Terms and Conditions of Tariff for 2009-14

Explanatory Memorandum

1.0 Introduction

1.1 Section 61 of the Electricity Act 2003 requires the appropriate commission to specify the terms and conditions for the determination of tariff:

Section 61. (Tariff regulations):

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

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

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

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

(d) safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;

(e) the principles rewarding efficiency in performance;

(f) multi year tariff principles;

(g) that the tariff progressively, reflects the cost of supply of electricity and also, reduces cross-subsidies in the manner specified by the Appropriate Commission;

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

(i) the National Electricity Policy and tariff policy:

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

1.2 Section 178(2)(s) of the Act further empowers the Central Electricity Regulatory Commission (CERC) to make regulations on the terms and conditions for the determination of tariff under section 61. Section 79 of the Act provides that functions of Central Commission and as such the CERC is require to make tariff regulations in respect of the generating companies and the transmission licensees covered under the said provision (Section 79).

1.3 It would be pertinent to mention in this context that CERC was constituted under the erstwhile Electricity Regulatory Commissions Act, 1998, and in exercise of powers under the 1998 Act, the Commission had issued terms and conditions for determination of tariff for the period 2001-04. After the enactment of the Electricity Act 2003, the CERC framed regulations, in exercise of the powers under Section 178 of the Act, on the terms and conditions for the determination of tariff for the period 2004-09 in March 2004. The present tariff period 2004-09 would end on 31st March 2009 and the Commission proposes to specify the terms and conditions of tariff for the next control period i.e. for 2009-14.

2.0 Approach Paper for Tariff Regulations for 2009-14

2.1 The Commission initiated the process of framing the tariff regulations for 2009-14 in December 2007 by issuing an approach paper and soliciting comments of stakeholders on the bases and assumptions to be considered while framing the new terms and conditions of tariff and seeking to dovetail the experiences of the last eight and half years of tariff regulation by the Commission, starting from May 1999.

2.2 The Commission received comments from various stakeholders including State Governments, SERCs, Central sector utilities, State sector utilities, private sector utilities, financial and other organizations, and individual experts. A copy of the approach paper dated 11th December, 2007 issued by the Commission is at **Annexure-I** and brief of the comments received from the stakeholders on various issues posed is at **Annexure-II.**

2.3 The Commission also convened a meeting of the Central Advisory Committee on 28th April 2008 to discuss the approach paper on terms and conditions of tariff for 2009-14. A brief of the comments received from the participants on various issues posed is at **Annexure-III.**

3.0 Approaches to Rate of Return

3.1 Of the various issues highlighted in the approach paper, one of the key issues related to approach for rate of return – the issue posed was as to whether the Commission should adopt return on capital employed **(ROCE)** approach or continue with the existing return on equity **(ROE)** approach.

3.2 The Commission, while framing regulations for the previous periods, had recognized that Return on Capital Employed (ROCE) approach was preferable but because of lack of benchmarking for Debt-Equity mix, fluid situation in regard to interest rate and debt market in India, had decided to adopt Return on Equity (ROE) approach.

3.3 On the issue as to whether the Commission should have a fresh look at the approach for rate of return and change over to ROCE approach, majority view of the stakeholders was in favour of continuing with the existing ROE approach as the situation especially in regard to interest rate fluctuation and debt market in India has not yet stabilized to enable projection of a firm normative interest rate for the purpose of arriving at return on capital employed.

3.4 The general sentiment of the members of the Central Advisory Committee was also in favour of continuing the existing ROE approach because of not-so-stable interest rate regime.

3.5 In this context, the Commission would like to reiterate that ROCE approach is definitely preferable over the ROE approach because of its inherent feature of inducing efficiency in fund management and encouraging competition. However, the Commission cannot remain oblivious of the realities of the debt market, more so of the fluctuations in interest rates as witnessed in recent past. The Commission feels that unless the debt market stabilizes it may not be feasible to arrive at a normative interest rate which can be applied for calculating the return on capital employed. At the same time, the interest rates on loans advanced vary significantly from company to company depending upon its financial strength and standing in the market. It may not therefore be appropriate to assign the same normative interest rate – if at all such normative interest rate can be derived – for all companies across the board.

3.6 The Commission has also taken note of the fact that the revision of norms of tariff would be applicable only to the existing plants and those projects of CPSUs and State utilities for which PPAs are executed by 6.1.2011, as the new projects will be linked to tariff based competitive bidding guidelines. As an exception, the developer, of a hydroelectric project would have the option of getting the tariff determined by the appropriate Commission on the basis of performance based cost of service regulations if the conditionality of following transparency with regard to award of project and land etc are fulfilled.

3.7 The Commission is also aware of the fact that there still exists significant disparity in the nature of entities under the purview of the Commission. Implementation of ROCE approach would raise a large number of issues as it requires computation of annual Weighted Average Cost of Capital (WACC) due to progressive change and reduction in the capital employed. A single WACC for the entire power sector and the control period would not be appropriate as the terms and conditions at which a utility obtains loan and raises equity varies widely depending upon the credit rating of the utility and the time period. New investments, particularly by the private sector are generally targeted at a specified debt equity norm and the return on equity projected will give an appropriate signal of assured proper return on that investment.

3.8 Another important point worth noting in this context is that as per Section 61 of the Act, the State Commissions are also to be guided by the terms and conditions of tariff notified by CERC for generation and transmission. It would be all the more difficult for the State Commissions to adopt the normative interest rate, if any, notified by CERC for the utilities regulated by the State Commissions, since such utilities in some cases may not be in a position to bargain interest rate for loans equivalent to that availed by the large entities regulated by CERC.

3.9 Given these realities and with due regard to the sentiment of the stakeholders and the members of the Central Advisory Committee, the Commission has decided to continue with the existing ROE approach for the tariff period 2009-14.

Important Issues in Tariff Regulations

4.0 Having decided on the approach to rate of return, the Commission would like to discuss the issues that flow from the approach and dwell on the manner in which the Commission has tried to balance the interests of the investor and the beneficiaries/consumers with due regard to the guiding principles especially as enunciated in Section 61 of the Act.

5.0 Capital Cost

5.1 In a cost based regulation capital cost of the project is perhaps the most important parameter. The capital cost on the completion of the project is the starting point as the rate base for deciding the return on the investment made by the generators. Different philosophies and practices have been followed in the different tariff periods which are discussed below:

5.2 Prior to 1992 and during the period 1992 to 1997 and 1997 to 2001, the capital cost of the project used to be based on gross book value as per the audited accounts. The changes in the capital cost by the way of capitalization and FERV were also being accounted for and tariff was being adjusted retrospectively. This practice has been followed even during the tariff period 2004-09.

5.3 Under the existing methodology of fixation of tariff for the period 2004-09, reliance is on the audited figures as certified by the Auditors of the companies and completion of supplementary audit by the CAG of India in case of Govt. owned companies. This takes considerable time resulting in allowing provisional tariff. Again in respect of additional capital expenditure for which the utilities can approach the Commission twice during the period 2004-09, there is a considerable passage of time between completion of work and approach to the Commission for the award of tariff. This results in retrospective application of revision in tariff and also delay in reaching the finality with regard to tariff of the various units and stations. The present dispensation requires revisiting the same tariff which entails additional work on the petitioner, beneficiaries and the Commission and the same case being heard in the Commission more than once. The beneficiaries that are situated at far flung places have also to gear up to present their view point resulting in additional time and effort. It is also recognized that any retrospective revision particularly where the tariff has gone up is not getting reflected in the ARR petition filed by beneficiaries with the State Regulatory Commission and gets postponed resulting in distortion in tariff between different periods. Considering all such aspects, the Commission felt that it is better to provide a reasonable amount of certainty to the entire exercise of tariff fixation and reduce the impact of provisional tariff as well as retrospective implementation of any revision. With this in view, the Commission is moving towards the concept of projected capital expenditure with a truing up exercise during the terminal year of the control period. However, in order to give flexibility to the petitioner and to accommodate any abnormal variation, the generating company or the transmission licensee shall have the option to come before the Commission one more time prior to 2013-14 for a revision in the tariff.

5.4 In case of new generating stations the tariff was being awarded on the admitted capital expenditure actually incurred up to the date of commercial operation of the generating stations subject to prudence check by the Commission. In case of existing generating station the capital cost as on the starting day of the tariff period was being determined based on the capital cost as already admitted by the Commission which also used to be based on capital expenditure actually incurred. The regulation 18 provides for admissibility of additional capital expenditure after the COD of the stations.

5.5 The regulation further provided for revision of tariff twice during the tariff period taking into account the admitted additional capitalization. Such revision in tariff takes place post facto and applied retrospectively from the start of the tariff period. The beneficiaries do not have much scope to pass on such increase in tariff on account of additional capitalization to the end consumers retrospectively. The Commission, with due regard to this consideration, had provided during the tariff period 2001-04 as follows:

> *Any expenditure approved in the project cost but incurred during a tariff period shall have to wait till the next tariff revision unless it constitutes more than 20% of the approved cost.*

5.6 Similarly, with regard to the base rate i.e. capital cost, the Commission had observed in its tariff order dated 21.12.2000 for the tariff period 2001-2004 that to ensure predictability of tariff, the criteria for determining the base should be clear and unambiguous and went on to say at para 2.8.1 of the Order, as follow:

> *The basic feature of the CAS recommendation on determination of rate base therefore is that we should resort to the audited balance sheet of the station/line, each year to determine the tariff of that year. The Commission envisages practical difficulties in relying on the balance sheet as suggested by CAS. It should be kept in mind that tariff is to be determined station wise/line wise. Presently, <u>no audited station wise/line wise (or region wise) balance sheets are available disclosing in a verifiable manner the debt and equity</u>. Further the actual book figures are based on the ground realities whereas the tariffs are determined on normatives and hence reliance cannot be had on book figures. On a sample study we found that the net block on tariff basis and on balance sheet basis differ. For instance, the adjustments between head office and stations are purely internal on which regulator cannot have a control. There might be inter station transfers of assets and borrowings at corporate level. Exchange rate variations adjusted in the books distort the values of assets, if not approved by Regulators.*

Moreover, there is bound to be a time lag between the availability of audited balance sheet and the commencement of a year whereas tariff is required to be determined before the commencement of a year. In fact it is preferable to determine Tariff for the full tariff period in advance, subject to permissible additional capitalisation during the tariff period. It is therefore, more appropriate to develop parallel data commencing from commercial operation particularly of assets, debt and equity in order to keep track of the rate base on normative levels. The trail has to be followed independently commencing from approved project cost. These can be certified by the Auditors. Thus the methodology for obtaining rate base has to be different i.e. independent of the balance sheet.

5.7 Whereas we intend to agree with the above philosophy of normative capital cost, we are not inclined to do away with the reliance on books of account totally. The gross block on the books of accounts duly certified by the auditors is authentic and clearly indicates the actual capital expenditure including committed liabilities and would be known at least a year before the start of the new tariff period or reasonably firm projections of remaining expenditure can be made six months before the commissioning of the unit/station. The proposed regulation therefore provides that for the existing generating station or transmission licensee the actual capital expenditure as admitted by the Commission as on 31.03.2008 would be the starting point for the rate base for the next tariff period. In addition, the generating company or the transmission licensee as the case would be required to furnish the projected additional capital expenditure for the last year of the previous tariff period and for each year of the tariff period. Such projected additional capital expenditure could be examined in the Commission based on the justifications furnished by the generating company or the transmission licensee as the case may be and the additional capital expenditure found justified could be considered for inclusion in the capital cost for the purpose of tariff.

5.8 Truing up of the actual additional capital expenditure shall be done in the terminal year of the tariff period. However, the generating company or the transmission licensee shall have the option to approach the Commission one more time for truing up during the tariff period. Any excess recovery or shortfall as a result of such truing up exercise shall be adjusted or paid for along with interest at SBI PLR as on the 1st April of respective financial year.

5.9 In case of a new generating station or transmission system, the generating company or the transmission licensee as the case may be shall have the option to approach the Commission for determination of tariff six months before the COD and the Commission shall determine tariff based on the capital cost actually incurred, projected capital expenditure to be incurred till the COD and the projected additional capital expenditure for each year of the tariff period.

5.10 With the provision for truing up and adjustment of excess recovery or shortfall as a result of such truing up at the rate of SBI PLR as on the 1st April of the respective financial year, the concern of inflated projection of capital expenditure or additional capital expenditure is also taken care of. This would also obviate the need for provisional tariff. The proposed tariff regulation therefore does away with the provision for provisional tariff.

5.11 While admitting the projected capital expenditure as on COD, prudence check of capital cost shall be carried out based on the applicable benchmark norms to be published separately by the Commission from time to time. This is in line with Tariff Policy. The Commission has already initiated the process for evolving benchmarks for thermal generation projects and transmission projects. In cases where benchmark norms are not published, prudence check shall include scrutiny of the reasonableness of the capital cost, financing plan, interest during construction, use of efficient technology, cost and time over-run, and such other matters for determination of tariff. The capital cost for the purpose of tariff shall include reasonable IDC & financial charges, IEDC, initial spares, and additional capital expenditure during the tariff period.

5.12 The provision for additional capital expenditure has also been rationalized by limiting admission of capital expenditure beyond the cut off date to the account of change in law, the liabilities to meet award of arbitration or for compliance of the order or decree of a court and deferred works relating to ash pond or ash handling system in the original scope of work.

5.13 In the tariff regulation for 2004-09, the concept of cut off date was introduced and it was expected that all the necessary works and equipments would be in place by the cut off date within the original scope of work. The cut off date was defined as first financial year closing after one year of the COD. However, it was found that stations achieving COD in the last quarter would be getting only about 12 to 15 months for completion of balance works and payments of liabilities after the COD. It is therefore provided in the draft regulation that in case the date of commercial operation falls in the last quarter of the financial year, the cut off date shall be the financial year closing after two years of the date of commercial operation of the generating station or the transmission system.

5.14 The need for additional capital expenditure on new works not within the original scope of work and expenditure on minor item and asset brought after the cut off date could be on roads, buildings, hospitals, schools, club, batteries, computers, telecom, instruments, tools, spares, ACs, fans, coolers, conveyors, relays etc.

5.15 The prudence check of hundreds of such items is a tedious and time consuming exercise particularly in case of thermal generating stations. A certain degree of subjectivity creeps in, causing regulatory uncertainty and disputes. Therefore, a provision has been made for special allowance on normative basis in Rs.lakh/MW per year to meet expenses on new assets of capital nature including in the nature of minor asset.

5.16 Based on the additional capital expenditure in NTPC existing stations namely Singaurli, Vindhyachal, Ramagundam & Korba for the period 1997-2006, the average capex claimed under new works and in the nature of minor assets is as under:

Name of the Generating Station	COD of the Station	Average Cost/MW based on Last 9 Year data	Average Cost/MW based on Last 5 Year data
Units		Rs. Lakh/MW	Rs. Lakh/MW
Singrauli STPS	01.05.1988	0.43	0.67
Vindhyachal STPS St-I	01.02.1992	0.24	0.29
Korba STPS	01.06.1990	0.31	0.47
Ramagundam STPS St-I & II	01.04.1991	0.26	0.33
Weighted average		0.32	0.46
Weighted Average of First 4 Years of last 9 year period			0.14

5.17 These figures represent the nature of expenditure between 11 and 20 years. In case of new stations like Farakka, Unchahar, Kahalgaon etc. the additional capitalisation under these regulations was very marginal or almost nil in the first 10 years.

5.18 In view of this, in respect of coal/lignite thermal generating stations the following special allowance in Rs. Lakh/MW/year terms is allowed:

Year of Operation	**Compensation Allowance**
0 to 10 years	Nil
11 to 15 years	0.15
16 to 20 years	0.35
21 to 25 years	0.65

5.19 This separate compensation allowance shall be admissible unit-wise based on years of operation from respective COD to meet the expenses on additional capital expenditure on new asset not within the original scope of work including assets in the nature of minor assets. The capital cost of the tariff shall not be disturbed. In case of gas/liquid fuel base stations of NTPC, NEEPCO and transmission systems not much of expenditure has been found to be incurred under these heads. In case of hydro generating stations, it is provided that similar allowance may be allowed on merit on case to case basis where certain parts have to be replaced due to erosion caused by high silt content in water.

6.0 Renovation and Modernisation:

6.1 With regard to Renovation and Modernisation, the National Electricity Policy of Government of India provides as follows:

> *"5.2.21 – One of the major achievements of power sector has been significant increase in availability and plant load factor of thermal power stations specially over the last few years. Renovation and modernisation for achieving high efficiency levels needs to be pursued vigorously and all existing generation capacity should be brought to minimum acceptable standards. The Govt. of India is providing financial support for this purpose.*
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> *5.2.22 For projects performing below acceptable standards, R&M should be undertaken as per well defined plans featuring necessary cost - benefit analysis. If economic operation does not appear feasible through R&M, then there may be no alternative to closure of such plants as the last resort.*

5.2.23 In cases of plants with poor O&M record and persisting operational problems, alternative strategies including change of management may need to be considered so as to improve the efficiency to acceptable levels of these power stations."

6.2 Para 5 (g) of the Tariff Policy provides that

"Renovation and modernization (it shall not include periodic overhauls) for higher efficiency levels needs to be encouraged. A multi year tariff (MYT) framework may be prescribed which should also cover capital investments necessary for renovation and modernisation and an incentive framework to share the benefits of efficiency improvement between the utilities and the beneficiaries with reference to revised and specific performance norms to be fixed by appropriate Commission. Appropriate capital costs required for pre-determined efficiency gains and/or for sustenance of high level performance would need to be assessed by appropriate Commission."

6.3 The expected or rated 'useful' life of power plants has historically been considered as 25 years for Thermal, 35 years for Hydro and 15 years for Diesel generators and Gas turbines. For the purpose of tariff, this denotes the period over which 90% of the capital cost has to be recovered as depreciation. Among the power plants, tariff determination of which is in the Commission's jurisdiction, Neyveli TPS-I, Badarpur TPS and Talcher TPS have already outlived their initial rated 'useful' life, and extensive R&M works have been carried out and/or are proposed. The first 200 MW unit of Singrauli STPS has also now been in operation for 25 years. In view of these, it has been felt necessary to lay down the principles regarding R&M beyond the useful life.

6.4 As the plant approaches the end of its specified rated 'useful' life, it may start suffering gradually increasing outages due to wear and tear, and may require increased maintenance and spares input. Beside the plant availability, its energy conversion efficiency may also show a downward trend. However, the status does not suddenly change in any way on the day the plant completes the rated 'useful' life. It continues to work, and the gradual changes mentioned earlier also continue.

6.5 Presently capital dozing of essential nature including modernisation and R&M after useful life is allowed as per actual subject to prudence check.

6.6 As a plant heads towards the end of its rated 'useful' life, the plant owner would have to ponder over four options: (i) keep the plant in operation at the acceptable efficiency, availability and reliability, and with increasing O&M cost and risk of catastrophic failure, (ii) scrap it totally and replace it with a new plant, (iii) sell off the plant, and (iv) extend its beneficial life through a planned one time Renovation and Modernisation (R&M).

6.7 In the absence of a definite life extension it is difficult for regulatory commissions to allow any capital expenditure due to enhanced requirement of repair and maintenance of old plants. R&M plan with definite life extension is a major exercise requiring detailed planning and has certain level of uncertainty regarding the benefits. Even the costs involved get modified to some extent as the actual execution of plan is undertaken. But for the purpose of taking loan and repayment, life extension has to be assessed in each case. This type of exercise is more relevant for revival plan of neglected plants. For a poorly maintained plant R&M results in better efficiency & performance. On the other hand, in case of an old well maintained plant, just enhanced repair and maintenance may be adequate to maintain the performance & efficiency.

6.8 In the last case, the plant owner would also have to decide about the extent and staging of R&M. Other important factors coming into play would be the extent to which the plant has aged, the extent to which its components/systems have become obsolete (particularly from the angle of availability of spares), and the improvement in efficiency offered by a new plant due to technological development and / or larger size. With so many variables, each having its own financial implication, no definite principle could be laid down. The decision may have to primarily be on comprehensive techno-economic considerations, after the required residual life assessment (RLA) studies and cost-benefit analysis.

6.9 The generator is, therefore, required to come up with a detailed proposal with estimation of R&M expenditure along with cost benefit analysis and definite extended life from a reference date and in such cases, the Commission may allow actual R&M expenditure to be included in the capital cost for the purpose of tariff during extended life.

6.10 However, the relevant point in the present discussion is that the plant owner should not be discouraged (by any regulatory restrictions) from taking the most optimal route. More specifically, the tariff criteria to be applied should be equitable, and should not distort the techno-economic evaluation. While it is important that the plant owner is duly compensated for any fresh investment and risks, it is equally important that the beneficiaries pay according to benefits, derived from the plant in future years. In general, it can be said that if a plant is in a reasonable shape, it should be continued in operation, and the tariff formulation should support it.

6.11 The benefits available from a power plant to its customers can be measured in two primary parameters: peak-hour support and energy. The Availability Tariff (ABT) concept takes care of this in principle. However, some fine-tuning is required in permitting maintenance expenditure for motivating the generator to continue operation of the plant after its rated useful life.

6.12 The Commission has therefore, decided to provide an alternative option to generators in case of thermal generating stations by way of an additional compensation in Rs. Lakh/MW per year terms so that the plant owner remains incentivised to maintain the unit availability at a good level after its useful life. This should be sufficient enough for the continuous and progressive maintenance dozing subsequent to the useful life on year to year basis.

