

**Brief of the comments and suggestions received from members of  
Central Advisory Committee in regard to various issues indicated in Approach  
Paper of Terms and Conditions of Tariff Regulations for the tariff period  
1.4.2014 to 31.3.2019**

( Ref No. 20/2013/CERC/Fin(Vol-I)/Tariff Reg/CERC Date: 25<sup>th</sup> June'2013)

**1 National Thermal Power Corporation (NTPC)**

**1.1 Capital Cost**

- a) The tariff claim based on projected capital expenditure need to be continued as it helps to minimize the impact/quantum of retrospective revision of tariff and thus provides tariff certainty to both beneficiaries and generators.
- b) Generating company should be provided some flexibility to change the yearly phasing of the capex within the overall allowed projected capex for the tariff period. Further, the Commission may also consider allowing utilities to bill/recover from the beneficiaries on the basis of annual truing up based on audited financial statements, subject to final truing up by CERC.
- c) In any case, the time taken for project completion in a regulatory system would be subject to regulatory prudence check and would be allowed by the regulator after affording opportunity to all the concerned stakeholders.
- d) The existing provision of allowing IDC on equity infusion above desired level should continue to be allowed till COD.
- e) The timeline for completion of projects needs to be reviewed to enable at least top 35%-40% of the total units to claim additional return. As most of the projects now get completed in 50-55 months (including private projects), a completion schedule of 52 months for 500 MW & 60/62 months for 660/800 may be considered.
- f) The concept of benchmarking capital cost for normative capital cost may not be possible in India presently.

- g) Various transmission equipments, such as, ICT, bus reactor, bay equipment, line reactor and EHV transformer are installed in generating stations' switchyard and are grid interface of the power plants. The provision of initial spares of the above equipment permitted for transmission licensees should be allowed in case of generating stations also and should accordingly be factored into allowable capital spares. Allowance of capital spares for similar equipments need to be consistent and should be independent of ownership, location and type of business.
  
- h) A generating station may need to make expenditures which has become necessary for successful and efficient operation of generation system including switchyard which is part of the evacuation of generation and are interface with the Grid/Transmission. Even the expected life of such equipment located in a power plant gets changed due to prevailing grid behaviour & parameters (voltage, frequency and impulse/surge etc.). Therefore, necessity of allowing such equipment post cut-off date does not change merely because of the equipment being located in power plant or transmission system or vice versa. Therefore, the norms as finalized for such equipments in case of transmission may be extended to generating stations also in view of similar nature of equipments.
  
- i) The concept of Cut-Off Date should be dispensed with and utilities should be allowed to defer expenditure to the extent it is within the original scope of work. If the concept is to be retained it is submitted that capex/spares for which award has been placed before cut off date but could not be capitalized by cut off date needs to be allowed. It is also submitted that the cut off date may be extended by a year.
  
- j) Although efforts are made to award/procure main plant and other major Balance of Plant (BOP) packages through competitive bidding, mandating the same through the tariff regulations 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. Therefore, the procurement of main plant / major packages through ICB and other packages through competitive bidding may not be made mandatory through Regulations.

- k) The existing methodology for commissioning and declaration of commercial operation is well established and accepted and therefore may be continued. Further, 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.
- l) Retrofitting RGMO requires a long period of time on steady load to tune control systems that may not be possible before COD. Hence, RGMO logic should not be treated as a pre-condition for COD.
- m) The costs involved and benefits of efficiency improvement should be left to the generating companies.
- n) In coal stations, high pressure and temperature parts require constant maintenance and replacement after a certain time. Therefore, coal stations should necessarily be allowed additional capitalization on account of successful and efficient operation in view of much higher operating risk.
- o) Commission may cap the tariff adjustment up to the level of projected capital expenditure till the end of the respective year. This will be fair for the Utilities as well as the beneficiaries, since the interest payment /recovery can be minimised and the tariff paid by the beneficiaries will also be adjusted on year on year basis and will improve their cash outflows in case of projected capital expenditure materializing due to other issues. In any case, the tariff thus recovered by the generating company will be subjected to prudence check of the Central Commission at the end of the tariff period.

