make up, design cooling water temperature/back pressure.

16.3.2 Actual Gross Station Heat Rate

a) Actual Gross Station Heat Rate (kCal/kWh) for Coal and Lignite based stations of NTPC, NSPCL and NLC Stations

S. No	Stations	Capacity/Configuration (MW)	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Current Wt. Avg. Norm	Five Year Average
1	Singrauli Super Thermal Power Station	2000 (200X5+500X2)	2393	2393	2393	2392	2390	2463	2392
2	Rihand Super Thermal Power Station	2500 (Stage 1: 2X500, Stage 2 & 3: 3X500)	2347	2347	2346	2350	2357	2409	2349
3	Tanda Thermal Power Station	440	2728	2727	2732	2770	2760	2825	2743
4	Unchachar FGUTPP	1050 (210x5)	2387	2384	2403	2418	2405	2500	2399
5	Korba Super Thermal Power Station	2600 (3X200+4X500)	2369	2375	2381	2383	2384	2442	2378

S. No	Stations	Capacity/Configuration (MW)	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Current Wt. Avg. Norm	Five Year Average
6	Vindhyachal Super Thermal Power Station	4260 (6X210+2X500+2X500+2X500)	2376	2372	2371	2370	2371	2447	2372
7	Sipat Super Thermal Power Station	2980 (660X3 + 500X2)	2361	2349	2349	2340	2344	2375	2349
8	Ramgundam Super Thermal Power Station	2600 MW	2372	2371	2371	2371	2370	2442	2371
9	Simhadri Super Thermal Power Station	2000 MW(Stage-I= 2X500, Stage-II= 2X500)	2351	2349	2348	2366	2368	2405	2356
10	Farakka Super Thermal Power Station	2100 (3X200MW+2X500MW+1X500MW)	2415	2407	2400	2399	2404	2446	2405
11	Kahalgaon Super Thermal Power Station	2340 (4x210+3*500)	2372	2378	2390	2405	2398	2452	2389
12	TTPS Thermal Power Station	460 (Stage # I: 4 X 60, Stage # II: 2X 110)	2867	2859	2851	2843	2823	2950	2849
13	Tal kaniha Super Thermal Power Station	3000 MW (2x500 MW+4x500 MW)	2356	2357	2352	2360	2385	2425	2362
14	Badarpur Thermal Power Station	705	2773	2750	2749	2749	2755	2825	2755
15	Dadri Thermal Power Station	1820 (210x4+490X2)	2389	2393	2392	2400	2395	2460	2394
16	NSPCL – Bhilai Ext	500/(2x250)	NA	2494	2370	2348	2349	2500	2390
NLC Stations									
1	TPS I	420MW (2*210MW)	3924	3933	3944	3960	3897	4000	3932
2	TPS I Exp	630 MW (3 X 210 MW)	2739	2743	2751	2745	2737	2750	2743

S. No	Stations	Capacity/Configuration (MW)	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Current Wt. Avg. Norm	Five Year Average
3	TPS II Stage I	840 MW (4 X 210 MW)	2947	2917	2894	2883	2874	2900	2903
4	TPS II Stage II	2x125MW	2950	2893	2877	2880	2871	2900	2894
5	Barsingsar TPP	420MW (2*210MW)					2601	2750	2601
DVC Stations									
1	Bokaro TPS	630 MW (3x210)	3023	2883	2816	3010	2861	2700	2919
2	Chandrapura TPS	890 MW (130x3+2x250)	3049	3197	3296	2928	2422	3100	2978
3	Durgapur TPS	350 MW (1x140+21x210)	3049	2957	2914	2825	2847	2820	2918
4	Mejia TPS	2340 MW (4x210 + 2x250 + 2x500)	Adequate Data not submitted.						

b) Actual Gross Station Heat Rate (kCal/kWh) for Gas based Stations of NTPC and NEEPCO other than small gas turbine stations

Stations	Capacity/ Configuration	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Current Norm	Five Year Average
NTPC (Combined Cycle)								
Anta GPS	419.33 MW (88.71*3 GTs + 153.2*1 STG)	2067	2038	2036	2040	2073	2075	2051
Auraiya GPS	663.36 MW 4GT (111.19MW EACH) +2ST(109.3 MW EACH)	2092	2111	2090	2098	2099	2100	2098
Kawas GPS	656.2 (106*4+116.1*2)	2012	2004	2035	2023	2027	2075	2020
Gandhar GPS	657.39	2015	2022	2024	2015	2024	2040	2020

Stations	Capacity/ Configuration	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Current Norm	Five Year Average
NTPC (Combined Cycle)								
Faridabad GPS	431.586 MW (2X137.758 MW GT+1X156.07 MW ST)	1969	1917	1930	1915	1946	2075	1935
Dadri Gas Power Plant	829.78	1975	1950	1975	1981	2002	2075	1977
Kayamkulam Gas Power Plant	359 MW(2*115 MW + 1*129 MW)	1958	1957	1973	1986	1965	2000	1968
NEEPCO								
Assam GPS	291 MW, (6 X 33.5 +3 X 30) MW	2665	2565	2666	2733	2817	2500	2689
Agartala GPS	4 X 21 MW = 84 MW	3771	3763	3762	3833	3425	3700	3711

16.3.3 Variance Analysis

16.3.3.1 Based on the analysis of actual data it is observed that all the above coal based stations of NTPC are achieving the SHR below the normative SHR. In all the stations the actual five year average heat rate has been lower than the norm by around 2-4%.

16.3.3.2 With regards to NLC stations the actual five year average heat rate has been very close to current heat rate norms.

16.3.3.3 With regards to DVC stations actual five year average heat rate is higher than the norm except for Chandrapura Station.

16.3.3.4 Further, for Agartala GPS the actual five year average heat rate has been considerably higher than the norm. However, the heat rate achieved by the station in FY 2012-13 was well within the norms.

16.4 Stakeholders Response

16.4.1.1 The extracts of the suggestions received from various stakeholders on the issues flagged in approach paper is as below:

i. The Station Heat Rate norm should be determined based on the average of past four or five year actual data and on the basis of design SHR after considering the relaxation provided in the current regulation whichever is lower.

ii. One of the stakeholders suggested that the improvement in Station Heat Rate on account of PAT schemes should be considered, however, one of the stakeholder suggested that the same should not be considered.

iii. Station Heat Rate should be approved considering various operational constraints like partial loading/erratic load pattern, low PLF and deteriorated coal quality as coal quality is expected to deteriorate further during the Control Period FY 2014-15 to FY 2018-19. Further, while approving SHR the blending ratio should be considered and in case the generating station has to operate on other blending ratio, the deterioration in heat rate should be allowed while approving the norm. One of the stakeholder suggested that the SHR should be approved on sliding scale basis with regard to varying PLF.

iv. Degradation in SHR to be considered over the life of the project. One of the stakeholders suggested the concept of Annual Heat Rate Degradation factor may be specified in consultation with CEA.

v. Some of the stakeholders suggested that SHR norm for plant operating on imported coal should be separately specified.

vi.

vii. The current margin of 6.50% allowed over the design heat rate for new coal/lignite based thermal power station should be increased to 8% and the current margin of 5%for new gas based station to be increased to 8%-10%. One of the stakeholder suggested that the station heat rate norm should be on the basis of P&G Test report as current margin of

6.50% for coal based station does not completely factor in the actual site conditions.

viii. Coal GCV degradation on account of Stacking loss to be allowed as there is considerable difference in the GCV as received and as fired especially in case of imported coal due to high volatile matter content.

ix. Station heat rate during stabilisation period should be separately specified.

16.5 Commission's Proposal

16.5.1 After considering the actual performance of the generating stations and the suggestion and comments received from various stakeholders, the Commission proposes that the station heat rate norms should reflect the current level of operational efficiency along with improvement that can be achieved during the next Control Period. The Commission therefore is of the opinion that the norm should be based on the actual data for the past five years.

16.5.2 As evident from the actual heat rate data for the generating station it is observed that all the coal based generating stations of NTPC have achieved heat rate lower than the approved norms as per the Tariff Regulations, 2009.

16.5.3 The Commission observes that Unchahar station which comprises of five units of 210 MW has been consistently achieving a heat rate of around 2400-2420 kCal/kWh as against the heat rate norm of 2500 kCal/kWh. The Commission observes that the heat rate norm for 200 MW series units have been kept unchanged from the first Tariff Regulations, 2001. The Commission however of the view that due to better O&M practices and technological development the stations are now able to achieve better heat rates and therefore the Commission proposes that the norm can be slightly normalised to reflect the current operational efficiencies of the stations. The Commission therefore proposes to revise the heat rate norms for 200

MW series units to 2425 kCal/kWh from the present norm of 2500 kCal/kWh.

16.5.4 Further, with regards to norm for 500 MW series units the stations that comprise of only 500 MW units have been considered like Rihand and Tal Kaniha. These two stations comprise of only 500 MW units and as evident from the actual data as submitted by NTPC these stations have been able to consistently achieve heat rate of around 2360 kCal/kWh. The five year average heat rate for Tal Kaniha STPS have been around 2362 kCal/kWh whereas for Rihand it has been around 2350 kCal/kWh. The Commission proposes that the norm can be slightly normalised to reflect the current operational efficiencies of the stations. The Commission therefore proposes to revise the heat rate norms for 500 MW series units to 2375 kCal/kWh from the present norm of 2425 kCal/kWh. Further, to validate and test these norms, weighted average heat rate for stations having combinations of 200 MW and 500 WM units were computed on the basis of revised norms which resulted into combined station heat rate of around 1-2% higher than the five year average heat rates.

16.5.5 The Commission further had approved relaxed norms for some of the generating stations after taking due consideration of plant vintage. In case of Badarpur TPS and Tanda TPS the Commission had approved a norm of 2825 kCal/kWh whereas the five year average heat rate achieved by the station was 2755 kCal/kWh and 2743 kCal/kWh respectively. Further with regards to Talcher TPS the Commission had approved a heat rate of 2950 kCal/kWh whereas the five year average heat rate achieved by the station was 2849 kCal/kWh. The Commission is of the view that the stations have been granted relaxed norms in Tariff Regulations, 2009 to accommodate the impact of vintage of these stations. There has been additional capitalisation in these stations which has translated into performance and therefore the norms can be normalised to reflect the current operational efficiency of these stations. Accordingly, the Commission proposes to revise the heat rate norm for Badarpur, Tanda and Talcher TPS as 2750 kCal/kWh, 2750 kCal/kWh and 2850 kCal/kWh respectively.