6.13 In case of poorly maintained plants like Tanda & Talcher TPS which were taken over by the NTPC, the R&M expenditure is worked out as follows:

Name of Station	Tanda TPS	Talcher TPS
Capacity (MW)	440	460
Date of Take over	15.1.2000	1.4.1996
R&M Expenditure up to 2006	229.06	431.50
R&M in Rs. Lakh/MW/Year	8.68	9.38

6.14 It can be seen that R&M expenditure is phased in 8-10 years period. The CEA's R&M guidelines provide a norm of Rs.0.8 to 1.25 Crore /MW for poorly maintained stations with PLF of less than 40% which translates into Rs 8 to 12.5 lakh/MW over 10 year period. In our opinion for a well maintained station, a compensation of Rs. 5 Lakh/MW/Year should be reasonable enough to incentivise the generator to keep the units running after their useful life. This will have tariff impact of the order of 6 Paise/kWh sent out and there will be no increase in the capital base accounted for giving returns on equity..

6.15 The above compensation shall be admissible unit wise from the respective date of completion of useful life of the respective units. In case of exercising this option by generator, capital base of tariff shall not be disturbed and there would be no relaxation in efficiency & performance parameters. This options shall not be available for the stations which has undergone Renovation and Modernization (R&M) and cost of such R&M as admitted by the Commission is already included in the Capital Cost.

7.0 Debt/Equity Ratio

7.1 Financing plan of the project plays a predominant role in the determination of tariff. The present regulations applicable during the period 2004-09 contain provisions in regard to debt-equity ratio of the existing projects, new projects and apportionment of additional capitalization. It has been felt that the regulations should be simplified.

7.2 As per the Tariff Policy, issued by the Government of India, all the new power projects would be financed in the debt-equity ratio of 70:30. The investors are free to put equity more than 30% of the project cost, but the excess equity deployed over and above 30% would be treated as notional loan, which would be serviced at weighted average rate of interest of the project over a weighted average tenure. However, if equity deployed is less than 30%, the same will be considered for determination of tariff. Further in RoE approach, equity does not get reduced after the loan is repaid. So, investors get RoE along with depreciation amount after loan repayment. In such case equity, if more than 30% will have adverse impact on consumers. Moreover, most of the generation projects are being financed in the debt-equity ratio of 70:30.

7.3 Considering these aspects, the Commission proposes a uniform capital structure with a debt-equity ratio of 70:30 for all the power projects i.e. whether it is initial project cost, additional capital expenditure or renovation & modernization case. However, if equity is declared less than 30% actual amount of equity would be considered for tariff determination.

7.4 In case of existing projects, the Commission has already allowed a capital structure while approving tariff for the period of 2004-09. The Commission has also considered additional capital expenditure as per the current Regulations. The capital structure of such projects, as approved by the Commission as on 31.03.2009, shall not be disturbed in the next tariff period. However, additional capital expenditure, if any, shall be serviced in the debt-equity ratio of 70:30.

8.0 Rate of Return on Equity (ROE)

8.1 The Commission had specified a post-tax ROE rate of 16% for the tariff period 2001-04 and 14% for the tariff period 2004-09.

8.2 Section 5.3(a) of the Tariff Policy stipulates that while laying down rate of return the Commission shall maintain balance between the interests of consumers and the need for investments. The Central Commission would notify, from time to time, the rate of return on equity for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital which shall be followed by the SERCs also. The rate of return notified by CERC for transmission may be adopted by the State Electricity Regulatory Commissions (SERCs) for distribution with appropriate modification taking into view the higher risks involved. The policy also stipulates that for the purposes of return on equity, any cash resources available to the company from its share premium account or from its internal resources that are used to fund the equity commitments of the project under consideration should be treated as equity subject to certain limitations in regard to debt-equity ratio.

8.3 The power sector in India, during last few years, has been able create a lot of enthusiasm amongst the investors and attract investment. In the last five years, there have been rapid developments in the equity market and debt market related to power sector in India. Various CPSUs and private entities working in power sector have entered into primary market to raise funds. The Initial Public Offers floated by NTPC, PGCIL and Reliance Power were oversubscribed by 13.16, 64.50 and 61.52 times respectively. The sector is at the take off stage at present and there is a need to ensure that the confidence evinced is sustained.

8.4 The rate of return on equity may be fixed by using any of the scientific model like dividend growth model, price/earning ratio, capital asset pricing model, risk premium model, etc or by linking to an appropriate benchmark with a mark up. As on date only few entities working in power sector in India have entered into primary market and that to very recently. To calculate rate of return by using a scientific model one needs sufficient volume of related data for calculation of beta value, expected rate of return, P/E ratio, etc. Except a few companies, such as NTPC, Reliance Energy, PGCIL, not many generating companies and transmission licensees like those in the State Sector are listed in the Stock Exchange. As else where mentioned, the State Commissions are also required to be guided by the procedures and methodologies prescribed by the Central Commission. We do not have sufficient data in regard to the power sector, particularly scripts traded in the secondary market. As such, it shall not be appropriate to estimate the rate of return by using any of the scientific models. Moreover the debt market in India is not yet stable. This leads to difficulty in linking the rate of return to a benchmark with a mark up.

8.5 The recent Initial Public Offers floated by NTPC, PGCIL and Reliance Power shows that, even with the existing post-tax rate of return @ 14%, the IPOs were able to create sufficient enthusiasm amongst the investors. As such, the Commission has come to the conclusion that the post tax rate of ROE of 14% may continue.

9.0 Post-Tax Vs Pre-Tax Rate of Return

9.1 The Commission specified, for the tariff period 2001-04 and 2004-09 post-tax rate of return on equity and allowed income tax, in respect of income from core businesses only, as pass-through to be recovered separately on actual. In general, the profit of the utilities should be equal to ROE specified because all other elements of tariff are based on the general premise of pass-through. But practically, the profit of the utilities is influenced by other factors such as profits of non-core business carried out by the utilities, UI earnings, efficiency gains, incentive earned, difference in the depreciation allowed under tariff and the Income Tax Act, 1961, income tax holiday allowed in power sector etc.

9.2 The issue posed in the approach paper was whether the existing system of post-tax return should be continued or pre-tax return, factoring the tax rates be allowed. The Commission discussed various options like post-tax rate of return, as existing, post-tax rate of return with a cap limiting tax burden to the RoE component only, normative Income Tax on admitted RoE subject to tax actually paid and pre-tax rate of return. Most of the utilities are enjoying income tax holiday and/or paying Minimum Alternate Tax. Under pre-tax return, it may not be possible to pass on these benefits to the beneficiaries. There is also the uncertainty in regard to applicable income tax rate, as the tax rates and other concessions keep changing from year to year.

9.3 Moving to a normative pre-tax regime shall require grossing up by the present post tax ROE by the prevalent tax rates to determine the appropriate Pre-tax Return on Equity. Any change in tax rates and other concessions which are not within the control of generating company or the transmission licensee need to be fully adjusted while determining an appropriate rate. There are not many avenues for tax planning in the power business except for section 80 IA under the Income Tax Act. The tax holiday is for limited period and not for entire life of the project. While new projects would be entitled to come under MAT on account of tax holiday, older plants may have to pay tax at normal rates which is about three times higher than the MAT. In view of the difference in rates of tax, it may not be possible to arrive at single rate of pre-tax return and it may not be advisable to arrive at different pre-tax rates for different entities based on their applicable & effective tax rates. Changing from post tax to pre tax would expose the investors to tax risk which is beyond the control of the entity.

9.4 Considering the above facts the Commission proposes to continue with the existing system of post tax return with certain modifications to insulate the beneficiaries, to the extent possible, from the burden of paying tax on income beyond the allowable ROE by excluding income on incentive and net UI income.

9.5 This will ensure that the benefit of income tax exemptions available for infrastructure projects, etc is passed on to the beneficiaries and at the same time the beneficiaries do not have to pay income tax on income components like income on incentive and net UI income.

10.0 Treatment of FERV

10.1 The existing regulation provides that every generating company and transmission licensee shall recover FERV on year to year basis as income on expense in the period in which it arises. Recoveries from or payment to the beneficiaries on account of FERV are done directly. The Commission has so far not allowed hedging of foreign loans. The tariff policy says that FERV risk shall not be a pass through. It further provides that appropriate costs of hedging and swapping of loans to take care of foreign exchange variations should be allowed for the debt obtained in foreign currencies.

10.2 The money market developments offer a range of products and derivatives for hedging/swapping of foreign currency exposures and the Commission encourages the utilities to make use of the financial products available and to hedge their exposures to the extent considered feasible and use their expertise in this direction.

10.3 It is also recognized that small generating companies and transmission licensees do not have the expertise or capability to take appropriate forex hedging instruments and hence such arrangement may not be practicable for them. Again, utilities can not obtain forward covers for the entire foreign exposure in one instance which could be obtained in phased manner depending on cost of hedging, prevailing market conditions etc. It has also been gathered after discussion with the industry and the financial institutions that generally a company does not go for hedging of the entire amount of foreign loan due to various reasons like perception about variation in a particular foreign currency due to political and economic situations; mix of foreign currencies in the basket of foreign loans availed and hedging of each such currency may not necessarily be beneficial. In case of some foreign currencies, hedging may not be available. 100% hedging is not likely to be the main optimal forex risk policy and may not reflect the least cost option for customers.

10.4 As such, in line with the tariff policy, the Commission decides to allow the cost of hedging of foreign currency exposure. However, in view of the above realities it has been provided in the proposed regulation that to the extent hedging is not resorted to, FERV shall be allowed as pass-through.

11.0 **Interest on Loan**

11.1 The Commission, for calculation of interest on loan has been considering weighted average rate of interest and normative repayment. After detailed discussions, the Commission has proposed, in order to simplify the matter, to consider the repayment for the tariff period as equal to the depreciation allowed. However, if as on 1.4.2009, the cumulative depreciation recovered is more than the cumulative normative loan repayment, the Commission proposes that the deemed repayment for the first year of the tariff period shall be equal to the depreciation allowed by the Commission for that year plus the difference between the cumulative depreciation recovered and cumulative normative loan repayment as on 01.04.2009. Also to encourage the entities to make every effort to re-finance the loan as long as it results in net benefit to the beneficiaries, the Commission has proposed to allow sharing of the net benefit between the beneficiaries and the utilities in the ratio of 2:1.

11.2 The interest rates on loan financed by FIs/banks vary depending on the financial strength and standing. This also varies between public sector and private sector status of the borrowing entities since in the eyes of international lending institutions public sector enjoys the support of the government in case of default, which is not available to the private sector. The private sector investor needs to be assured of a rate of return commensurate with the interest. Most of the IPPs do not enjoy any credit rating and depend upon non recourse or partial recourse funding by FIs and banks and thus has the risk of differential rate of interest on their borrowing.

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

12.0 **Interest on Working Capital**

12.1 The operation and maintenance cost generally includes stores and spares, repairs & maintenance, insurance, security, administrative expenses, employees cost and corporate office expenses. Most of these cost elements other than stores and spares are normally paid at the end of the period and as such no working capital is required to be maintained against these cost components. Also the receivables accrue not on the first date of the month but consistently over the 30 days of the month. The entities in most of the cases get considerable amount of credit against there various transactions. Considering all the above cases, the Commission proposes to exclude O&M expenses for this purpose and also reduce the period of receivables from two months to 45 days for the purpose of calculation of interest on working capital.

12.2 The maintenance spares were based on Historical Capital Cost and was cause of dispute and litigation in the past. The Commission is now intend to specify norms for maintenance spares as a percentage of O&M norms. Based on the information furnished by the CPSUs, inventory of the stores maintained by them for the last five years, following norms for maintenance spares are specified.

Coal/Lignite based Generating Stations	20% of O&M norms.
Gas/Liquid based Generating Stations	30% of O&M norms.
Hydro Generating Stations	15% of O&M norms.
Transmission Systems	15% of O&M norms.

13.0 Depreciation

13.1 As per the existing regulations, Value Base for the purpose of -depreciation is Historical Cost of the asset which includes additional capitalization and FERV up to 31.03.2004. Depreciation is calculated by applying the depreciation rates notified by the Commission using Straight Line Method over the useful life of the asset and considering Salvage Value of 10%. On repayment of entire loan, the remaining depreciable value is spread over the balance useful life of the asset. Depreciation is chargeable from the first year of operation. In case of operation of the asset for part of the year, depreciation is charged on pro rata basis. To provide cash flow to the utilities to make them repay their debt Advance Against Depreciation (AAD) is allowed subject to certain condition.

13.2 The Tariff policy stipulates that the 'Commission may notify the rates of depreciation in respect of generation and transmission assets. The depreciation rates so notified would also be applicable for distribution with appropriate modification as may be evolved by the Forum of Regulators. The rates of depreciation so notified would be applicable for the purpose of tariffs as well as accounting. There should be no need for any advance against depreciation. Benefit of reduced tariff after the assets have been fully depreciated should remain available to the consumers.'

13.3 The word 'Depreciation' is interpreted differently by different stakeholders and professionals. From accounting point of view, in line with the Accounting Standard issued by the Institute of Chartered Accountants of India, 'Depreciation is a measure of the wearing out, consumption or other loss of value of a depreciable asset arising from use, efflux of time or obsolescence through technology and market changes'. It reflects annual consumption of a capital asset in use. From Investor's point of view, depreciation is a non-cash expense which reduces tax burden but generates internal cash for further investment. From engineering point of view, depreciation means decline in capability or loss of value in an asset over time of usage. From Economist's point of view, economic depreciation over a given period is the reduction in the remaining value of the future services. Under certain circumstances, such as unanticipated increase in the price of the services generated by an asset, its value may increase rather than decline. Depreciation is then negative. So far as the Income Tax is concerned, it is designed in the fiscal policy of the Government to give incentives to certain category of entities for furtherance of investments. Regulators have two view points on depreciation. One view is depreciation is the refund of capital subscribed, and the other view is depreciation is a constant charge against an asset to create a fund for its replacement.

13.4 While determining the tariff, the Regulators have to ensure that: (i) capital is refunded to the investors over estimated life of assets, i.e. refund of capital; (ii) capital invested in the regulated business is allowed sufficient return so that the investors find the business attractive enough to invest, i.e. return on investment; and (iii) reasonable amount of operation and maintenance expenses is allowed, i.e. reimbursement of O&M expenses. And one of the major components of capital deployed is loan. As such it is important that the Commission ensures the availability of sufficient cash flow in the hands of the utilities to take care of the loan repayment obligation. For the control period 2004-09, the Commission took care of this cash flow requirement by allowing AAD, in case normative depreciation amount is not sufficient to meet the loan repayment obligations.

13.5 The Commission has proposed gearing of 70% investment with 30% equity in future so that the burden on the consumers on account of cost of capital would be reduced. From the experience it is found that long tern loans are available for the power sector for the period 10-15 years. In absence of AAD, the amount of depreciation calculated as per the existing methodology will not be enough to meet the loan repayment obligation.

13.6 It is evident from the Tariff Policy that CERC has been entrusted with the responsibility of notifying rates of depreciation in respect of generation and transmission assets. At the same time it is also the responsibility of the Commission to see that sufficient cash flow is available to the generators and transmission licenses to meet their loan obligations arising out due to high gearing. In Indian context, loans are available for a term of 10-15 years. In some rare cases long term loan is extended to 20 years. Loans from multi-lateral agencies like IBRD, ADB, and JBIC are available for longer period of over 20 years. If loan is available for 15 years, annual repayment would be around 4.67% of the total investment taking into consideration 70% debt of the total investment. Whereas refund of capital in the form of depreciation is available to the extent of 3.60% in case of thermal stations and 2.57% in case of hydro stations which may not be sufficient to meet the loan repayment obligations without advances against depreciation.

13.7 Another possibility of meeting loan repayment obligation is going for a roll over loan i.e. a new loan for meeting the repayment of old loan. But, that will not reduce the interest burden of the consumers. Providing higher rate depreciation in initial period of project will give some comfort to the investors towards repayment of their loan. At the same time it will reduce the interest burden of the consumers and tariff will be reduced once the loan is repaid on account of reduced depreciation available over the balance useful life of the plant.

13.8 The Commission has allowed higher rate of recovery beyond the normal rate of depreciation linked to life during the tariff period 2004-09 for meeting the loan repayment obligation by way of providing AAD. The AAD was allowed subject to certain conditionalities like a ceiling of one-tenth of the normative gross loan. It was noted that the rate of depreciation plus AAD allowed for tariff purposes exceeded the rate as per Companies Act, 1956 in some cases, resulting in front loading in tariff.

13.9 Most of the CPSUs are either listed or on the verge of listing in the Stock Exchange. Further, India is going to adopt International Financing Reporting System (IFRS) from 01.04.2011 as per which all the commercial entities will have to follow uniform system of accounts as prescribed by the international agency. Under such circumstances it is not advisable to prescribe different rates of depreciation for the assets, used in power sector.

13.10 As per the Accounting Standards (AS6) issued by Institute of Chartered Accountants of India, 'Useful life is the period over which a depreciable asset is expected to be used by the enterprise'. As per section 205 of Companies Act, companies are required to provide depreciation in the books of accounts based on the useful life of asset. However, in power sector the practice of considering depreciation towards the repayment of loan has been in vogue for quite sometime and has come to stay. The fact that AAD allowed over and above the rate arrived at on the basis of useful life to take care of repayment of loan has not given enough incentive for generating companies to look forward to long term loans. While on one hand it is argued that the Indian debt market is not having depth and the availability of long term loan is limited, it is imperative that the infrastructure companies, particularly power sector investors, who contract a sizeable amount of funding through loan should be able to facilitate long term funding with tenure of at least 15 years door to door, if not more to be made available by the banks and financial institutions. The entities should use their propensity to avail large amounts of loans with the FIs/banks, and negotiate for long term low cost funding.

13.11 Considering the above facts, the Commission decides that, for the purpose of refund of capital over the estimated useful life of the assets concerned, the loan repayment period of 15 years be made applicable to all normative loans and accordingly link this repayment period of 15 years to arrive at the rate of depreciation. The Commission, therefore, proposes to divide estimated life of the project into two parts for the purpose of tariff determination. The first part would be 15 years during which the loan capital would be refunded to the investors in the form of depreciation @ 4.67% and thereafter it will be applicable @ 2% in case of thermal generating stations and @ 1% in case of hydro stations and transmission stations.

14.0 **<u>O&M EXPENSES</u>**

<u>14.1 Thermal generating stations</u>

14.1.1 The Operation & Maintenance Cost for the purpose of tariff covers a vast spectrum of expenditure incurred on the employees, repair and maintenance of the generating stations/transmission system; administrative overheads etc. but exclude the expenditure on fuel i.e. primary fuel as well as secondary and alternate fuels.

14.1.2 Prior to formation of regulatory commissions, Govt of India in its tariff notifications for old NTPC stations allowed O&M expenses based on actual of previous year of the start of the five year tariff periods i.e. 1992-97, escalating at 10% per annum and for new station based on 2.5% of the current capital cost in the first year and then escalating @10% per annum. This was as per recommendations of the K P Rao committee report. This principal was adopted by the CERC for the existing stations but in case of new stations, Commission allowed O&M expenses based on 2.5% of the capital cost as on COD.

14.1.3 The CERC notification for 2001-04 had laid down that the regulated entities should include in their tariff petition, details of year-wise actual O&M cost data for the previous 5 years duly certified by statutory auditors. It was very clearly specified that the data should exclude all abnormal expenses such as water charges. The average O&M based on the actual O&M expenses for the years 1995-96 to 1999-2000 would correspond to the year 1997-98. This average O&M expense is escalated @ 10% p.a. to arrive at O&M expenses of 1999-2000. Thereafter the escalation factor shall be 6% p.a. In the case of new thermal stations, which did not exist for a period of 5 years, the base O&M was to be fixed with reference to 2.5% of the capital cost duly escalated @ 10% to bring it to 1999-2000. A deviation of the escalation factor computed from the actual data that lies within 20% of the above notified escalation factor (which works out to 1.2% on either side of 6%) was to be absorbed by the utility. Deviations beyond this limit were to be adjusted on the basis of actual escalation factor

14.1.4 After deliberating in detail, Commission finalized O&M expenses for the tariff period. The existing provisions at regulation 21 (iv) for the tariff period 2004-09 are as follows:

14.1.5 **<u>Existing provisions</u>**

"(iv) <u>Operation and Maintenance expenses</u>

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

(a) Coal-based generating stations except Talcher Thermal Power Station and Tanda Thermal Power Station of National Thermal Power Corporation Ltd

(Rs. lakh/MW)

Year	*200/210/250 MW sets*	*500 MW and above sets*
2004-05	*10.40*	*9.36*
2005-06	*10.82*	*9.73*
2006-07	*11.25*	*10.12*
2007-08	*11.70*	*10.52*
2008-09	*12.17*	*10.95*

Note

For the generating stations having combination of 200/210/250 MW sets and 500 MW and above set, the weighted average value for operation and maintenance expenses shall be adopted.

(b) (i) Talcher Thermal Power Station

The base operation and maintenance expenses including insurance, for the year 2000-01 shall be derived by averaging the actual operation and maintenance expenses for the years 1998-99 to 2002-03 based on the audited balance sheets and by excluding abnormal operation and maintenance expenses, if any, after a prudence check by the Commission.

The average of such normalised operation and maintenance expenses, after prudence check, for the years 1998-99 to 2002-03 considered as operation and maintenance expenses for the year 2000-01 shall be escalated at the rate of 4% per annum to arrive at operation and maintenance expenses for the base year 2003-04.

The operation and maintenance expenses for the base year 2003-04 shall be escalated further at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant year of tariff period.