## **1.2 Renovation & Modernization**

- a) Both the provisions/options available to the generator for carrying out R&M, i.e. based on actual capitalization as well as the provision of normative Special Allowance on annual basis as provided in the present Tariff Regulations 2009 needs to be continued for providing comfort and regulatory certainty to the generators.
- b) Further, the Commission should prescribe the special allowance of Rs 18 lakh/MW for the Tariff Period 2014-19 with an escalation to be worked out with weightage of 50%

WPI and 50% CPI based on 2012-13 indices. Any expenditure towards change in law and/or ash dyke and ash handling system and expenditure on equipment other than BTG for life extension beyond 25 years would need to be considered exclusive of special allowance so arrived and will need to be serviced separately as additional capital expenditure.

- c) Further, in case of R&M schemes, which have been already approved by the Commission and are under implementation, the provision of capitalization of new equipment against corresponding de-capitalization of old replaced equipment should be continued in the next tariff period. In case of gas based stations, any additional capital expenditure which has become necessary for extension of life gas turbines from 15 to 25 years 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 have been provided in the Tariff Regulations 2009. Such provision should be continued.

### **1.3 Depreciation**

- a) The present methodology in practice of arriving at station COD based on weighted average COD of individual units may be continued.
- b) With regard to the Capital Expenditure at the fag end of Useful Life (say after 22nd year), in case there is additional capital expenditure near the end of useful life, the depreciation recovery gets accelerated due to short balance life. Therefore, in such cases depreciation may be separately serviced as individual stream during the next 10 years.
- c) In case of additional expenditure during fag end of life, the depreciation on account of the additional capital expenditure may be serviced over a period equal to its loan repayment period. Therefore, re-assessment of useful life on this account would not be required.
- d) Further, it may not be practically feasible to cover all capex items under R&M or Special Allowance. Capital expenditure towards development of ash dyke, ash handling system including cost of land that may be required after 25 years and any

expenditure required for BOP equipments/facilities would need to be considered separately as the same cannot be factored into R&M for BTG. Besides, provision of compensatory allowance available to coal based stations needs to be extended beyond 25 years as expenses for which compensation allowance is given would also continue to be required after R&M. It is therefore suggested that add-cap provisions applicable beyond cut-off date till end of useful life needs to be extended to apply to the extended life after R&M.

- e) For the extended life minor assets in nature of Miscellaneous Bought Out Assets (MBOA), Vehicles, Fire Fighting equipment and systems, medical equipments, safety equipment etc also need to be considered along with the compensatory allowance.
- f) Further, reassessing life at the start of every tariff period/every additional capital expenditure would lead to inconsistency and add to regulatory uncertainty.
- g) Depreciation can be charged over the balance life of assets along with the original written down value up to 90%. Depreciation of original assets up to 90% value can be as per its original life of 25 years. Depreciation of assets capitalized after 20 years may be recovered over the period matching with its loan repayment period which is presently about 10 years.
- h) 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. Accordingly, the rate of depreciation should be enhanced to cover the repayment of loan within 8-9 years. Alternatively, Advance against Depreciation needs to be considered in the wake of present loan tenure available.

#### **1.4 Net Fixed Asset v/s Gross Fixed Asset Approach**

- a) Gross Fixed Asset (GFA) approach should continue in the interest of desired growth of the power sector. Adoption of NFA approach may severally affect the internal resource

generation of power generating companies and further investment in the power sector will be impacted adversely.

- b) Further, NTPC submitted that it has been planning the capacity addition targets on the cash flow projections based on the GFA approach. Any change in the approach at this stage on such a fundamental principle would severely affect the cash flow of NTPC and would jeopardize the capacity addition plan of not only NTPC, but of the whole country.
- c) Existing approach of Gross Fixed Asset based tariff determination may be continued.