16.5.6 As regard to DVC stations the actual data suggests that the station actual average heat rate for Bokaro TPS has been 2919 kCal/kWh as against the norm of 2700 kCal/kWh. Whereas in case of Chandrapura TPS the actual average heat rate for five year has been 2978 kCal/kWh as against approved norm of 3100 kCal/kWh which may be on account of addition of 250 MW units. The Commission therefore proposes to retain the norms for Bokaro TPS and Chandrapura TPS (Unit 1-3). With regards to Durgapur TPS the actual average heat rate works out to around 2918 kCal/kWh as against the approved norm of 2820 kCal/kWh. The Commission however, proposes to retain the norm for the station at 2820 kCal/kWh.

16.5.7 For lignite fired stations the actual data suggests that the current norms are almost close to the actual heat rates achieved for NLC TPS-II and NLC TPS-I Expansion stations and therefore the Commission proposes to retain the norms for the two stations. NLC TPS- I station is the oldest station of NLC and due to the vintage of this station relaxed heat rate was approved. The actual five year average heat rate of 3932 kCal/kWh achieved by the station is slightly less than the current norm of 4000 kCal/kWh approved in Tariff Regulations, 2009. The Commission considering the vintage of the station proposes to retain the same level of heat rate for the next Control Period.

16.5.8 For Gas based generating station, the Commission for the purpose of determination of the norm has analysed the actual data as submitted by the Generating Stations.

16.5.9 For new coal based generating stations, as per the Tariff Regulations for 2009-2014, the margin of 6.5% over and above design heat rate is allowed. In this regard, the Commission has gone through the actual heat rate achieved by existing generating station and on the basis of the same proposes to review the same considering some of the existing central generating stations.

16.5.10The Commission observed that in case of Simhadri Power Station which comprises of four 500 MW Units the design turbine cycle heat rate is 1944.4 kCal/kWh for Unit 1 and 2 (Stage – I) and 1932.50 for Unit 3 and 4

(Stage-II). Further the boiler efficiency for stage I is 87.27% whereas for Stage II is 84.50%. The Design heat rate therefore as computed works out to around 2228kCal/kWh and 2290 kCal/kWh for stage I and stage II respectively. By considering the current norm of 6.5% margin above the design heat rate results in a heat rate of 2373 kCal/kWh and 2435 kCal/kWh for Stage I and Stage II respectively and the weighted average heat rate works out to 2404 kCal/kWh. However, the actual five year average heat rate for the station works out to be 2356 kCal/kWh. Similar is the case for other units as well.

16.5.11 The Commission therefore proposes that the norm can be slightly normalised to reflect the current operational efficiencies of the stations and therefore intends to bring down the margin to 4.50% from the current 6.50%. Further, with regards to new generating stations based on coal rejects the Commission proposes to keep the above norm applicable for such generating stations, however, for such generating stations the design heat rate shall be approved by the Commission on case to case basis.

16.5.12 With regards to gas/liquid based thermal generating station the Commission proposes to retain the current norm for the new generating stations.

16.6 Proposed Norms

a. Existing Thermal Generating Station

(i) Existing Coal-based Thermal Generating Stations, other than those covered under clauses (b) and (c) below

200/210/250 MW Sets	**500 MW Sets (Sub-critical)**
2425 kCal/kWh	2375 kCal/kWh

Note 1

In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the gross station heat rate shall be 40 kCal/kWh lower than the gross station heat rate specified above.

Note 2

For the generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average gross station heat rate of the combinations.

(ii) Thermal generating stations of NTPC Ltd.:

Badarpur TPS	2750 kCal/kWh
Talcher TPS	2850 kCal/kWh
Tanda TPS	2750 kCal/kWh

(iii) Thermal Generating Stations of Damodar Valley Corporation (DVC):

Bokaro TPS	2700 kCal/kWh
Chandrapura TPS (Unit 1 to 3)	3100 kCal/kWh
Durgapur TPS	2820 kCal/kWh

(iv) Lignite-fired Thermal Generating Stations

For lignite-fired thermal generating stations, except for TPS-I and TPS-II (Stage I & II) of Neyveli Lignite Corporation Ltd, the gross station heat rates specified under sub-clause (i) for coal-based thermal generating stations shall be applied with correction, using multiplying factors as given below:

(i) For lignite having 50% moisture: 1.10

(ii) For lignite having 40% moisture: 1.07

(iii) For lignite having 30% moisture: 1.04

(iv) For other values of moisture content, multiplying factor shall be pro-rated for moisture content between 30-40% and 40-50% depending upon the rated values of multiplying factor for the respective range given under sub-clauses (a) to (c) above.

(v) TPS-I and TPS-II (Stage I & II) of Neyveli Lignite Corporation Ltd:

TPS-I 4000 kCal/kWh

TPS-II 2900 kCal/kWh

TPS- I (Expansion) 2750 kCal/kWh

(vi) Open Cycle Gas Turbine/Combined Cycle generating stations:

Existing generating stations of NTPC Ltd and NEEPCO

Name of generating station	Combined cycle (kCal/kWh)	Open Cycle (kCal/kWh)
Gandhar GPS	2040	2960
Kawas GPS	2050	3010
Anta GPS	2075	3010
Dadri GPS	2000	3010
Auraiya GPS	2100	3045
Faridabad GPS	1975	2900
Kayamkulam GPS	2000	2900
Assam GPS	2500	3440
Agartala GPS		3700
Sugen	1850	2685
Ratnagiri	1850	2685

(b) New Thermal Generating Station achieving COD on or after 1.4.2014

(a) Coal-based and lignite-fired Thermal Generating Stations

= 1.045 X Design Heat Rate (kCal/kWh)

Where the Design Heat Rate of a generating unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR, zero percent make up, design coal and design cooling water temperature/back pressure.

Provided that the design heat rate shall not exceed the following maximum design unit heat rates depending upon the pressure and temperature ratings of the units:

Pressure Rating (Kg/cm2)	150	170	170	247
SHT/RHT (0C)	535/535	537/537	537/565	565/593
Type of BFP	Electrical Driven	Turbine Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1955	1950	1935	1830
Min. Boiler Efficiency				
Sub-Bituminous Indian Coal	0.87	0.87	0.87	0.87
Bituminous Imported Coal	0.89	0.89	0.89	0.89
Max Design Unit Heat Rate (kCal/kWh)				
Sub-Bituminous Indian Coal	2247	2241	2224	2103
Bituminous Imported Coal	2197	2191	2174	2056

Provided further that in case pressure and temperature parameters of a unit are different from above ratings, the maximum design unit heat rate of the nearest class shall be taken:

Provided also that where unit heat rate has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers, the unit design heat rate shall be arrived at by using guaranteed turbine cycle heat rate and boiler efficiency.

Provided further, wherein the boiler efficiency is below 87% for Sub-bituminous Indian coal and 89% for bituminous imported coal the same shall be considered as 87% and 89% respectively for Sub-bituminous Indian coal and bituminous imported coal for computation of station heat rate.

Provided also that if one or more generating units were declared under commercial operation prior to 1.4.2014, the heat rate norms for those generating units as well as generating units declared under commercial operation on or after 1.4.2014 shall be lower of the heat rate norms arrived at by above methodology and the norms as per the regulation 36(C)(a)(i):

Provided also that in case of lignite-fired generating stations (including stations based on CFBC technology), maximum design heat rates shall be increased using factor for moisture content given in Regulation sub-clause (C)(a)(iv) of this regulation:

Provided also that for Generating stations based on coal rejects, the Commission will approve the Design Heat Rate on case to case basis.

<u>Note</u>: In respect of generating units where the boiler feed pumps are electrically operated, the maximum design unit heat rate shall be 40 kCal/kWh lower than the maximum design unit heat rate specified above with turbine driven BFP.

(b) Gas-based / Liquid-based thermal generating unit(s)/ block(s)

= 1.05 X Design Heat Rate of the unit/block for Natural Gas and RLNG (kCal/kWh)

= 1.071 X Design Heat Rate of the unit/block for Liquid Fuel (kCal/kWh)

Where the Design Heat Rate of a unit shall mean the guaranteed heat rate for a unit at 100% MCR and at site ambient conditions; and the Design Heat Rate of a block shall mean the guaranteed heat rate for a block at 100% MCR, site ambient conditions, zero percent make up, design cooling water temperature/back pressure.

17 Auxiliary Energy Consumption

17.1 Background

17.1.1 The Commission in its Tariff Regulations, 2001 prescribed separate norms for units of 200 MW series and units of 500 MW series. The Commission for these units specified different norms for units operating with and without cooling tower. The Commission further in case of 500 MW series prescribed separate norms for units operating with electrical Boiler Feed Pumps (BFP) and Steam driven BFP. The Commission further prescribed an additional 0.50% APC for units under stabilisation period. The above norms were applicable uniformly for coal as well as lignite fired stations. The Commission for gas based stations specified separate norms for Open Cycle Operation and Combined Cycle Operations.

17.1.2 The Commission in its subsequent Tariff Regulations, 2004 stipulated separate norms for coal and lignite based stations. Further, the Commission also specified relaxed norms for Talcher and Tanda TPS taking cognisance of smaller sized units and vintage of these stations. In case of lignite fired stations the Commission except for TPS-I and TPS-II specified additional 0.50% over and above that allowed for coal fired stations as auxiliary consumption. The Commission for TPS-I and TPS-II specified relaxed norms taking cognisance of unit sizes and vintage of the units. The Commission further prescribed an additional 0.50% APC for units under stabilisation period.

17.1.3 The Commission in the Tariff Regulations, 2009 retained the norms for 200 MW series however the Commission tightened the norms for 500 MW series based on actual performance of plants. However, in Tariff Regulations, 2009 the Commission did not specify any separate norms for stabilisation period.

17.2 Issues brought out in Approach Paper

17.2.1 The Commission in its Approach Paper brought out the following issue inviting suggestions.

"In view of the above, the stakeholders are requested to share their experiences to assess if there is a scope for improvement in the norms for auxiliary consumption.

A fresh view may be required on inclusion of colony and construction power in auxiliary consumption.

Further, the norm for 300/330 MW units may have to be specified separately for which suggestions/comments are invited along with authentic support data available, if any."

17.3 Existing norms vis-à-vis Actual data

17.3.1 Existing Norms

The existing regulations for tariff period 2009-14 as amended provide following norms for Gross Station Heat Rate for the thermal generating stations:

a) Coal-based generating stations except at (b) below:

S. No.	***Unit Size***	***With Natural Draft cooling tower or without cooling tower***
(i)	*200 MW series*	*8.5%*
(ii)	*500 MW & Above*	
	Steam driven boiler feed pumps	*6.0%*
	Electrically driven boiler feed pumps	*8.5%*

Provided further that for thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%.

