TERMS AND CONDITIONS OF TARIFF REGULATIONS

Approach Paper for
Control Period 1.4.2014 TO 31.3.2019

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1.0 Introduction

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. Section 61 of the Act requires the Commission to specify the terms and conditions for the determination of tariff. Further, section 178(2) (s) of the Act empowers Central Commission to make regulations on the Terms and Conditions for the determination of tariff under section 61. The Central Commission has issued Terms and Conditions of tariff for period 2001-04 under Electricity Regulatory Commissions Act, 1998 and after enactment of Electricity Act, 2003, the Commission has issued the Regulations on Terms and Conditions of Tariff for the control periods 2004-09 and 2009-14. CERC (Terms and Conditions of Tariff) Regulation, 2004 for 1.4.2004 to 31.3.2009 along with statement of reasons was issued vide notification no. L-7/25(5)/2003-CERC on 26th March 2004 and is available on website (weblink: *http://cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf*). *The* CERC (Terms and Conditions of Tariff) Regulations, 2009 for period 1.4.2009 to 31.3.2014 was issued vide notification No.L-7/145(160)/2008-CERC date 19th January, 2009 (weblink: *http://cercind.gov.in/Regulations/Terms-and-Conditions-of-Tariff-Regulations_2009-2014.pdf*)

In accordance with the regulations issued from time to time as aforesaid, the Commission has been determining the tariff of the generating stations covered within its jurisdiction and inter-State transmission of electricity through transparent and participative process. At the end of the 11th Plan (ending on 31st March,12), the Central Commission has determined the tariff for about 45794.84 MW installed capacity of central sector and 4797.50 MW capacity of Private sector/Joint venture companies and associated inter-state transmission system.

1.2 Section 61(i) of the Act provides that while specifying the terms and conditions of tariff, the Commission shall be guided by the National Electricity Policy and Tariff Policy. The Central Government in exercise of its powers vested under section 3 of the Act has notified the Tariff Policy on 6th January'2006. Para 5.1 of the Tariff Policy provides that all future requirements of power should be procured competitively by distribution licensees except in case of expansion of existing projects or where a State controlled or owned company is an identified developer. The Tariff Policy mandates that even the tariff for all the new generation and transmission projects should be decided on the basis of competitive bidding after a period of five years (i.e. after 5th January, 2011) with certain exceptions. The Tariff policy, also therefore recognises that the tariff for existing generation and transmission projects shall continue to be determined through regulatory tariff mechanism.

1.3 The Commission, while determining the tariff, takes into account objectives of safeguarding consumer interest as well as ensuring recovery of cost of electricity in a reasonable manner. To achieve these objectives, the Commission undertakes various regulatory measures which are consistent with the principles set out under section 61 of Electricity Act, 2003 and Tariff Policy, 2006. The Terms and Conditions of Tariff specified by the Central Commission for determination of tariff for generating companies and transmission licensees also act as guiding principles for the State Electricity Regulatory Commissions.

1.4 For tariff period 2014-19, the existing tariff norms may have to be reviewed by keeping in view the developments in the sector during the ongoing tariff period, current and perceived challenges in the Power sector and duly recognizing the need for sustainable market development. Though it is important to maintain regulatory certainty in tariff approach, the tariff should reflect the changing market conditions.

1.5 The purpose of this approach paper is aimed at soliciting views of stakeholders on the different aspects of tariff setting during control period 2014-19.

2.0 Basic Approach of Tariff Setting

As per the approach paper floated by Planning Commission for the 12th Plan, the GDP growth rate of 9.0 per cent per year will require the energy supply to grow at about 6.5 and 7.0 per cent per year. Therefore, it is important to harness all the available resources to increase power generation and corresponding transmission systems to carry the power to the load/demand centres. The approach of tariff setting plays important role for attracting investment in power generation and transmission.

2.1 In line with the objectives of safeguarding consumer interest and to ensure recovery of cost of electricity in a reasonable manner, performance based cost of service regulation was adopted in previous tariff periods. The hybrid approach, consisting of norms on actual cost of service and pre-specified normative cost basis was being followed to induce efficiency in financial and operational performance.

Under the Availability Based Tariff (ABT), two part tariff structure (fixed +variable cost) is being followed for generation tariff with incentive and disincentive mechanism. Recovery of fixed charges is based on the availability of plant while the recovery of variable charges is linked to operational parameters like normative Station Heat Rate (SHR), auxiliary consumption etc. The fixed charges have five components namely Return on Equity (ROE), Interest on Loan, Deprecia0tion, Operation & Maintenance cost, and Interest on Working Capital. There are incentive/ disincentives built in for over/under achievement of target availability and normative parameters. The tariff structure of transmission system is governed through single component of annual fixed charges with incentive linked to availability. The congestion charges and sharing of transmission charges are notified through separate regulations.

Prospects for Tariff Regulation 2014-19

2.2 In view of the anticipated growth in demand and the existing challenges in the power sector, a balanced approach is required to be adopted for tariff determination in the larger interest of the sector. Further, a focus is needed to improve the operational efficiency so that benefit on account of efficiency gains should be shared with the beneficiaries and the consumers at large. It is equally important to harness all resources to increase proportionate mix of power generation.

i) **Financial Norms (Hybrid Approach)**: The existing tariff setting follows a hybrid approach where performance based cost of service approach by considering actual cost and normative parameters specified in the regulations. Components like return on equity, operation and maintenance expenses and interest on working capital have been specified on normative basis whereas cost of debt have been on actual basis. The Capital cost of project including interest during construction and financing charges, any gain or loss on account of foreign exchange rate variation, capitalized initial spares and additional capital expenditure etc. have been admitted after prudence check. The normative parameters are expected to induce operational and financial efficiency. While continuing with the hybrid approach, ensuing Tariff Regulations for the control period 2014-19 may provide more weightage for normative parameters to induce efficiency during operation as well as in development phase.

ii) **Operational Norms** : The operational norms and the methodology to determine such norms should reflect the optimum level of efficiency during next tariff period.