### **1.5 Debt/Equity Ratio**

- a) In order to provide regulatory certainty, the existing approach should continue with the same Debt: Equity ratio of 70:30 for new investments and existing Debt Equity ratio of 50:50 for existing projects (i.e. projects where investment approval was made before 1992).

### **1.6 Return on Investment (RoI)**

- a) Considering the complexities involved in implementation of the RoCE approach and in view of the immature bond market and turbulent and volatile financial markets in India, it is suggested that RoE approach may be continued. This would provide regulatory certainty to the developers.

### **1.7 Return on Equity (RoE)**

- a) Considering the scenario of 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. Hence linking the expected ROE to the benchmark rate also presents a case for at least 20% Return on Equity.

- b) Further, the Return on Equity should be revised periodically taking into account the current developments in the industry's risk-return profile and changing market conditions.
- c) Thermal power generators should be compensated for the higher operational risks by increasing the ROE further by at least 2.0% to 2.5%.
- d) The existing pre tax return on equity by grossing up ROE with applicable MAT/Corporate Tax Rates should continue.
- e) To encourage investment in the power sector, the Return on Equity should be estimated following the CAPM approach, which is estimated to be around 20.11%.

### **1.8 Cost of Debt**

- a) The existing method should continue and no normative rate of interest may be fixed.
- b) The existing method of working out cost of debt should continue by considering weighted average rate of interest, calculated on the basis of actual loan, actual interest rate and scheduled loan repayment.

### **1.9 Interest on Working Capital (IOWC)**

- a) Amount and stock of fuel oil/O&M expenses/maintenance spares/receivables specified in the existing regulations should continue.
- b) The existing methodology should continue since all the elements required and related for maintenance and operation of the power projects must be factored for the purpose for the purpose of working out allowable Working Capital.
- c) In case of ROCE approach, working capital can be considered as a part of the Regulatory Asset Base. However, in view of the difficulties in implementation of ROCE approach, it is again submitted that ROE approach may be continued along with the present dispensation for working capital.

- d) 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.

### **1.10 Operation and Maintenance Cost (O&M Cost)**

- a) While fixing the base rate of O&M cost for the 2014-19 tariff period, CERC should consider the following:
- Separate provision for water charges
  - Variable pay in the Base Cost
  - Escalation rate to be used for base O&M Cost fixation: The current methodologies followed by CERC can be said to be a variant of RPI-X method, except that the RPI (Retail Price Index) factor or the inflation rates are currently based on the past trend of inflation indices. This approach should be slightly modified so that the escalation rates are based on the actual inflation rates, as we have seen wide variation in the inflation rates causing significant under recovery by the regulated entities. Hence the approach of determining the base O&M cost based on the past actual and providing escalations as per current escalation rates would be appropriate for Indian context.
  - Issue of Pay Revision (allowing 50% increase in employee cost due to pay revision). This shall be subject to adjustments based on the actual impact of pay revision to be implemented based on the guidelines to be issued by Dept. of Public Enterprises, Govt. of India.
  - Fixation of O&M Cost Norm for Gas stations: The machine size for older vintages is lower and spares are not easily available. Therefore the norm of O&M expenses for such machines should be higher as compared to the machines with newer vintage.
  - In O&M expenses also there should be provision for Change in Law.



- b) The escalation of O&M cost during the tariff period should be based on the actual escalations of the inflation indices. Thus, the weightage of WPI and CPI should be 80% and 20% respectively for calculating the escalation rate.
- c) In case of NTPC, O&M expenses is 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.