(b) Other Coal-based generating stations:

(i)	*Talcher Thermal Power Station*	*10.50%*
(ii)	*Tanda Thermal Power Station*	*12.00%*

(iii)	*Badarpur Thermal Power Station*	*9.50%*
(iv)	*Bokaro Thermal Power Station*	*10.25%*
(v)	*Chandrapura Thermal Power Station*	*11.50%*
(vi)	*Durgapur Thermal Power Station*	*10.50%*

(c) Gas Turbine /Combined Cycle generating stations:

(i) Combined Cycle 3.0%

(ii) Open Cycle 1.0%

(d)Lignite-fired thermal generating stations:

(i) All generating stations with 200 MW sets and above:

The auxiliary energy consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (iv) (a) above.

Provided that for the lignite fired stations using CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (iv) (a) above.

(ii) Barsingsar Generating station of NLC using CFBC technology: 11.50%

(iii) TPS-I, TPS-I (Expansion) and TPS-II Stage-I&II of Neyveli Lignite Corporation Ltd.:

TPS-I	*12.00%*
TPS-II	*10.00%*
TPS-I (Expansion)	*9.50%*

17.3.2 Actual Auxiliary Consumption

The Actual Auxiliary Consumption (APC) for these stations is as shown in the table below:

Stations	**FY 2008-09**	**FY 2009-10**	**FY 2010-11**	**FY 2011-12**	**FY 2012-13**	**Five year Average**	**Weighted Average Norm**

Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Five year Average	Weighted Average Norm
Singrauli Super Thermal Power Station	6.96%	7.01%	7.07%	7.01%	6.99%	7.01%	7.25%
Rihand Super Thermal Power Station	6.30%	6.53%	6.69%	6.84%	6.99%	6.67%	7.30%
Tanda Thermal Power Station	11.99%	11.61%	11.37%	11.65%	11.83%	11.69%	12.00%
Unchahar FGUTPP	7.93%	7.85%	8.37%	8.29%	8.23%	8.13%	8.50%
Korba Super Thermal Power Station	5.75%	6.09%	6.54%	6.16%	6.18%	6.15%	7.08%
Vindhyachal Super Thermal Power Station	6.11%	6.06%	6.12%	6.40%	6.28%	6.19%	7.24%
Sipat Super Thermal Power Station	5.04%	5.60%	5.52%	5.75%	6.28%	5.64%	6.50%
Ramgundam Super Thermal Power Station	5.57%	5.51%	5.56%	5.90%	5.90%	5.68%	7.08%
Simhadri Super Thermal Power Station	5.24%	5.43%	5.49%	5.74%	5.98%	5.58%	6.00%
Farakka Super Thermal Power Station	6.78%	7.20%	6.52%	6.83%	6.72%	6.81%	7.07%
Kahalgaon Super Thermal Power Station	8.60%	7.85%	7.47%	7.98%	7.68%	7.92%	7.40%
TTPS Thermal Power Station	9.70%	10.25%	10.37%	10.43%	10.31%	10.21%	10.50%
Tal kaniha Super Thermal Power Station	5.50%	5.67%	5.79%	5.94%	6.49%	5.88%	6.00%
Badarpur Thermal Power Station	7.49%	7.97%	8.37%	8.48%	8.04%	8.07%	9.50%
Dadri Thermal Power Station	7.47%	7.86%	6.93%	6.32%	6.52%	7.02%	7.15%
NSPCL – Bhilai Ext	NA	8.68%	8.54%	8.45%	8.64%	8.58%	8.50%

Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Five year Average	Weighted Average Norm
Bokaro TPS	10.57%	10.75%	11.54%	11.68%	11.19%	11.15%	10.57%
Chandrapura TPS	9.42%	9.31%	9.01%	10.04%	9.54%	9.46%	9.42%
Durgapur TPS	10.06%	10.62%	11.10%	10.84%	10.68%	10.66%	10.06%
Mejia TPS	10.50%	10.92%	10.72%	10.22%	8.68%	10.21%	10.50%
NLC TPS- I	12.19%	11.76%	12.32%	11.96%	11.55%	11.96%	12.00%
NLC TPS-II Stg I	9.67%	9.61%	9.88%	9.60%	9.67%	9.69%	10.00%
NLC TPS-II Stg II	9.97%	9.53%	9.51%	9.66%	9.66%	9.67%	10.00%
NLC TPS – I Exp	8.56%	8.70%	8.46%	7.65%	8.56%	8.39%	9.50%
Barsingsar TPS	17.3.3	17.3.4	17.3.5	17.3.6	12.68%	12.68%	11.50%

Actual Auxiliary Consumption for Gas based Stations of NTPC and NEEPCO other than small gas turbine stations

S. No	Stations	Capacity/ Configuration	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Current Norm	Five Year Average
1	Anta GPS	419.33 MW (88.71*3 GTs + 153.2*1 STG)	2.23%	2.16%	2.58%	1.93%	2.22%	3.00%	2.23%
2	Auraiya GPS	663.36 MW 4 GT (111.19MW EACH) +2ST(109.3 MW EACH)	2.27%	2.39%	2.53%	2.56%	2.81%	3.00%	2.51%
3	Kawas GPS	656.2 MW (106*4+116.1*2)	1.52%	1.70%	1.87%	1.80%	2.06%	3.00%	1.79%
4	Gandhar GPS	657.39 MW	1.78%	1.37%	1.61%	1.70%	1.77%	3.00%	1.65%
5	Faridabad GPS	431.586 MW (2X137.758 MW GT+1X156.07 MW ST)	2.46%	2.27%	2.30%	2.24%	2.47%	3.00%	2.35%
6	Dadri Gas Power Plant	829.78	2.53%	2.35%	2.38%	2.40%	2.40%	3.00%	2.41%

S. No	Stations	Capacity/ Configuration	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Current Norm	Five Year Average
7	Kayamkulam Gas Power Plant	359 MW(2*115 MW + 1*129 MW)	1.49%	1.44%	2.37%	3.26%	2.52%	3.00%	2.22%
NEEPCO									
1	Assam GPS	291 MW, (6 X 33.5 +3 X 30) MW	1.77%	1.82%	1.55%	1.29%	2.68%	3.00%	1.82%
2	Agartala GPS	4 X 21 MW = 84 MW	0.62%	0.61%	1.81%	1.90%	1.72%	1.00%	1.33%

17.3.7 Variance Analysis

17.3.7.1 In case of NTPC generating stations the actual five year average auxiliary consumption for most of the stations except for Kahalgaon TPS is lower than the weighted average norm for the station. In most of the cases the norm is slightly higher than the actual auxiliary consumption that the stations have been able to achieve. In case of Badarpur TPS, the norms for auxiliary consumption was relaxed taking into consideration the plant vintage, however the actual data suggests that the actual five year average auxiliary consumption is 8.07% as against the actual norm of 9.50% allowed for the station.

17.3.7.2 In case of NLC stations the actual auxiliary consumption for the stations is almost at the level of current norms except in case of NLC TPS- I Expansion wherein the actual five year average auxiliary consumption works out to around 8.39% as against the norm of 9.50%.

17.3.7.3 Similarly in case of Badarpur TPS the actual five year average Auxiliary consumption computed is 8.07% which is much lower than the relaxed approved norm of 9.50%.

17.3.7.4 For DVC stations the actual APC is higher than the norms except in case of Chandrapura TPS wherein the actual APC is considerably lower than the norm of 11.50% approved for first three units of 130 MW.

17.3.7.5 For NTPC gas based stations the actual auxiliary consumption works out to around 2.50% as against the current norm of 3.00%.

17.3.7.6 For Assam GPS the actual APC works out to be lower than the norm however, for Agartala GPS the actual auxiliary consumption is working out to be higher than the allowed norm.

17.4 Stakeholders Responses

17.4.1 The extracts of the suggestions received from various stakeholders on the issues flagged above are as follows:

i. Stakeholders suggested that the auxiliary power consumption norm should be derived based on the actual past 4-5 years data or on the basis of design value whichever is lower. Further some of the stakeholders suggested that there should be an operating margin allowed over and above the APC derived on actuals for past year and any efficiency gain arising on account of lower APC should be shared with the beneficiaries.

ii. One of the stakeholders suggested that for new generating stations the APC norms can be reduced slightly however, to account for gradual deterioration, a linear indexation mechanism may be introduced for plants more than ten years old. Further, there should be differentiation on APC norms for generating stations based on static excitation system and rotating excitation system (0.35%) for Units size of 200 MW.

iii. Some of the stakeholders suggested that colony consumption and construction power should not form part of auxiliary power consumption. Whereas, some of the stakeholders (mostly generating companies) opined that such consumption should form a part of auxiliary energy consumption.

iv. Some of the stakeholders suggested that additional APC should be allowed for equipment to be installed to comply with environmental norms. In this regards the stakeholders demanded 1%-2% APC for stations with Flue gas desulphurisation units, 0.40% for Additional pump for ash disposal and relaxation on account of desalination plants for coastal plants.

v. Stakeholders suggested that for gas based stations the APC norms should be decided after considering the following:
   a. Size of Units.
   b. Type of Generating Transformers
   c. Special Consideration for gas booster stations run by electrically driven motors.
   d. Partial Loading due to low scheduling and low gas availability resulting in higher APC. In this regard one of the stakeholders also suggested that the Commission should specify APC norms vis-à-vis PLF in steps of 5%.

vi. Further, one of the stakeholder suggested that the existing norms of APC may be continued with additional margin on account of following:
   a. Additional margin of 3.50% for Motor Driven Boiler Feed Pump (MDBFP)
   b. Additional margin of 1% for stations with Tube Mills
   c. Additional margin of 0.50% for pipe conveyors and associated conveyors.
   d. Additional margin of 0.50% for distant located water supply.
   e. Additional margin of 0.20% for coal quality deterioration.

vii. One of the stakeholders suggested that there should be separate norms for different unit sizes operating in India.

viii. Some of the stakeholders suggested APC norm of 12% for stations based on CFBC technology.

17.5 Commission's Proposal

17.5.1 The Commission after going through the suggestions and comments received from the stakeholders and the actual auxiliary consumption data for the stations for the past five years proposes to set norms on the basis of past five year actual data. In this regard in case of NTPC stations the actual auxiliary consumption is very close to the current norms and therefore the Commission proposes to retain the earlier norms for auxiliary consumption.

17.5.2 With regards to NLC stations as the actual auxiliary consumption is close to the current norms for all the stations except for TPS I expansion the Commission proposes to retain the norms for auxiliary consumption for these stations. With regards to TPS I Expansion unit the five year actual APC is around 8.36% as against the approved norms of 9.50%. The Commission therefore proposes to revise the norm for the station to 8.50% from the current norm of 9.50%. Similarly for Badarpur TPS the actual five year average auxiliary consumption for the station is 8.07% as against the actual norm of 9.50%. The Commission therefore proposes to revise the norms for the station to 8.50%.For generating stations based on Coal Rejects the Commission proposes to approve the norm of 10%.