(ii) Tanda Thermal Power Station

The base operation and maintenance expenses including insurance, for the year 2001-02 shall be derived by averaging the actual operation and maintenance expenses for the years 2000-01 to 2002-03 based on the audited balance sheets and by excluding *abnormal operation and maintenance expenses, if any, after a prudence check by the Commission.*

The average of such normalized operation and maintenance expenses, after prudence check, for the years 2000-01 to 2002-03 considered as operation and maintenance expenses for the year 2001-02 shall be escalated at the rate of 4% per annum to arrive at operation and maintenance expenses for the base year 2003-04.

The operation and maintenance expenses for the base year 2003-04 shall be escalated further at the rate of 4% per annum to arrive at permissible operation and maintenance expenses for the relevant year of tariff period.

(c) Gas Turbine/Combined Cycle generating stations

(Rs. lakh/MW)

Year	*Gas Turbine/Combined Cycle generating stations other than small gas turbine power generating stations*		*Small gas turbine power generating stations*
	With warranty spares of 10 years	*Without warranty spares*	*Without warranty spares*
2004-05	*5.20*	*7.80*	*9.46*
2005-06	*5.41*	*8.11*	*9.84*
2006-07	*5.62*	*8.44*	*10.24*
2007-08	*5.85*	*8.77*	*10.65*
2008-09	*6.08*	*9.12*	*11.07*

(d) Lignite-fired generating stations

(Rs.lakh/MW)

Year	*200/210/250 MW series*	*TPS-I of NLC*
2004-05	*10.40*	*15.20*
2005-06	*10.82*	15.81
2006-07	*11.25*	16.44
2007-08	*11.70*	17.10
2008-09	*12.17*	17.78

14.1.6 The above normative O&M were arrived at after considering an annual escalation rate of 4%.

14.1.7 The above normative, O&M expenses have been allowed in tariff in respect of thermal generating stations of NTPC, NLC and NEEPCO for the period 2004-09. CERC has allowed O&M expenses based on actual in case of Tanda, Talcher TPS of NTPC, thermal generating stations of DVC and Badarpur TPS of Govt of India.

14.1.8 The Commission in order to facilitate this process of finalization of terms & conditions of tariff vide order dated 7th Jan 2008 directed the generating companies namely NTPC, NLC, NEEPCO, DVC, to furnish the details of actual O&M expenditure for the financial years 2002-03 to 2006-07 in respect of their thermal generating stations. The similar data was sought from SEBs/State Utilities and IPPs in order to arrive at reasonable norms for the next tariff period. The actual O&M data for these years have been submitted by all the utilities and the same are discussed in subsequent paragraphs.

14.1.9 The actual O&M expenses of coal/lignite based generating stations of NTPC, NLC, DVC and some of the comparable generating stations of SEBs/IPPs in the units sizes of 200/210/250 MW and 500 MW are as follows:-

	Station	Unit	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**
A	**200/210/250 MW Sets**						
1	Dadri Coal(4x210)	Rs Lakh	11228	9945	10896	12262	12713
		Rs. Lakh/MW	13.37	11.84	12.97	14.60	15.13
2	Unchahar (2x210+2x210+1x210)	Rs Lakh	10927	11406	11800	12196	12215
		Rs. Lakh/MW	13.01	13.58	14.05	14.52	13.70
3	Kahalgaon(4x210 MW)	Rs Lakh	10580	10876	11648	13263	15063
		Rs. Lakh/MW	12.60	12.95	13.87	15.79	17.93

4	NLC TPS-I Expansion (2x210)	Rs Lakh		2210	3176	3582	4280
		Rs. Lakh/MW		7.18	7.56	8.53	10.19
5	NLC TPS-II stage-I (3x210)	Rs Lakh	6117	7149	7180	6998	7285
		Rs. Lakh/MW	9.71	11.35	11.40	11.11	11.56
6	NLC TPS-II stage-II (4x210)	Rs Lakh	8156	9532	9573	9330	9713
		Rs. Lakh/MW	9.71	11.35	11.40	11.11	11.56
7	Dahanu (2x250 MW)	Rs Lakh	4782	4200	5327	5029	6079
		Rs. Lakh/MW	9.56	8.40	10.65	10.06	12.16
8	Bhatinda (2x210 MW)	Rs Lakh	3808	3792	4299	4610	4735
		Rs. Lakh/MW	9.07	9.03	10.24	10.98	11.27
B	**500 MW Sets**						
9	Rihand St-I&II(4x500)	Rs Lakh	11071	10065	11671	15694	17678
		Rs. Lakh/MW	11.07	10.07	11.67	11.95	8.84
10	Simhadri (2x500)	Rs Lakh	2819	7641	8191	8875	9518
		Rs. Lakh/MW	8.47	7.64	8.19	8.87	9.52
11	Talcher (2x500+4x500)	Rs Lakh	7860	10458	14200	19198	21630
		Rs. Lakh/MW	7.86	7.61	6.43	6.78	7.21

C	**Mix of 200/210/250 MW & 500 Sets**						
12	Vindhyachal (6x210+4x500)	Rs Lakh	21834	2624	19260	19894	23256
		Rs. Lakh/MW	9.66	1.16	8.52	8.80	9.59
13	Korba (3X200+3X500)	Rs Lakh	17611	18352	19094	21203	23210
		Rs. Lakh/MW	8.39	8.74	9.09	10.10	11.05
14	Farakka (3x200+2x500)	Rs Lakh	17953	19286	20413	22902	23681
		Rs.	11.22	12.05	12.76	14.31	14.80

		Lakh/MW					
15	Singrauli (5x200+2x500)	Rs Lakh	16805	17321	19834	21380	24664
		Rs. Lakh/MW	8.40	8.66	9.92	10.69	12.33
16	Ramagundam (3x200+3x500+1x500)	Rs Lakh	18942	20322	19221	23295	27960
		Rs. Lakh/MW	9.02	9.68	9.11	8.96	10.75

14.1.10 It can be seen that in the category of 200 MW/210 MW/250 MW series O&M expenses per MW of NTPC generating stations, in Rs. lakh/MW term are higher than the NLC stations, State Sector generating stations and Dahanu TPS of BSES. In case of NLC stations R&M expenses and consumption of stores and spares is lower than NTPC stations perhaps due to low operation levels. On the other hand O&M expenses of Dahanu & Bhatinda TPs do not include corporate nature of expenses.

14.1.11 In general, O&M expenses for stations namely Dadri, Kahalgaon, Unchahar having 210 MW sets are higher than the O&M expenses of stations having 500 MW sets namely Simhadri, Rihand and Talcher.

14.1.12 O&M expenses for Kahalgaon TPS during 2004-05 to 2006-07 are higher than the O&M expenses of Dadari and Unchahar and appear to be on account of higher Repairs & Maintenance (R&M) expenses and higher consumption of stores.

14.1.13 The generating stations namely Singrauli, Korba, Ramagundam and Farakka STPS of NTPC have combination of 200 MW/210 MW and 500 MW sets. O&M expenses/MW in case of Farakka STPS are high as compared to Singrauli, Korba and Ramagundam STPS, which are old generating stations. The lower operational level of Farakka STPS as compared to Singrauli, Ramangundam and Korba STPS does not support higher O&M expenses of Farakka STPS. O&M expenses per MW in this category are less than O&M expenses/MW in 200 MW/210 MW/250 MW series category of NTPC generating stations.

14.1.14 The NTPC has included the value of certain capitalized spares consumed in the O&M expenses separately. The NTPC has changed the accounting policy in 1999-2000 and started capitalizing the spares of capital nature in the books of accounts. CERC however does not allow capitalisation of spares other than initial spares in the capital cost for the purpose of tariff. Since these spares are part of gross block in the book of accounts the same cannot not shown in the books of account as revenue expenses. Where as, for the purpose of CERC tariff, these would be part of O&M.

14.1.15 There has been sudden increase in employee cost in the year 2005-06 and 2006-07 in respect of NTPC stations. It appears that the increase is on account of provisions for the pay revision. The details of such provisions along with basis of estimation have been sought from NTPC. It is also given to understand that the report of the committee on pay revision has already been submitted to the Govt.

14.1.16 The O&M expenses of NTPC stations include incentive & ex-gratia paid to its employees, donations, and loss in stock, prior period adjustments, claims and advances written off, provisions including provisions of pay revision. These have been excluded for the normalization of O&M expenses for the 3 years i.e.2004-05 to 2006-07. It is because the CERC had specified the normative O&M expenses with effect from 1.4.2004. The normalized O&M expenses for the coal based stations of NTPC are as follows:

	Station	Unit	**2004-05**	**2005-06**	**2006-07**
A	**200/210/250 MW Sets**				
1	Dadri Coal(4x210)	Rs Lakh	10308	11462	11282
		Rs. Lakh/MW	12.27	13.64	13.43
2	Unchahar (2x210+2x210+1x210)	Rs Lakh	11042	11215	10587
		Rs. Lakh/MW	13.15	13.35	11.87
3	Kahalgaon(4x210 MW)	Rs Lakh	11336	12974	14175
		Rs. Lakh/MW	13.50	15.44	16.87

B	**500 MW Sets**				
4	Rihand St-I&II(4x500)	Rs Lakh	10914	14158	15943
		Rs. Lakh/MW	10.91	10.78	7.97
5	Simhadri (2x500)	Rs Lakh	7826	8404	8660
		Rs. Lakh/MW	7.83	8.40	8.66
6	Talcher (2x500+4x500)	Rs Lakh	13,570	18,303	19,964
		Rs. Lakh/MW	6.15	6.46	6.65
C	**Mix of 200/210/250 MW & 500 Sets**				
7	Vindhyachal (6x210+4x500)	Rs Lakh	18367	18557	21923
		Rs. Lakh/MW	8.13	8.21	9.04
8	Korba (3X200+3X500)	Rs Lakh	18149	19975	20915
		Rs. Lakh/MW	8.64	9.51	9.96
9	Farakka (3x200+2x500)	Rs Lakh	19001	21182	20781
		Rs. Lakh/MW	11.88	13.24	12.99
12	Singrauli (5x200+2x500)	Rs Lakh	18445	19736	23045
		Rs. Lakh/MW	9.22	9.87	11.52
13	Ramagundam (3x200+3x500+1x500)	Rs Lakh	18259	22055	25252
		Rs. Lakh/MW	8.66	8.48	9.71
	Total NTPC	Rs Lakh	**157217**	**178020**	**192526**
		Rs. Lakh/MW	**9.36**	**9.77**	**9.98**
	Average of 3 Years	Rs Lakh		**175921**	
		Rs. Lakh/MW		**9.72**	

14.1.17 The average escalation during the last 5 years works out as 5.17% for the thermal generating stations considering weightage of 60% for WPI and weightage of 40% for CPI.

14.1.18 Escalating the average of 3 years i.e. 2004-05 to 2006-07 @ 5.17% every year the normative O&M expenses in 2009-10 works out as Rs. 11.97 Lakh per MW. It can be seen that the normalized O&M expenses of 11.97 Lakh based on NTPC and some SEBs/IPPs actuals considering actual escalation rates are lower than the normative O&M expenses allowed by the Commission for the year 2008-09.

14.1.19 The man power engaged in the operation has remained nearly same despite capacity addition of about 3000 MW. This implies that through rationalization of man power and proper management, NTPC has been able to absorb escalation in prices over and above the 4%

considered by the Commission and also the impact of earlier pay revision.

14.1.20 The next pay revision is due with effect from 1.4.2007 and it may not be possible to absorb the next pay revision impact. The Commission has therefore, decided to consider a normative pay revision impact of 45% increase in employee costs on overall basis while specifying the normative O&M expenses across the board for all central utilities. The actual increase may be higher or lower than the normative increase of 45% in different segments of employees. Considering this O&M expenses for NTPC coal based stations for the year 2009-10 works out as Rs. 13.77 Lakh/MW. For this normalized O&M expenses of Rs. 9.72 Lakh/MW have been escalated at annual escalation rate of 5.17% to arrive at O&M expenses of 2009-10 without pay revision and then the 45% increase in employee cost has been factored in to arrive at normative O&M expenses in 2009-10 with pay revision impact.

14.1.21 It has been seen that O&M expenses of stations having 200/210 MW units and stations having 500 MW set units in Rs. Lakh/MW terms are not in the ratio of their capital cost. The one reason for this is that the employee cost is almost double in stations like Dadri, Unchahar and Khalgaon having 210 MW sets due to higher man power deployed than the stations like Rihand, Talcher, and Simhadri having 500 MW sets.

14.1.22 The repair and maintenance expenses in 210 MW set stations are also high as compared to 500 MW set stations. The one reason could be that the stations like Rihand, Talcher, and Simhadri having 500 MW sets are relatively new and other reason could be availability of spares at higher cost because of shift of preference from 210 MW to 500 MW sets. Never the less it is felt that there is still scope for optimisation of O&M expenses for stations having 200/210 MW units.

14.1.23 On the other hand NTPC stations namely Singrauli, Ramagundam, Vindhyachal, Korba Farakka etc which have mix of 200/210 MW and 500 MW sets and are relatively older stations have average O&M expenses of the order of Rs. 13.71 Lakh/MW including impact of pay revision indicating that the O&M expenses of 500 MW sets would be increasing with time.

14.1.24 Apart from existing stations, NTPC is setting up two new stations namely Bahr TPS and Sipat TPS having 660 MW units based on super critical technology which are expected to be commissioned during tariff period 2009-14. However, specific O&M data for such station in Indian conditions is not available. As such, for the time being O&M norm for these units' sizes are being kept slightly less than that for 500 MW units size as Manpower/MW and repair & maintenance cost/MW should also be lower. In case of 300/330/350 MW units being planned by some of the IPPs, the O&M norms shall be in-betweens in proportion of norms for 200/210 MW unit sets and 500 MW unit sets.

14.1.25 On consideration of all these, Commission allows following O&M expenses for 200 MW series, 300 MW series, 500 MW series and 660 MW series:

(Rs. Lakh/MW)

Year	200/210/250 MW sets	300/330/350 MW sets	500 MW and above sets	660 MW and above sets
2009-10	15.70	14.00	12.50	11.50
2010-11	16.51	14.72	13.15	12.09
2011-12	17.37	15.49	13.83	12.72
2012-13	18.26	16.29	14.54	13.38
2013-14	19.21	17.13	15.29	14.07

Note

For the generating stations having combination of 200/210/250 MW sets and 500 MW and above set, the weighted average value for operation and maintenance expenses shall be adopted.

14.1.26 Apart from above NTPC has stations like Badarpur TPS which has 210 MW units and 95 MW units, Talcher which has 60 MW units and 110 MW units, and Tanda TPS which has 110 MW units. TPS-I Station of NLC has 50 MW units and 100 MW units. In this type of configurations O&M expenses of these stations and some of the IPPs and State Utility stations are as follows:

	Station	Unit	2002-03	2003-04	2004-05	2005-06	2006-07
1	Badarpur(3x95+ 2x210)	Rs Lakh	19774	14863	18573	17606	22255
		Rs. Lakh/MW	28.05	21.08	26.34	24.97	31.57
2	Nasik (2x125+ 3x210)	Rs Lakh	6121	9028	8639	7232	10438
		Rs. Lakh/MW	6.96	10.26	9.82	8.22	11.86
3	Tanda (4x110	Rs Lakh	8460	8101	7632	8128	8641

	MW)						
		Rs. Lakh/MW	19.23	18.41	17.35	18.47	19.64
4	Talcher taken over(4x60+ 2x110)	Rs Lakh	10094	10154	10959	10539	12053
		Rs. Lakh/MW	21.94	22.07	23.82	22.91	26.20
5	Parli (2x30+3x210)	Rs Lakh	5994	7722	7778	8655	10596
		Rs. Lakh/MW	8.69	11.19	11.27	12.54	15.36
6	NLC TPS-I (6x50+3x100)	Rs Lakh	8727	10099	9901	10085	10415
		Rs. Lakh/MW	14.54	16.83	16.50	16.81	17.36
7	Surat Lignite (2x125)	Rs Lakh	4732	5426	5208	4750	5685
		Rs. Lakh/MW	18.93	21.70	20.83	19.00	22.74

After normalisation, the O&M expenses of these stations are worked out as follows:

	Station	Unit	2004-05	2005-06	2006-07
1	Badarpur(3x95+2x210)	Rs Lakh	11165	15532	14760
		Rs. Lakh/MW	15.84	22.03	20.94
2	Nasik (2x125+3x210)	Rs Lakh	8166	7128	9661
		Rs. Lakh/MW	9.28	8.10	10.98
3	Tanda (4x110 MW)	Rs Lakh	7194	7487	7856
		Rs. Lakh/MW	16.35	17.01	17.85
4	Talcher takenover(4x60+2x110)	Rs Lakh	9249	9729	10582
		Rs. Lakh/MW	20.11	21.15	23.00
5	Parli (2x30+3x210)	Rs Lakh	9467	9583	10063
		Rs. Lakh/MW	11.27	12.54	15.36
6	NLC TPS-I	Rs Lakh	9467	9583	10063

	(6x50+3x100)				
		Rs. Lakh/MW	15.78	15.97	16.77
7	Surat Lignite (2x125)	Rs Lakh	5185	4738	5667
		Rs. Lakh/MW	20.74	18.95	22.67

14.1.27 In case of Badarpur TPS, the Commission had allowed O&M expenses of Rs.142.75 Crore/year during 2004-09, with the expectation that manpower shall be rationalized and O&M expenses shall be brought down. However, it is seen that NTPC has not been able to bring down the O&M expenses within the norms during 2004-05 to 2006-07. The manpower remains high above 2/MW.

14.1.28 In case of Talcher TPS O&M expenses are continue to be high even after Renovation & Modernization of the station. There has been considerable reduction in man power in Tanda TPS but there is not much rationalization of man power in case of Talcher TPS. It is felt that there is still scope for rationalization of O&M expenses in case of Talcher TPS & Badarpur TPS. The Commission therefore, expects 5% reduction in O&M cost every year for these stations and as such, escalation in O&M gets nullified with reduction in O&M expenses. Accordingly, following O&M expenses are being allowed for these stations considering 45% increase in employee cost due to pay revision:

Year	**Talcher TPS**	**Tanda TPS**	**Badarpur TPS**
2009-10	**28.50**	**24.00**	**27.00**
2010-11	**28.50**	**25.24**	**27.00**
2011-12	**28.50**	**26.55**	**27.00**
2012-13	**28.50**	**27.92**	**27.00**
2013-14	**28.50**	**29.36**	**27.00**

14.1.29 The actual O&M expenses of DVC stations are as follows:

Name of Station	Unit	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**
Bokaro TPS (3x210 MW)	Rs Lakh	15,908	13,685	16,671	16,938	16,806
	Rs. Lakh/MW	25.25	21.72	26.46	26.89	26.68
Chandrapura TPS (3x130 MW)	Rs Lakh	17,080	9,868	12,456	13,535	12,345
	Rs. Lakh/MW	43.79	25.30	31.94	34.70	35.27
Durgapur TPS	Rs Lakh					

(1x140 MW + 1x210 MW)		9,997	8,892	10,095	12,504	12,180
	Rs. Lakh/MW	28.56	25.41	28.84	35.72	31.23
Mejia TPS (4x210 MW)	Rs Lakh	12,973	10,190	11,911	20,093	15,161
	Rs. Lakh/MW	15.44	12.13	14.18	23.92	18.05

14.1.30 It has been observed that the manpower to MW ratio is very high in case of DVC stations. There is scope for drastic rationalization of man power. During the tariff period 2004-09, Commission had not allowed the escalation for the thermal generating stations of DVC expecting them to rationalize the man power. However, ATE had ruled against the CERC order on this issue had directed to allow escalation on the O&M expenses on year to year basis stating that specific reason has not been provided for deviation from the principle of allowing escalation on year to year basis. It is felt that in case of Mejia and Bokaro TPS which has 210 MW units O&M norms as applicable to other station of 210 MW units. In case of Chandrapura TPs and Durgapur TPS it is considered reasonable to apply norms as specified above for Tanda TPS and Badarpur TPS of NTPC.