### **1.11 Station Heat Rate (SHR)**

- a) Operating norms should be based on the average performance of units in the country and not confined to NTPC stations alone. Further, operating norms should be based on past performance of units in the country including State Utilities / IPPs of relevant vintage and should factor in operating constraints, like, partial loading due to erratic load pattern of the beneficiaries and lower operating load factor due to shortfall of quantity and quality of fuel which is expected to continue in future.
- b) Considering the actual heat rate achieved and at the base of 85% DC during the present tariff period and the predicted deviations due to three factors like reduction in boiler efficiency (20 kCal/kWh) due to coal quality degradation, average annual ageing loss (12.5 kCal/kWh) and partial loading (10%) of the units (34.5 kCal/kWh), the anticipated heat rate of 500 MW units during the start of coming tariff period would be of the order of:

- 500 MW units:  $2386 + 20 + 12.5 + 34.5 = 2453$  kCal/kWh (8.0% of Design)
- 200 MW units:  $2425 + 20 + 12.5 + 34.5 = 2492$  kCal/kWh (8.5% of Design)
- 660 MW units:  $2325 + 20 + 12.5 + 22.0 = 2379.5$  kCal/kWh (7.8% of Design)

Therefore, existing norms of station heat rate should be continued in case of 200 MW. In case of 500 MW the norms needs to be set at 2450 kCal/kWh. And in case of 660 MW units, margin above design should be 8.0% in view of future scenario as elaborated above.

Further, with regard to the gas based stations, in view of deterioration in Gas Turbine, WHRB performance deterioration, performance data of last 5 yrs and projected partial loading in the coming years, the existing norms of station heat rate of Anta, Faridabad, Kawas, Gandhar & Kayamkulam Station should be increased by 25 kCal/kWh whereas Auraiya station tariff Heat rate should be increased by 50 kCal/kWh for Tariff period 2014-19.

### **1.12 Secondary Oil Consumption**

- a) The present regulations provide for 1.0 ml/kWh for coal based stations with a provision for sharing of savings with the beneficiaries. Given the fuel shortage scenario, which is likely to continue in the next tariff period also, and erratic load pattern of most beneficiaries, conditions of partial loading and backing down would require oil support for safe boiler operations. Therefore, the existing norms may be continued. Whereas, some of the NTPC stations like Farakka and Badarpur are already operating above the stipulated norms and therefore, further relaxation of 0.5 ml/kWh may be provided for such stations.

### **1.13 Auxiliary Energy Consumption**

- a) The existing norms of auxiliary power consumption as specified by CERC during 2009-14 period may be continued for the period 2014-19 along with consideration for additional margin as given below:
  - Additional Margin for MDBFP for 660 MW and 800 MW units: 3.5%
  - Additional Margin for Stations with Tube Mills: 1%
  - Additional Margin for Pipe Conveyor and associated conveyors: 0.5%
  - Additional Margin for Station with distantly located water source: 0.5%
  - Coal Quality Deterioration: 0.2%
- b) Further, with regard to the Tanda TPS and Talchar TPS, NTPC submitted that existing norms of auxiliary power consumption as specified by CERC during 2009-14 period may be revised for the period 2014-19 with additional margin of 0.5% to take care of present condition and additional partial loading of 10% above 09-14 period due to grid constraint & coal supply/availability. With regard to Badarpur TPS, existing norms of auxiliary power consumption as specified by CERC during 2009-14 period may be

revised for the period 2014-19 along with additional margin of 1.5 % to take care of present condition and additional partial loading of 5 % above 2009-14 period due to low grid demand, poor coal & water availability and augmentation of closed CW system with additional CT.

- c) Further, with regard to the environmental measures taken by NTPC Power Stations, the existing APC norms of need to be revisited with additional consideration for the additional margin on account of the following:
- Additional Margin for FGD: 1%
  - ESP Upgrade: increased APC on account of upgrades/retrofit should also be taken into consideration while formulating the APC norms in Tariff.
  - Additional Pump for Ash Disposal / Utilisation: 0.4%
- d) The existing APC norms of Gas stations need to be revisited with additional consideration for Partial Loading below 80% for all Gas stations.
- e) The colony consumption is considered as part of the auxiliary consumption of the stations. Construction power consumed is generally sourced from the distribution company and the cost incurred is accounted as IEDC which forms part of capital cost as on COD for tariff purposes. Therefore, the existing established practices may continue.

