CERC (Terms and Conditions of Tariff) Regulations, 2009

Statement of Objects and Reasons

1. Introduction

1.1 The Electricity Act, 2003 (hereinafter referred to as "the Act") assigns the following functions to the Central Electricity Regulatory Commission (hereinafter referred to as the "Commission"), among others:

a) to regulate the tariff of generating companies owned or controlled by the Central Government;
b) to regulate the tariff of generating companies other than those owned or controlled by the Central Government specified in Clause(a), if such generating companies enter into or otherwise have a composite scheme for generation and sale of electricity in more than one state;
c) to regulate the inter-state transmission of electricity;
d) to determine tariff for inter-state transmission of electricity;

Section 61 of the Act empowers the Commission to specify, by regulations, the terms and conditions for the determination of tariff in accordance with the provisions of the said section and the National Electricity Policy and Tariff Policy. In terms of clause (s) of sub-section (2) of section 178 of the Act, the Commission has been vested with the powers to make regulations, by notification, on the terms and conditions of tariff under section 61. As per section 178(3) of the Act, the Commission is required to make previous publication before finalizing any regulation under the Act. Thus as per the provisions of the Act, the Central Commission is mandated to specify, through notification, the terms and conditions of tariff of the generating companies and inter-State transmission systems covered under clauses (a) ,(b) and (c) of sub-section (1) of section 79 of the Act after previous publication.

1.2 In exercise of the powers vested under sections 61 and 178 (2)(s) of the Act and all other enabling powers and in compliance of the requirement under section 178 (3) of the Act, the Central Commission issued vide public notice no. L-7/145/160/2008-CERC dated 29th August, 2008 the draft of Central Electricity Regulatory Commission (Terms and Conditions of Tariff} Regulations, 2008 for the tariff period from 1.4.2009 to 31.3.2014 (hereinafter referred to as the draft regulations} along with explanatory memorandum for comments/suggestions/objections thereon. Subsequently, public hearing was held on 3rd and 4th November 2008 to hear views of all the stakeholders and consumers, if any. A statement indicating in brief the comments received from various stakeholders is enclosed as **Annexure-I.** The list of participants in the public hearing held on 3rd and 4th November 2008 is enclosed as **Annexure-II.**

2. Consideration of the views of the stakeholders and analysis and findings of the Commission on important issues

2.1 The Commission considered the comments of the stakeholders on the draft regulations, views of the participants in the public hearing as well as their written submissions received during and after the public hearing. The regulations have been finalized after detailed analysis and due consideration of the various issues raised. The analysis of the issues and findings of the Commission thereon are discussed in the subsequent paragraphs.

3. Preliminary Objections to the Regulations

3.1 In response to the draft regulations, UPPCL and MPPTCL have submitted preliminary objections arguing that before the Commission frames the regulations for terms & conditions of tariff, it is imperative that the Commission should first specify a regulation under sub-section (5) of section 62 of the Act providing for the procedure for calculation of expected revenues from tariff and other charges by the generating companies and licensees.

3.2 UPPCL in its comments has submitted that section 61(d) of the Act enjoins upon the Commission to safeguard the consumer interests while ensuring recovery of the cost of electricity in a reasonable manner. Moreover, para 5.3(a) of the Tariff Policy stipulates that the Commission shall maintain balance between the interests of consumers and the need for investment while laying down the rate of return. In view of these statutory requirements, the Commission has a statutory obligation to provide for tariff determination by Annual Revenue Requirement (ARR) under section 62(5) in place of norms. It has been urged that as normative cost is higher than the actual, it is non-incurred and its recovery with the fuel price adjustment is therefore illegal. UPPCL has suggested that the calculation of the revenue should be based on the average of revenue of three years under section 62(5) of the Act and the difference between the tariff based on the norms and the average of the three years calculated under section 62(5) should be disallowed being in the nature of non-incurred expenses.

3.3 MPPTCL in its comments has submitted that a combined reading of sections 61 and 62 of the Act implies that data/details regarding expected annual revenue requirement are required to be called from generating companies or licensees. Thereafter this cost is required to be compared with the tariff determined as per the regulations framed under section 61. The Commission is thereafter required to invoke its power of regulation under section 79 to regulate the tariff keeping in view the need for reasonable return to the generators/licensees and safeguarding the interests of the consumers. Therefore, without specifying the methodology for computation of ARR as mandated under section 62(5) read with section 178(2)(u) of the Act, determination of tariff under section 62 would be a half hearted approach to regulate the tariff under section 79 of the Act.