14.1.31 On the similar lines following O&M norms are allowed for lignite based Generating stations and TPS-I of NLC:

Year	**200/210/250 MW sets**	**125 MW sets**	**TPS-I**
2009-10	**15.70**	**24.00**	**21.50**
2010-11	**16.51**	**25.24**	**22.61**
2011-12	**17.37**	**26.55**	**23.78**
2012-13	**18.26**	**27.92**	**25.01**
2013-14	**19.21**	**29.36**	**26.30**

14.1.32 The O&M expenses of gas/liquid fuel based stations of NTPC, NEEPCO and other IPP and State Utility stations are as follows:

	Station	Unit	2002-03	2003-04	2004-05	2005-06	2006-07
1	Anta (3x88.7+1x 153.2)	Rs Lakh	4926	4226	6810	5678	5065
		Rs. Lakh/MW	11.75	10.08	16.24	13.54	12.08
2	Auraiya (4x111.19+2x10 9.3)	Rs Lakh	5469	6695	6012	6179	6118
		Rs. Lakh/MW	8.24	10.09	9.06	9.32	9.22
3	Dadri (4x130.19+2x15 4.51)	Rs Lakh	3752	7837	5697	8896	9558
		Rs. Lakh/MW	4.52	9.44	6.87	10.72	11.52
4	Faridabad (2X140.827+1X 149.932)	Rs Lakh	3803	3607	2977	3265	6279
		Rs. Lakh/MW	8.81	8.36	6.90	7.56	14.55
5	Kawas (4x106+2x116.1)	Rs Lakh	8663	8193	8975	7504	7124
		Rs. Lakh/MW	13.20	12.49	13.68	11.44	10.86
6	Gandhar (3x144.3+1x224 .49)	Rs Lakh	5177	4332	4910	6573	6510
		Rs. Lakh/MW	7.88	6.59	7.47	10.00	9.90
7	Kaymkulam (2x 116.6+ 1x126.38)	Rs Lakh	3800	3648	3237	2950	3462
		Rs. Lakh/MW	10.57	10.14	9.00	8.20	9.63
8	Baroda 2 (1x106+1x54)	Rs Lakh	1168	1375	1146	1121	1496
		Rs. Lakh/MW	7.30	8.59	7.16	7.00	9.35
9	Samalkot CCGT	Rs Lakh	290	1372	3106	2257	2686
		Rs. Lakh/MW	5.01	6.24	14.12	10.26	12.21

10	Badoda 1(3x32+1x49)	Rs Lakh	1670	1549	1284	2030	1549
		Rs. Lakh/MW	11.52	10.68	8.86	14.00	10.69
11	Indraprastha GPS (6x30+3x34)	Rs Lakh			5242	3235	3681
		Rs. Lakh/MW			18.59	11.47	13.05
12	Assam (6x30+3x37)	Rs Lakh	3317	5744	4628	4101	5358
		Rs. Lakh/MW	11.40	19.74	15.90	14.09	18.41
13	Agartal (4x21)	Rs Lakh	1531	1674	1329	1968	2288
		Rs. Lakh/MW	18.22	19.93	15.83	23.43	27.24

14.1.33 The O&M expenses after normalization works out as follows:

	Station	Unit	**2004-05**	**2005-06**	**2006-07**
1	Anta (3x88.7+1x153.2)	Rs Lakh	6134	5042	4149
		Rs. Lakh/MW	14.63	12.02	9.90
2	Auraiya (4x111.19+2x109.3)	Rs Lakh	5798	5926	5771
		Rs. Lakh/MW	8.74	8.93	8.70
3	Dadri (4x130.19+2x154.51)	Rs Lakh	5450	8629	9059
		Rs. Lakh/MW	6.57	10.40	10.92
4	Faridabad (2X140.827+1X149.932)	Rs Lakh	2856	3097	6006
		Rs. Lakh/MW	6.62	7.18	13.92
5	Kawas (4x106+2x116.1)	Rs Lakh	8749	7184	6508
		Rs. Lakh/MW	13.33	10.95	9.92
6	Gandhar (3x144.3+1x224.49)	Rs Lakh	4752	6341	6112
		Rs. Lakh/MW	7.23	9.65	9.30
7	Kaymkulam (2x 116.6+ 1x126.38)	Rs Lakh	3176	2905	3217

		Rs. Lakh/MW	8.83	8.08	8.95
8	Baroda 2 (1x106+1x54)	Rs Lakh	1125	1106	1483
		Rs. Lakh/MW	7.03	6.91	9.27
9	Samalkot CCGT	Rs Lakh	3089	2237	2621
		Rs. Lakh/MW	14.04	10.17	11.92
	Sub-Total	Rs Lakh	**41129**	**42467**	**44927**
		Rs. Lakh/MW	**9.35**	**9.66**	**10.22**
10	Badoda 1(3x32+1x49)	Rs Lakh	1266	2017	1538
		Rs. Lakh/MW	8.73	13.91	10.61
11	Indraprastha GPS a(6x30+3x34)	Rs Lakh	4693	3235	3681
		Rs. Lakh/MW	16.64	11.47	13.05
12	Assam (6x30+3x37)	Rs Lakh	4281	3970	4540
		Rs. Lakh/MW	14.71	13.64	15.60
13	Agartala (4x21)	Rs Lakh	1202	1945	2213
		Rs. Lakh/MW	**14.31**	**23.15**	**26.34**

14.1.34 It can be seen that NTPC is incurring much higher O&M expenses than the norms in their Kawas, Anta, Auraiya and Dadri Gas/Liquid fuel based stations. This is due to the fact that warrantee period for supply of free spares has expired and now they have to procure spares at high costs. It is now felt that it is not reasonable to not provide for adequate O&M expenses. The Commission intends to estimate a reasonable cost of warrantee spares embedded in the capital cost of these stations separately and reduce the same from the capital cost. Accordingly the Commission is specifying uniform norms for gas/liquid fuel based stations other than small gas turbine stations.

14.1.35 In the case of small gas turbines O&M expenses of Assam GPS and Agartala GPS are much higher than the O&M expenses of Indraprastha GPS and Baroda 1 GPS. This is perhaps due to higher capital cost and more transportation and gestation period for north eastern states of Assam and Agartala. Further, actuals of these stations are much higher than the norms. It is because NEEPCO had not participated during the process of finalization of norms for these stations and Commission has worked out norms based on actuals for their starting years when no capital overhaul was done. On this account NEEPCO has already suffered enough on account of their failure to represent their case before us. It is also seen that O&M expenses of Agartala are much higher than the Assam GPS in Rs. Lakh/MW term. This is because Agartala has only gas turbines which operate on open cycle. Where as in combined cycle station weighted average O&M cost comes down due to low O&M expenditure relating to Waste heat recovery boilers & steam turbine which contribute about1/3 of the capacity.

14.1.36 Accordingly, following O&M expenses are being allowed for the NTPC and NEEPCO gas/Liquid fuel Based stations:

Year	Gas based Stations other than small gas turbine stations	Assam GPS	Agartala GPS
2009-10	**12.15**	**15.40**	**23.50**
2010-11	**12.78**	**16.20**	**24.71**
2011-12	**13.44**	**17.03**	**25.99**
2012-13	**14.13**	**17.91**	**27.34**
2013-14	**14.86**	**18.84**	**28.75**

14.2 Hydro Generating Stations

14.2.1 Existing provisions of O&M expenses during 2004-09

(a) For the existing hydro stations in operation for 5 years or more

O&M expenses including insurance for the existing hydro generating stations which are in operation for 5 years or more, shall be derived on the basis of actual O&M expenses for the years 1998-99 to 2002-03, based on audited balance sheets, excluding abnormal expenses, if any, after prudence check by the Commission.

The average of such normalized O&M expenses, after prudence check, for the years 1998-99 to 2002-03 considered as O&M expenses for the year 2001-01 shall be escalated @ 4% per annum to arrive at O&M expenses for the base year 2003-04. The base year O&M expenses shall be further escalated @4% P.A. to arrive at O&M expenses for the relevant year of period 2004-09.

(b) For hydro stations not in existence for a period of 5 years

O&M expenses shall be fixed @ 1.5% of the capital cost as admitted by the Commission and escalated @ 4% P.A. to arrive at O&M for the base year 2003-04. Base O&M expenses are further escalated @ 4% P.A. to arrive at permissible O&M expenses for the relevant year of tariff period 2004-09.

(c) For new hydro stations commissioned on or after 1.4.2004:

The base O&M expenses shall be fixed at 1.5% of the actual capital cost as admitted by the Commission, in the year of commissioning and shall be escalated @ 4% P.A for subsequent years.

Before finalizing the above methodology to arrive at the allowable O&M expenses during the tariff period 2004-09, an attempt was made by the Commission to arrive at normative value of O&M expenses for Hydro stations in terms of Rs. lakhs/MW, as was approved for thermal stations. A normative O&M expenditure of Rs.10.92 lakhs/MW for the year 2004-05 with escalation @ 4% per annum for subsequent years of tariff period was proposed in the draft regulations. However, various hydro generating companies were not in favor of Commission's recommendations for normative O&M expenses for hydro stations. Commission after scrutiny of the comments of the stakeholders on draft regulations made following observations in its order dated 29th March, 2004 :

" 173. In the draft regulations, the following normative operation and maintenance expenses for different years of the tariff period were proposed:

Year	*O&M expenses (Rs. in lakhs/MW)*
2004-05	*10.92*
2005-06	*11.36*
2006-07	*11.81*
2007-08	*12.28*
2008-09	*12.77*

174. It has been submitted that normative operation and maintenance expenses of Rs.10.92 lakh/MW for the year 2004-05 *and escalation of same by 4% per annum needs to be reviewed in the light of reasons summarized below:-*

(a) Hydro projects are site-specific and any two projects of same capacity (MW) are not identical. The cost of operation and maintenance for each hydro project depends upon the following factors amongst others.

(i) Layout of the project
(ii) Location of the dam, plant, power house etc.
(iii) Location of the employee colonies
(iv) Topography of the area
(v) Remoteness of the project
(vi) Law and order situation
(vii) Silt content in the water

(b) The spares of old power stations are not available in the market on account of discontinued manufacturing as a result of fast changing technology. The spares of these equipments have to be got manufactured (if not kept earlier in project stocks) which increases the cost of these spares and the delivery period is also longer.

(c) The insurance charges are based upon the sum insured and has to be a percentage of cost of project rather than on Rs.Lakh/MW basis.

(d) Provision of operation and maintenance expenses of about Rs. 11 lakh/MW/year will most certainly not be adequate for small hydro power generating stations. The utilities, who have almost all hydro power generating stations which are more than 20 years old have submitted that in order to keep these old plants running efficiently, there is need to provide reasonable operation and maintenance cost norm of Rs. 20 lakh/MW/ year.

175. We take note of the apprehension of the hydro power utilities that operation and maintenance cost of a hydro power generating station is site-specific and any two hydro power generating stations of same capacity may not have same operation and maintenance cost. Apart from this, remote location of the hydro power generating stations together with siltation problems encountered by most of them are subject to higher operation and maintenance cost. Thus, normative operation and maintenance expenses as proposed in the draft regulations may not be adequate to maintain the operation and maintenance quality and may affect adversely the performance of hydro power generating stations. We have, therefore, decided that *operation and maintenance expenses of hydro power generating stations shall be worked out in the following manner."*

Commission's acceptance of methodology for O&M expenses applicable for the tariff period 2004-09 has been explained at para 1.1 above.

14.2.2 **Methodology to arrive at O&M expenses for the period 2009-14:**

14.2.2.1 The Commission in order to facilitate this process of finalization of terms & conditions of tariff, vide order dated 7th Jan 2008 directed the generating companies namely NHPC, NHDC, NEEPCO, DVC, SJVNL to furnish the details of actual O&M expenditure for the financial years 2002-03 to 2007-08 in respect of their hydro generating stations. The actual O&M data have been submitted by all the utilities and the same are discussed in subsequent paragraphs.

14.2.2.2 An analysis has been made of the actual O&M data submitted by various hydro generating companies for the period 2002-03 to 2006-07. The O&M expenses of various stations include incentive & ex-gratia paid to its employees and expenditure on account of VRS. These have been excluded for the normalization of O&M expenses for the 5 years i.e.2002-03 to 2006-07.

14.2.2.3 Actual normalized O&M expenditure of various hydro stations (after excluding incentive, ex-gratia and expenditure on VRS) during the period 2002-03 to 2006-07 depicts a large variation of normative O&M cost in terms of Rs. lakh/MW. These have been summarized in respect of NHPC, NEEPCO & DVC stations in the following table:

(Rs. lakhs/MW)

Station	Capacity (MW)	2002-03	2003-04	2004-05	2005-06	2006-07	Average
NHPC							
Chamera-I	540	10.06	11.65	12.46	11.09	12.53	11.56
Baira siul	180	17.34	17.14	18.61	21.00	22.16	19.25
Chamera-II	300	-	-	14.18	14.14	14.74	14.35
Loktak	105	35.47	31.97	34.65	38.71	39.96	36.15
Rangit	60	26.94	28.58	30.13	34.71	48.41	33.75

Dhauli Ganga	280	-	-	-	-	14.90	14.90
Uri	480	9.35	12.23	10.39	10.82	10.31	10.62
Tanakpur	94.2	28.47	26.14	24.43	31.51	32.93	28.69
Salal	690	10.71	10.76	9.17	12.71	9.22	10.52
NEEPCOO							
Kopili & Khandong	275	12.50	11.02	9.81	13.34	16.80	12.69
Doyang	75	22.55	25.14	22.40	22.45	27.65	24.04
Ranganadi	405	10.43	9.08	9.16	11.84	18.12	11.72
DVC							
Maithon	63.2	13.72	13.93	20.40	15.42	18.24	16.34
Panchet	80	8.15	7.40	10.44	11.34	14.15	10.30
Tilaiya	4	73.5	70	102.7	83	90.7	84

14.2.2.4 From the above analysis it would be seen that the normative O&M cost (Rs. lakhs/MW) shows large variations from company to company as well as from station to station. For NHPC, average normative O&M cost for the period period 2002-03 to 2006-07 has been found to vary from Rs. 10.52 lakhs/MW for Salal to Rs. 36.15 lakhs/MW in respect of Loktak H.E. station. Similarly for NEEPCO, the variations are from Rs. 11.72 lakhs/MW for Ranganadi to Rs. 24.04 lakhs/MW for Doyang HEP. For DVC stations, average normative O&M cost is varying from Rs. 10.30 lakhs/MW for Panchet to Rs. 84 lakhs/MW in respect of Tilaiya H.E. station.

14.2.2.5 Thus, keeping in view the large variations in the normative O&M cost of hydro stations and observations of Commission at para-175 of its order dated 26.3.2004 which still holds good, it shall be appropriate to continue with the existing methodology applicable during the current tariff period 2004-09 to work out the allowable O&M in tariff on plant to plant basis.

14.2.2.6 The average escalation during the last 5 years works out as 5.17% considering weightage of inflation in CPI & WPI as 40% & 60% respectively.

14.2.2.7 The next pay revision is due with effect from 1.4.2007 and it may not be possible to absorb the pay revision impact all the time. The Commission has therefore, decided to consider a pay revision impact of 45% increase in employee costs while working out the O&M expenses across the board for all central sector utilities.

14.2.2.8 The methodology to take into account the impact of pay revision has been illustrated in the following table with sample data of O&M expenses of 'X' H E station :

(Rs. lakh)

Station	2003-04	2004-05	2005-06	2006-07	2007-08	Average
X	5400	6000	6500	7000	7500	6480

14.2.2.9 Considering average O&M expenses as O&M expenses for the year 2005-06, it shall be escalated @ 5% per annum to arrive at O&M expenses for the base year 2008-09

O&M expenses for the base year 2008-09 = Rs. 7500 lakh
O&M expenses for the year 2009-10 = Rs. 7875 lakh
(with 5% annual escalation)

Assuming contribution of 'Employee cost' in the total O&M expenses in the year 2009-10 amounts to 35%,

Employee cost = 7875x 0.35= Rs. 2756 lakh

Corresponding employee cost after allowing 45% hike due to pay revision shall be 2756x 0.45= Rs 1240 lakh

Thus, total O&M expenses to be allowed during 2009-10= 7875+ 1240 = Rs. 9115 lakh

14.3 **Transmission**

14.3.1 The Commission had directed the regulated entities POWERGRID and Powerlinks Transmission Limited (PTL) to submit details of their O&M expenses for the period 2002-03 to 2006-07. In response, POWERGERID has submitted information up to 2006-07. PTL has started commercial operation only during 2006-07. It has submitted information for the year 2006-07 as well as for 2007-08. The Commission had separately asked for somewhat less exhaustive information from other entities engaged in transmission. Only KPTCL and MP Transmission Co. Ltd have submitted such information.

14.3.2 For the tariff period 2009-14, few changes in the approach are being proposed. Firstly, the norms are proposed to be based on per km basis rather than per ckt-km basis, since majority of expenses are not affected by the circuit configuration. However, after arriving at basic norm on per km basis, this value is proposed to be modulated based on the voltage level and circuit configuration of the line. Similarly, in case of O&M expenses for sub-station, after arriving at basic norm for O&M expenses per bay, it is proposed to modulate it based on voltage level.

14.3.3 The staring point of the process is normalization of actual data of O&M expenses submitted by POWERGRID. This normalization has been done in the following manner:

(i) Abnormal security expenses on deployment of special security have not been considered.
(ii) Electricity charges have been apportioned in the ratio of electricity consumption in the sub-station and that in the colony. Only former have been considered for the process of normalization.
(iii) Donations, ex-gratia and productivity linked incentives have not been considered in continuation of the current policy.
(iv) It is observed that there is significant efficiency improvement by POWERGRID in terms of number of employees per km as well as number of employees per bays. Similar trend has been observed for HVDC line as well as sub-station. Normalized number of employees is found out based on average for last 2-3 years for all the regions (except NER), when the value seems to have more or less stabilized. The employee cost for each year has been normalized based actual employee cost or that arrived at based on normalized number of employees per bay and per km in case of AC systems and number of employees per km and per Station in case of HVDC station, which ever is lower. In case of NER, normalized number of employees have been restricted to 1.5 times of that for the other regions.
(v) Normalized O&M expenses for each HVDC station is arrived at by reducing actual expenses in the same ratio as that of overall normalized O&M expenses to the overall actual O&M expenses for the region concerned. In case of HVDC Dadri station, there was steep increase in O&M expenditure from 2005-06 to 2006-07. From the information submitted by POWERGRID, it is seen that this increase has been attributed to repair of damaged three number converter transformers and replacement of converter transformers. Since it is not normal to have so much expenditure on converter transformers in a single year, for the process of normalization, the O&M expenses for HVDC Dadri has been restricted to 120% of the previous year. This normalization at HVDC Dadri Station is reflected in the total O&M expenses for NR as well.

14.3.4 The actual expenditure and normalized expenditure for various regions is given in the following tables:

Actual O&M Expenses as informed by POWERGRID
(Rs Lakh)

	2002-03	2003-04	2004-05	2005-06	2006-07
NR	11706.50	11719.44	12333.18	12650.28	18852.10
WR	4671.28	4909.87	4882.07	5156.46	5959.28
ER	4748.43	5695.7	5924.48	6607.97	8056.63
SR	6557.13	8784.95	9112.76	10157.71	10934.44
NER	4157.11	4646.54	4766.77	4730.28	5297.96
Total	31840.45	35756.5	37019.26	39302.695	49100.41

	2002-03	2003-04	2004-05	2005-06	2006-07
NR	9472.34	8856.86	10168.72	10794.24	14299.34
WR	4441.57	4397.95	4628.58	4919.03	5498.98
ER	3134.271	3838.965	4680.16	5594.50	7446.9972
SR	5930.33	7565.63	8501.59	9552.43	9979.21
NER	3040.35	3343.88	3514.18	3462.22	4252.47
Total	26018.86	28003.28	31493.23	34322.426	41476.992

14.3.5 To arrive at norm for HVDC station, normalized expenses for individual HVDC stations for various years are escalated @5.17% per annum (the average inflation during the period 2002-03 to 2006-07) to arrive at normalized O&M expenses at 2006-07 price level. These normalized O&M expenses at 2006-07 price level are divided by the Station capacity (in 100's MW) to arrive at values in Rs lakhs/100 MW. In case of HVDC BTB, station capacity is doubled to arrive at the norm. Average value of normalized O&M expenses or HVDC stations works out to Rs 30.6 lakh/100 MW. However, considering higher values during the recent period, it is proposed to have norm of Rs 35 lakh/100 MW of HVDC station capacity.

14.3.6 The normalized O&M expenses for HVDC stations of the region concerned were deducted from the overall region-wise normalized expenses. The resulting values represent normalized expenses for AC sub-stations and transmission lines (Ac as well as DC). These values for the years 2002-03 to 2005-06 were escalated @5.17% per annum to arrive at normalized O&M expenses at the price level of 2006-07. To segregate normalized O&M expenses into O&M expenses for the lines and that for sub-stations, regression analysis was carried out with total normalized O&M expenses as dependent variable and line length (km) and number of bays as independent variables. Line length and number of bays were considered as at the end of the year. The regression analysis leads to following relationship for the year 2006-07 between normalized O&M expenses and line length & number of bays.

Normalized O&M expenses = 0.434 x line length (km) + 19.17 x Number of bays

14.3.7 Thus, based on this analysis, average norms for the year 2006-07 should be Rs 0.434 lakh /km and Rs 19.17 lakh per bay. However, these values arrived at after statistical analysis can only act as guide. The allowable O&M expenses on all India basis when calculated using these values turn out to be somewhat higher than normalized O&M expenditure. Therefore, these values were scaled down by 10%. Thus, the proposed average norm work out to Rs 0.391 lakh per km and Rs 17.25 lakh per bay.