#### **1.14 Normative Annual Plant Availability**

- a) As the domestic coal availability would be mostly out of control of generators, there is a case for lowering of target availability to avoid under recovery of Fixed Cost by generators. To protect the interest of the developers, the Target Availability should be suitably aligned. Therefore, Target Availability may be set at 80% for existing power stations and 70% for the new stations, which are covered under new FSA. For gas based stations, existing norms of annual plant availability may be continued.

#### **1.15 Transit & Handling Losses**

- a) The existing norms of 0.2% for the pit head station and 0.8% for the non- pithead stations may be continued.

### **1.16 Incentive**

- a) The current provisions of linking incentives to the fixed charges of the station and differential incentive for the old and new stations may be continued.
- b) Thermal stations are essentially base load stations designed to meet the base load requirement of the country. Hence the concept of differential incentive for off-peak and peak period should not be applied for thermal stations.

### **1.17 Availability of Domestic Fuel**

- a) The amount of blending of imported coal in a power plant would depend factors such as the GCV of the domestic coal, GCV of the imported coal (low GCV or high GCV), shortfall in supply of domestic coal from linked mines etc. Hence considering all these factors, the blending of imported coal should be left to the generators to decide depending on the situations as mentioned above along with the boiler design.
- b) Further, CEA in its study of range of blending of imported coal with domestic coal has observed that the blending of coal in the existing power stations is normally in the range of 10 to 15% by weight. Considering all the relevant factors, CEA has recommended a maximum blending ratio of 30% by weight in the future boilers. Hence the commission may consider this limit as the maximum blending ratio. However, while fixing any norm for blending of imported coal, CERC need to recognize that it is not practically possible to accurately control the blending with the existing plant designs/ infrastructure so as keep the same within the prescribed limit.
- c) Technically it is not possible to specifically schedule power from only domestic or imported power to any individual beneficiary. Hence, it is suggested that the idea of taking prior consent of beneficiaries must be dispensed with.

### **1.18 Tariff Application Methodology**

- a) Tariff claim based on projected capital expenditure needs to be continued.

### **1.19 Additional Issues**

- a) Mandatory Solar Power Generation Facility on TG Hall of New Power Stations: It is proposed that the capital cost in roof top solar facility may be included in the capital expenditure of the project for tariff purposes. The beneficiaries of the station shall be given credit in their monthly energy charges corresponding to solar energy generated in proportion to their allocation from station. In other words, the solar energy thus generated at the station shall be supplied to the beneficiaries without any charges & their energy bill from the station shall be reduced to the extent of solar energy generated.
- b) Expenses on initiatives for encouraging environment need to be allowed in tariff.
- c) Need for stabilization period for units after COD has increased in view of introduction of new technologies and shift from sub-critical to supercritical technology and gradual increase in size of the unit from 200/500 MW to 660/800 MW. Therefore, the stabilization period of 1 year may be introduced having 80% of the regular post - stabilization norm.
- d) Cyclic loading shall lead to more wear and tear of the plant and as a result higher Repair and Maintenance shall be required. Therefore, it is submitted that higher O&M expenses norms may be provided in view of cyclic loading pattern.
- e) The compensatory allowance should be allowed as under:

| S. No. | Years of Operation | Compensatory Allowance (Rs lakh / MW / Year) |
|--------|--------------------|--|
| 1      | 5-10               | 0.30   |
| 2      | 11-15              | 0.55   |
| 3      | 16-20              | 0.75   |
| 4      | 21-25              | 1.00   |

- f) Certain demurrage charges on normative basis should be considered as part of the transportation cost of coal.

## **2 National Hydroelectric Power Corporation Ltd. (NHPC)**

## **2.1 Capital Cost**

- a) Time of construction of Hydro projects should not be standardized/restricted, otherwise, development of hydro power, the only solution for peak shortage, may become commercially unviable.
- b) Benchmarking of capital cost should not be introduced for hydro projects.