3.0 Financial Norms (Hybrid approach)

3.1 Capital Cost

3.1.1 The determination of Capital cost is a critical step in tariff. The Capital cost forms the rate base for determination of return on investment. The existing regulations determine the capital cost as on date of commercial operation (COD) based on expenditure incurred duly certified by Auditors. In case the project was commissioned prior to the tariff control period, capital cost of the project as admitted by the Commission during that tariff period is considered and additional capitalization during the tariff control period is allowed after due diligence. For new projects whose date of commercial operation falls within the tariff period, capital cost is determined after prudence check.

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. For the control period 2009-14, the Commission switched over to the methodology of determination of capital cost based on the projected capital expenditure. This enabled the generating companies/transmission licensees to file their tariff application prior to commissioning of the project. The undischarged liabilities were not included in the projected/actual capital expenditure for the purpose of capitalization 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.

3.1.2 Areas for improvement in existing approach for determination of capital cost include following :

i) The capital cost as on COD of new unit/generating station /transmission system was allowed to be claimed on projected basis subject to the fact that actual COD of new unit/station/transmission system would occur within six months from the filing of tariff petition. However, it has been 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. It was noticed that the objective of faster disposal of petitions by doing away with provisional tariff got defeated due to considerable variations in projected capital cost vis-à-vis actual capital cost as on COD.

ii) The construction efficiency is a key element for preventing slippage in commissioning of project. The delay in commissioning has a direct impact on the capital cost of project. In case of delay in commissioning of the project, capital cost would increase on account of interest during construction (IDC), escalation in prices and increase in establishment charges and the same can be capitalized with allowance of time overrun. Bringing efficiency during construction phase is an area of concern. It is felt that the construction period may be standardized with the provision for normative IDC to bring efficiency in construction period.

iii) The other area of concern is the execution of project by the developer. While the developer may have the freedom of execution of the project in an efficient manner, a need has been felt for introduction of mandatory International Competitive Bidding (ICB) for the main plant packages/ major packages and for the all remaining packages to ensure competitiveness of prices. In case of single bidder, it would be difficult to consider that cost as efficient cost for determination of tariff due to lack of competition.

iv) The commissioning of the generating stations and transmission systems and their commercial operation, is declared after successful completion of the trial operation/run. In case of transmission system, it is to be ensured that an element of the transmission system is in regular service after successful charging and trial operation. It is being felt that there is a need to specify a methodology of trial operation for generating station and transmission system and to ensure regular use of service in case of transmission system which should be followed by the generators. Similarly, the methodology of trial operation for bay equipment, Inter-connecting transformer, Reactors, Fixed Series Compensation, and transmission lines may be specified for transmission projects. In some cases, non availability of evacuation system and adequate load has delayed the trial operation and commissioning of the plants. There is also an issue of the mismatch between the commercial operation of a generating station and the associated transmission systems which has the impact on specifying COD as well as IDC of the generating station or the transmission system which needs to be addressed.

The data telemetry and communication and restricted governing mode of operation is requirement of system operator for visualizing status of real time grid. There is a need to ensure completion of data telemetry and communication to respective RLDC/NLDC/SLDC for declaring COD of transmission system/generating station and operationalisation of restricted Governing mode of Operation (RGMO) in case of generating station.

v) 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 period. The benchmark capital cost may be used as normative capital cost to induce efficiency in procurement of plant & machinery and timely development of project. The benchmark capital cost needs periodical review as it varies over a period of time due to escalation in prices, technological improvement and market competition etc.

vi) The treatment of additions at the fag end of project life and after allowing compensatory allowance has consequential impact on tariff as entire depreciation would have to be charged within balance useful life. The additional capital expenditure during fag end would be justified when project is expected to provide its intended service for reasonable period. This position calls for requirement of re-assessment of useful life so that investment during fag end of life could be justified.

vii) There is need to address the additional capital expenditure by generators to meet the efficiency improvement targets under the Perform, Achieve & Trade (PAT) scheme.

viii) The Tariff Regulation, 2009 provides for compensation allowance for the coal/lignite based stations depending upon years of operation for meeting any expenditure of capital nature. The efficacy of continuation of the same needs to be reviewed.

ix) In case compensation allowance is to be allowed for coal-based/lignite fired generating Stations, the necessity for developing and extending such compensation allowance to the transmission system and hydro generating stations may also be considered.

x) The truing up provision has been introduced first time with effect from 1.4.2009. It is felt that truing up provision may also provide guiding or procedural aspects so as to maintain uniformity and clarity on scope/methodology of truing up.

3.1.3 In view of the above, the stakeholders may furnish their comments and suggestions on the following:

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 operation 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.*

3.2 Renovation & Modernisation

3.2.1 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 of the generating station of a unit thereof. In case of transmission system, it is supported by Detailed Project Report giving information about reference date, financial package, phasing of expenditure, schedule of completion, useful life, reference price level, estimated completion cost, record of consultation with beneficiaries etc.

3.2.2 It has been experienced that the generating Companies filed their claims without giving estimated life extension period. Also, in case of sustenance of performance norms, it is difficult to establish a cost benefit analysis except that there may be extension of life for a further period of 10-20 years. In certain old plants, R&M nature of works has been claimed without any specified life extension. Servicing of such R&M expenditure at the fag end of the useful life of the station is an issue. There may, therefore, be a need to specify a period over which any R&M expenditure with or without life extension or any additional capital expenditure at the fag end of useful life be provided to be serviced over a period of 15-20 years.