17.5.3 With regards to gas based generating station the Commission proposes to revise the earlier norm of 3% for combined Cycle generation to 2.50% however for open cycle the Commission proposes to retain the norm of 1%.

17.5.4 As regards the colony consumption, the Commission proposes that the same should not form a part of auxiliary consumption as the same doesn't form part of auxiliary system of the power plant. With regards to inclusion of construction power the Commission proposes that construction power is an expense of capital nature which should ideally form a part of capital cost of the unit under construction. There is no rationale for including the same in auxiliary consumption of other unit. This is more so important as the beneficiaries of the two units may be different and therefore allowing expenses of one unit on other shall not be justified principally and therefore the Commission proposes that the same should be accounted separately.

17.6 Proposed Norms

1. Auxiliary Energy Consumption:

a) Coal-based generating stations except at (b) below:

	Unit Size	**With Natural Draft cooling tower or without Cooling Tower**
(i)	200 MW series	8.5%
(ii)	300/330/350/500 MW and above	
	Steam driven boiler feed pumps	6.0%
	Electrically driven boiler feed pumps	8.5%

Provided further that for thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%.

(b) Other Coal-based generating stations:

(i)	Talcher Thermal Power Station	10.50%
(ii)	Tanda Thermal Power Station	12.00%
(iii)	Badarpur Thermal Power Station	8.50%
(iv)	Bokaro Thermal Power Station	10.25%
(v)	Chandrapur Thermal Power Station	9.50%
(vi)	Durgapur Thermal Power	10.50%

	Station	

(c) Gas Turbine /Combined Cycle generating stations:

(i) Combined Cycle 2.5%

(ii) Open Cycle 1.0%

(d) Lignite-fired thermal generating stations:

(i) All generating stations with 200 MW sets and above:

The auxiliary energy consumption norms shall be the auxiliary energy consumption norms of coal-based generating stations at (v) (a) above

Provided that for the lignite fired stations using CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (v) (a) above.

(ii) Barsingsar Generating station of NLC using CFBC technology: 11.50%

(iii) TPS-I, TPS-I (Expansion) and TPS-II Stage-I&II of Neyveli Lignite Corporation Ltd.:

TPS-I	12.00%
TPS-II	10.00%
TPS-I (Expansion)	8.50%

(d) Generating Stations based on coal rejects : 10%

18 Secondary Fuel Oil Consumption

18.1 Background

18.1.1 The Commission in its Tariff Regulations, 2001 specified different norms for stations during and after stabilisation period. However, the said norms was uniform for coal as well as lignite fired stations. In its subsequent Regulations, 2004 the Commission specified separate norms for coal fired stations and lignite fired stations. The Commission based on the actual performance data prescribed tighter norms for coal as well as lignite fired stations. The Commission further taking into cognisance the vintage of the units and smaller unit size specified relaxed norms for Tanda and Talcher thermal stations.

18.1.2 The Commission in Regulations, 2009 further tightened up the norms based on the actual performance data. In this Regulation the Commission prescribed relaxed norms for DVC stations owing to lower achievable performance of these stations in the past.

18.2 Issues brought out in Approach Paper

18.2.1 The Commission in its Approach Paper brought out the following issue inviting suggestions:
In view of the above, stakeholders are requested to share their experiences with the supporting data to assess if there is a scope for revision of the existing norms of secondary fuel oil consumption.

18.3 Existing norms vis-à-vis Actual data

18.3.1 *Existing Norms*

a) *Coal-based generating stations other than at (c) below :1.0 ml/kWh*

b) *(i) Lignite fired generating stations except stations based on CFBC technology and TPS-I :2.0 ml/kWh*
(ii) TPS-I :3.5 ml/kWh
(iii)Lignite fired stations based on CFBC technology :1.25 ml/kWh

c) *Coal-based generating stations of DVC*

Mejia TPS Unit – I to IV	*2.0 ml/kWh*
Bokaro TPS	*2.0 ml/kWh*

Chandrapur TPS	*3.0 ml/kWh*
Durgapur TPS	*2.4 ml/kWh*

18.3.2 Actual Secondary Fuel Oil Consumption

The actual secondary fuel oil consumption for various generating stations is as shown below:

S. No	Stations	Norm (ml/kWh)	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Five year Average
1	Singrauli STPS	1	0.29	0.24	0.24	0.65	0.21	0.33
2	Rihand STPS	1	0.16	0.20	0.21	0.25	0.51	0.27
3	Tanda TPS	1	0.70	0.44	0.70	0.48	0.59	0.58
4	Unchachar FGUTPP	1	0.27	0.17	0.33	0.76	0.40	0.39
5	Korba STPS	1	0.08	0.09	0.12	0.22	0.10	0.12
6	Vindhyachal STPS	1	0.20	0.18	0.12	0.21	0.21	0.19
7	Sipat STPS	1	0.53	0.20	0.21	0.11	0.50	0.31
8	Ramgundam STPS	1	0.16	0.10	0.13	0.12	0.22	0.15
9	Simhadri STPS	1	0.10	0.22	0.09	0.21	0.42	0.21
10	Farakka STPS	1	1.21	0.83	0.39	0.60	1.53	0.91
11	Kahalgaon STPS	1	1.19	1.00	0.72	0.83	0.66	0.88
12	Talcher TPS	1	0.33	0.63	0.52	0.44	0.38	0.46
13	Tal kaniha STPS	1	0.64	0.63	0.45	0.40	0.59	0.54
14	Badarpur TPS	1	0.59	0.75	0.81	1.00	1.51	0.93
15	Dadri TPS	1	1.81	1.03	1.08	1.01	1.10	1.21
NLC Stations								
1	NLC TPS-I	3.50	2.28	1.22	2.09	1.33	1.22	1.63

S. No	Stations	Norm (ml/kWh)	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Five year Average
2	NLC TPS-I Exp	2	1.30	1.22	1.80	0.90	0.69	1.18
3	NLC TPS Stg-I	2	1.36	1.32	0.81	0.65	0.48	0.92
4	NLC TPS Stg-II	2	1.49	0.49	0.58	0.59	0.49	0.73
5	Barsingsar TPP	1.25					0.56	0.56
DVC Stations								
1	Bokaro	2.0	2.80	1.68	1.39	1.55	1.43	1.77
2	Chandrapur	3.0	1.53	5.02	2.41	3.37	1.53	2.77
3	Durgapur	2.4	6.33	4.32	3.58	3.11	3.77	4.22
4	Mejia	2.0	0.00	0.00	1.79	1.95	1.49	1.74

18.3.3 Variance Analysis

18.3.3.1 The Commission in its present norms has specified a specific secondary fuel oil consumption of 1ml/kWh however, almost all the stations of NTPC except for Dadri TPS has been able to achieve SFOC below 1 ml/kWh. Even in case of Dadri TPS the secondary fuel oil consumption in recent years have been around 1 ml/kWh.

18.3.3.2 With regards to lignite fired stations the actual five year average data is less than the current norms as evident from the table above.

18.3.3.3 For DVC stations, the average actual secondary fuel oil consumption for last five years is lower than the norm except in case of Durgapur station.

18.4 Stakeholders Responses

i. The Stakeholders have suggested that Secondary Fuel Oil Consumption (SFOC) norm should factor in more number of shutdowns in future on account of anticipated fuel shortages that the stations may have to face in the next Control Period. Further, the norm should specify the number of start-ups included and should also specify additional secondary fuel oil to be considered for each start-ups in excess of specified number not due to fault of generating company.

ii. Some stakeholders suggested that except for lower capacity old units, on the basis of data available with the State Commissions, SFOC may be considered at lower level at around 0.75 ml/kWh.

iii. Most of the generating stations suggested that the present norm should be continued.

iv. Some of the Stakeholders suggested that the SFOC norms should be determined on the basis of the last 4 to 5 years actual data. Further, the norm should be determined considering operating margin over and above actual data with sharing of gains on account of lower consumption to be passed on to the consumers.

v. One of the stakeholder suggested that SFOC should be made a part of Energy charge and not Annual Fixed Charges.

vi. SFOC norm during stabilisation period should be separately specified.

18.5 Commission's Proposal

18.5.1 The Commission has gone through the suggestions of various stakeholders and analysed the past years' actual data. Based on the analysis of actual data for last five years, it is observed that for pit head coal based generating stations the actual SFOC have been around 0.50 ml/kWh as compared to non pit head stations like Badarpur TPS, Dadri TPS and Tanda TPS wherein the actual SFOC is close to 1ml/kWh. The Commission therefore, proposes to revise the norms for secondary fuel oil consumption on the basis of pit head and non pit head stations. The Commission proposes to approve a norm of 0.50 ml/kWh and 1 ml/kWh for pit head and non pit head stations respectively.

18.5.2 With regards to lignite fired stations for TPS-I it is observed that actual five year average SFOC works out to around 1.50 ml/kWh, the Commission therefore proposes to revise the norm to 1.50 ml/kWh from the current 3 ml/kWh. For lignite fired stations based on CFBC technology the Commission proposes to revise the current norm of 1.25 ml/kWh to 1 ml/kWh. In case of DVC stations the five year actual average value for the stations have been lower than the norm and the Commission therefore proposes to revise the norms for these stations based on the actual achieved during FY 2008-09 to FY 2012-13.

18.5.3 For new generating stations based on coal rejects the Commission proposes to approve SFOC norm of 2 ml/kWh.

18.6 Proposed Norms

(a) Coal-based generating stations other than at (c) below

Pit Head Stations – **0.50 ml/kWh**

Non-Pit Head Stations – **1.00 ml/kWh**

(b) (i) Lignite-fired generating stations except stations based on CFBC technology and TPS-I 2ml/kWh

(ii) TPS-I **1.5ml/kWh**

(iii) Lignite-fired generating stations based on CFBC technology **1.00 ml/kWh**

(c) Coal-based generating stations of DVC

Mejia TPS	1.0 ml/kWh
Bokaro TPS	1.5 ml/kWh
Chandrapur TPS	1.5 ml/kWh
Durgapur TPS (Unit 1-3)	2.4 ml/kWh

(d) Generating Stations based on Coal Rejects: 2 ml/kWh

19 Transit and Handling Losses

19.1 Background

The Commission in its Tariff Regulations, 2001 did not specify norms for transit and handling losses. However, the Commission in its subsequent regulations approved separate norms for pit Head and non pit head stations. The Commission in its Regulations, 2009 also approved separate norms for pit head and non pit head stations.