## **2.2 Renovation & Modernisation**

- a) CERC Regulations has the provisions of special allowance @5 lakh/MW/year and with escalation @5.72% per annum for thermal generating stations as an alternative of renovation & modernization after useful life of the station. Hydro generating stations have the useful life of 35 years, affected by technological obsolescence, require R&M after useful life, takes longer time for R&M like any other type of generating stations, therefore, it is justified to allow similar allowance to hydro generating stations.

## **2.3 Return on Equity (RoE)**

- a) Due to rising cost of capital & investment in the country it is imperative to increase the base rate for return on equity to atleast 18% to attract the investment in power sector. Further, additional 2% return on equity should be allowed for all type of hydro projects.

## **2.4 Interest on Working Capital (IOWC)**

- a) Due to imposition of Water Usage Charges by the Govt. of Jammu & Kashmir for use of water for generation of electricity in J&K, it become imperative to introduce one month water usage charges as forth component in working capital. The one month water usage charges shall be derived from actual payment of last year.

## **2.5 Auxiliary Energy Consumption**

- a) The existing auxiliary consumption including transformation losses should be revised as under:

| Unit Size     | Surface |        | Underground |        |
|---------------|---------|--------|-------------|--------|
|               | Rotary  | Static | Rotary      | Static |
| Upto 200 MW   | 2.0%    | 2.3%   | 2.7%        | 3.0%   |
| 200 - 600 MW  | 1.8%    | 2.1%   | 2.5%        | 2.8%   |
| 600 - 1200 MW | 1.5%    | 1.8%   | 2.2%        | 2.5%   |
| Above 1200 MW | 1.2%    | 1.5%   | 1.9%        | 2.2%   |

- b) Further, it is proposed that condition of providing continuous 03 hrs DC for availing 100% PAF for that day may be modified to 1.5 hrs for two times in a day instead of 03 hrs in respect of older Power Stations where present live storage is less than 60% of designed live storage.

## **2.6 Normative Annual Plant Availability**

- a) NAPAF already fixed should be continued.

## **2.7 Incentive**

- a) Incentives for old stations should be more liberal than the new stations. In this regard, it is suggested that,
  - Rate of secondary energy should be equal to primary energy charge rate, and
  - Incentive for higher availability (higher PAF) should be allowed on full AFC of the power station instead of 50% AFC.

- b) Further, peaking / differential tariff should be implemented for hydro generators as an additional incentive for supporting the grid. Alternatively, 25% higher Energy Charges Rate (ECR) should be provided for peaking energy during peaking period.

## **2.8 Tariff Application Methodology**

- a) Tariff determination on existing methodology is suitable and should be continued.

## **2.9 Additional Issues**

- a) Compatibility of Government Policies and Tariff Regulations: Free power should be allowed as per allocation of power issued by MOP in case of central generating stations. Further, in accordance with the provision of Tariff Policy, 2006 / Hydro Power Policy, 2008, there should be the treatment of 100 units per month to each project affected family (PAF) free of cost. Further, as per the provision of Tripartite Agreement (TPA), payments made beyond a period of 60 days from the date of billing or 45 days of the receipt of bills, whichever is later shall attract surcharge/interest at the rate of 15% p.a. compounded quarterly. The above provisions shall be incorporated in Tariff Regulations.
- b) Accumulation of dues: In case of delayed payment the adjustment of payment made by the beneficiaries needs to be defined as under: (i) Late payment surcharge, taxes,

duties, cess, royalty etc., (ii) Outstanding dues of more than 60 days on FIFO basis, and (iii) Current dues.

### **3 Power Trading Corporation (PTC)**

#### **3.1 Capital Cost**

- a) Only the actual cost should be taken for tariff setting purpose. Benchmark cost may be used for prudential check but not for tariff setting.
- b) Delay in construction would severely affect capex and Commission should not consider allowing the cost escalation due to delay for reasons other than force majeure. Therefore, comparison between the initial cost intimated to the Commission and the completed cost must be thoroughly examined and not just for the sake of completing the document. To begin with, part of IDC may be disallowed beyond an agreed project completion time and should be absorbed by the developer.