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

3.2.4 In light of above, comments/suggestion are solicited on " *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 Depreciation

3.3.1 Depreciation is a major component of annual fixed cost. It is accepted in regulatory regime that the depreciation represents service to capital subscribed and normally considered a cash flow available for repayment of loan. The Para 5.8.2 of the National Electricity Policy, provides that "depreciation reserve is created so as to fully meet the debt service obligation." The regulatory meaning of depreciation was pronounced in 2009-14 tariff period which held that there should be enough cash flow available to meet the repayment obligations of the generating Company or transmission licensee during first 12 years of operation. This regulatory meaning has gained precedence in tariff setting approach. In 2009-14 regulations, the depreciation rate has been considered based on normative repayment period of 12 years to repay the normative loan (70% of the capital cost). The provision of Advance against Depreciation (AA*D)* was dispensed with in line with Tariff Policy, 2006 and fair life got delinked at least for first 12 years of operation, while setting the depreciation rates.

3.3.2 The areas for discussion in existing approach are as follows :

i) While combining assets or units, the treatment of weighted average life may have a mismatch in respect of completion of 12 years of each individual units or assets. Similarly, there will be a mismatch at the end of completion of useful life of combined units vis-à-vis individual units. Since useful life is linked with depreciation after 12 years, there will be a consequential impact on recovery of depreciation.

ii) The treatment of depreciation on account of additional capital expenditure at the fag end of life and also the Special allowance approved in lieu of renovation and modernisation as the same have consequential impact on the tariff due to recovery of depreciation over balance useful life. Similarly, the additional capital expenditure after allowing the Special allowance has an impact on recovery of depreciation. As more assets of regulated entities are approaching towards completion of useful life, this issue requires attention. The need is felt that pre-specified useful life could be revised and extended after re-assessment of useful life for spread over of balance depreciation.

iii) In view of Para (ii), the need for re-assessment of useful life for treatment of additions during fag end of life has been recognized. The re-assessment of useful life is also been supported by Accounting Standard-6. It is perceived that extension by way of re-assessment of useful life will provide certainty to distribution licensee for getting supply beyond useful life and consumers will be benefited by availing supply of electricity at lower cost.

iv) The useful life of substations and for transmission lines, as specified in Tariff Regulation, 2009, is 25 years and 35 years respectively. However, the actual life of these transmission assets may be much more than 25/35 years.

3.3.3 In view of the above, the stakeholders may furnish their comments and suggestions on the following:

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?

3.4 Net Fixed Asset v/s Gross Fixed Asset Approach

3.4.1 The existing approach of Gross Fixed Assets creates internal resources for capacity replacement/addition through return on equity base of 30% (normative equity) even though the assets are written off up to 10% (salvage value).

3.4.2 The new Companies entering into generation and transmission business may not reinvest for capacity replacement/addition as market situation undergo change. In case of Return on Capital Employed approach, GFA approach gets replaced with Net Fixed Asset approach. Thus, fresh look is required in the existing approach of GFA (liability side).

3.4.3 The comments are invited on following issues :

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.

3.5 Debt/Equity Ratio

3.5.1 Debt: Equity ratio is the most important factor for the promoters as it has an impact on return on investment. In case of existing projects declared under commercial operation prior to 1.4.2009, debt-equity ratio as allowed prior to 1.4.2009 by the Commission has been considered for the purpose of tariff. A Debt: Equity ratio of 70:30 has been adopted for financing new projects commissioning after 1.4.2009 and for additional capitalization. The equity in excess of normative level is normally treated as normative loan unless allowed by the Commission and in case of equity below the normative level, actual equity is being used for determination of Return on Equity in tariff computations.

3.5.2 The Debt: Equity ratio followed is consistent with the Tariff Policy, 2006. It is however possible that gradual structuring of the debt markets may have lead to higher reliance/availability of debt to corporate. The suggestions of stakeholders are invited on "*whether there is a need to revisit the existing approach for debt: equity ratio or to continue with the existing composition?*"

3.6 Return on Investment (RoI)

3.6.1 In cost plus tariff approach, the cost of service of regulated utilities includes return on investment i.e. return on equity and cost of debt. The ROI is determined based on the **rate base** and **rate of return.** The Debt: Equity ratio has been in the range of 50:50 to 80:20. The debt: equity ratio and return on capital are influenced by various financial factors. There are two options available for return on investment namely-

(i) Return on Capital Employed (ROCE) ;and
(ii) Return on Equity (ROE) with pass through of cost of debt.

Return on Equity(RoE) v/s Return on Capital Employed (RoCE)

3.6.2 The Commission, while framing regulations for previous periods, examined Return on Capital Employed (ROCE) approach and ROE approach. In view of lack of benchmarking for Debt-Equity mix and volatility with respect to interest rate and debt market in India, out of the two, Return on Equity (ROE) approach was accepted during previous tariff period 2009-14 as explained in Statement of Reasons issued by Commission. (weblink : *http://cercind.gov.in/2009/ February09/ SOR-regulations-on-T&C-of-tariff-05022009.pdf*).

Presently, Debt market in India is comparatively structured. As per report of working sub group on Infrastructure- 12th five year plan, the bank credit to the infrastructure sector exhibited a steady growth from **Rs. 7,243** crore in 1999-2000 to **Rs. 5,52,682** crore in 2011-12 (up to June 2011). Flow of funds in the infrastructure sector through investments by Insurance companies is also growing.

In spite of a well-developed regulatory and financial system, the corporate bond market in India is only **3.3%** of GDP as assessed by ASSOCHAM in their study paper on "Capital Markets – Key to Double Digit Growth. In contrast to a mature equity market, bond market in India is relatively under-developed as compared to other

Asian economies and developed nations. The share of corporate bonds to GDP is **10.6%** in China, **41.7%** in Japan & **49.3%** in Korea.

The debt market in India, especially the corporate bond market, is yet to establish a firm foothold in the Indian Capital market. There is a huge potential for expansion of debt markets as there is a continuous demand for investment in growing infrastructure sector.

It cannot be denied that there has been and there will be turbulence in the financial market and we just cannot expect a "stable bond market" in absolute terms. A low economic growth scenario may worsen the stability of market and vice versa. The instability of market would involve inherent risk on account of change in cost of debt. The bench marking of debt-equity ratio and cost of debt for the purpose of determining the rate of return is normally difficult in unstable market. Further, ROCE approach may be reviewed from implementation aspects discussed in subsequent paragraphs.