19.2 Issues brought out in Approach Paper

"Suggestion/comments of stakeholder are solicited with supporting data to review existing norms of transit & handling losses."

19.3 Existing norms vis-à-vis Actual data

19.3.1 Existing Norms

The existing norms for pit head and non pit head stations is as shown below:

a) *Pit Head Stations* - *0.20%*

b) *Non Pit Head Stations* - *0.80%*

19.3.2 Actual Transit and Handling Losses

The actual transit and handling losses for pit head and non pit head stations of NTPC stations are as follows:

Table: Actual Transit and Handling Losses for Pit Head Stations

S. No	Pit Head Stations	FY 2008-09		FY 2009-10		FY 2010-11		FY 2011-12		FY 2012-13		Five Year Average	
		D & E	I	D & E	I	D & E	I	D & E	I	D & E	I	D & E	I
1	Singrauli STPS	0.12%	0.00%	0.14%	0.00%	0.19%	0.18%	0.02%	0.12%	0.20%	0.00%	0.13%	0.06%
2	Rihand STPS	0.16%	0.06%	0.10%	0.01%	0.10%	0.01%	0.10%	0.00%	0.11%	0.01%	0.11%	0.02%
3	Korba STPS	0.23%	0.00%	0.13%	0.43%	0.16%	0.16%	0.18%	0.16%	0.19%	0.18%	0.18%	0.19%
4	Vindhyachal STPS	0.23%	0.03%	0.19%	0.17%	0.19%	0.19%	0.17%	0.19%	0.19%	0.18%	0.19%	0.15%
5	Sipat STPS	0.28%	0.00%	0.34%	0.37%	0.09%	0.08%	0.12%	0.17%	0.12%	0.24%	0.19%	0.17%

S. No	Pit Head Stations	FY 2008-09		FY 2009-10		FY 2010-11		FY 2011-12		FY 2012-13		Five Year Average	
		D & E	I	D & E	I	D & E	I	D & E	I	D & E	I	D & E	I
6	Ramgundam STPS	0.22%	0.14%	0.18%	0.11%	0.18%	0.04%	0.11%	0.00%	0.17%	0.04%	0.17%	0.07%
7	Farakka STPS	0.26%	0.13%	0.20%	0.13%	0.19%	0.11%	0.21%	0.11%	0.19%	0.11%	0.21%	0.12%
8	Kahalgaon STPS	0.18%	0.05%	0.16%	0.08%	0.12%	0.08%	0.13%	0.09%	0.13%	0.09%	0.14%	0.08%
9	Talcher TPS	0.23%	0.10%	0.18%	0.05%	0.13%	0.08%	0.18%	0.10%	0.16%	NA	0.18%	0.08%
10	Tal kaniha STPS	0.18%	0.02%	0.18%	0.03%	0.19%	0.03%	0.18%	0.07%	0.24%	0.10%	0.19%	0.05%

D&E = Domestic and E-auction Coal; I = Imported Coal

Table: Actual Transit and Handling Losses for Non Pit Head Stations

S. No	Non Pit Head Stations	FY 2008-09		FY 2009-10		FY 2010-11		FY 2011-12		FY 2012-13		Five year average	
		D & E	I	D & E	I	D & E	I	D & E	I	D & E	I	D & E	I
1	Tanda TPS	0.47%	NA	0.33%	NA	0.49%	NA	0.58%	NA	0.73%	NA	0.52%	NA
2	Unchachar FGUTPP	0.60%	0.25%	0.74%	0.16%	0.80%	0.17%	0.72%	0.18%	0.81%	0.17%	0.73%	0.19%
3	Simhadri STPS	0.53%	0.29%	0.61%	0.10%	0.74%	0.14%	0.71%	0.14%	0.72%	0.18%	0.66%	0.17%
4	Badarpur TPS	0.80%	0.20%	0.80%	0.20%	0.80%	0.20%	0.80%	0.20%	0.80%	0.20%	0.80%	0.20%
5	Dadri TPS	0.73%	0.37%	0.76%	0.24%	0.74%	0.23%	0.75%	0.19%	0.77%	0.18%	0.75%	0.24%

D&E = Domestic and E-auction Coal; I = Imported Coal

19.3.3 Variance Analysis

The Commission in its current norms has approved transit and handling loss of 0.20% for pit head stations against which the actual five year average data for almost all the stations are very close to the norm. For some of the stations like Singrauli, Rihand and Kahalgoan TPS the actual transit and handling losses is lower than the norm. In case of non pit head stations, the transit and handling losses for three of the stations are close to the norm whereas for couple of stations like Tanda and Simhadri the actual losses are less than the current norm.

19.4 Stakeholders Reponses

The extracts of the suggestions received from various stakeholders on the issues flagged above are as follows:

i. Stakeholders submitted that imported coal require port handling and will have handling loss higher than normal coal transportation from collieries through railway or belt conveyors and further, imported coal has higher free moisture content and during transportation the moisture content gets altered. Therefore additional transit loss should be considered to the extent of this moisture loss.

ii. One of the stakeholders submitted that the definition of pit head and non pit head should be clarified/defined in the Regulation.

iii. Some of the stakeholders suggested that the present norms for pit head and non pit head based stations should be continued.

iv. Some of the stakeholders submitted that the present norms are not adequate and the actual transit loss is higher and suggested to increase the present norms to 1.50% to 2.50%.

v. Some of the stakeholders submitted that the transit and handling losses for non pit head based stations should be linked to distance of transportation from the coal mine.

vi. One of the stakeholders submitted that the norm for transit and handling loss of coal should be determined separately for imported coal based plants and for washed coal.

19.5 Commission's Proposal

19.5.1 The Commission after going through the suggestions and the actual data is of the view that the current norms are close to the actual and therefore the Commission proposes to retain the current norm for transit and handling losses for pit head and non pit head stations. With regards to transit and handling losses for imported coal the Commission observes that there is some transit and handling losses the Commission based on the five year actual data proposes to approve a norm of 0.20% as allowable transit and handling loss for imported coal.

19.6 Proposed Norms

Pithead generating stations	:	0.2%
Non-pithead generating stations	:	0.8%

Provided that in case of pit head stations if coal or lignite is procured from sources other than the pit head mines which is transported to the station through rail transit loss of 0.80% shall be applicable.

Provided further that in case of imported coal the transit and handling losses shall be 0.20%.

20 Norms of Operation for Hydro Generating Stations

20.1 Background

20.1.1 The Commission in its first Regulations, 2001 approved following norms with regards to hydro generating stations:

1) Normative Capacity Index
2) Auxiliary Consumption
3) Transformational Losses

20.1.2 Moving ahead, the Commission in its subsequent regulation in Regulations, 2004 also approved the above norms with regard to hydro generating stations however, the Commission approved separate norms for capacity index for first year of commercial operations and thereafter.

20.1.3 The Commission in its Tariff Regulations, 2009 introduced new norms of Normative Annual Plant Availability Factor (NAPAF) along with amendment to recovery mechanism linked to NAPAF instead of Capacity Index. Further the Commission approved recovery mechanism for fixed charges to recover only 50% of Annual fixed charges corresponding to NAPAF and 50% to be recovered as energy charge.

20.2 Issues brought out in Approach Paper

20.2.1 The Commission in its approach paper stated that the existing Operational norms of Hydro generation include norms for auxiliary consumption, transformation losses and normative annual plant availability factor. With regard to the same the Commission invited suggestion of the following:

In view of the above, comments are invited on the need to review the existing approach for operational norms for further improvement and Normative Annual Plant Availability Factor (NAPAF).

20.3 Existing norms vis-à-vis Analysis of Actual Performance

20.3.1 Existing Norms

(i) Normative annual plant availability factor (NAPAF) for hydro generating stations:

...

Station	Type of Plant	Plant Capacity (Number of Units x MW)	NAPAF (%)
NHPC			
Chamera – 1	Pondage	3 x 180	90
Biarasiul	Pondage	3 x 60	85
Loktak	Storage	3 x 35	85
Chamera-II	Pondage	3 x 100	90
Rangit	Pondage	3 x 20	85
Dhauliganga	Pondage	4 x 70	85
Teesta – V	Pondage	3 x 170	85
Dulhasti	Pondage	3 x 130	90
Salal	ROR	6 x 115	60
Uri	ROR	4 x 120	60
Tanakpur	ROR	3 x 31.4	55
NHDC			
Indirasagar	Storage	8 x 125	85
Omkareshwar	Pondage	8 x 65	90
THDC			
TehriStg – 1	Storage	4 x 250	77
SJVNL			
Nathpa Jhakri	Pondage	6 x 250	82
NEEPCO			
KopiliStg – 1	Storage	4 x 50	79
Khandong	Storage	3 x 25	69
Kopili Stg. - 2	Storage	1 x 25	69
Doyang	Storage	3 x 25	73
Ranganadi	Pondage	3 x 135	85
DVC			

Station	*Type of Plant*	*Plant Capacity (Number of Units x MW)*	*NAPAF (%)*
Panchet	*Storage*	*2 x 40*	*80*
Tilaiya	*Storage*	*2 x 2*	*80*
Maithon	*Storage*	*3 x 20*	*80*

(ii) Auxiliary Energy Consumption(AUX)

(a) Surface Hydro Generating Stations

i. with rotating exciters mounted on the generator shaft - 0.7%

ii. with static excitation system - 1%

(b) Underground hydro generating stations

i. with rotating exciters mounted on the generator shaft - 0.9%

ii. *with static excitation system - 1.2%*

20.3.2 Actual NAPAF and Auxiliary Consumption

NAPAF

The actual NAPAF for hydro generating stations for last five years is as shown in the table below:

Station	**Type**	**Current Norm**	**FY 2008-09**	**FY 2009-10**	**FY 2010-11**	**FY 2011-12**	**FY 2012-13**	**Five Year Average**
Bairasul Power Station	Pondage	85%	92.51%	90.34%	94.26%	94.19%	97.29%	93.72%
Loktak Power Station	Storage	85%	86.48%	68.86%	74.75%	79.01%	91.80%	80.18%
Salal Power Station	ROR	60%	49.60%	58.79%	62.41%	63.02%	65.07%	59.78%
Tanakpur Power Station	ROR	55%	51.29%	62.23%	61.75%	64.06%	63.90%	60.65%
Chamera - I Power Station	Pondage	90%	96.62%	96.51%	98.00%	86.41%	96.60%	94.83%
Uri Power Station	ROR	60%	71.36%	71.65%	81.14%	75.06%	79.79%	75.80%
Rangit Power Station	Pondage	85%	89.72%	90.55%	91.28%	92.24%	93.07%	91.37%
Chamera - II Power Station	Pondage	90%	97.44%	96.69%	93.88%	95.52%	95.43%	95.79%
Dhauliganga	Pondage	85%	89.02%	91.57%	90.75%	92.68%	92.59%	91.32%