#### **3.2 Renovation & Modernisation**

- a) Special allowance has served its purpose and should continue. Loss of capacity charges is a fear for developers than getting special allowance (as it is lower), therefore, the instances of misuse will be minimal.

#### **3.3 Depreciation**

- a) Useful life should be considered as 25 years only as 70% of the depreciation is recovered in first 12 years. Balance left is small and it doesn't make much difference if it is recovered in next 13 years or more than that.
- b) Life of Transmission line should be considered as 35-40 years as the quality of material as well as a factor of safety has improved in last couple of years. The life of projects in the coastal area or hilly terrain can still be considered to be 25 years for transmission projects.

#### **3.4 Net Fixed Asset v/s Gross Fixed Asset Approach**



- a) Gross Fixed Asset (GFA) approach is being currently used and should be allowed to continue for sustained interest of investors in the sector. Even if there is surplus generated on account of accumulated depreciation, investors would reinvest in the sector.

### **3.5 Return on Investment (RoI)**

- a) RoE approach (15.5%) should be continued. Problem with RoCE approach is that a benchmark cost of debt cannot be determined. It may be 9% for companies like NTPC and 14% for some IPPs.

### **3.6 Interest on Working Capital (IOWC)**

- a) Inventory, one month's operation and maintenance cost, 2 months receivable etc. are small components of total tariff. Major component is fuel cost (~60%). Capacity charges are close to 40% (RoE and depreciation constitute half of it). So there will not be much impact on total tariff by including Working Capital rather it will complicate tariff determination process.

### **3.7 Operation and Maintenance Cost (O&M Cost)**

- a) For the time being, O&M cost should be the actual cost incurred. For future, a normative rate may be worked out. International benchmarking may be followed to compare the earlier decided O&M cost particularly for supercritical plants and new generating units both in terms of O&M cost as well as auxiliary consumption.

### **3.8 Availability of Domestic Fuel**

- a) As compared to control period 2009-14, acute fuel shortage is expected during 2014-19. All India PLF is coming down by 4-5% every year in last 3 years. Therefore, stranded capacity may in turn affect the repayment capacity of the loan component making investment unviable. Hence, use of imported coal should be allowed till there is shortage in the country. Some mechanism has to be worked out for this after discussions with stakeholders.
- b) Use of imported coal should be allowed till there is shortage in the country. Some mechanism has to be worked out for this after discussions with stakeholders

## **4 Mumbai Grahak Panchayat (MGP)**

### **4.1 Capital Cost**

- a) Tariff determination should be on the basis of Actual Capital Expenditure and not on the basis of Projected expenditure.
- b) The benchmark capital cost as specified by Central Commission may be considered for the purpose of normative capital cost. Further, construction period may be standardized with provision for normative interest during construction to bring efficiency in construction period.
- c) To ensure competitiveness, International Competitive Bidding should be made mandatory for main plant packages/major packages and competitive bidding for all other packages.

### **4.2 Depreciation**

- a) The estimation of useful life of substations and transmission lines should be revised to 30 years and 40 years respectively.

### **4.3 Return on Equity (RoE)**

- a) The pretax return on equity should be rolled back to 14% to increase competitiveness amongst power companies.

### **4.4 Interest on Working Capital (IOWC)**

- a) MGP recommend that for calculating interest on working capital, only one month's receivable be taken into account for following reasons: (i) One month's security deposit is collected by Power companies from consumers in advance and retained by them, and (ii) Hefty penalty rates on defaulting consumers have brought down the outstanding receivables drastically.

## **5 Minutes of Central Advisory Committee Meeting**

### **5.1 Capital Cost**

- a) Tariff should be determined based on the actual cost and benchmark cost should be considered for reference purpose.
- b) There is a need to identify agencies to undertake prudence check of capital cost.
- c) IDC may be approved for un-controllable parameters only and IDC on account of controllable parameters (for example, delay resulting from poor contract management) should be disallowed.
- d) Benchmarking of capital cost should not be adopted for hydro projects
- e) Implementation of FGMO/Communication system etc should be linked to Fixed Cost recovery. Allocation of transmission corridor for power exchanges should be made. It was also viewed that the power exchanges must be ready to bear the cost for allocation of transmission corridor.