3.6.3 Rate of Return: The rate of return needs to be linked with weighted average of capital cost by benchmarking debt and equity in ROCE approach. As regards the return on equity element, the present level of ROE or revised ROE may be specified by independent review. There is a need, however, to lay down a clear basis for determining the interest on debt. This may be linked with Govt. Securities yield as Bank PLR has inherent risk factor. Thus, a composite return on investments (Debt & Equity both) along with risk premium needs to be defined in ROCE approach.

3.6.4 Rate Base: The rate of return is applied to a rate base and method of arriving rate base is different in both methods. In the existing ROE approach, ROE is calculated on the equity base while interest cost is calculated on outstanding normative debt and interest is allowed at actual return in Investment. In ROCE method, rate base will be the total capital employed, which represents investments made by the utility on which return is calculated and provided in the tariff.

3.6.5 While deciding the approach for rate of return, following issues need to be considered :

i) The volatile debt market condition makes it difficult to benchmark Debt-Equity mix. Significant variations in the risk premium affect cost of debt. It is pertinent to note that SBI PLR/ Bank Advance Rate undergo frequent changes indicating fluctuating rate of interest.

ii) The Central Commission is determining tariff for project/unit/generating station /transmission element wise. Arriving at financing information for computation of rate base for individual elements or units may be difficult in ROCE approach.

iii) The feasibility of having uniform Weighted Average of Capital Cost (WACC) for all the regulated Companies Public/Private, having different credit rating (AAA or B or D) and in respect of projects of different vintage (existing/new) needs to be examined while switchover to ROCE approach.

3.6.6 In view of above, following issues have emerged on which comments of stakeholders are solicited:

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.

3.7 Return on Equity (RoE)

3.7.1 The Commission had specified a post-tax ROE of 16% for tariff period 2001-04 and 14% for the tariff period 2004-09. However, after prolonged deliberations on ROE, while framing the 2009-14 regulation, the Commission had decided post-tax Return on Equity at a benchmark rate of 15.5% for entire tariff period to be grossed up by applicable tax rate. Further, w.e.f. 31-12-2012, return on equity 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 Commission has a clear mandate under section 61(d) of the Electricity Act'2003 to fix a rate of return for equity that will not only attract investment but generate sufficient resources for further growth in the sector.

3.7.2 The following aspects can be taken into account while specifying Return on Equity (ROE):

i) There is a need to encourage investment in view of shortfall of funds in the power sector. The expected shortfall in source of funds has been assessed in the report published by *Working Group on Power for 12th Plan which states that "On the basis of the fund requirement and availability estimated in previous sections, the debt shortfall has been computed at around Rs. 97,444 crore and the equity shortfall has been computed at around Rs. 90,363 crore, implying a total funding shortfall of Rs. 1,87,807 crore."*

ii) It is noticed that power market has grown up substantially after enactment of the Electricity Act, 2003 hence; the risk premium to be built in ROE would then be further discounted. The cost plus tariff regime would protect regulated entity from market risk as it is pass through in regulated regime. The discounting of risk premium for arriving at the norm for ROE could be justified in cost plus regime. While taking a view on risk premium for specifying the level of ROE, it is important to look at the project risks and market risks involved in cost plus regime.

iii) In view of the variation in risk premium over the tariff period, the option of introducing market linked return has been thought of to capture inordinate variation of risk premium over a tariff period. It is felt that market linked return could be considered by linking risk premium with beta factor of power sector keeping other parameters constant and by using Capital Asset Pricing Model (CAPM).

iv) The introduction of appropriate model or scientific model to work out Return on Equity is to be examined. One of the options is to use Capital Assets Pricing Model to arrive at market expected rate of return and to specify return on equity

v) The rate of return has been changed for storage/pondage based hydro station for encouraging investment. The need for differential rate of return for generation projects, transmission projects is required to be examined.

vi) In case of pre-tax ROE approach by grossing of post tax return by tax component, treatment of tax benefit under 80 I A need to be examined. More often, it has been represented by the beneficiaries that the ROE with grossing up of tax rates has led to accrual of benefits more than intended, especially in cases, where the plant or scheme is enjoying the benefit under 80IA. If the intent of grossing up of base rate by tax rate is to compensate the developer on account of his tax liability, it (the tax rate) should be grossed up by actual tax paid and not by the normative corporate tax, which in some cases leads to excessive benefit to developers. This issue is to be addressed.

vii) If ROCE is applied, can this ROE be used for the purpose of computation of Weighted Average Rate of Capital Cost (WACC) or to be changed?

3.7.3 Accordingly, the following issues have emerged for considerations on which stakeholders may furnish comments and suggestions.

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?*

3.8 Cost of Debt

3.8.1 Presently, interest on loan is pass through and is computed by considering weighted average rate of interest on the basis of actual loan, actual interest rate and scheduled loan repayment.

3.8.2 The recent development of financial market/ debt market contemplates changes in following area :

i) As of now, debt market is gradually structuring and foreign debt market is becoming accessible to the Indian companies. The rising cost of domestic borrowing as seen presently could lead to an increase in demand for External Commercial Borrowings (ECBs) amongst Indian Companies; however, there are several constraints like limit on borrowing, shorter tenures of up to 5 years, high hedging costs, exposure to foreign exchange risks etc. Keeping in view of the limitation on ECBs, the existing mechanism of encouraging developer for reduction of cost of debt through swapping, hedging is to be examined.

ii) It is being felt that allowable cost of debt may be linked to a benchmark yield on comparable bonds or normative debt for achieving financial efficiency. The possibility of normative cost of debt or benchmarking of debt is to be examined.

Alternately, the ceiling for cost of debt may also require to be examined as the cost of debt varies depending upon credit rating and financial condition of project developer.