14.3.8 It is fair to assume that only expenditure on spares and repair & maintenance will be dependent on voltage level (for line as well as sub-station O&M) and on circuit configuration (for line). The expenditure on spares and repair & maintenance forms about 15% of the O&M expenses for lines as well as sub-stations. Therefore, to arrive at voltage and circuit configuration dependent norms, 85 % of the average norm per km and per bay has been kept fixed and remaining 15% has been modulated. The hypothesis for such modulation is that expenses on spares and repair & maintenance for various voltage levels and circuit configuration will be in the same ratio as the ratio of cost of construction of new bay and new line. The cost ratios used for the calculation are as under:

Transmission Line

Line Volatge and ckt configuration	Cost ratio Considered for calculations
765 kV	1.33
400 kV D/C	1.00
400 kV S/C	0.67
220kV D/C	0.50
220 kV S/C	0.33
132 kV D/C	0.40
132 kV S/C	0.26
HVDC line	1.17

Bays

Bay Voltage	Cost ratio Considered for calculations
765 kV	3.33
400 kV	1.00
220 kV	0.47
132 kV	0.36

14.3.9 Such modulation leads to norms at 2006-07 price level. These norms are than escalated @5.17 % per annum to arrive at norms for the year 2009-10. Since, wage revision for the PSU employees is imminent, it has been decided to consider 45% increase in wages for the purpose of fixing norms for the period 2009-14. It is observed that about 30% of the line O&M expenses, 60% of the AC sub-station O&M expenses and 30% of the HVDC station O&M expenses are on account of employee salaries and wages. Accordingly, the norms for the years 2009-10 have been modified for 45% salary hike. These norms are than escalated @5.17% per annum to arrive at norms for the subsequent years of the tariff period 2009-14. The proposed norms are as under:

Proposed Norms for Transmission Line

(Rs Lakh/km)

	2009-10	2010-11	2011-12	2012-13	2013-14
HVDC line	0.534	0.562	0.591	0.621	0.653
765 kV	0.550	0.578	0.608	0.640	0.673
400 kV S/C	0.486	0.511	0.538	0.565	0.595
400 kV D/C	0.518	0.545	0.573	0.603	0.634
220 kV S/C	0.453	0.476	0.501	0.527	0.554
220 kV D/C	0.470	0.494	0.520	0.547	0.575
132 kV S/C	0.446	0.469	0.493	0.519	0.546
132 kV D/C	0.460	0.484	0.509	0.535	0.563

(Rs Lakh/bay)

	2009-10	2010-11	2011-12	2012-13	2013-14
765 kV bay	35.46	37.29	39.22	41.25	43.38
400 kV bay	24.73	26.01	27.35	28.77	30.25
220 kV bay	22.27	23.42	24.63	25.91	27.25
132 kV bay	21.76	22.88	24.07	25.31	26.62

Proposed Norms for HVDC station*

(Rs Lakh/100 MW)

2009-10	2010-11	2011-12	2012-13	2013-14
46.2	48.6	51.1	53.7	56.5

* Foe HVDC BTB, two HVDC stations will be counted at the same location

14.3.10 In order to judge suitability of the proposed norm a comparison has been carried out between the recovery by applying proposed norms vis-à-vis actual and normalized O&M expenditure. This comparison is tabulated below:

Comparision of recovery of POWERGRID from proposed norms vis-a-vis actual O&M expenditure and normalized O&M expenditure

(Rs Lakh)

		2004-05	**2005-06**	**2006-07**
NR	Total Alowable as per proposed norms	10041.35	11953.76	13943.13
	Actual Expenditure	12333.18	12650.28	18852.10
	Normalized Expenditure	10168.72	10794.24	14299.34
WR	Total Alowable as per proposed norms	5628.79	6475.97	7356.79
	Actual Expenditure	4882.07	5156.46	5959.28
	Normalized Expenditure	4628.58	4919.03	5498.98
SR	Total Alowable as per proposed norms	9214.34	10550.94	11447.23
	Actual Expenditure	9112.76	10157.71	10934.44
	Normalized Expenditure	8501.59	9552.43	9979.21
ER	Total Alowable as per proposed norms	4822.40	5304.31	6582.85
	Actual Expenditure	5924.48	6607.97	8056.63
	Normalized Expenditure	4680.16	5594.50	7447.00
NER	Total Alowable	1732.47	1822.03	1916.23
	Actual Expenditure	4766.77	4730.28	5297.96
	Normalized Expenditure	3514.18	3462.22	4252.47
Total	**Total Alowable as per proposed norms**	**31439.35**	**36107.01**	**41246.23**
	Actual Expenditure	**37019.26**	**39302.70**	**49100.41**
	Normalized Expenditure	**31493.23**	**34322.43**	**41476.99**

14.3.11 It is clear from the above comparison that proposed norms lead to recovery of normalized expenditure, which was the purpose of the whole exercise.

14.3.12 It may be noted that the norms so arrived do not take into account actual expenditure of POWERGRID in the year 2007-08. The regulated entities have been given time up to 31.08.2008 to submit information for such information. Therefore, the norms proposed may undergo change during finalization on this account. Further, till this proposal was finalized, data from DVC was not available. The DVC network is essentially a low voltage network with small line lengths. Therefore, in the past it has been observed that O&M expenses of DVC are on lower side. Once information from DVC is available, separate norms for their relatively low voltage network will be proposed for comments by stakeholders before issuing final norms.

14.3.13 Following information is required from POWERGRID to improve upon the process:

(i) Region-wise/year-wise expenses on petition filing fee for CERC. This is because of the decision that fees for filing of the petition in CERC will not be part of the norms and the same has to be reimbursed based on actuals. For this purpose, the actual expenses incurred by the POWERGRID on the petition filing fees need not be considered in the normalized expenditure. In the absence of such details, for the present, entire legal expenses furnished by POWERGRID have been considered.

(ii) Ideally, average line length and average number of bays for the year need to be considered. Since, details as at the end of 2001-02, were not available, year-end values have been used. POWERGRID may submit this additional information.

(iii) Break-up of miscellaneous expenses as this head forms large proportion of the O&M expenses. For the present, entire claim of miscellaneous expenses has been considered for normalization.

14.3.14 Major part of the PTL system is in the form of 400 kV D/C lines. The per km O&M expenses for PTL works out to Rs 0.49 lakh and Rs 0.70 lakh for the years 2006-07 and 2007-08 at 2006-07 price level. This is significantly higher than the proposed norms of Rs 0.421 lakh/km (without salary hike) for 400 kV D/C lines at 2006-07 price level. Prima-facie it appears that this may be because of significantly higher allocation of expenses at corporate office level. In case of POWERGRID, the allocation from corporate office generally forms less than 10% of the regional O&M expenses. Being a single project company, somewhat more activities are expected at the corporate office level in case of PTL. However, the allocation of corporate office expenses works out much higher than expected, forming 60-70% of the regional O&M expenses of PTL. This is in spite of the fact that number of employees/km at regional level in case of PTL is much higher (about 56 and 41 employees per 1000 km during 2006-07 and 2007-08) as compared to POWERGRID (about 26 employees per 1000 km for regions other than NER). Perhaps, being a new entity, PTL's expenses do not form representative sample. There is no doubt that in coming years PTL will also carry out required optimization to be well within the norms. Reduction in number of employees per 1000 km within a year is just one indication of this process.

14.3.15 The information submitted by KPTCL and MPTCL also does not form representative sample because their system contains high percentage of relatively low voltage network and separate information for 132 kV and above network is not available.

15.0 Norms of Operation

15.1 Norms of Operation for thermal Generation Stations

15.1.1 The Commission started the process of finalizing the terms & conditions of the tariff for the next tariff period starting from 1.4.2009 and in order to facilitate this process of finalization of terms & conditions of tariff, vide order dated 7th Jan 2008 directed the generating companies namely NTPC, NLC, NEEPCO, DVC, to furnished the details of operational and performance data for the financial years 2002-03 to 2007-08 in respect of their existing thermal generating stations. The similar data was sought from SEBs/State Utilities and IPPs in order to arrive at reasonable norms for the next tariff period. The operational and performance data for these years have been submitted by all the Central Generating stations regulated by CERC and some of the IPPs and State Utilituies as well.

15.1.2 Since the generating stations based on technology using super critical boiler namely Sipat, Barh etc. are under construction, the Commission intends to finalise the performance and operational norms for such generating stations as well. NTPC was, therefore, directed to furnish a reasonable estimate of performance and operational parameters along with the requisite details of turbine heat rate, boiler efficiency, unit and station auxiliary energy consumption excluding colony consumption, heat balance diagram of the generating stations, correction curves like variation in gross heat rate with variation in load, life cycle degradation factor, etc to enable the Commission to take a view in this regard.

15.1.3 Commission also intends to specify operational norms for the Lignite Based Plants based on Circulating fluidized bed combustion (CFBC) boiler technology. In this regard NLC has already approached CERC to fix the norms for its up coming lignite based Barsingsar TPS in Rajasthan based on Circulating fluidized bed combustion (CFBC) boiler technology.

15.1.4 Para 5.3 f) of the Tariff Policy on operating Norms reads as follows:

> *"Suitable performance norms of operations together with incentives and dis-incentives would need be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. Except for the cases referred to in para 5.3*

(h)(2), the operating parameters in tariffs should be at "normative levels" only and not at "lower of normative and actuals". This is essential to encourage better operating performance. The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipments, nature of operations, level of service to be provided to consumers etc. Continued and proven inefficiency must be controlled and penalized.

The Central Commission would, in consultation with the Central Electricity Authority, notify operating norms from time to time for generation and transmission. The SERC would adopt these norms. In cases where operations have been much below the norms for many previous years, the SERCs may fix relaxed norms suitably and draw a transition path over the time for achieving the norms notified by the Central Commission. "

15.1.5 CEA was requested to look into the operation and performance parameters of Central generating stations and make their recommendations by 31.7.2008. CEA is yet to make its recommendations. In the absence of CEA recommendations, Commission is proceeding on its own based on the data available with them since CERC terms and conditions of tariff shall act as guidelines for State Commissions. Necessary corrections, if considered necessary could be effected as and when CEA recommendations are received.

15.1.6 The various operational parameters namely Target Availability, PLF, Station Heat Rate, Auxiliary Energy Consumption and specific fuel oil consumption are discussed in subsequent paragraphs based on actual operation and performance of coal/lignite based and Gas/Liquid fuel based generating stations of NTPC, NLC, DVC, & NEEPCO and some of the comparable generating stations of SEBs/IPPs.

15.1.7 Though the Commission has sought the data for the years 2002-03 to 2006-07 from generating companies but for the purpose of analysis and specifying operation norms for the next tariff period the Commission has relied upon the data for the period 2004-05 to 2006-07. It is because the present norms were effective from 1.4.2004 and by this time ABT with UI mechanism was fully established in all the regions of the country. However, in case of generating stations of DVC, Commission has issued the norms from 2006-07 onwards. Therefore in case of DVC's stations actual data of 2006-07 has been considered.

15.1.8 In case of Badarpur TPS, Talcher TPS and Tanda TPS which were taken over by NTPC from different entities, Commission have specified plant specific norms considering their historical background, actual conditions, age, unit sizes etc.

15.1.9 As a result of major R&M works in case of Tanda & Talcher, these stations for the last three four years improved upon their operational & performance parameters. Commission has already reviewed the norms incase of Tanda and Talcher TPS w.e.f. 1.4.2007 and 1.10.2007 respectively based on the improved performance levels achieved. Therefore, Commission is of the view that the present norm specified by it should continue in the next tariff period also.

16.0 Target Availability for recovery of Full Fixed Charges (AFC) and for the payment of Incentive

16.1 Existing Provisions

16.1.1 The existing regulations for tariff period 2004-09 as amended provide following norms for the Target Availability for recovery of full Annual Fixed Charges (AFC) for the thermal generating stations:

(a)	All thermal generating stations, except those covered under clause (b) below	80 %.
(b)	Generating station of Neyveli Lignite Corporation (NLC) (TPS-I, TPS-II, Stage I &II and TPS-I (Expansion),	75%

16.1.2 Through separate tariff orders, CERC allowed following relaxed norms of Target Availability for the thermal Generating stations of Damodar Valley Corporation (DVC) and Badarpur TPS of NTPC:

Station	2006-07	2007-08	2008-09
Mejia(4x210)	78%	80%	80%
Bokaro (3x210);	55%	65%	75%
Chandrapur (3x130+3x120)	55%	55%	60%
Durgapur (1x210+1x140)	60.5%	67%	74%
Badarpur TPS (3x95+2x210)	75%	*75%*	*75%*

16.1.3 The same % norms were specified for the Target Plant Load Factor for payment of incentive.

16.2 Coal/Lignite based Stations

16.2.1 The availability of the various coal/Lignite based generating stations in the last 5 years i.e. 2002-03 to 2006-07 is as follows:

Generating Station	2002-03	2003-04	2004-05	2005-06	2006-07
Dadri Coal(4x210)	92%	93%	96%	95%	98%
Kahalgaon(4x210 MW)	72%	84%	84%	92%	92%
Unchahar (2x210+2x210+1x 210)	72%	71%	73%	77%	96%
Rihand St-I&II(4x500)	98%	91%	90%	97%	93%
Talcher (2x500+4x500)	74%	82%	82%	87%	92%
Simhadri (2x500)	NA	94%	95%	94%	94%
Singrauli (5x200+2x500)	92%	90%	91%	89%	84%
Korba (3X200+3X500)	91%	90%	93%	88%	91%
Farakka (3x200+2x500)	NA	70%	71%	85%	85%
Ramagundam (3x200+3x500+1x500)	92%	90%	94%	92%	92%
Vindhyachal Super Thermal Power Station (6x210+4x500)	87%	85%	91%	94%	94%
Badarpur(3x95+2x210)	NA	NA	NA	91%	90%
Talcher takenover(4x60+2x110)	56%	68%	80%	88%	88%
Tanda (4x110 MW)	NA	NA	NA	NA	91%
Others					
Raichur (7x210 MW)	87%	88%	89%	89%	80%
Bhatinda (2x210 MW)	85%	97%	93%	88%	94%
GGSS Roop Nagar (6x210MW)	91%	90%	88%	90%	93%
Dahanu (2x250 MW)	91%	97%	97%	95%	97%
Lignite based stations					
NLC TPS-I	N.A.	N.A.	N.A.	N.A.	N.A.
NLC TPS-I(Exp.)	N.A.	70%	88%	96%	101%
NLC TPS-II(stage-I)	83%	74 %	71%	72 %	53%
NLC TPS-II (Stage-II)	81%	73%	75%	69%	81%
Surat Lignite	76%	79%	85%	88%	83%

16.2.2 The actual PLF of the various coal/Lignite based generating stations in the last 5 years i.e. 2002-03 to 2006-07 are as follows:

NTPC's station	2002-03	2003-04	2004-05	2005-06	2006-07
Dadri Coal(4x210)	82%	84%	93%	92%	96%
Kahalgaon(4x210 MW)	68%	81%	83%	89%	89%
Unchahar (2x210+2x210+1x210)	67%	70%	74%	77%	96%
Rihand St-I&II(4x500)	88%	91%	91%	85%	92%
Talcher (2x500+4x500)	73%	82%	82%	84%	90%
Simhadri (2x500)	NA	88%	93%	88%	92%
Singrauli (5x200+2x500)	92%	89%	90%	88%	84%
Korba (3X200+3X500)	89%	89%	93%	87%	90%
Farakka (3x200+2x500)	64%	68%	69%	82%	81%
Ramagundam (3x200+3x500+1x500)	92%	89%	91%	86%	89%
Vindhyachal Super Thermal Power Station (6x210+4x500)	86%	82%	90%	92%	93%
Badarpur(3x95+2x210)	85%	88%	88%	87%	86%
Talcher takenover(4x60+2x110)	73%	82%	82%	84%	90%
Tanda (4x110 MW)	58%	75%	86%	86%	91%
Others					
Raichur (7x210 MW)	89%	88%	83%	71%	89%
Bhatinda (2x210 MW)	79%	92%	90%	86%	94%
GGSS Roop Nagar (6x210 MW)	90%	90%	86%	85%	89%
Dahanu (2x250 MW)	91%	100%	101%	99%	102%
Lignite based stations					
NLC TPS-I	83%	84%	81%	76%	76%
NLC TPS-I(Exp.)	NA	54%	88%	84%	89%
NLC TPS-II(stage-I)	83%	74%	72%	70%	57%
NLC TPS-II (Stage-II)	80%	80%	72%	72%	73%
Surat Lignite	73%	75%	82%	86%	80%

16.2.3 The average availability and average PLF of the various coal/Lignite based generating stations of the last 3 years i.e. 2004-05 to 2006-07 are as follows:

NTPC's station	Availability	Actual PLF

Dadri Coal(4x210)	96%	94%
Kahalgaon(4x210 MW)	89%	87%
Unchahar (2x210+2x210+1x210)	82%	82%
Rihand St-I&II(4x500)	93%	89%
Talcher (2x500+4x500)	87%	85%
Simhadri (2x500)	95%	91%
Singrauli (5x200+2x500)	88%	88%
Korba (3X200+3X500)	90%	90%
Farakka (3x200+2x500)	80%	77%
Ramagundam (3x200+3x500+1x500)	93%	89%
Vindhyachal Super Thermal Power Sation (6x210+4x500)	93%	92%
Badarpur(3x95+2x210)	91%	87%
Talcher takenover(4x60+2x110)	85%	85%
Tanda (4x110 MW)	N.A.	88%
Others		
Raichur (7x210 MW)	90%	81%
Bhatinda (2x210 MW)	92%	90%
GGSS Roop Nagar (6x210 MW)	86%	86%
Dahanu (2x250 MW)	96%	101%
Lignite based stations		
NLC TPS-I	N.A.	78%
NLC TPS-I (Expansion)	95%	87%
NLC TPS-II(stage-I)	65%	66%
NLC TPS-II (Stage-II)	72%	73%
Surat Lignite	85%	83%

16.2.4 It can be seen that most of the coal based stations of indicated above has average availability (Declared) and average PLF (actual availability) in the range of 85% to 96% and 85% to 101% respectively except Farakka & Unchahar stations of NTPC. However, the Farakka and Unchahar stations have achieved availability of 85% & 96% respectively in year 2006-07. Further, the actual PLFs are equal to or less by about 2-3% as compared to the availability except in case of Dahanu TPS. We feel that there is sufficient ground to increase the Target Availability norm for the coal based generating stations to 85% for the recovery of full Annual Fixed Charges (AFC) except in case of some of the DVC stations as discussed subsequently. In case of Badarpur TPS whose availability is of the order of 91%, we intend to keep the target availability norm of 82% as against norm of 75% at present with due regard to the fact that 95 MW has already out lived their useful life and OEM is not ready to provide life extension guarantees. In case of Talcher and Tanda TPS, revised norms of 80% have been specified about a year back. These stations being old stations, Commission would like to keep the normative plant availability factor for these stations at 82% slightly lower than the other thermal generating stations.

16.2.5 With the implementation of Electricity Act 2003, CERC started regulating DVC since 2004-05. DVC was allowed progressively improving norms from 2006-07 and onwards allowing them time to improve upon their performance. The actual availability of past years is not available as DVC is still in the process of scheduling and dispatch from their stations as per ABT requirement. We are therefore, relying upon the actual **PLF** of DVC's station for fresh look on norms for them which are as follows:

Station	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**
Mejia(4x210)	60%	73%	73%	80%	85%
Bokaro (3x210);	56%	49%	45%	48%	60%
Chandrapura (3x130+3x120)	17%	20%	29%	31%	33%
Durgapur (1x210+1x140)	36%	54%	48%	59%	67%

16.2.6 It is seen from above table that PLF levels have improving trend and except Chandrapur TPS, all the stations has achieved the PLF more than the target availability for the year 2006-07. Generally, stations are expected to have availability more than the actual PLF. The normative availability or PLF in year 2006-07 is more than the average of 5 years (2002-03 to 2006-07) and there appears to be a further scope for improvement. Mejia station of DVC is having relatively new units and of unit size of 210/250 MW and actual PLF is more than 85% for the year 2006-07 and therefore, for Mejia TPS target availability norm is being kept at par with other coal based stations i.e 85%.

16.2.7 The Chandrapura and Durgapur stations are old as well as have small size units. Bokaro is also old station. These stations are yet to achieve target availability levels specified for 2007-08 and 2008-09. Therefore, target availability for these stations of year 2008- 09 as given under shall be the norm for the tariff period 2009-14:

Bokaro (3x210);	75%
Chandrapur (3x130+3x120)	60%

Durgapur (1x210+1x140)	74%

16.2.8 In case of lignite stations of NLC, only TPS-I (Expansion) is able to achieve availability and actual PLF level of more than 85%. TPS-II stage-I & II have not been able to achieve target availability levels of 75%. This is mainly on account Shortfall in Lignite supply due to Land acquisition problem in Mines. TPS-I has achieve availability of 78%. NLC has requested for lower availability of 68.49% in case of TPS-I and 72% for NLC TPS-II. NLC has submitted that TPS-I is facing more forced outages of boilers which were commissioned in 1960. Further, there is lot of variations in lignite quality and higher wetness of lignite due to rain resulting in choking in bunker chutes and raw lignite feeders, all leading to frequent fluctuations in the load of the unit which results in low PLF. Frequent outages of mills and slag conveyors causes reduction in availability

16.2.9 The availability achieved by NLC TPS-I (Exp) is higher than the normative 75% and other coal based power stations of NTPC of similar sizes are also achieving norms at higher levels on sustained basis, it would therefore be reasonable to raise the normative plant availability factor to 80%. TPS-II stations of NLC has suffer due to land acquisition problem in Mine-II. Till the problem is resolved, there is a case to keep the availability norms for this station at 75% as there is no possibility of an alternate arrangement for this station. As regards TPS-I, the availability norm is being relaxed to 72% considering its old age and problem of frequent failure of mills.

16.2.10 The competitive bidding documents in respect of ultra mega power projects namely Sasan UMPP, Munda UMPP etc. based on super critical technology provided for 85% availability and bidders response has been very good in these ultra mega power projects. In case of new lignite based station, we don't see any constraint of mining lignite and use of CFBC boilers should only enhance there availability. As such, in respect of new coal & lignite based stations including stations based on super critical boiler technology and based on CFBC technology whose commercial operation start on 1.4.2009 or after shall also have a target availability of 85%.

16.2.11 As regards target plant load factor for the payment of incentive is concerned, it is not relevant now when the Commission has decided to switch over to the availability based incentive scheme for the thermal generating stations. This has been discussed separately. In coal based station we intend to keep the target availability for payment of incentive as the same as that of target availability for the recovery of full fixed charges.