Station	Type	Current Norm	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Five Year Average
Power Station								
Dulhasti Power Station	Pondage	90%	95.08%	95.58%	91.54%	94.78%	83.89%	92.18%
Teesta- V Power Station	Pondage	85%	74.14%	92.94%	88.38%	86.44%	85.54%	85.49%
Sewa-II Power Station	Pondage	80%			81.14%	84.57%	81.10%	82.27%
Chamera -III Power Station	Pondage	85%					90.48%	90.48%
Indira Sagar	Pondage	85%	97.57%	89.49%	88.40%	90.41%	90.15%	91.20%
Omkareshwar	Pondage	90%	98.79%	99.83%	96.40%	97.58%	97.26%	97.97%
SJVNL	Pondage	82%	96.08%	98.55%	98.32%	104.26%	105.15%	97.97%
THDC	Pondage	77%	80.61%	83.98%	74.41%	85.57%	81.99%	81.31%
Kopili Stg I	Storage	79%	87%	63%	68%	78%	63%	71.87%
DHEP	Storage	73%	97%	62%	77%	74%	66%	75.20%
RHEP	Pondage	85%	98%	95%	90%	94%	95%	94.48%
Khadong	Storage	69%	N/A	64%	61%	76%	74%	68.58%
Kopili Stg II	Storage	69%	N/A	61%	61%	74%	84%	70.26%

Actual Auxiliary Consumption

The actual auxiliary consumption of hydro generating stations for last five years is as shown in the table below:

Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Current Norm	Five Year Average
Bairasul Power Station	0.38%	0.40%	0.39%	0.42%	0.43%	1.00%	0.40%
Loktak Power Station	0.55%	0.46%	0.33%	0.34%	0.37%	1.00%	0.41%
Salal Power Station	0.24%	0.15%	0.14%	0.13%	0.14%	1.00%	0.16%
Tanakpur Power Station	0.64%	0.57%	0.56%	0.57%	0.66%	1.00%	0.60%
Chamera - I Power Station	0.21%	0.20%	0.18%	0.16%	0.17%	1.20%	0.18%
Uri Power Station	0.97%	0.99%	0.96%	0.98%	0.97%	1.20%	0.98%
Rangit Power	0.24%	0.23%	0.23%	0.24%	0.29%	1.00%	0.24%

Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Current Norm	Five Year Average
Station							
Chamera - II Power Station	0.36%	0.38%	0.28%	0.29%	0.29%	1.20%	0.32%
Dhauliganga Power Station	1.22%	1.20%	1.19%	1.19%	1.19%	1.20%	1.20%
Dulhasti Power Station	0.98%	1.01%	0.97%	0.95%	1.04%	1.20%	0.99%
Teesta- V Power Station	0.32%	0.25%	0.22%	0.22%	0.22%	1.20%	0.25%
Sewa-II Power Station	NA		0.99%	1.38%	1.40%	1.00%	1.26%
Chamera -III Power Station	NA				0.91%	1.20%	0.91%
Chutak Power Station	NA				0.13%	1.20%	0.13%
Indira Sagar	0.58%	0.48%	0.46%	0.36%	0.39%	1.00%	0.45%
Omkareshwar	0.49%	0.57%	0.56%	0.47%	0.49%	1.00%	0.51%
SJVNL	0.92%	0.88%	0.88%	0.90%	0.73%	1.20%	0.51%
THDC	1.20%	1.20%	0.61%	0.53%	0.37%	1.20%	0.78%
DHEP	N/A	0.12%	0.29%	0.20%	0.20%	1.00%	0.20%
RHEP	N/A	0.26%	0.35%	0.41%	0.36%	1.00%	0.35%
Kopili II	0.33%	0.32%	0.38%	0.32%	0.28%	1.00%	0.33%

20.3.3 Variance Analysis

20.3.3.1 With regard to availability for hydro generating stations apart from Loktak hydro station all other stations have achieved the NAPAF higher than the norm specified. In case of Loktak hydro station the average five year actual availability achieved is 5% less than the NAPAF approved for the station. In case of Uri station the five year average APAF of 75.80% achieved for the station is considerably higher than the current norm of 60%. Further, five year actual availability for Bairasul, Rangit, Dhauliganga, SJVNL have been relatively higher than the current norms.

20.3.3.2 With regard to auxiliary consumption the five year actual average data in some of the stations suggests that the actual auxiliary consumption is considerably lower than the current norm. These stations are Salal, Chamera I&II, Ranjit and Teesta V and the auxiliary consumption for these stations are considerably below the approved norms.

20.4 Stakeholders Responses

20.4.1 The extracts of the suggestions received from various stakeholders on the issues flagged above are as follows:

i. Some of the stakeholders suggested that the present norms for NAPAF should continue.
ii. There is a need for review of existing values of NAPAF and auxiliary consumption based on actual data of hydro generating stations for last 4 to 5 years. While computing the normative auxiliary consumption for a station, it is necessary to consider the transformation losses separately if the station is with single phase transformer.
iii. One of the stakeholders suggested that in big Reservoirs like Indira Sagar, levels changes from maximum at the end of monsoon to minimum at the beginning of next Monsoon. As a result, the variation in available head at different levels is quite large. The machines are not designed to operate at full capacity at minimum head i.e. at MDDL. Thus, Machine Rating varies. Accordingly, the Project PAFY gets affected adversely, even if the generating units are available. To overcome this deficiency, peaking capability of generating units corresponding to reducing water heads, the Installed Capacity (IC) in the PAFY Formula may be replaced with Peaking Capability of Generating Station corresponding to reducing levels of Reservoir.
iv. Some of the stakeholders suggested that the present norms for auxiliary power consumptions should be retained stating it as adequate.
v. One of the stakeholders suggested that keeping in view the rising trend of tariff, the rate for the energy generated over and above the design energy should be increased to at least Rs 1.25/kWh.
vi. Some of the stakeholders suggested that the hydrological benefits should also be shared with the beneficiaries in the ratio of 50:50.

vii. One of the stakeholders suggested that for the Hydro generating station, auxiliary power shall include operations at reservoirs called Head Works and also colony power as these are generally located at remote locations. Norms shall be higher for lower sized plants as auxiliary power is totally dependent upon the size of sets also. The smaller size sets installed in the past will need higher norms. The auxiliary power norms could be decided like as done in case of thermal sets depending upon sizes;125, 250 and 500 MW thermal sets having 10, 7.5 and 6%; hydro stations below 100 MW need to be given 3%, Below 200 MW - 2% APC.

viii. One of the stakeholders suggested that the Declared Capacity considered for determination of PAFM should account for deemed availability on account of constraints put by State/Inter State Authority on release of water.

20.5 Commission's Proposal

20.5.1 The Commission has gone through the suggestions and comments received and the actual five year data for annual plant availability factor and auxiliary consumption and proposes that the performance norms for hydro generating stations should be reviewed on the basis of five year actual data provided by the utilities.

20.5.2 The Commission with regards to availability achieved by the hydro stations is of the view that the actual availability achieved by most of the stations are very close to the current norm specified and therefore the Commission proposes to retain the norms of NAPAF for these stations. However for some of the stations wherein the actual PAF is higher than the norm the Commission proposes to revise the same. The stations where such variations have been observed are Bairasul, Ranjit, Dhauliganga, SJVNL, Uri stations. The Commission for these stations proposes to revise the norms as mentioned subsequently.

20.5.3 With regard to auxiliary energy consumption the auxiliary consumption for some of the stations are considerably lower than the current norm specified and accordingly there is scope to improve the norms based on the actual data. Therefore the Commission on the basis of actual past years performance proposes to revise the norms as mentioned in Proposed Norms.

20.6 Proposed Norms

(1) The following Normative annual plant availability factor (NAPAF) shall apply to hydro generating station:

(a) Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8%, and where plant availability is not affected by silt: 90%

(b) In case of storage and pondage type plants with head variation between full reservoir level and minimum draw down level is more than 8% and when plant availability is not affected by silt, the moth wise peaking capability as provided by the project authorities in the DPR (approved by CEA or the State Government) shall form basis of fixation of NAPAF.

(c) Pondage type plants where plant availability is significantly affected by silt : 85%.

(d) Run-of-river type plants: NAPAF to be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant.

(2) In case of Pumped storage hydro generating stations, the quantum of electricity required for pumping water from down-stream reservoir to up-stream reservoir shall be arranged by the beneficiaries duly taking into account the transmission and distribution losses etc. up to the bus bar of the generating station. In return beneficiaries will be entitled to equivalent energy of 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir from the generating station during peak hours and the generating station shall be under obligation to supply such quantum of electricity during peak hours:

Provided that in the event of the beneficiaries failing to supply the desired level of energy during off-peak hours, there will be pro-rata reduction in their energy entitlement from the station during peak hours:

Provided further that the beneficiaries may assign or surrender their share of capacity in the generating station, in part or full, or the capacity may be reallocated by the Central Government, and in that event the owner or assignee of the capacity share shall be responsible for arranging the equivalent energy to the generating station in off-peak hours, and be entitled to corresponding energy during peak hours in the same way as the original beneficiary was entitled.

(3) A further allowance may be made by the Commission in NAPAF determination under special circumstances, e.g. abnormal silt problem or other operating conditions, and known plant limitations.

(4) A further allowance of 5% may be allowed for difficulties in North East Region.

(5) Based on the above, the Normative annual plant availability factor (NAPAF) of the hydro generating stations already in operation shall be as follows :-

Station	**Type of Plant**	**Plant Capacity No. of Units x MW**	**NAPAF (%)**
NHPC			
Chamera – 1	Pondage	3 x 180	90
Biarasiul	Pondage	3 x 60	90
Loktak	Storage	3 x 35	85
Chamera-II	Pondage	3 x 100	90
Chamera – III	Pondage	3 X 77	85
Rangit	Pondage	3 x 20	90
Dhauliganga	Pondage	4 x 70	90
Teesta – V	Pondage	3 x 170	85
Dulhasti	Pondage	3 x 130	90
Salal	ROR	6 x 115	60
Sewa -II	Pondage	3 X 40	80
Uri	ROR	4 x 120	70
Tanakpur	ROR	3 x 31.4	55

NHDC			
Indirasagar	Storage	8 x 125	85
Omkareshwar	Pondage	8 x 65	90
THDC			
TehriStg – 1	Storage	4 x 250	77
SJVNL			
NathpaJhakri	Pondage	6 x 250	90
NEEPCO			
KopiliStg – 1	Storage	4 x 50	79
Khandong	Storage	3 x 25	69
Kopili Stg. - 2	Storage	1 x 25	69
Doyang	Storage	3 x 25	73
Ranganadi	Pondage	3 x 135	85
DVC			
Panchet	Storage	2 x 40	80
Tilaiya	Storage	2 x 2	80
Maithon	Storage	3 x 20	80

(10) **Auxiliary Energy Consumption (AUX) :**

(a) Surface hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.7%

(ii) with static excitation system : 0.5%

(b) Underground hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.9%

(ii) with static excitation system : 1%

21 Norms of Operation for Transmission System

21.1 Background

21.1.1 The target availability for recovery of full transmission charges during the Tariff Period 2004-09 for AC system was fixed at 98%, whereas for HVDC bi-pole links and HVDC back-to-back stations, the same was fixed at 95%.