3.8.3 In view of above, fresh look is required on following issues on which comments/suggestions of stakeholders are solicited:

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.*

3.9 Interest on Working Capital (IOWC)

3.9.1 The working capital is separately specified by Commission for Coal-based/lignite-fired thermal generating station, Open-cycle Gas Turbine/Combined Cycle thermal generating stations and hydro generating station & transmission system. The working capital is determined based on fuel stock, inventory of maintenance spares, one month operation and maintenance cost and two months receivable depending on type of thermal generating station, hydro and transmission projects.

The following areas are identified for discussion/consideration by stakeholders:

i) Stock of fuel considered for working capital in respect of various type of generating stations requires fresh deliberations. The actual fuel stock is required to be examined while determining working capital or some benchmark need to be fixed

ii) The resources created from return and depreciation is used as internal resources for capacity addition programmes and hence, is not available for meeting working capital requirements. This position led to conclusion that the short-term funding has to be obtained from banking institutions for which interest liability has to be borne by the regulated entity. Therefore, IWC based on the cash credit was followed during previous tariff period.

It was observed that tariff recoverable includes returns and depreciation which are not cash expenses, and the additional recoveries would provide enough funds to meet the working capital requirements for operation. With increased private sector participation and in view of huge capacity addition during previous years, consideration of depreciation and return as cash expenses for the purpose of working capital based on requirement of creation of internal sources for capacity addition programme needs review.

iii) Since return on equity has been allowed on pre-tax basis i.e. grossing up by tax rate, the tax rate component has also been accounted under working capital while computing two months receivable. This may be reviewed as the tax component may not form a part of working capital.

iv) In respect of working capital allowed for maintenance spares, it is to be examined from the view point that O&M expenses also covers maintenance spares expenditure. It is to be deliberated whether the 15% maintenance spares should be made as part of working capital or O&M expenses in the existing methodology.

v) The treatment of IWC in case of ROCE approach to be looked into for working out rate base in ROCE.

3.9.2 The following issues have emerged for considerations on which stakeholders comments/suggestions are solicited:

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.*

3.10 Operation and Maintenance Cost

3.10.1 The Commission has notified normative cost of O&M for thermal generating stations and transmission system in the existing tariff regulations based on the data of 2004-05 to 2007-08. The expansion of capacity and use of latest technology is expected to reduce O&M cost. These factors call for the review of normative O&M cost.

3.10.2 The O&M norms are required to be revisited from the following angles:

i) The fixed escalation rate, used for arriving year on year O&M cost, should take into account the WPI and CPI indexation. However, variation in WPI & CPI index pose challenge in specifying the fixed escalation rate for the entire tariff period. In addition to this, the fixed escalation rate does not capture the variation due to unexpected expenses on account of wage revision, increase of water charges etc.

ii) Alternatively, the concept similar to RPI-X (where 'X' can linked to pre specified expected efficiency gains in O&M say 1%, 0.5% etc.) may be introduced for determining the O&M cost. The first year O&M norm would be formed on the basis of trend of actual expenditure during past five years. Next year onward, it would not be escalated on the basis of a fixed escalation rate as being done presently based on last five year inflation. But, it will be escalated by a rate (RPI-X) where RPI is the suitable combination of WPI and CPI and term 'X' will represent pre-specified expected efficiency. This will capture variation of WPI & CPI as well as optimum operational efficiency.

iii) In respect of generation by hydro, although each hydro plant is different based on the location, type of plant, mode of operation, siltation, hydrological aspects, there is still a need for bringing cost of O&M of a hydro station on normative basis as in case of thermal station/transmission system. In this context, the existing methodology of allowing O&M as a percentage of capital cost in New Hydro stations and based on past 5 years data of actual O&M expenses for existing stations needs to be reviewed.

3.10.3 In view of the above, the stakeholders may furnish their comments and suggestions on the following:

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 weight age 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) *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.*

4.0 Alternate Tariff Design: Based on First Year Tariff with Indexation for Balance Life

In Para 3 above, we have discussed hybrid approach based on actual cost and normative cost basis tariff working. As an alternative to this approach, the tariff design based on first year tariff with indexation for balance life is discussed in subsequent paragraph.

4.1 Owing to capital intensive nature of power projects, the investors seek greater regulatory certainty considering the financial risk involved in making huge investment. While the MYT regime implies certainty of tariff norms for a control period, there are variations in tariff norms from one control period to the other. The changes in tariff norms are also applied on projects commissioned earlier. The tariff for new projects is determined based on capital employed at the time of commissioning of the project. The capital cost determined by the Commission is used for determination of Annual Fixed Cost (AFC) during each control period. The difference in tariff between two control periods is due to variation in norms of different components.

4.2 It is argued that investment decisions are made at a particular point of time based on the prevailing market conditions, the then applicable laws, regulations etc. The investment planning is done on the long term basis where the investor also factors in some of the controllable variables over the useful life cycle of the project. This calls for a tariff design which is predictable over the useful life of the project with provision for periodic adjustment on account of factors which cannot be projected on the date of investment. In other words, the tariff design should be such as to give a predictable trajectory of recovery of cost and should not be subjected to periodic changes in financial and operational norms.

4.3 One possible way forward could be to determine the tariff (fixed charge) for a new project only for the first year based on the financial and operational norms prevailing on the COD, with provision for periodic revision of the fixed component of the fixed charge to take into account the changes in O&M cost, depreciation and interest on loan etc. By way of an illustration if the Annual Fixed Cost (AFC) is determined at Rs 1.5 /unit for the first year, about 20-25% (towards O&M component) of the AFC may be treated as an escalable component. The escalation rate for the escalable component may be determined by the Commission on year on year basis based on WPI and CPI. The remaining 75-80% of the AFC may have a degression curve to factor in depreciation, interest on loan etc. The Commission needs to determine the degression curve every year keeping in view the factors of depreciation and interest on loan etc. The same trajectory may be applicable during the entire contract period and any change in subsequent tariff regulation may not be applicable. The energy charge covering the cost of fuel can be a pass through with norms for SHR specified in the regulations.

4.4 This approach would provide certainty of tariff to developer/beneficiaries while at the same time bringing simplicity in the entire approach to tariff determination.