17.0 Gas/Liquid Fuel based stations other than small gas turbine stations

17.1 The availability of the various Gas/Liquid fuel based generating stations NTPC in the last 5 years i.e. 2002-03 to 2006-07 is as follows:

NTPC's gas based station	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**
Auraiya	87%	89%	82%	91%	90%
Anta	88%	87%	86%	91%	88%
Dadri	83%	88%	89%	90%	85%
Kawas	82%	88%	91%	93%	95%
Jhanor Gandhar	64%	58%	71%	81%	82%
Faridabad	79%	96%	98%	95%	89%
Kayamkulam (RGCCP)	N.A.	N.A.	85%	96%	93%

17.2 The actual PLF of the various Gas/Liquid fuel based generating stations of NTPC and NEEPCO in the last 5 years i.e. 2002-03 to 2006-07 is as follows:

Station	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**
Auraiya	73%	73%	71%	74%	79%
Anta	75%	75%	76%	76%	80%
Dadri	72%	70%	75%	74%	77%
Kawas	73%	68%	49%	50%	63%
Jhanor Gandhar	47%	56%	70%	78%	79%
Faridabad	71%	74%	84%	78%	75%
Kayamkulam (RGCCP)	67%	67%	20%	11%	36%

17.3 The average availability and average PLF of the various Gas/Liquid fuel based generating stations of NTPC of the last 3 years i.e. 2004-05 to 2006-07 are as follows:

Station	**Availability**	**Actual PLF**
Auraiya	87%	75%
Anta	88%	77%
Dadri	88%	75%

Kawas	93%	54%
Jhanor Gandhar	78%	76%
Faridabad	94%	79%
Kayamkulam (RGCCP)	91%	22%

17.4 It can be seen that all the above plants of NTPC are maintaining availability from 87% to 94% except in case of Jhanor Gandhar GPS. However, Jhanor Gandhar has improved its availability gradually to 80.94% in year 2005-06 and 82.27% in year 2006-07. However, the actual PLFs are much lower than the respective availability. This indicates that the gas/liquid fuel based stations are not getting dispatch. The allocation of APM gas which is cheapest is sufficient to sustain operation of station around 70%. For operations above 70% level, dual fuel firing arrangements are in place in all gas/liquid fuel based stations of NTPC except in case of Gandhar. Due to High prices of liquid fuels i.e Naptha and HSD, NTPC was also purchasing spot gas which was relatively cheaper than the Naptha or HSD. The generator declares available capacity on day ahead basis for the station separately for APM gas (Gas on Administered Price mechanism), on LNG/spot gas and liquid fuel Naptha/HSD due to wide variation in prices of APM gas, spot gas, HSD and Naptha. The station is scheduled separately by the respective RLDCs. But due to very high prices of spot gas and HSD/Naptha beneficiaries do not ask for dispatch of capacity on spot gas/liquid fuel. Nevertheless, from the availability data, there is a case for increasing target availability norm for the gas/liquid based generating stations to 85% for the recovery of full Annual Fixed Charges (AFC) except in case of Gandhar GPS. The Gandhar GPS does not have duel fuel firing facility and does not have sufficient allocation and supplies from the Gandhar gas fields. NTPC has therefore, made arrangement for diverting about 3/4th of gas available for Kawas GPS from HBJ pipe line to Gandhar in 2000. But even after diversion of Kawas gas and supplementing generation from spot gas, this station has not been able to achieve a availability of 85%. Nevertheless, NTPC must try to arrange spot gas for the stations additionally to achieve a availability of 85%. As such, we are fixing the target availability norm for the Gandhar GPS at 85%.

17.5 In case of new gas/liquid fuel based stations, we intend to keep the target availability norms for the recovery of full fixed charges same as that of existing stations i.e. 85%.

18.0 Small Gas turbine stations of NEEPCO

18.1 The actual availability for the period 2002-03 to 2006-07 as achieved by the station is as below:

Station	2002-03	2003-04	2004-05	2005-06	2006-07	Average (last 3 years)
Assam GPS	66%	77%	78%	72%	72%	**74%**
Agartala GPS	NA	91%	83%	97%	94%	**91%**

18.2 It is observed that the Target Availability of 80% could not be achieved by the Assam GPS from 2002-03 to 2006-07. It is because the station is not getting required quantity of gas for availability declaration of 80%. The station was conceived for a performance level of 68.5% with an allocation of 1.0 MCMD of gas from Assam gas fields. In view of implementation of ABT in the north-eastern region from 1.11.2003, NEEPCO has tried to obtain additional linkage and supply of gas from MP&NG but could get only 0.4 MCMD of gas additionally on fall back basis w.e.f 13.1.2005. With 1.4 MCMD of gas a generation level of the order of 70% only is possible. Arranging of spot gas or any other alternate fuel in the remote north-eastern region is also not a feasible option. In this back drop, Commission themselves had taken up the matter of additional allocation with MP&NG which had expressed its inability to sanction more gas for the station. Further, the calorific value of gas over the years has deteriorated from 8510 Kcal/SCM in 1995-96 to 8278 Kcal/SCM in 2007-08. With the fall in calorific value, the quantum of gas required to maintain generation levels further increased. In view of above, there is a case for relaxation of target availability norm for the Assam GPS station. Accordingly, a target availability norm of 70% is allowed for the tariff period 2009-14.

18.3 In case of Agartala GPS, the station is able to achieve a average availability of 91% in last three years i.e. 2004-05 to 2006-07. As such, a target availability norm of 85% is allowed for the Agartala GPS.

18.4 The new small gas turbine stations, the target availability norm for the full recovery of fixed charges shall also be 85%.

18.5 As regard, Target availability norm for payment of incentive is concerned, the same shall be at 85% during peak hours (3 hours duration in a day to be specified by respective RLDC) over the year for all small gas turbine stations including Assam as well as Agartala GPS of NEEPCO.

19.0 Gross Station Heat Rate (SHR):

19.1 Coal/Lignite based thermal generating stations

19.1.1 Existing Provisions

The existing tariff regulations for tariff period 2004-09 as amended provide following norms of Gross Station Heat Rate for the thermal generating stations:

(a) Coal-based thermal power generating stations, other than those covered under clauses (b) & (c) below

200/210/250 MW sets	***500 MW and above sets***
2500 KCal/kWh	***2450 KCal/kWh***

Note 1

In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the gross station heat rate shall be 40 kCal/kWh lower than the station heat rate indicated above.

Note 2

For generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average station heat rate.

(b) Talcher Thermal Power Station 2975 kCal/kWh

(c) Tanda Thermal Power Station 2850 kCal/kWh

19.1.2 Through separate orders CERC allowed relaxed norms of gross station heat rates for Badarpur TPS of NTPC and thermal generating stations of DVC as follows:

(In kCal/kWh)

Station	***2006-07***	***2007-08***	***2008-09***
Badarpur TPS (3x95+2x210)	*2885*	*2885*	*2885*
Mejia(4x210)	*2625*	*2550*	*2500*
Bokaro (3x210);	*3250*	*2900*	*2770*
Chandrapura (3x130+3x120)	*3100*	*3100*	*3100*
Durgapur (1x210+1x140)	*3100*	*2940*	*2820*

19.1.3 For lignite based stations following are the existing norms:

"(1) For lignite-fired generating stations except for TPS-I and TPS-II (Stage I & II) of Neyveli Lignite Corporation Ltd, the gross station heat rates specified under clause (a) above for coal-based thermal power generating stations shall be corrected, using multiplying factors as given below:

(i) For lignite having 50% moisture: Multiplying factor of 1.10

(ii) For lignite having 40% moisture: Multiplying factor of 1.07

(iii) For lignite having 30% moisture: Multiplying factor of 1.04

(iv) For other values of moisture content, multiplying factor shall be pro-rated for moisture content between 30-40 and 40-50 depending upon the rated values of multiplying factor for the respective range given under sub-clauses (i) to (iii) above.

(2) TPS-I and TPS-II (Stage I & II) of Neveli Lignite Corporation Ltd

TPS-I 3900 kCal/kWh
TPS-II 2850 kCal/kWh"

19.2 The actual Station Heat Rate of the various coal/lignite based generating stations for the year 2002-03 to 2006-07 is as follow:

NTPC's station	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**
Dadri Coal(4x210)	2465	2462	2434	2421	2414
Kahalgaon(4x210 MW)	2480	2460	2453	2444	2433
Unchahar (2x210+2x210+1x210)	2459	2458	2451	2430	2410
Rihand St-I&II(4x500)	2392	2385	2376	2337	2360
Talcher (2x500+4x500)	2406	2414	2400	2376	2368
Simhadri (2x500)	2438	2404	2375	2361	2355
Singrauli (5x200+2x500)	2410	2410	2413	2401	2401
Korba (3X200+3X500)	2412	2419	2402	2379	2372
Farakka (3x200+2x500)	2474	2478	2530	2442	2434
Ramagundam (3x200+3x500+1x500)	2441	2442	2425	2406	2378

Vindhyachal Super Thermal Power Station (6x210+4x500)	2456	2458	2430	2400	2393
Badarpur(3x95+2x210)	2803	2789	2788	2765	2751
Talcher takenover(4x60+2x110)	3144	3000	2924	2914	2904
Tanda (4x110 MW)	3137	2846	2758	2753	2749
State Utilities/IPP Stations					
Raichur (7x210 MW)	2495	2510	2590	2592	2595
Bhatinda (2x210 MW)	2560	2531	2521	2548	2439
GGSS Roop Nagar (6x210 MW)	2582	2556	2559	2529	2549
Dahanu (2x250 MW)	2317	2210	2272	2298	2289

Lignite based stations					
NLC TPS-I	3925	3933	3981	3992	3920
NLC TPS-I(Exp.)	N.A.	3000	2848	2769	2751
NLC TPS-II(stage-I)	3031	3011	2886	2884	2895
NLC TPS-II (Stage-II)	2879	2883	2860	2874	2891
Surat Lignite	2514	2477	2546	2516	2563

19.3 The average gross station heat rate for last 3 years i.e. 2004-05 to 2006-07:

(KCal/kWh)

NTPC's station	**Norm**	**Actual SHR**
Dadri Coal(4x210)	2500	2423
Kahalgaon(4x210 MW)	2500	2443
Unchahar (2x210+2x210+1x210)	2500	2430
Rihand St-I&II(4x500)	2430	2358
Talcher (2x500+4x500)	2450	2382
Simhadri (2x500)	2450	2364
Singrauli (5x200+2x500)	2486	2405
Korba (3X200+3X500)	2475	2384
Farakka (3x200+2x500)	2480	2469
Ramagundam (3x200+3x500+1x500)	2471	2403
Vindhyachal (6x210+4x500)	2480	2408
Badarpur(3x95+2x210)	2885	2768
Talcher takenover(4x60+2x110)		2914
Tanda (4x110 MW)		2753
State Utilities/IPP Stations		
Raichur (7x210 MW)		2592
Bhatinda (2x210 MW)		2503
GGSS Roop Nagar (6x210 MW)		2546
Dahanu (2x250 MW)		2286
Lignite based stations		
NLC TPS-I	3900	3965
NLC TPS-I(Exp.)	2750	2790
NLC TPS-II(stage-I)	2850	2889
NLC TPS-II (Stage-II)	2850	2875
Surat Lignite		2542

19.4 The all the above coal based stations of NTPC are achieving the SHR below the normative SHR. The one of the reason for this is that the plant PLF is more than the 80% in fact in some cases it is around 90%. But if we see the other well maintain plants like Raichur, Bhatinda, Roop Nagar etc. of 210/250 MW series, the SHR is more than the 2500 kcal/kWh in the operating range of 80-85% PLF. The SHR of 2286 Kcal/kWh in Dahanu TPS could be because of sustained level of higher PLF of around 100% and more and maintaining of coal quality near design coal with the blending of imported coal. Further most of the NTPC 210 MW units are older units and would be approaching their useful life and would be due for R&M in next tariff period. It may therefore, not be advisable to reduce the SHR norm for the existing 210 MW units. However, in case of new 210 MW units coming up on or after 1.4.2009, it should be possible to achieve better heat rates due to improvement in pressure and temperature parameters. As such, for such new 210 MW units we intend to keep the station heat rate norm as 2450 kCal /kWh.

19.5 The 500 MW units on the other hand are relatively new and it would be reasonable to reduce station heat rate norm for them from 2450 kCal/kWh to 2400 kCal/kWh. For the new 500 MW units also same station heat rate norm is being kept.

19.6 Some developers are in the process of putting up the generating stations having unit sizes of 300/330/350 MW with almost same operating parameters of pressure and temperature as that of 500 MW units, and therefore, in respect of these unit sizes also the same SHR is allowed as in case of 500 MW units.

19.7 In case of super critical boiler technology stations having units size of 600/660 or more has got better efficiency than the 500 MW units due to higher pressure and temperature parameters. NTPC for its up coming Sipat and Barh thermal generating stations based on super critical technology has indicated following SHR:

Performance parameters	***Sipat-I***	***Barh-I***
Capacity	*3x660 MW*	*3x660 MW*
Station Heat Rate (kCal/kWh)	*2265*	*2305*

19.8 NTPC has suggested a operating margin of 7-8% for actual operating conditions. If we go by NTPC suggestion then the SHR for such stations would work out between 2423 to 2489 kcal/kWh. This is some thing close to 500 MW based on sub-critical technology. As such, we are unable to accept NTPC suggestion.

19.9 CEA had constituted a Committee to recommend the next higher unit Size for coal fired thermal power stations which submitted its report in November 2003. Committee recommended 800 MW and 1000 MW unit sizes as the next higher unit sizes based on super critical technology with pressure and temperature of 246 kg/cm2 and 566/593 0C respectively out of the following makes in different design segment of pressure and temperatures.

Pressure	***Temperture (MS/RH)***	***Efficiency***
(kg/cm^2)	***^{0}C***	***(%)***
169	*538/538*	*38.60*
246	*538/538*	*39.29*
246	*538/566*	*39.56*
246	*566/566*	*39.91*
246	*566/593*	*40.24*
246	*600/600*	*40.56*

19.10 The unit size is not point of contention here. The important point here is that the design of generating units available in this class varies from manufacturer to manufacturer. Such units are being installed for the first time in the country and performance under Indian conditions is not established. On these considerations, it would be reasonable to allow a SHR norm of 2350 Kcal./kWh for such units of 660/660 MW and above based on super critical technology after due consideration of variation in operating conditions and variation in quality of coal.

19.11 In case of NLC stations, It can be seen that actual heat rates are slightly higher than the norms during the previous 3 year of operation. The higher heat rate in case of TPS-II could be attributed to the low PLF. The higher heat rate in case of TPS-I is stated to be on account of more forced and partial outages of the very old units of TPS-I. The decision to continue with these old units or to phase them out rest with NLC. On our part, we are not inclined to relax the norm any further for TPS-I. The higher SHR for TPS-I (Expansion) is not justified and we would like to retain it. In view of this the present station heat rate norms for the NLC generating stations would continued for the next tariff period also.

19.12 In case of Badarpur TPS actual average SHR of last three year is worked out as 2768 Kcal./kWh as against present norm of 2885 Kcal./kWh. There appears to be a scope for reduction in SHR norm and therefore, we are of the view that a SHR norm of 2825 Kcal./kWh would be sufficient for Badarpur TPS. In case of Tanda and Talcher TPS gross heat rate norms have been specified a year back and we intend to retain the same for the next tariff period.

19.13 DVC was allowed progressively improving norms from 2006-07 and onwards allowing them time to improve upon their performance. The norms of Station heat rate to be achieved for generating stations of DVC for 2008-09 are as follows:

Mejia (3x210 MW)	2500
Bokaro (3x210);	2770
Chandrapura (3x130+3x120)	3100
Durgapur (1x210+1x140)	2820

19.14 The actual **SHR** of DVC's stations for the years 2002-03 to 2006-07 are as below:

Station	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**
Mejia(4x210)	3217	3285	2969	2575	2514
Bokaro (3x210);	3651	3703	3744	3366	3290
Chandrapura (3x130+3x120)	4479	3595	3378	3324	3228
Durgapur (1x210+1x140)	3556	3569	3491	3169	3069

19.15 It can be seen that DVC is yet to achieve the norms specified by the CERC for the year 2008-09. As such, we are specifying the same norms of 2008-09 to be adopted for the tariff period 2009-14.

20.0 Gas/Liquid Fuel based Stations other than small gas turbine stations

20.1 Existing Norms

20.1.1 The existing tariff regulations for tariff period 2004-09 as amended provide following norms of Gross Station Heat Rate for the gas/liquid fuel based thermal generating stations:

(e) Gas Turbine/Combined Cycle generating stations

(i) Existing generating stations owned by National Thermal Power Corporation Ltd

Name of Generating station	Combined cycle (kCal/kWh)	Open cycle (kCal/kWh)

Gandhar GPS	2000	2900
Kawas GPS	2075	3010
Anta GPS	2075	3010
Dadri GPS	2075	3010
Auraiya GPS	2100	3045
Faridabad GPS	2000	2900
Kayamkulam GPS	2000	2900

(ii) Generating stations declared under commercial operation on or after 1.4.2004

	Advanced Class Machines	**E/EA/EC/E2 Class Machines**
Open cycle	2685 kCal/kWh	2830 kCal/kWh
Combined cycle	1850 kCal/kWh	1950 kCal/kWh

20.2 The actual gross station heat rate (SHR) for Gas/liquid fuel based generating stations of NTPC from 2002-03 to 2006-07 are as under:

Station	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**
Auraiya	2072	2096	2079	2089	2068
Anta	2017	2085	2058	2067	2032
Dadri	1970	1998	1982	1967	1947
Kawas	1996	2017	1998	2008	1987
Jhanor Gandhar	1934	1958	1997	2018	2026
Faridabad	1935	1909	1875	1885	1904
Kayamkulam (RGCCP)	1977	1980	1972	1986	1960

20.3 The averages gross station heat rates (SHR) for Gas/liquid fuel based generating stations of NTPC from 2004-05 to 2006-07 as against the norms are as under:

Station	Actual PLF	Norm	Avg. SHR
Auraiya	75%	2100	2079
Anta	77%	2075	2052
Dadri	75%	2075	1965
Kawas	54%	2075	1998
Jhanor Gandhar	76%	2000	2014
Faridabad	79%	2000	1888
Kayamkulam (RGCCP)	22%	2000	1973

20.4 It can be seen that all the above gas/liquid fuel based stations of NTPC have been able to maintain station heat rate within the norm despite low station PLF level in the last three years. This may be due to operation of modules on optimum levels due to availability of spot gas.

20.5 The allocation of APM gas which is cheapest is sufficient to sustain operation of station around 70%. For operations above 70% level, dual fuel firing arrangements are in place in all gas/liquid fuel based stations of NTPC except in case of Gandhar. Due to High prices of liquid fuels i.e Naptha and HSD, NTPC was also purchasing spot gas which was relatively cheaper than the Naptha or HSD.

20.6 The generator declares available capacity on day ahead basis for the station separately for APM gas (Gas on Administered Price mechanism), on LNG/spot gas and liquid fuel Naptha/HSD due to wide variation in prices of APM gas, spot gas, HSD and Naptha. The station is scheduled separately by the respective RLDCs. But due to very high prices of spot gas and HSD/Naptha beneficiaries do not ask for dispatch of capacity on spot gas/liquid fuel.

20.7 The Gandhar GPS does not have duel fuel firing facility and does not have sufficient allocation and supplies from the Gandhar gas fields. NTPC has therefore, made arrangement for diverting about 3/4th of gas available for Kawas GPS from HBJ pipe line to Gandhar in 2000.

20.8 On all these considerations, we are not inclined to change the SHR norm for the gas/Liquid fuel based stations.

20.9 In case of new gas/liquid fuel based stations, though there is reported improvement in the efficiency levels but due to paucity of gas in the country and very high prices of liquid fuels we do not anticipate high performance level for new generating stations based on liquid fuel and as such, we intend to retain present SHR norms for the new gas/liquid fuel based stations for the tariff period 2009-14.

21.0 Small gas turbine stations

21.1 Existing Norms

21.1.1 The existing tariff regulations for tariff period 2004-09 as amended provide following norms of Gross Station Heat Rate for the small gas turbine generating stations:

(iii) Small Gas Turbine Power Generating Stations:

(a) Assam Gas Based Power Station, Kathalguri:

Open Cycle -- 3225 kCal/kWh

Combined Cycle -- 2250 kCal/kWh

(b) Agartala Gas Based Power Station, Ramachandranagar:

Open Cycle -- 3580 kCal/kWh

(c) Other than (a) and (b) above:

	With Natural Gas	**With Liquid Fuel**
Open Cycle	3125 kCal/kWh	1.02 x 3125 kCal/kWh
Combined Cycle	2030 kCal/kWh	1.02 x 2030 kCal/kWh

21.2. The actual SHR achieved by the small gas turbine stations of NEEPCO namely Assam GPS and Agartala GPS for 2002-03 to 2006-07 are as follows:

(kCal/kWh)

Station	2002-03	2003-04	2004-05	2005-06	2006-07
Assam GPS	2736	2329	2417	2322	2376
Agartal GPS	3637	3582	3437	3370	3463

21.3 The averages gross station heat rates (SHR) for small gas turbine stations of NEEPCO from 2004-05 to 2006-07 as against the norms are as under:

(kCal/kWh)

Station	Norms	Average SHR
Assam GPS	2250	2372
Agartal GPS	3580	3454

21.4 The reasons for higher actual station heat rate (SHR) than the normative in case of Assam GPS are stated to be part load / low load operation due to non availability of adequate gas, deteriorating quality of gas and frequent shutdown because of gas booster problems resulting from low gas pressure. As discussed earlier, there appears to be no possibility of getting additional gas. As such, we are relaxing the SHR norm for the Assam GPS to 2400 kCal/kWh for the tariff period 2009-14.

21.5 It can be seen that average actual heat rate in the last 3 years is well below the normative of 3580 kcal/kWh. The reason for improved actual heat rate is because of gradual improvement in actual PLF. As confirmed by NEEPCO that there is no constraint in gas supply to this station we believe that, if not better than the present, at least the same trend of actual PLF could be maintained by the station in the next tariff period also. Hence, it is considered that there is scope for improved norm of heat rate of 3500 kcal/kWh even after keeping margin for externalities to keep a balance in the interest of the generator as well the consumer. Accordingly, station heat rate norm for Agartal GPS would be 3500kcal/kWh for the tariff period 2009-14.