## **5.2 Renovation & Modernisation**

- a) Norms for Special allowance, GFA and ROE should be continued.
- b) Norms for R&M should also be prescribed. The regulations should be based more on indexation. Alternative tariff design deliberated in the approach paper should also be considered.

## **5.3 Depreciation**

- a) Depreciation should take care of debt repayment. But, depreciation recovered over and above the debt repayment liability should be used for creation of new assets.

## **5.4 Return on Investment (RoI)**

- a) As envisaged in the Tariff Policy, there is need to move towards ROCE approach leaving scope for financial engineering.
- b) ROCE is good for large investors because of their capability of raising debts. However, small investors prefer ROE approach over ROCE.

- c) Norms for Special allowance, GFA and ROE should be continued. There should be incentive for peak hour supply.

### **5.5 Return on Equity (RoE)**

- a) Generators and lenders perceive high risk in power sector due to issues related to environment clearances, land acquisition, right of way, fuel and transmission constraints. It has become difficult for developers to seek lending for the projects. In view of this, some stakeholders suggested that the returns should not be lowered.
- b) Further, ROE should be linked to bank rate as was done under the Sixth Schedule of the erstwhile Electricity (Supply) Act, 1948.
- c) There is a case for differential ROE for hydro projects because of difference in gestation period.
- d) Continuity of principles should be there for greater regulatory certainty for existing investment. ROE must be fixed considering the interest of the investors.

### **5.6 Operation and Maintenance Cost (O&M Cost)**

- a) O&M for hydro projects should be based on actual O&M cost. Rate of secondary energy rate should be equal to primary energy rate.

### **5.7 Station Heat Rate (SHR)**

- a) Competitive environment should be created within tariff regime. There is no need to change norms for a plant where investment has already been made. CERC Regulation should reduce the discretionary powers of CERC itself.
- b) Normative SHR should be very close to design heat rate and incentive structure should be built to induce the generators to reach to the level of design heat rate.

### **5.8 Secondary Oil Consumption**

- a) The Commission should adopt less prescriptive and more normative approach so that efficient developers can be rewarded. Competitive environment should be created within tariff regime. There is no need to change norms for a plant where investment

has already been made. CERC Regulation should reduce the discretionary powers of CERC itself.

#### **5.9 Operation and Maintenance Cost (O&M Cost)**

- a) The Commission should adopt less prescriptive and more normative approach so that efficient developers can be rewarded. Competitive environment should be created within tariff regime. There is no need to change norms for a plant where investment has already been made. CERC Regulation should reduce the discretionary powers of CERC itself.

#### **5.10 Normative Annual Plant Availability**

- a) There is no need to change norms for a plant where investment has already been made. CERC Regulation should reduce the discretionary powers of CERC itself.
- b) Availability norms should be reviewed in view of fuel shortages.

#### **5.11 Transit & Handling Losses**

- a) There is no need to change norms for a plant where investment has already been made. CERC Regulation should reduce the discretionary powers of CERC itself.

#### **5.12 Incentive**

- a) There should be incentive for peak hour supply.
- b) Normative SHR should be very close to design heat rate and incentive structure should be built to induce the generators to reach to the level of design heat rate

#### **5.13 Availability of Domestic Fuel**

- a) Fuel Shortage: There is a need to define specific circumstances under which the availability norms for reimbursement of Fixed Cost can be lowered.

#### **5.14 Additional Issues**

- a) Reactive power injection and primary response capabilities by generators should be encouraged.

- b) There was no need to make drastic changes in the existing regulations. Controllable and Un-controllable factors should be defined.
- c) The distribution utilities are resorting to load shedding instead of buying power for the consumers. This is costing more to the consumers as they are made to pay high cost for diesel generators as back up supply.
- d) Review of past MYT should be undertaken and approach paper should be backed up by data analysis.

--X--