4.5 There are, however, certain issues that need to be addressed in this process, e.g. the issues relating to additional capitalisation, treatment of actual interest rate etc.

a. Replacement of assets and additional capital expenditure during the life cycle of the project may have an impact on the AFC. The question that arises is how does one take care of these factors in proposed approach? Such additional capital expenditure might distort the degression curve. However, one can argue that given the experience of the Commission in tariff determination including on additional capitalisation issues during the last 15 years, the issue of additional capital expenditure can be handled in the normative tariff design. This can be addressed either by providing for certain margin in the capital cost or by providing for separate approval of the additional capitalisation and consequent revision of AFC and degression curve to adjust for such additional capital expenditure.

b. Another challenge to implement the above approach could be in terms of setting the degression curve in the first year itself. The benefits arising out of change in market factors like lowering of interest rate and improvement in Station Heat Rate etc may not be shared with the beneficiaries. One may, however, argue that these issues can be handled by providing for determination of degression curve for each project separately based on the actual interest rate availed by the project developer for that project. At the same time, performance of the plant in terms of SHR can be reviewed every five years and energy charge can be passed through based on the revised SHR after every five years.

4.6 Based on above discussion, the comments of stakeholder are solicited on the following :

a) Whether the approach of determination of tariff (fixed charge for the first year with fixed and indexed components for remaining period as explained above should be adopted for the new projects?

b) *How should the degression curve be set?*

c) *What difficulties are foreseen in implementation of the above mentioned approach?*

5.0 Operational Norms

5.1 Approach for Operational Norms

5.1.1 Various operational parameters namely Target Availability, Plant Load Factor (PLF), Station Heat Rate, Auxiliary Energy Consumption, lime consumption (for lignite based stations) and specific fuel oil consumption were specified by the Commission during 2009-14 tariff period. These norms were specified based on the data collected from various inter-state generating stations for the period 2004-05 to 2007-08. The Commission had sought recommendation of Central Electricity Authority to look into the operational norms specified for central generating stations.

5.1.2 The Tariff Policy, 2006 has set a principle for specifying operational norms. It provides that, "*Suitable performance norms of operations together with incentives and dis-incentives would need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. Except for the cases referred to in para 5.3 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.'………………*

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

5.2 Operational Norms for Thermal Generation

5.2.1 Station Heat Rate

5.2.1.1 Along with the price and gross calorific value (GCV) of the fuel, Station Heat rate (SHR) also has an impact on computation of energy charges. The actual gross station heat rate is at variance with the guaranteed design heat rate provided by the manufacturer due to different operating conditions and variation in quality of fuel. The norms of gross station heat rate during the existing tariff period has therefore been provided with additional margin of 6.5% over the gross station heat rate guaranteed by OEM in case of new coal/lignite based stations and with additional margin of 5% over the gross station heat rate guaranteed by the OEM in case of new gas/liquid fuel base CCGT stations. This has been done as per the advice of Central Electricity Authority.

5.2.1.2 In case of existing stations, heat rate norms were specified based on performance data collected for the period 2004-05 to 2007-08. Further, there are relaxed norms in case of certain stations of DVC, NTPC and NLC due to certain specific reasons.

5.2.1.3 The existing heat rate norms for the new and existing generating stations would require to be reviewed along with the margin over and above the heat rate guaranteed by the OEM based on actual performance data during the last five years. The efficacy of continuation of specifying heat rate norms in terms of guaranteed design heat rate may also be reviewed. The methodology for determining heat rate and criteria for specifying efficient heat rate are important considerations for the Commission. The heat rate is crucial parameter as it has substantial impact on tariff. The gain/savings on account of heat rate are to be shared with the beneficiaries and hence the Commission needs to specify it giving due consideration to all relevant factors including shortage of domestic coal supply in the country for protecting consumer interest. The heat rate norms would also required to be seen in the light of efficiency improvement targets achieved by the generating stations under the PAT scheme

5.2.1.4 The Comments/suggestions are invited from all the stakeholders *on "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.

5.2.2 Specific Secondary Fuel Oil Consumption

5.2.2.1 The existing norm for the Secondary Fuel Oil Consumption is 1.25 ml/KWh for lignite based CFBC technology and 1.0 ml/KWh for Coal based project with the provision for sharing of savings with the beneficiaries. Further reduction in specific secondary fuel oil consumption norms may adversely affect the boiler operations under different operating conditions including partial loading of units due to fuel shortage conditions.

5.2.2.2 *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.*

5.2.3 Auxiliary Energy Consumption

5.2.3.1 The existing norms of auxiliary consumption of coal based generating station varies from 6.0% for unit size of 500 MW and above to 8.5% for 200 MW series units with steam driven boiler feed pumps and electrically driven boiler feed pumps with relaxed norms for specific generating stations of smaller size. In respect of gas based generating station, auxiliary consumption varies from 1.0-3.0% depending on open or combined cycle operation. The existing norm of auxiliary consumption of lignite based generating station is 0.5% more than coal based generating station with electrically driven feed pump and 1.5% more if the lignite fired station is using CFBC technology.

5.2.3.2 The auxiliary consumption does not include colony power consumption and construction power consumption.

- *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.*

5.2.4 Normative Annual Plant Availability

5.2.4.1 In control period 2009-14, the target availability has been determined based on the data available for the past years. The recovery of fixed charges was linked to availability. Generating stations were also incentivized for high availability. The availability of 85% is specified with exceptions of specific plant wise availability. The existing availability norms are uniform for all the generating stations. Now with the increase of private participation, access to imported fuel by private developer and technological improvement may have improved the availability. The issue of different availability norms for existing and new plants has been contemplated.

5.2.4.2 The recent shortage of domestic fuel has affected availability of the plants and their scheduling in case of shortage of fuel. The existing norm for availability may therefore needs to be revisited with fresh look. In the event of bridging gap through e-auction or imported coal (other than fuel arrangement agreed in purchase agreement), the need of prior consent, maximum permissible limit of blending etc. also need to be deliberated. The issues of treatment of availability and fixed charges, if the consent is not given by beneficiaries, are to be considered in the context of normative availability for recovery of full fixed charges and for incentive purpose.