21.6 For the new small gas turbine stations the same norms are being retained for the next tariff period.

22.0 Secondary fuel oil consumption

22.1 Existing Provisions

22.1.1 The existing regulations for tariff period 2004-09 as amended provide following norms for the specific fuel oil consumption for the coal/lignite based thermal generating stations:

	Description	During Stabilizatio	Subsequent period

		n period	
(a)	Coal-based generating stations:		
(i)	All coal-based thermal power generating stations except those covered under sub-clauses (ii) and (iii) below	4.5 ml/kWh	2.0 ml/kWh
(ii)	Talcher Thermal Power Station (w.e.f 1.4.2007)		2.0 ml/kWh
(iii)	Tanda Thermal Power Station (w.e.f 1.10.2007)		2.0 ml/kWh
(b)	Lignite-fired generating stations	5.0 ml/kWh	3.0 ml/kWh

22.1.2Through separate tariff orders, CERC allowed following relaxed norms of specific fuel oil consumption for the thermal Generating stations of Damodar Valley Corporation (DVC) and Badarpur TPS of NTPC:

(ml/kWh)

stations	2006-07	2007-08	2008-09
Mejia(4x210)	3.25	2.50	2.00
Bokaro (3x210);	3.50	2.75	2.00
Chandrapura (3x130+3x120)	3.00	3.00	3.00
Durgapur (1x210+1x140)	3.00	3.00	3.00
Badarpur TPS (3x95+2x210)	2.60	2.60	2.60

22.2 The actual specific fuel oil consumption of the various coal/lignite based generating stations of NTPC, NLC and some of the State utilities and IPPs for 2002-03 to 2006-07 are as given below:

Station	2002-03	2003-04	2004-05	2005-06	2006-07
Dadri Coal(4x210)	0.44	0.17	0.16	0.21	0.11
Kahalgaon(4x210 MW)	0.63	0.54	0.53	0.41	0.61
Unchahar (2x210+2x210+1x210)	0.64	0.50	0.43	0.36	0.27
Rihand St-I&II(4x500)	0.22	0.22	0.17	0.25	0.17

Talcher (2x500+4x500)	0.46	0.83	0.65	0.50	0.27
Simhadri (2x500)	NA	0.66	0.23	0.19	0.19
Singrauli (5x200+2x500)	0.18	0.23	0.30	0.31	0.44
Korba (3X200+3X500)	0.24	0.21	0.11	0.11	0.10
Farakka (3x200+2x500)	1.78	1.94	2.42	0.94	0.90
Ramagundam (3x200+3x500+1x500)	0.21	0.23	0.17	0.24	0.19
Vindhyachal Super Thermal Power Station (6x210+4x500)	0.21	0.18	0.16	0.15	0.14
Badarpur(3x95+2x210)	0.42	0.30	0.33	0.34	0.42
Talcher takenover(4x60+2x110)	1.60	1.55	0.78	0.40	0.44
Tanda (4x110 MW)	2.12	0.99	0.74	0.62	0.40
Others					
Raichur (7x210 MW)	1.10	0.73	0.60	0.75	0.44
Bhatinda (2x210 MW)	0.63	0.32	0.24	0.37	0.33
GGSS Roop Nagar (6x210 MW)	1.28	0.91	0.97	0.61	0.44
Dahanu (2x250 MW)	0.31	0.11	0.14	0.18	0.12
Lignite based stations					
NLC TPS-I	3.62	1.42	3.03	3.46	3.43
NLC TPS-I(Exp.)	N.A.	5.42	1.57	1.38	1.07
NLC TPS-II(stage-I)	0.79	1.21	0.92	1.53	0.79
NLC TPS-II (Stage-II)	2.73	0.41	1.05	1.08	0.89
Surat Lignite	1.40	1.22	0.96	0.69	1.13

22.3 The average specific fuel oil consumption of the various coal/lignite based generating stations of NTPC, NLC and some of the State utilities and IPPs for 2004-05 to 2006-07 are as given below:

(ml/kWh)

Station	**Average SFC**
Dadri Coal(4x210)	0.16
Kahalgaon(4x210 MW)	0.52
Unchahar (2x210+2x210+1x210)	0.36
Rihand St-I&II(4x500)	0.20
Talcher (2x500+4x500)	0.48
Simhadri (2x500)	0.20
Singrauli (5x200+2x500)	0.35
Korba (3X200+3X500)	0.11
Farakka (3x200+2x500)	1.42

Ramagundam (3x200+3x500+1x500)	0.20
Vindhyachal (6x210+4x500)	0.15
Badarpur(3x95+2x210)	0.36
Talcher takenover(4x60+2x110)	0.54
Tanda (4x110 MW)	0.59
Others	
Raichur (7x210 MW)	0.60
Bhatinda (2x210 MW)	0.31
GGSS Roop Nagar (6x210 MW)	0.68
Dahanu (2x250 MW)	0.15
Lignite based stations	
NLC TPS-I	3.31
NLC TPS-I(Exp.)	1.34
NLC TPS-II(stage-I)	1.22
NLC TPS-II (Stage-II)	0.72
Surat Lignite	0.93

22.4 It can be seen that the average specific fuel oil consumption of all the above coal based generating stations for the last 3 years varies between 0.15 to 0.68 ml/kWh except Farakka TPS irrespective of unit size. It is because most of the stations are operating above 80% PLF. In case of Farkka TPS, the average of last 3 year is 1.42 Ml/kWh but in years 2005-06 and 2006-07 average specific fuel oil consumption is less than 1.0 Ml/kWh with PLF of about 82%. As such, we are reducing the specific fuel consumptions norms of coal based stations to 1 ml/kWh except for the coal based stations of DVC as discussed below.

22.5 In case of lignite based stations of NLC, the average actual specific fuel oil consumption in the last three(3) years for all the stations is around 1.01 ml/kWh to 1.34ml/kWh except NLC TPS-I which is 3.31 ml/kWh. In case of Surat lignite stations last 3 years average is 0.93 ml/kWh and it is a new stations. The reason for higher oil consumption in case of TPS-I is that units of this station are more than 40 years old, the unit efficiency is low and secondary fuel consumption is high. In view of this, in case of TPS-I, specific fuel consumption of 3.5 ml/kWh is being allowed. However, oil consumption in other lignite based stations is significantly lower than the present norm. As such, there is scope for reducing the norms for specific fuel oil consumption to 2.0 ml/kWh for lignite based stations in the next tariff period.

22.6 The actual specific fuel oil consumptions of DVC's plant for 2002-03 to 2006-07 are as given below:

Station	2002-03	2003-04	2004-05	2005-06	2006-07
Mejia(4x210)	6.29	5.20	4.85	3.25	3.92
Bokaro (3x210);	5.93	4.01	3.59	3.14	2.39
Chandrapura (3x130)	0.35	4.94	2.61	0.95	1.83
Durgapur (1x210+1x140)	13.19	9.57	7.29	3.36	3.15

22.7 It can be seen that only Chandrapura TPS has been able to achieve the SFC in 2006-07 below the norm of 2008-09. The other stations of DVC are still to achieve norms for 2008-09 specified by the Commission. As such, the norms for DVC stations of 2008-09 are being retained for the next tariff period except for chandrapura TPS for which a norm of 2 ml/kWh shall be adopted for tariff period 2009-14.

23.0 Auxiliary Energy Consumption

23.1 Coal/Lignite based thermal generating stations

23.1.1 Existing Provisions

23.1.1.1 The existing regulations for tariff period 2004-09 as amended provide following norms for the Auxilliary Energy Consumption for the coal/lignite based thermal generating stations:

		With cooling tower	Without cooling tower
(a)	Coal-based generating stations:		
(i)	200 MW series	9.0%	8.5%
(ii)	500 MW series		
	Steam driven boiler feed pumps	7.5%	7.0%
	Electrically driven boiler feed pumps	9.0%	8.5%
(iii)	Talcher Thermal Power Station (w.e.f. 1.10.2007)	10.5%	
(iv)	Tanda Thermal Power Station (w.e.f. 1.4.2007)	12.0%	

(c)	Lignite-fired thermal power generating stations:		
(i)	All generating stations, except TPS-I and TPS-II (Stage I & II) of Neyveli Lignite Corporation Ltd:	The auxiliary energy consumption norms shall be 0.5 percentage point more than the above auxiliary energy consumption norms of coal-based generating stations at (v) (a) (i) & (ii) above.	
(ii)	TPS-I & TPS-II Stage-I&II of NLC		
	TPS-I	12%	
	TPS-II	10%	

23.1.1.2 Through separate tariff orders, CERC allowed following relaxed norms of auxiliary energy consumption for the thermal Generating stations of Damodar Valley Corporation (DVC) and Badarpur TPS of NTPC:

Station	2006-07	2007-08	2008-09
Mejia(4x210)	11%	9.6%	9%
Bokaro (3x210);	10.5%	10.25%	10.25%
Chandrapura (3x130+3x120)	11%	11%	11%
Durgapur (1x210+1x140)	11.5%	10.7%	10.5%
Badarpur (3x95+2x210)	11.0	11.0	11.0

23.1.2 The actual Auxiliary Energy Consumption (AEC) of the various coal/lignite based staions thermal generating stations for 2002-03 to 2006-07 are as given below :

Station	2002-03	2003-04	2004-05	2005-06	2006-07
Dadri Coal(4x210)	8.00%	8.05%	7.35%	7.39%	7.45%
Kahalgaon(4x210 MW)	9.56%	9.64%	8.88%	8.51%	8.58%
Unchahar (2x210+2x210+1x210)	8.76%	8.93%	8.58%	8.37%	8.18%
Rihand St-I&II(4x500)	8.03%	7.65%	7.98%	7.30%	6.49%
Talcher (2x500+4x500)	7.11%	7.49%	6.82%	5.75%	5.39%
Simhadri (2x500)	6.01%	6.18%	5.65%	5.65%	5.56%
Singrauli (5x200+2x500)	6.86%	6.92%	6.96%	7.11%	7.24%
Korba (3X200+3X500)	6.15%	6.68%	6.59%	6.52%	6.11%
Farakka (3x200+2x500)	8.02%	8.16%	8.50%	7.00%	6.67%

Ramagundam (3x200+3x500+1x500)	6.50%	6.63%	6.89%	6.40%	6.21%
Vindhyachal (6x210+4x500)	7.00%	7.19%	7.01%	7.06%	7.13%
Badarpur(3x95+2x210)	9.15%	9.68%	9.04%	8.84%	8.05%
Talcher takenover(4x60+2x110)	11.47%	10.73%	10.58%	10.07%	10.19%
Tanda (4x110 MW)	13.84%	12.88%	12.00%	11.92%	11.34%
Others					
Raichur (7x210 MW)	8.50%	8.50%	8.69%	8.63%	8.21%
Bhatinda (2x210 MW)	8.97%	8.91%	9.42%	8.97%	8.80%
GGSS Roop Nagar (6x210 MW)	8.26%	8.33%	8.57%	8.51%	8.38%
Dahanu (2x250 MW)	7.41%	7.33%	7.52%	7.59%	7.65%
Lignite based stations					
NLC TPS-I	11.57%	11.51%	11.41%	11.27%	11.55%
NLC TPS-I(Exp.)	N.A.	9.78%	9.05%	9.08%	8.47%
NLC TPS-II(stage-I)	9.70%	9.69%	9.85%	9.68%	9.40%
NLC TPS-II (Stage-II)	9.63%	9.40%	9.74%	9.75%	9.73%
Surat Lignite	11.21%	11.30%	11.37%	11.14%	11.18%

23.1.3 The average Auxiliary Energy Consumption (AEC) of the various coal/lignite based staions thermal generating stations for 2004-05 to 2006-07 are as given below:

NTPC's station	**Norm**	**Actual AEC**
Dadri Coal(4x210)	9.00%	7.40%
Kahalgaon(4x210 MW)	*9.00%*	8.66%
Unchahar (2x210+2x210+1x210)	*9.00%*	8.38%
Rihand St-I&II(4x500)	7.50%	7.26%
Talcher (2x500+4x500)	7.50%	5.99%
Simhadri (2x500)	7.50%	5.62%
Singrauli (5x200+2x500)	8.57%	7.10%
Korba (3X200+3X500)	8.25%	6.41%
Farakka (3x200+2x500)	8.40%	7.39%
Ramagundam (3x200+3x500+1x500)	*8.14%*	6.50%
Vindhyachal (6x210+4x500)	*8.40%*	7.07%
Badarpur(3x95+2x210)	*11.00%*	8.64%
Talcher takenover(4x60+2x110)	*10.50%*	10.28%

Tanda (4x110 MW)	*12.00%*	11.75%
Others		
Raichur (7x210 MW)		8.51%
Bhatinda (2x210 MW)		9.06%
GGSS Roop Nagar (6x210 MW)		8.49%
Dahanu (2x250 MW)		7.59%
Lignite based stations		
NLC TPS-I	12.00%	11.41%
NLC TPS-I(Exp.)	9.50%	8.87%
NLC TPS-II(stage-I)	10.00%	9.64%
NLC TPS-II (Stage-II)	10.00%	9.74%
Surat Lignite		11.23%

23.1.4 In case of coal based stations, the auxiliary energy consumption (AEC) of all the above plants of NTPC are below the normative auxiliary energy consumption. This is again perhaps because of station performance above 80% PLF. If we go by the unit sizes then stations with units of 210/200 MW alone have AEC between 7.40% to 8.66% and stations having units of 500 MW alone have AEC between 5.62% to 7.10%. Similarly stations having combination of 500/200/210 MW units also have similar margins. But in case of some of the state utilities stations namely Raichur, Bhatinda, Roop Nagar etc. the AEC varies between 8.49% to 9.01%. There appears to be scope to bring down the Normative AEC for the next tariff period by 0.5% point across the board.

23.1.5 Some of the developers are in the process of putting up the plant having the size of 300/330/350 MW with almost same operating parameters of pressure and temperature as that of 500 MW units however number of units would be more due to smaller unit size are provided with slightly higher aux energy consumption of 0.5% point over aEC norm of 500 MW units.

23.1.6 In case of super critical boiler technology stations having units size of 600/660 or more has got better efficiency than the 500 MW units due to higher pressure and temperature parameters. NTPC has indicated following aux energy consumption for its up coming stations:

Performance parameters	***Sipat-I***	***Barh-I***
Capacity	*3x660 MW*	*3x660 MW*
Aux energy Consumption (%)	*5.65*	*5.75*

23.1.7 The above appears to be unit aux. energy consumptions. Such units are being installed for the first time in the country and performance under Indian conditions is not established. Therefore, Commission has the view that normative AEC proposed for the 500 MW units size shall be applicable for such units also.

23.1.8 In case of Badarpur TPS, Talcher TPS and Tanda TPS which has been taken over by NTPC from different entities, Commission have plant specific norms. The R&M works in case of Tanda & Talcher is almost complete and Commission has already reviewed the norms incase of Tanda and Talcher TPS w.e.f. 1.4.2007 and 1.10.2007 respectively based on the performance over last 3 year period. Therefore, Commission is of the view that the present norm specified for these stations shall continue for the next tariff period.

23.1.9 In case of Badarpur TPS actual average of last three year of AEC is 8.6% as against present norm of 11%. Therefore, Commission is reducing norm of AEC to 9% for the Badarpur TPS.

23.1.10 The actual auxiliary energy consumption (AEC) of DVC's stations for 2002-03 to 2006-07 is as given below:

Station	**2002-03**	**2003-04**	**2004-05**	**2005-06**	**2006-07**
Mejia(4x210)	12.81%	10.94%	11.02%	10.58%	10.47%
Bokaro (3x210);	11.54%	11.80%	11.48%	11.34%	11.11%
Chandrapura (3x130+3x120)	18.56%	15.75%	12.23%	11.54%	11.22%
Durgapur (1x210+1x140)	14.26%	11.95%	12.82%	11.67%	11.05%

23.1.11 It can be seen that DVC stations are yet to achieve the norms specified for them for the year 2008-09 and as such, we are retaining the norms of 2008-09 for the tariff period 2009-14.

23.1.12 In case of lignite based stations, actual auxiliary consumption of all the NLC stations are with in the norm fixed for the current tariff period 2004-09. However, in case of NLC TPS-I (Exp.) auxiliary consumption is 8.87 % which is much below the present norm of 9.5%. As such, the normative auxiliary consumption for NLC TPS-I(Exp.) has been reduced to 9% for the next tariff period. Also in view of reduced AEC in new TPS-I (Expansion), AEC norm shall continue to be 0.5% point lower than the respective coal based stations for the new lignite based stations.

23.1.13 Whereas for other lignite based stations of NLC, we retaining the existing norms for the next tariff period 2009-14. keeping normative of other lignite based generating stations shall remain same for next tariff period.

23.2 Gas/Liquid Fuel based Stations

23.2.1 Existing Provisions

23.2.1.1 The existing regulations for tariff period 2004-09 as amended provide following norms for the Auxilliary Energy Consumption for the gas/liquid fuel based thermal generating stations:

(b) Gas Turbine/Combined Cycle generating stations:

(i) Combined cycle 3.0%

(ii) Open cycle 1.0%

23.2.2 The actual auxiliary energy consumption (AEC) for Gas/liquid fuel based power generating stations of NTPC and NEEPCO are as under:

Station	2002-03	2003-04	2004-05	2005-06	2006-07
Auraiya	1.89%	1.91%	1.81%	1.80%	1.80%
Anta	2.87%	2.56%	2.73%	2.52%	2.13%
Dadri	2.72%	2.57%	2.52%	2.32%	2.20%
Kawas	1.76%	2.22%	2.40%	2.19%	1.74%
Jhanor Gandhar	2.22%	2.33%	2.03%	1.95%	1.95%
Faridabad	2.11%	2.19%	1.97%	2.31%	2.27%
Kayamkulam (RGCCP)	2.16%	2.3%	4.03%	6.18%	2.6%
Assam GPS	3.23%	2.83%	2.94%	2.88%	2.86%
Agartal GPS	1.77%	1.42%	0.89%	0.40%	0.58%

23.2.3 The average auxiliary energy consumption (AEC) for Gas/liquid fuel based power generating stations of NTPC and NEEPCO for 2004-05 to 2006-07 are as under:

Station	Actual AEC

Auraiya	1.80%
Anta	2.46%
Dadri	2.35%
Kawas	2.11%
Jhanor Gandhar	1.98%
Faridabad	2.18%
Kayamkulam (RGCCP)	4.27%
Assam GPS	2.90%
Agartal GPS	0.62%

23.2.4 In case of Gas/liquid fuel based stations of NTPC, the Weighted Average of actual auxiliary consumption is below the existing AEC norm of 3% for combined cycle operation except in case of Kayamkulam GPS. Even in small gas turbine station of assam GPS it is lower than 3%. In case of Agartal GPS which operates on open cycle actal is 0.62% gainst norm of 1%. In Kayamkulam higher AEC is because of very low operation levels. In the present circumstances of paucity of gas and high prices of liquid fuel, Commission is for the continuation with the present norm of 3% for AEC for combined cycle operation and 1% for the open cycle operation for next tariff period.

23.3 Operational Norms for Lignite based stations using Circulating Fluidized Bed Combustion (CFBC) Technology

23.3.1 NLC through a separate petition had sought to specify norms of operation for its Lignite based stations in Rajasthan based on CFBC technology. NLC has sought following norms:

Station	Norms claimed
Capacity (MW)	2x125
Availability/PLF (%)	75
Station Heat Rate (kCal/kWh)	2587
Aux energy Consumption (%)	12.00
Specific Fuel Consumption (ml/kWh)	3.00
Lime Stone Consumption (Kg/kWh)	0.05

23.3.2 Rajasthan Electricity Regulatory Commission has allowed following norms of operation for its Jalipa Kapurdi Station lignite based thermal generating station and actual average performance of Surat Lignite Station for three years (2004-05 to 2006-07) is as follow:

	Surat Lignite	Jalipa Kapurdi (RERC Norm)
Capacity (MW)	125	8x125 MW
Availability/PLF (%)	85/83	80
Station Heat Rate (kCal/kWh)	2542	2600
Aux energy Consumption (%)	11.23%	9.50
Specific Fuel Consumption (ml/kWh)	0.93	3.00
Lime Stone Consumption (Kg/kWh)	N.A.	Factored in Fixed Cost

23.3.3 The SHR norm specified by RERC is based on SHR of 2550 for lignite having 30% Moisture whereas norm of 2587 kCal/kWh sought by NLC is subject to correction for moisture content above 30% as per the factors specified for other lignite based stations. The actual average SHR of Surat Lignite TPS is lower than the normative SHR prescribed by RERC for Jalipa Kapurdi Station lignite based thermal generating station. The actual average of SFC is order of 1 ml/kWh and less than the normative SFC prescribed by RERC for Jalipa Kapurdi Station lignite based TPS of 3ml/kWh. The auxiliary energy consumption norm of 9.5% specified by RERC appears to be on lower side for a configuration of 2x125 MW as comparison to actual performance of Surat Lignite TPS. The Target Availability norm of 75% sought by NLC is also on lower side. As such, we are allowing following norms of operation for CFBC Technology based lignite fired stations:

Station	Norms
Availability/PLF (%)	80
Station Heat Rate (kCal/kWh)	2550#
Aux energy Consumption (%)	12.00
Specific Fuel Consumption (ml/kWh)	2849.00
Lime Stone Consumption (Kg/kWh)	0.05 kg/kWh to be factored in Fixed Cost

corresponding to 30% moisture and subject to adjustment for moisture content.