21.1.2 During the Tariff Period 2009-14, the Commission retained the target availability for AC system at the proposed level of 98% in view of the past performance of the transmission lines of POWERGRID system and specified following operational norms.

21.2 Existing provisions

21.2.1 The relevant extract of CERC (Terms and Conditions of Tariff) Regulations, 2009 is as follows:

"28. __Normative Annual Transmission Availability Factor (NATAF)__ shall be as under:

(1) AC system	*:*	*98%*
(2) HVDC bi-pole links	*:*	*92%*
(3) HVDC back-to-back Stations	*:*	*95%"*

21.3 Issues brought out in Approach Paper

21.3.1 The Commission in its Approach Paper invited comments and suggestions from the stakeholders on the following issue:

"In view of the above, comments are invited on the need to review the existing approach for operational norms and level of Normative Annual Transmission Availability Factor (NATAF). Suggestions are invited on weightage factor to be applied for arriving outage hours for calculating NAFM of transformer and Switchable reactor of substation element."

Comments/Suggestions received on Approach Paper

The suggestions received from various stakeholders on this aspect are as follows:

1) Chhattisgarh State Electricity Regulatory Commission suggested that in view of the technological advances and the increased share of higher voltage systems, the present Transmission Availability Factor for a calendar month (TAFM) level needs upward review. It is submitted that in view of the limited data with SERCs, CEA may be better placed to suggest the optimum level of TAFM.
2) POWERGGRID submitted that
    a) The normative target availability for full recovery of fixed cost of the transmission system may be fixed at 96% for AC transmission system and the planned maintenance outage should be excluded from the calculation of transmission system availability.
    b) The calculation of availability, which was applicable for the Tariff Period from FY 2001-04 and FY 2004-09 may be applied. However, the guidelines specified in CERC Tariff Regulations, 2009 are appropriate and may be retained for the ensuing Tariff Period with the exception of the calculation of availability, which needs to be modified.
    c) Same methodology should be adopted for calculation of availability of HVDC system as was adopted by CERC for the last 12 years (FY 1997-98 to FY 2004-09).
    d) On account of increase in the normative availability of the transmission elements, the scope of earning the incentives has reduced drastically for POWERGRID in the successive Tariff Periods since the maximum availability can be 100%. Further, the introduction of incentive mechanism linked to AFC has resulted in reduction of the quantum of incentive earned as AFC gets reduced over the years. Hence, there is a need to increase the margin of incentives available to the Utility. It is therefore proposed that the previous regime of allowing incentive on the equity base of the Utility should be restored.
    e) The Commission, while notifying the Tariff Regulations, 2009 introduced additional multiplication factors in the weightage for ICTs and Reactors and no explanation was given by the Commission.

Determining the multiplication factor of 2.5 for weightage of transformer by equating one 315 MVA transformer with D/C twin line of 200 km and applying same weightage for different capacity of transformer is unjustified and needs modification. Determination of weightage factor by equating with 50 MVAR capacity reactors and applying the same multiplying factors for all capacity reactors is also not justified.

3) In the existing methodology, equal weightage is given to all the elements irrespective of the location at generation end or at transmission system. There should be some difference in weightage in such elements.
4) The weightage for equipment should be considered half of the norms if standby supply is made available. In true sense, it should not be considered unavailable as in the case of thermal units, standby equipment does not impact availability.
5) CEA submitted that the availability of POWERGRID lines is calculated on regional basis, which gives them an advantage in terms of incentive. There is a need to penalise POWERGRID or any other Inter-State Transmission Licensee in case of frequent or abnormal trippings on a particular line due to any reason other than force majeure. Further, to avoid manipulation, it is suggested that Member Secretary, RPC should file the availability report of ISTS licensees under affidavit.
6) POSOCO submitted that non-availability of reactors could lead to opening of other lines to control over-voltage and would result in structural deficiency in the transmission system. Therefore, NAFM of transmission lines may factor in higher weightage for outage / non-availability of the reactors. Further, COD of transmission system planned with reactors may be allowed only when all the elements including line reactors are available and operating in healthy condition.

21.4 Analysis of Actual Performance and Commission's Proposal

21.4.1 POWERGRID submitted region-wise transmission system availability from FY 2008-09 to FY 2012-13 for AC system, HVDC bi-pole links, and HVDC back-to-back stations, which is summarised in the table below:

Table: Transmission System Availability of Regional AC Transmission System

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Average
NR	99.67	99.66	99.86	99.92	99.87	**99.80**
WR	99.55	99.73	99.42	99.95	99.91	**99.71**
ER	99.73	99.83	99.95	99.99	99.95	**99.89**
SR	99.53	99.84	99.95	99.94	99.96	**99.84**
NER	99.28	99.24	99.57	99.93	99.925	**99.59**

Table: Transmission System Availability of HVDC transmission System

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Average
Rihand-Dadri	98.27	99.32	98.70	#	99.93	**99.05**
Balia-Bhiwadi						
Talcher-Kolar	99.23	98.03	99.75	99.16	99.32	**99.10**
Vindhyachal BTB	98.81	98.78	99.35	99.92	99.78	**99.33**
Chandrapur BTB	99.13	98.46	97.85	99.46	99.79	**98.94**
Sasaram BTB	98.94	99.99	100.00	100.00	99.83	**99.75**
Gazuwaka BTB	99.63	99.41	99.07	99.71	99.73	**99.51**

Details not furnished

21.4.2 It is observed that average transmission system availability for regional AC transmission system in five regions from FY 2008-09 to FY 2012-13 ranges from 99.59% to 99.89%. In case of HVDC Bipole scheme Rihand - Dadri and Talcher - Kolar average transmission system availability from FY 2008-09 to FY 2012-13 is 99.05% and 99.10% respectively. In case of HDVC back-to-back stations average transmission system availability from FY 2008-09 to FY 2012-13 ranges from 99.33% to 99.75%.

21.4.3 Further, installation of spare ICT and spare reactors has been allowed in respect of AC system as well HVDC system. Further, in case of HVDC system availability has increased due to installation of spare Converter Transformers. The conventional insulators were also replaced by polymer insulators, which have helped in achieving higher availability for AC system.

21.5 Transmission System Availability Factor- Proposed Norms

21.5.1 In view of above, during the tariff Period 2014-19, it is proposed to have differential norm of NATAF for recovery of Annual Fixed Charges and for incentive purposes.

Normative Annual Transmission Availability Factor (NATAF) for recovery of Annual Fixed Charges shall be as under

(1)	AC system	:	98%
(2)	HVDC bi-pole links and HVDC back-to-back Stations	:	95%

Normative Annual Transmission Availability Factor (NATAF) for Incentive applicability shall be as under:

(1)	AC system	:	99%
(2)	HVDC bi-pole links and HVDC back-to-back Stations	:	98%

21.6 Computation of transmission system availability factor- Commission's Proposal

21.6.1 The procedure for computation of transmission system availability factor for a month is specified in the Appendix-IV of CERC (Terms and Conditions of Tariff) Regulations, 2009. The Commission in its Approach Paper invited suggestions on the existing approach for computation of Transmission System Availability, along with the weightage factor to be applied for outage hours for transformer and reactors.

21.6.2 The Commission during formulation of Regulations for Tariff Period 2009-14 had analysed the formula for transmission system availability applicable during Tariff Period 2004-09. In this context the Statement of Objects and Reasons for CERC (Terms and Conditions of Tariff) Regulations, 2009 states as under:

"34.1 In the tariff regulations for 2004-2009, the availability of a transmissionsystem (for payment of transmission charges and incentive) is required to be workedout through formulae in which

(i) A transmission line circuit has a weightage proportional to its length and Surge Impedance Loading (SIL), for working out the weighted average availability of transmission lines.

(ii) A transformer/bus reactor has a weightage proportional to its MVA/MVAR rating, for working out the weighted average availability of transformers/bus reactors.

(iii) Transmission line circuits, transformers and bus reactors have weightage proportional to their respective numbers in a transmission system, in computation of the system's overall availability.

34.2 While the same procedure for transmission system availability calculation had been proposed in the draft tariff regulations for 2009-2014, the Commission has observed two drawbacks in the above scheme, as discussed below:

a) The SIL has no direct relationship with the power carrying capability of a transmission line. For example, SIL of a 400 kV line with twin Moose conductors is 515 MW, and a 400 kV line with quad Bersimis conductor has an SIL of 691 MW (1.34 times of the former), whereas the latter can easily carry twice the amount of power. Further, SIL loses its significance totally in case a line has a shunt reactor or series compensation. SIL is therefore, not a suitable criterion for weightage in line availability.

b) In the overall availability determination for a transmission system, line lengths, SIL and transformer/bus reactor ratings do not figure, and the three groups get a weightage only according to their numbers. In other words, a transformer or a reactor ultimately has the same weight as a line circuit irrespective of their size or length.

21.6.3 In order to overcome aforementioned drawbacks, the Commission specified formula in the CERC (Terms and Conditions of Tariff) Regulations, 2009 for calculation of availability. As regards weightage factors, as explained in Statement of Objects and Reasons for CERC (Terms and Conditions of Tariff) Regulations, 2009, factors have been applied such that a 315 MVA transformer would have the same weightage as a 200 km long D/C line with twin conductors, and a 50 MVAR switched reactor would have one-fourth the weightage of a 315 MVA transformer. The transmission lines have a weightage proportional to their circuit-km and number of sub-conductors (to which their current carrying capacity is directly proportional).

21.6.4 POWERGRID in their suggestions on the Approach Paper submitted that while certifying availability by RPC each circuit is considered as one element separately and transformer is also considered as one element but the weightage factor for transformer is still considered as 2.5 x MVA capacity of the transformer, which is not correct as both circuit are separated in calculation, the weightage factor for the transformer should have been made to half i.e. 1.25. It is also submitted that different weightage are to be considered for different capacity of transformer.