5.2.4.3 In view of above, comments/suggestions are invited from stakeholders on the following issues :

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?

5.2.5 Transit & Handling losses

Commission had specified norm of 0.2% for the pit head station and 0.8% for the non- pithead stations. The same may have to be reviewed based on the past data in this regard. *Suggestion/comments of stakeholder are solicited with supporting data to review existing norms of transit & handling losses.*

5.2.6 Operational Norms for thermal Power Plant based on coal rejects

5.2.6.1 The existing regulation provides operational norms for Coal-based/lignite-fired thermal generating stations and Open-cycle Gas Turbine/Combined Cycle thermal generating stations. The operational norms for thermal power plant based on reject coal were not specified as there was no plant existing based on reject coal. Recently, there have been developments regarding Thermal power plant based on reject coal supplying power to two or more States.

5.2.6.2 The power plant based on coal rejects would use by-product of the mining/processing of coal for power generation. The coal rejects exhibits distinguished characteristics. The Coal rejects cannot be stacked as it would require a substantial amount of land at the mine site and storing of rejects for prolonged period is hazardous and may lead to combustion leading to environmental damage. Thus, it is felt that separate operational norms for thermal power plant based on coal rejects may be decided.

5.2.6.3 *In view of the above, suggestions/comments are invited on the introduction of operational norms for thermal power plants based on coal rejects. What will be the norms for station heat rate, specific secondary oil consumption, Normative Annual Plant Availability and transit and handling losses ?*

5.3 Operating Norms for Hydro station

5.3.1 The existing Operational norms of Hydro generation include norms for auxiliary consumption, transformation losses and normative annual plant availability factor. Capacity Index as a measure of plant availability was implemented by the Commission during tariff periods 2001-04 & 2004-09. It was based on the concept that hydrology risk has to be borne by beneficiaries all the time. After consultation, capacity index concept was modified with the new concept of Normative Annual Plant availability Factor (NAPAF) during 2009-14 periods. This is based on the premise that hydrology risk is to be shared by the generator & the beneficiary in the ratio of 50:50. There is a need for review of existing values of NAPAF based on feedback from the generating stations/stakeholders on 4 years of actual PAF data.

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

5.3.2 *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).*

5.4 Operating Norms for Transmission System

5.4.1 Availability of Transmission System/elements is expected to increase with introduction of new technology like polymer insulators etc. Thus, fresh look is required while specifying availability of transmission system.

5.4.2 The methodology for computation of Transmission system availability in tariff period 2009-14 was changed from earlier tariff period. For computation of availability of transmission system, Transmission system Availability Factor for a month (TAFM) is computed which is equal to (100- 100X NAFM) , where NAFM is the non availability factor in per unit for the month . The procedure of computation of transmission system factor for a month is provided in Appendix-IV of existing Tariff Regulation, 2009.

For computation of NAFM for the transmission system, Outage hours for transformer is multiplied by a weightage factor of 2.5 and outage hours of reactors is multiplied by a weightage factor of 4. 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. It is felt that the weightage factors considered may be reviewed with actual data/availability.

The comments are invited on the existing approach for computation of Transmission system availability. The suggestions are also invited on weightage factors to be applied for outage hours of for transformer and reactors.

5.4.3 *(a) 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.*

5.5 Incentive

5.5.1 The incentive prior to 2009 was linked to the normative PLF and generation beyond normative PLF; incentive was used to be paid at 25 paisa in case of thermal generating station. In case of hydro generating station prior to 2009 was linked to the capacity charges and capacity-index. The incentive during tariff period 2009-14 is linked to the normative Availability and generation beyond normative availability is payable at the fixed charge rate for the stations which are more than 10 years old or at 50% of the fixed charge for the stations up to 10 years old. In case of hydro generating station incentive was linked to the capacity charges (50% of annual fixed charges) and normative availability.

5.5.2 Whereas linking of incentive to availability appears to be reasonable and on sound footing but payment of incentive at or in proportion to fixed charge leads to different incentive for different plants depending upon fixed charges of the station and years of operation. It also leads to sudden increase in incentive for the plant after 10 years with respect to percentage of fixed charges.

5.5.3 At present there is same incentive for availability during peak and off peak period. There is need for introducing differential incentive during peak and off peak periods. On the same consideration there is need of higher incentive for the storage and pondage type hydro generating station providing peaking support.

5.5.4 Any generation beyond the design energy is paid at 80 Paisa/kWh in case of hydro generating station. This may also be reviewed.

5.5.5 *Based on above, comments of stakeholders are solicited on following:*

i) Efficacy of linking incentive to fixed charges in view of variation of fixed charges over a useful life and vintage assets. Can incentive of old and new stations be at same level or differentiated based on vintage?

ii) Suggestions are invited on differential incentive for off peak and peak period for thermal and hydro generating stations. Similarly, comments for differential incentive mechanism for storage and pondage type hydro generating stations.

6.0 Additional Issues

6.1 Availability of Domestic Fuel

6.1.1 The shortage of fuel (Coal and Gas) has a potential to make existing operational capacity remaining stranded. The Coal India Ltd. has not been able to supply committed quantity of coal as per Fuel Supply Agreement. The uncertainty with respect to gas supply also continues. In the above circumstances, the generating stations are either forced to procure fuel from spot market (in case of gas and coal) or to procure imported coal at higher prices.

Consequential Impact

6.1.2 The adoption of this alternate route of procuring fuel may lead to a situation in which the generating stations may use blended coal to overcome the shortfall in coal through Fuel Supply Agreements. The electricity generation from blended coal may not be able to get dispatch schedule due to higher prices imported coal/gas leading to consequential impact on generation.