24.0 Provisions relating to hydro generating stations

24.1 The Commission vide order dated 8.2.2008 in Suo Motu petition no. 67/2003 had proposed amendment of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2004 in respect of hydro-electric generating stations. The Commission had invited comments and suggestions from the stakeholders on these draft amendment. The Explanatory Memorandum to the said order discussed in detail the need causing amendment to the existing hydro tariff formulation.

24.2 In these draft amendments new concepts of Normative Annual Plant Availability Factor (NAPAF), Capacity Charge Rate and Energy Charge Rate were proposed to be introduced. The generating companies namely, National Hydro-electric Power Corporation Limited, Satluj Jal Vidyut Nigam Limited, Tehri Hydro Development Corporation Limited, North-Eastern Electric Power Corporation Limited, Narmada Hydroelectric Development Corporation and Damodar Valley Corporation were directed to furnish by 7.3.2008, the information in respect of each of its hydro-electric generating station presently in operation, to enable the Commission to take a view on the determination of values of Normative Annual Plant Availability Factor, Capacity Charge Rate and Energy Charge Rate, proposed to be introduced.

24.3 Based on the information made available by the generating companies regarding weighted average of daily peaking capability/ declared capacities of their hydro plants during the last 4-5 years, the average ' Plant availability Factor' of each station has been assessed .

24.4 Following criteria / methodology has been applied for arriving at NAPAF of different hydro stations:

i) On the basis of performance data made available by various hydro generating companies for the period 2003-04 to 2007-08, actual plant availability of each station has been worked out. Chamera-I and Chamera-II stations of NHPC who have consistent performance in terms of providing peaking capability during last four years with no major siltation related problems are considered as benchmark. Normative plant availability factor (NAPAF) of these stations has been considered at 90%.

ii) Stations like Bairasiul, Rangit, Teesta – V, Dhauliganga who have major silt problems during monsoon period have been allowed a margin of 5%. NAPAF of these stations has been considered at 85%.

iii) For ROR type plants of NHPC not meant for peaking, actual plant availability factor is based on their average annual declared capacity for 5 years. It varies between 55-60%. NAPAF has been considered accordingly.

iv) In case of Indira Sagar whose avg. annual peaking capability data is available for one year only, peaking capability as provided by the project authorities has been considered.

v) In case of Tehri stg-I, since plant has not operated for full one year, the peaking capability as provided by the project authorities has been considered.

vi) In case of Nathpa Jhakri, peaking capability based on CEA approved design energy of downstream Rampur plant has been considered and NAPAF worked out accordingly.

vii) For NEEPCO stations which are mostly storage type schemes, their performance has been below par, varying from 57% to 80%. In these stations 5% additional margin over and above benchmark stations of NHPC, has been given and their NAPAF has been considered at 80%. Khandong-I (50 MW) and Kopili-II (25 MW) has been considered as a single plant for the purpose of NAPAF.

viii) In case of DVC, although benchmark value of NAPAF for storage type plant is 85%, these stations being very old (50 years approx.), 5% additional margin has been provided and NAPAF has been fixed at 80%.

24.5 In view of above, the Normative Annual Plant Availably Factor (NAPAF) in respect of various stations of the hydro generating companies shall be as given in the following table :

Station	Type of Station	Installed Capacity (MW)	Plant availability factor (%)		Capacity Charge Apportioning Factor (CCAF)
			Actual		(%)

				(Normative)	
NHPC					
Chamera -I	Pondage	540	95.0%	90%	50%
Biarasul	Pondage	180	91.7%	85%	50%
Loktak	Storage	90(Derated)	90.7%	90%	50%
Chamera-II	Pondage	300	93.1%	90%	50%
Rangit	Pondage	60	84.0%	85%	50%
Dhauliganga	Pondage	280	88.0%	85%	50%
Teesta-V	Pondage	510	N.A.	85%	50%
Dulhasti	Pondage	390	95%	90%	70%
Salal	ROR	690	57.1%	60%	50%
Uri	ROR	480	62.7%	60%	50%
Tanakpur	ROR	94.2	58.2%	55%	50%
NHDC					
Indirasagar	Storage	1000	85.8%	85%	50%
Omkareshwar	Storage	520	N.A.	90%	50%
THDC					
Tehri	Storage	1000	N.A	77%	70%
			`		
SJVNL					
NathpaJhakri	Storage	1500	77.5%	82%	50%
			(2 years)		
NEEPCO					
Kopili Stg - I	Storage	200	68.0%	80%	50%
Khandong I & II	Storage	75	80.0%	80%	50%
Doyang	Storage	75	57%	80%	50%
Ranganadi	Pondage	405	86%	85%	50%
DVC					
Panchet	Storage	80	86%	80%	50%
Tilaiya	Storage	4	N.A	80%	50%
Maithon	Storage	63.2	83%	80%	50%

24.6 The Capacity Charge Apportionment Factor (CCAF) has been considered as 50% for recovery of normative capacity charge of hydro stations. Thus recovery of capacity and energy charges shall be on 50:50 basis. This formulation has been found to be appropriate for most of the hydro stations. However, in case of Tehri HEP (THDC) and Dulhasti (NHPC), the prevalent composite energy rate works out to Rs. 5 /kwh and Rs. 4.72 / kwh respectively. The 50:50 formulation would cause the rate of energy generated over and above the design energy of the station to be very high i.e. Rs. 2.50 /kwh for Dulhasti and Rs. 2.36 / kwh for Tehri respectively. To curtail excess rate of energy generated above the scheduled energy, Capacity Charge Apportionment Factor (CCAF) for Dulhasti, and Tehri hydro stations shall be fixed at 70%. Thus in such cases, where composite energy rate is above Rs. 3.00 /kwh , recovery of capacity and energy charges shall be on 70:30 basis.

25.0 **Revised Scheme of Incentive and Disincentive for Thermal Generating Stations**

25.1 Historically incentive and disincentive in case of thermal generating stations are linked to station performance in terms of the station Plant Load Factor (PLF) till 2001.

25.2 With the introduction of concept of availability based tariff in tariff period 2001-04, recovery of full fixed cost was linked to a threshold availability level and as such, shortfall in recovery of full fixed charges in the event of availability being lower than the target availability was the disincentive. But incentive continued to be linked to station performance in terms of PLF.

25.3 The Central generating companies namely NTPC, NLC, NEEPCO as well as transmission licensee Power Grid argued vigorously for the availability based incentive during the finalization of terms and condition of tariff for the tariff period 2004-09. The Commission however, decided to continue with the above scheme of incentive linked to PLF and disincentive linked to availability during tariff period 2004-09 with minor modification observing as follows at Para 145 of its order dated 29.3.2004 -

> *"The issue of linking the incentive to PLF or availability was not debated threadbare in the recent hearings and as such, we would like to continue with the existing dispensation of incentive based on PLF. The Commission may, however, like to revisit the issue for a more informed debate after evaluating the experience of ABT. ABT has been implemented in all regions only recently. Some more time would be required for evaluating the experience. This should not be construed as regulatory uncertainty. Also, the issue is of much greater significance for the load centre and liquid fuel-based power stations, which may be required to back down regularly due to their higher variable cost. It would be prudent for the State Electricity Regulatory Commissions, in whose jurisdiction most of such power stations would fall, to examine this issue pragmatically."*

25.4 Neyveli Lignite Corporation (NLC) in March 2006 filed a Petition No. 19/2006 before the Commission praying for linking of incentive to availability instead of scheduled PLF for the thermal generating stations. During the hearing of the Petition on 6.6.2006 and later on 26.9.2006, NLC as well as NTPC were directed to develop a comprehensive paper on the subject for an informed debate. However, they did not prepare any such a paper.

25.5 Commission therefore, circulated a Discussion Paper titled "Revised Scheme of Incentive and Disincentive for Thermal Generating Stations" on 27.7.2007 through a public notice inviting suggestions/comments setting the tone for an informed debate on the issue.

25.6 A total of seventeen (17) responses (listed in Annexure-IV) were received on the discussion paper. Out of these, five (5) were from generating companies, i.e. NTPC, NLC, NEEPCO, APGENCO and Lanco APPL who are in agreement with the proposal, and had fully endorsed it. The State utilities on the other hand had opposed the CERC proposal on many grounds.

25.7 The paper had suggested linking incentive and disincentive to the availability on following grounds:

(i) That the incentive/disincentive for a generating station should be linked to parameters, which are under the control of station personnel (e.g. plant availability),
(ii) Adverse effect of incentive linked to PLF on merit-order of the stations,
(iii) Scheme would be in harmony with the recommendations of K.P. Rao Committee, M/s ECC and the NTF, and incentive scheme for the Ultra Mega Power projects (UMPPs).

(iv) The main consideration in the Commission's earlier decision to link incentive to PLF was the condition in the Eastern region at that time, of low dispatches because of lack of demand in the region. The power was bottled up in the region due to non-availability of inter-regional links. It was brought to the notice of the Commission that a substantial power is now being transmitted from Eastern region to the other regions. This was evident from the performance of thermal generating stations of NTPC and NLC for the year 2006-07.

25.8 The State Utilities objections were of as follows:

(a) Why effect such a change at the fag-end of the present tariff period? Let the change wait for the present tariff period to end.

(b) Incentive should be payable only when a plant perform above the threshold, and the measure of performance is PLF, not plant availability. Mere availability does not indicate efficiency.

(c) The proposal is not in line with clause 5.3 (f) of the Tariff Policy dated 6.1.2006.

(d) The proposal is contrary to the earlier decision of the Commission after detailed deliberation, and as fully explained in the order dated 4.1.2000.

(e) The Commission has already formulated its views, and is adopting a piecemeal approach.

(f) CEA's advice should have been sought by the Commission.

(g) The incentive payment to a generating company should be linked to the service rendered by it to the consumers.

(h) The proposal would further enrich the generating companies at the cost of the consumer.

(i) Generating companies are already making huge profits on account of low norms and through UI.

(j) The proposed scheme would not safeguard the consumers' interest, as required by section 61(d) of the Act.

(k) The proposal will make little difference for pit-head stations which do not have to back down. So why this change?

(l) The proposal will encourage the generating companies to mis-declare the plant availability.

25.9 It can be seen that beneficiaries are still reckoning the measure of performance as the PLF and not the availability. It has to be appreciated that the scheduled PLF (the present criterion for incentive) depends on plant availability (which is a measure of plant personnel's efficiency and equipment performance), as well as on requisition by beneficiaries during daily scheduling process. The requisitions by the beneficiaries depend on system's load-generation balance and a plant's position in merit-order (depending on its landed fuel cost). These are not within the control of generating station personnel. A lowering of scheduled PLF on account of lower requisitions by beneficiaries does not reflect and therefore must not be construed as a lowering of plant's performance. This was also brought out clearly in the K.P. Rao Committee report also. The perception that the measure of "service rendered" is the energy supplied by a station has to change, and the capability to supply power (which would normally be fully harnessed and utilized at least during the peak load hours) has to be accepted as the measure of service rendered.

25.10 One of the basic objectives of Availability Tariff for generating stations is to induce maximization of plant availability. This is done by linking the fixed cost (capacity charge) payment to availability declaration. An integral feature of the scheme is that backing down of a station during off-peak hours does not adversely affect the earning of the generating company. It is these features of ABT which have streamlined the operation of regional grids in India since 2002-2003, brought about economy (merit-order) in generation, improved the grid parameters, and removed a source of perpetual conflict between Central generating companies and the State utilities. There is no reason why these features should not be extended to payment of incentive when a station achieves plant availability above the norms.

25.11 It may further be appreciated that most of the Central thermal generating stations which fall in the Commission's jurisdiction are pit-head stations and do not have to back down. As such, their scheduled PLF is close to the plant availability and switching over to availability based incentive should not be posing any problem. It is important that the principles applied are correct. Besides, the main factor which has prompted the Commission in the matter is the fact that the issue is of much greater significance for the load-centre and liquid fuel-based power stations, which may be required to back down regularly due to their higher variable cost. These stations, being mostly intra-State, change in CERC regulations is necessary to enable the SERCs to effect the requisite change for the intra-State stations.

25.12 Some of the beneficiaries have argued that it would further enrich the generating companies at the cost of the consumer. In this regard, it has to be appreciated that both the Electricity Act and the Tariff Policy provide for incentivising for performance at levels higher than the norms. As any such incentive would definitely enhance the income of a generating company, but the same cannot be simply denied because it "enriches" the company. The right approach however, would be to ensure that the incentive is correctly directed, i.e. it rewards/induces enhancement of performance of the correct type, and that it brings benefits to consumers as well. In the present case, against the payment of incentive, the consumers would be in a position to get extra power from the generating stations, and higher peak demand would be met.

25.13 In this context, it would be necessary to examine as to what should really meant by consumers' interest. The cost of supply is one aspect of consumer interest but the supply of continuous and reliable power of reasonable quality is the other aspects of consumer interest. It is well established that Availability Tariff has dramatically improved the power supply availability, as also its continuity and quality. Linking incentive to plant availability is only an extension of the right principle.

25.14 The Commission had also consulted CEA on the issue and CEA vide letter dated 7.9.2007, has communicated its agreement with the concept of incentive/disincentive based on plant availability duly taking into the account the fuel availability.

25.15 For liquid fuel based Central stations it was proposed to work out the incentive based on the MW schedule during peak hours (to be specified by the respective RLDC in advance) instead of total declared capacity. CEA had suggested that this methodology may also be applied on all the existing gas based stations as they are also procuring RLNG in spot market at a high cost due to shortage of natural gas. Extending it further, in case of coal/lignite based stations where there is shortage of primary fuel beyond their control this dispensation could also be made applicable for such stations because this would lead to optimal utilization of available capacity during peak hours. The beneficiaries would be in real control in this situation as the availability would be based on schedule given by RLDCs during peak hours based on drawal schedule of beneficiaries. Such a treatment takes care of the State utilities' legitimate concerns while reconciling with the basic principles. Two aspects are being simultaneously addressed. One is that backing down in off-peak hours (due to their high variable cost and lower rank in merit order) should not bring down the incentive payable to the generating company. Secondly, the customers should not be required to pay incentive for plant capacity which is not harnessed even during peak load hours, even if available. Surely, there could be no objection to such a dispensation. As such, special treatment to gas based stations where primary fuel is in short supply is in no way discriminatory.

25.16 It has also been argued that the availability based incentive scheme would encourage the generating companies to mis-declare the plant availability. In our view such an eventuality is remote. It has to be appreciated that compared to the present scheme, in which incentive is linked to scheduled PLF, the generating companies would have nothing extra to gain by misdeclaration of plant availability They could get a higher incentive only if availability is over-declared, whereas in such a situation they could also be scheduled more based on declared availability and chance of incurring UI if unable to generate as per schedule.

25.17 Taking into account all aspects of the matter, we have decided to switch over to availability based incentive and disincentive scheme.

25.18 Now the question arises what should be the threshold level of availability for the purpose of incentive. The discussion paper was based on revenue neutrality concept as the change was proposed to be effected in the fag end of middle of the tariff period 2004-09 and as such, it was proposed to be kept at the same target level of scheduled PLF of 80%. But now the modified scheme shall be applicable in the next tariff period. Commission would not like that revenue loss or gain should act as deterrent in adoption of a correct principle and methodology. As such, we are not totally guided by the revenue neutrality concept. Therefore, as discussed earlier, it has been decided to raise the normative performance level of availability from 80% to 85 in general for all thermal generating stations based on the performance of stations in the last three years i.e. 2004-05 to 2006-07. In some of the station there are specific relaxations depending upon ground realities. This takes care of the CEA's concern of difference in Availability and scheduled PLFs of the thermal generating stations.

25.19 With regard to incentive/disincentive rate to be adopted, we are of the view that following aspects are important in this regard:

(i) If the disincentive could be in the form of denial of normative fixed charge for availability lower than the normative then the incentive could be in the form of additional fixed charge for availability in higher than the normative.

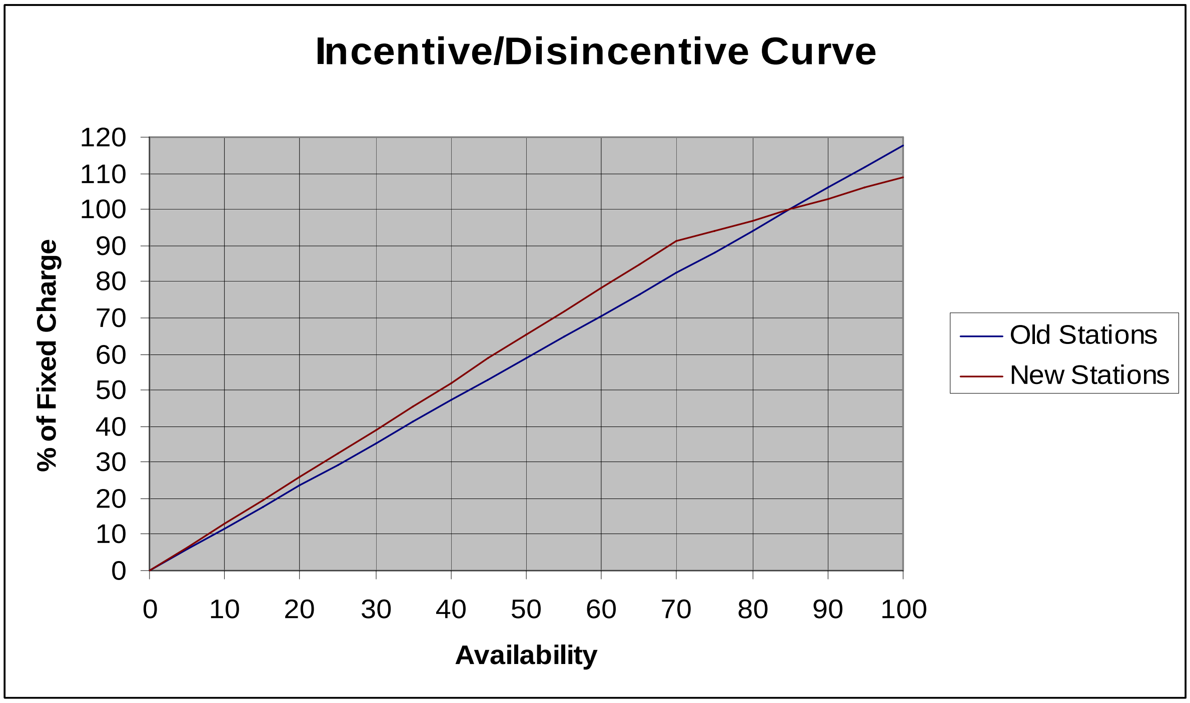
(ii) As such, recovery of fixed charge shall be on monthly basis and shall be inclusive of any incentive and disincentive depending upon the availability achieved during the month. This is a departure from the earlier practice of recovery of fixed charges linked to cumulative availability. This would allow the beneficiaries to meet any shortfall in availability (due to station being out partially or full) be met from sourcing supplies from alternate sources or over drawal from the grid at UI rates.

(iii) It would be easier for the new generating station to achieve the availability above normative whereas as the station become old it would be more credit worthy for the station to achieve availability above the normative. As such, rate of incentive should be more for stations which are in operation for more than 10 year from the COD in terms of normative fixed charge as compared to new stations which are in operation for 10 year or less from the COD.

(iv) The incentive and disincentive should be symmetrical in the normal operating range. For a thermal generating station normal operating range could be considered as station availability of 70%

and above. However, availability of less than 70% should not be acceptable and should be accompanied with denial of fixed charges on pro-rata basis. Since the recovery of fixed charges is based on monthly availability actual picture would become clear only at the end of the year and hence correction of incentive at the end of year in case annual availability achieved is lower than 70% is being allowed.

25.20 These aspects would be clear from the following illustrative graph:



25.21 Accordingly, following shall be provided in the regulations:

(1) The fixed charge for a thermal generating station shall be computed on annual basis and recovered on monthly basis based on the norms of operation as provided the regulations.

(2) The fixed charges (inclusive of incentive) payable to a thermal generating station for a calendar month shall be as per the following formulae:

(i) For generating stations in commercial operation for less than ten (10) complete financial years :

(AFC x NDM / NDY) x 0.5 (1.0 + PAFM / NAPAF):

Provided that in case the plant availability factor achieved during a financial year (PAFY) is less than 70%, then the total fixed charges for the year shall be restricted to

AFC x (0.5 + 35/ NAPAF) x (PAFY /70).

(ii) For generating stations in commercial operation for ten (10) complete financial years and more :

(AFC x NDM / NDY) x (PAFM / NAPAF)

Where,

AFC=	Annual fixed charges computed for the financial year, in Rupees.
NDM =	Number of days in the month
NDY =	Number of days in the financial year
PAFY =	Plant availability factor achieved during a financial year, in percent.
NAPAF=	Normative annual plant availability factor
PAFM=	Plant availability factor achieved during the month, in percent:

(iii) In a situation of shortage of main fuel in a thermal generating station, the generating company may declare ex-bus capacity which can be delivered at least for eight (8) hours during the day, along with total energy availability (in ex-bus MWh) for the day, clearly specifying the MW and MWh out of these which can only be generated by firing a supplementary fuel, if any and in all such cases, the maximum MW scheduled (based on beneficiaries' requisitions) shall be taken as the DC for the day.

25.22 The above tariff structure may also be adopted by the Department of Atomic Energy, Government of India for nuclear generating stations under their control and may specifying annual fixed charge (AFC), normative annual plant availability factor (NAPAF), installed capacity (IC), auxiliary power consumption and energy charge rate (ECR) for such stations.