21.6.5 As regards, switchable reactor, POWERGRID submitted that determination of weightage factor by equating with 50 MVAR capacity reactors and applying the same multiplying factors for all capacity reactors is not justified.

21.6.6 POWERGRID vide its letter dated 28 October, 2013 furnishing additional information further submitted justification for determination of multiplication factor. It submitted that as per concept given in the Statement of Reasons multiplication factor can be calculated as:

Average Ckm x Average no. of sub-conductor = Multiplication factor (ICT) x MVA capacity = Multiplication factor (Switchable Reactor) x MVAR capacity

Where,

Average Ckm= Total Ckm/Total no. of lines =96162/831 = 115.72

Average no. of sub-conductor = Total no. of sub-conductors/ Total no. of lines = 1682/831 = 2.02

Average MVA = Total MVA/Total no. of ICT = 149535/344 = 434.69

Average MVAR = Total MVAR / Total no. of reactor = 29187/277 = 105.37

Based on above POWERGRID has arrived at following Multiplication Factor:

Multiplication Factor for ICT = 0.54

Multiplication Factor for Switchable Reactor = 2.22

21.6.7 As per the Statement of Reasons for Tariff Regulations 2009-14, the transmission lines have a weightage proportional to their circuit-km and number of sub-conductors (to which their current carrying capacity is directly proportional). During the analysis, it is observed that the average no. of sub-conductor approach followed by the POWERGRID does not correctly reflect importance of sub-conductors. POWERGRID has submitted the actual transmission lines ckt-km in operation for FY 2012-13, as 96662 ckt-km (Refer 'Table-ckt-km of AC and HVDC lines' under Para 13.5). Converting such ckt-km in operation with the total no. of sub-conductors, for respective transmission line circuit configuration, total ckt-km works out to around 224808 ckt-km for FY 2012-13. In line with the approach followed in earlier, equating aforementioned system total ckt-km (224808 ckt-km) for FY 2012-13 with the total MVA capacity (149535 MVA) the resultant weightage works out to around 1.50.Further, with the present total MVAR capacity available in the system the resultant weightage factor for switchable reactor works out to 7.70.

21.6.8 Further, Power System Operation Corporation Ltd. in it suggestions mentioned that in case weightage factor to be applied for arriving outage hours for calculating NAFM of transformer and Switchable reactor of substation element, non-availability of reactors could lead to opening of other lines to control over-voltage and would result in structural deficiency in the transmission system. Therefore, NAFM of transmission lines may factor in higher weightage for outage / non-availability of the reactors.

21.7 Computation of transmission system availability factor- Proposed approach

21.7.1 In view of above it is proposed to retain the procedure for computation of transmission system availability factor for a month as specified in the Appendix-IV of CERC (Terms and Conditions of Tariff) Regulations, 2009. Further, it is proposed to retain the multiplication factor for switchable reactor as 7, whereas it is proposed to consider the weightage for transformer as 1.5. Stakeholders are requested to provide their suggestion on weightage factor to be applied for arriving outage hours for calculating NAFM of transformer and Switchable reactor of substation element to improve upon the process.

21.7.2 As regards procedure for calculation of Transmission System Availability Factor for a month it is proposed that non availability of related substation line bay/bay equipment shall be considered as non-availability of Transmission line.

22 Communication System forming part of inter-state transmission system

22.1 Background

22.1.1 The Unified Load Despatch & Communication (ULDC) scheme was introduced in different regions between year 2002 and year 2006.As, the Commission had not specified any regulation for determination of fees and charges for the assets under ULDC scheme during 2004-2009 period, the Commission determined the tariff of ULDC schemes in exercise of its power under Section 28(4) of the Act by adopting certain parameters modelled on the basis of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2004. During the tariff period 2009-14 the Commission decided to continue with the levelised tariff for the existing assets in the absence of any provision in CERC (Terms and Conditions of Tariff) Regulations, 2009 regarding determination of tariff of communication system and ULDC system of the Central Transmission Utility.

22.1.2 The Commission further directed staff to prepare a proposal for the tariff determination of the communication system under ULD&C scheme. The tariff of existing communication system under ULD&C scheme is on levellized basis whereas in multi year tariff principle, the tariff is for the five year control period only. It is observed that methodology followed for tariff determination of assets of existing ULD&C scheme is difficult to accommodate under the proposed Tariff Regulations. However, in case of new assets to be commissioned under ULD&C scheme after 1.4.2014, if any, it is felt that the tariff for such assets can be determined as per the regulations proposed for transmission system with certain modifications.

22.1.3 Further, the transmission licensee is creating assets under different communication scheme like Wide Area Measurement system (WAMS), Optical Fibre etc. and is used for the purpose of inter-state transmission. At present, petition of assets under the communication scheme other than ULD&C scheme have not yet come before the Commission for tariff determination. It appears that the communication assets other than

ULD&C scheme, if any, may come during the tariff period 2014-19. Hence, it is felt that those assets can also be considered as communication system for the purpose of tariff determination.

22.1.4 In view of above, it is proposed that the tariff for the new communication system including assets under ULD&C scheme, WAMS and fibre optics etc. shall be determined as proposed for the transmission system with certain modifications. However, in case of determination of tariff of the existing communication system under ULD&C forming part of Powergrid corporation of India Ltd shall as per the methodology followed by the Commission prior to 1.4.2014.

22.1.5 Further, sharing of ULDC charges has been governed through separate mechanism as specified by the Commission through separate order. The Commission felt that same shall be maintained. As regards to the new communication system including new assets under ULD&C scheme, these assets are being used for the voice and data communication for reliable grid operation. These communication systems are used by the regional beneficiaries including generating stations, long term customers. In view of above, it is proposed that tariff of new communication system including ULD&C scheme shall be shared by the regional beneficiaries in proportion to their allocation in ISGS or long term access capacity.

ABBREVIATIONS

Abbreviation	Full Form
AAD	Advance Against Depreciation
AFC	Annual Fixed Charges
APC	Auxiliary Power Consumption
APP	Association of Power Producers
APTEL	Appellate Tribunal For Electricity
ARR	Aggregate Revenue Requirement
BEE	Bureau of Energy Efficiency
BFP	Boiler Feed Pump
BPTA	Bulk Power Transmission Agreement
CAC	Central Advisory Committee
CAGR	Compound Annual Growth Rate
CAPM	Capital Asset Pricing Model
CCGT	Combined Cycle Gas Turbine
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CFBC	Circulating Fluidised Bed Combustion
Ckt-km	circuit kilometres
CPI	Consumer Price Index
CSR	Corporate Social Responsibility
CWIP	Capital Works in Progress
D&E	Domestic and E-auction Coal
DC	Declared Capacity
DHEP	Doyang Hydro Electric Project
DICs	Designated ISTS (Inter-State Transmission System) Customers
DOCO	Date of Commercial Operation
DTL	Delhi Transco Ltd.
DVC	Damodar Valley Corporation
ECB	External Commercial Borrowings
ECR	Energy Charge Rate
FERV	Foreign Exchange Rate Variation
FGMO	Free Governor Mode of Operation

Abbreviation	Full Form
FPA	Fuel Purchase Agreement
FRL	Full Reservoir Level
FSC	Fixed Series Compensation
GCV	Gross Calorific Value
GDP	Gross Domestic Product
GFA	Gross Fixed Asset
GIS	Gas Insulated sub-station
GOI	Government of India
G-Sec	Government Securities
HVDC	High Voltage Direct Current
IC	Installed Capacity
ICB	International Competitive Bidding
ICT	Inter-Connecting Transformer
IDC	Interest During Construction
IEDC	Incidental Expenditure during Construction
IPP	Independent Power Project
JPL	Jindal Power Limited
KHEP	Kopili Hydro Electric Project
M/C	Multi Circuit
MAT	Minimum Alternative Tax
MCR	Maximum Continuous Rating
MDDL	Minimum Draw Down Level
MoEF	Ministry of Environment and Forests
MVA	Milli Volt Ampere
MVAR	Reactive milliVolt Amperes
NAPAF	Normative Annual Plant Availability. Factor
NATAF	Normative Annual Transmission Availability. Factor
NBFC	Non-Banking Financial Companies
NEEPCO	North Eastern Electric Power Corporation Limited
NFA	Net Fixed Asset
NHDC	Narmada Hydroelectric Development Corporation Ltd
NHPC	NHPC Ltd.
NLC	Neyveli Lignite Corporation Ltd.

Abbreviation	Full Form
NSPCL	NTPC-SAIL Power Company Limited
NTPC	NTPC Limited
O&M	Operation and Maintenance
OEM	Original Equipment Manufacture
PAF	Plant Availability Factor
PAFM	Power Availability Factor for a calendar month
PAT	Perform, Achieve and Trade scheme
PGCIL	Power Grid Corporation of India Limited
PLF	Plant Load Factor
PLR	Prime Lending Rate
POC	Point of Connection
POSOCO	Power System Operation Corporation Limited
PPA	Power Purchase Agreement
PSU/ CPSU	Public Sector Undertaking/ Central Public Sector Undertaking
PTL	Powerlinks Transmission Limited
R&M	Renovation and Modernisation
R&R	Rehabilitation and Resettlement
RBI	Reserve Bank of India
RGGVY	Rajiv Gandhi Grameen Vidyutikaran Yojana
RGMO	Restricted Governor Mode of Operation
RHEP	Ranganadi Hydro electric Power Project
RLDC	Regional Load Despatch Centre
RLNG	Re Gasified Liquefied Natural Gas
ROCE	Return on Capital Employed
ROE	Return on Equity
ROI	Return on Investment
RPI	Retail Price Index
SAIL	Steel Authority of India Ltd.
SBI	State Bank of India
SCOD	Scheduled Commercial Operation Date
SEB	State Electricity Board
SERCs	State Electricity Regulatory Commissions

Abbreviation	Full Form
SFOC	Secondary Fuel Oil Consumption
SHR	Station Heat Rate
SIL	Surge Impedance Loading
SJVNL	Satluj Jal Vidyut Nigam Ltd.
SLDC	State Load Despatch Centre
STG	Steam Turbine Generator
STU	State Transmission Utility
SVC	Switchable Variable Capacitor
TAFM	Transmission Availability Factor for a calendar month
THDC	Tehri Hydro Development Corporation Limited
TPGL	Torrent Power Grid Limited
TPS	Thermal Power Station
TSA	Transmission Service Agreement
ULDC	Unified Load Despatch & Communication Scheme
UPPCL	Uttar Pradesh Power Corporation Ltd.
WACC	Weighted Average Cost of Capital
WAMS	Wide Area Measurement system
WPI	Wholesale Price Index