6.1.3 If the power plant is heavily relying on this alternative route of fuel procurement, the energy charges will be increased and may not be controllable. On the contrary, the beneficiaries may seek generating station to obtain their consent prior to procure costlier fuel. In case the consent is not given by beneficiaries, the generating Companies may not be able to recover capacity charges and may not be able to meet debt service obligations. The beneficiaries may have arguments in support of denying consents. If the power plants heavily rely on imported coal, one may argue that blending ratio adopted by generator may not be commensurate with actual shortage and generator may use higher quantity of imported coal to cover up inefficiency in procurement of domestic or cheaper coal. It may also be argued that pass-through of actual fuel charge as per the Tariff Regulations may not enforce the generating Companies to achieve efficiency in fuel procurement in terms of price and quality.

6.1.4 Another area of concern is difficulty in verification of GCV of blended coal, due to unavailability of separate value of GCV of domestic and imported coal as fired. It may therefore, be necessary to provide for payment of energy charges based on as received GCV of domestic and imported coal with suitable margin and adjustment for arriving at as fired GCV. This would require development of norms for such adjustment.

6.1.5 Further, as alternative, the Normative / agreed blending ratio may be decided in advance in consultation with the beneficiaries in due consideration of technical limitation of steam generator. The blending ratio in the domestic coal based plants varies depending upon the quality of design coal, the quality of actual coal being received, age of plant, unit loading etc. The beneficiary may be scheduled to the availability corresponding to the extent of normative /agreed blending ratio and the beneficiaries not desirous of blending may not be scheduled, for the power in excess of availability of domestic coal. The consent can be obtained in advance on monthly basis and it should not be linked with daily declaration. However, the scheduling and payment of incentives would need to be debated.

6.1.6 The Central Commission, vide third amendment to Tariff Regulation dated 30.12.2012, has already incorporated the regulation for maintaining transparency in fuel procurement by generator and sharing of fuel prices including fuel procurement through e-auction and imported coal. Further, clause 21(4) of the Tariff Regulation, 2009 provide for dealing with situation of shortage of fuel. However, it is appropriate to review whether there is a need to modify existing provisions of tariff regulations for scheduling during fuel shortage situation.

6.1.7 The following issues have emerged on which comments/suggestions of stakeholders are solicited:

a) *Can normative or agreed blending ratio be specified for the existing plant and new plant separately in consultation with the beneficiaries? What should be the Methodology to work out normative/agreed blending ratio for existing and new projects?*

b) *Is it necessary and practical to take prior consent of beneficiaries for blending the imported coal with domestic coal? If the beneficiaries do not provide consent, can plant/machine be considered as deemed available to the extent of normative/agreed blending ratio for the purpose of recovery of fixed charges? How to deal with the scheduling and incentive aspects if beneficiaries are not ready for blending of imported coal.*

c) *How to ensure procurement of fuel by the generator namely e-auction coal or imported coal, at reasonable and competitive prices. Should there be need to seek explanation for any variation beyond a pre-specified indexation.*

d) *Whether there is a need to review the existing provision of Regulation 21(4) of the Tariff Regulation, 2009 dealing with situation of shortage of fuel. Should there be incentive payable in the situation of fuel shortage and operation of plant as per Regulation 21 (4) or the provision need to ensure full recovery of fixed charges*?

e) *Any other suggestions/measures for addressing above issues.*

6.2 Tariff Application methodology

6.2.1 The existing approach of tariff application based on projected capital expenditure and anticipated commissioning of project within six months, result into frequent revision of tariff. The tariff revision is taking place at different stages like provisional tariff, final tariff, one time revision allowed for additional capital expenditure prior to end of tariff period and final tariff after true up with actual expenditure. It is being contemplated that too many revisions will cause regulatory burden on stakeholders.

6.2.2 Tariff in respect of a generating station is determined for the whole of the generating station or a stage or unit or block of the generating station, and tariff for the transmission system is determined for the whole of the transmission system or the transmission line or sub-station. In case of transmission system, the provision for element wise determination of tariff is increasing the number of petitions being filed. Further, transmission element wise assets are being clubbed for the entire transmission project as with the gradual commissioning of assets involved in that project. In order to simplify working of the tariff determination, the issue needs to be addressed by introducing tariff determination based on region wise tariff instead of individual project/ element wise tariff. In case of region wise tariff determination, the transmission licensee may require to separate out region wise assets with corresponding capitalized expenditure and financing information.

6.2.3 The comments are invited on following aspects:

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 provisions?*

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?*

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Abbreviations

MW	Megawatt
PSU/CPSU	Public Sector Undertaking/Central Public Sector Undertaking
PPA	Power Purchase Agreement
BPTA	Bulk Power Transmission Agreement
TSA	Transmission Service Agreement
GDP	Gross Domestic Product
ABT	Availability Based Tariff
ROE	Return on Equity
O&M	Operation and Maintenance
COD	Commercial Operation Date
ICB	International Competitive Bidding
ICT	Inter-connecting Transformer
FSC	Fixed Series Compensation
PAT	Perform, Achieve & Trade
IDC	Interest during Construction
IEDC	Incidental Expenditure during construction
AAD	Advance Against Depreciation
GFA	Gross Fixed Asset
NFA	Net Fixed Asset
ROCE	Return on Capital Employed
ROI	Return on Investment
PLR	Prime Lending Rate
WACC	Weighted Average Cost of Capital
IWC	Interest on Working Capital
WPI	Wholesale Price Index
CPI	Consumer Price Index
RPI	Retail Price Inflation
A&G	Administration and General Expenses
AFC	Annual Fixed Cost
SHR	Station Heat Rate
GCV	Gross Calorific Value
PLF	Plant Load Factor
GOI	Government of India
OEM	Original Equipment Manufacturer
CCGT	Combine Cycle Gas Turbine
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
DVC	Damodar Valley Corporation
NTPC	National Thermal Power Corporation Ltd
NLC	Nayvelli Lignite Corporation
CFBC	Circulating Fluidised Bed Combustion
NAPAF	Normative Annual Plant Availability Factor
NATAF	Normative Annual Transmission Availability factor