3.4 UPPCL has filed Writ Petition No. 11315 of 2008 in the High Court of Judicature at Allahabad, Lucknow Bench seeking a writ of mandamus or any other suitable writ to the Commission to disclose and provide procedure regulation as envisaged under section 62(5) read with section 178(2)(u) of the Act. The main ground taken in the petition is that in the absence of procedure contemplated under section 62(5) of the Act, the tariff is being determined on the normative parameters which allow recovery of unincurred expenditure by the generating companies and their unjust enrichment to the tune of thousands of crore at the cost of the beneficiaries.

3.5 The Commission is mandated under Section 61 of the Act to specify the terms and conditions for determination of tariff in the light of the principles laid down under clauses (a) to (h) of the said section and National Electricity Policy and Tariff Policy. The guiding factors for determination of terms and conditions of tariff are as under:

(a) commercial principles
(b) competition, efficiency, economical use of resources, good performance and optimum investments
(c) balance between consumer interest and recovery of the cost of electricity in a reasonable manner
(d) reward of efficiency of performance
(e) multi-year tariff principles
(f) tariff progressively reflects cost of generation and reduces cross subsidies
(g) promotion of cogeneration and generation from renewable resources
(h) National Electricity Policy
(i) Tariff Policy

3.6 The Central Government in exercise of its power under sub-section (1) of section 3 of the Act has notified the National Electricity Policy and Tariff Policy. Para 5.8.5 of the National Electricity Policy provides as under:

> " 5.8.5 All efforts will have to be made to improve the efficiency of operations in all the segments of the industry. Suitable performance norms of operations together with incentives and disincentives will need to be evolved alongwith appropriate arrangement for sharing the gains of efficient operations with the consumers. This will ensure protection of

> consumer interests on the one hand and provide motivation for improving the efficiency of operations on the other.”

3.7 Further, the Tariff Policy provides framework for performance based service regulations in respect of generation, transmission and distribution of electricity based on norms. Para 5.3(f) of the tariff policy dealing with the operating norms provides as under:

> “5.3.(f) **Operating norms**:
>
> Suitable performance norms of operations together with incentives and disincentives would need to be evolved alongwith appropriate arrangement of 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.. 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 and level of service to be provided to consumers etc. Continued and proven inefficiency must be controlled and penalized.”.

3.8 It is evident from the foregoing discussion of the provisions of Section 61 of the Act, the National Electricity Policy and the Tariff Policy that the Central Commission is mandated to specify the terms and conditions of tariff in respect of the generating companies covered under clauses (a) and (b) of sub-section (1) of section 79 of the Act and inter-State transmission of electricity **based on norms and not on actuals**. Therefore, the Commission does not agree with the argument of UPPCL that ‘the normative cost being higher than the actual, it is non-incurred and its recovery with the fuel price adjustment is therefore illegal’. The Commission also does not subscribe to the views of MPPTCL that in the absence of a separate regulation under section 62(5), determination of tariff under section 62 would be a half hearted approach to regulate the tariff under section 79 of the Act. The Commission has all along been following the Multi-Year Tariff principles based on norms. The norms being specified by the Commission are aimed at inducing efficiency in operation, are 'relatable *to past performance'*, and do '*take into consideration the latest technological advancements, fuel, vintage of equipments'*.

3.9 Clause (5) of Section 62 of the Act which is the focus of objection by MPPTCL and UPPCL reads as under:

> "The Commission may require a licensee or generating company to comply with such procedure as may be specified for calculating the expected revenue from the tariff and charges which he or it is permitted to recover."

3.10 The sub-section has two parts: firstly, the Commission may specify a procedure for calculation of expected revenues from tariff and charges by the generating companies and licensees which they are permitted under law to recover; secondly, the Commission may require the generating companies or licensees to comply with such procedure for calculation of expected revenues.

3.11 The generating companies or the transmission licensees are permitted under law to charge the tariff on the basis of the provisions of the tariff regulations specified by the Central Commission. The tariff regulations of 2004 for the control period 2004-09 provide for the detailed procedures for calculation of different elements of tariff. The generating companies and transmission licensees are required to file the tariff petitions containing the detailed calculation of different elements of tariff in accordance with the provisions of the regulations. The Commission in the course of proceedings also calls for any further information including revised calculations as is considered necessary for determination of tariff. Such data/information are utilized by the Commission for prudence check while determining the tariff of the generating companies and transmission licensees falling within its jurisdiction.

3.12 The Commission has considered the provisions of section 62(5) and other relevant provisions of the Act and the submissions of UPPCL and MPPTCL and is of the view that the scope of sub-section (5) of section 62 is limited to specifying the formats for calculating the expected revenue from tariff by the generating company and the transmission licensee. The Commission has decided to specify regulation in this regard. As regards sharing of the gains arising out of improved performance vis'-s-vis' norms, the Regulation on terms and conditions of tariff issued under section 178(2)(s) of the Act by the Commission already provide for sharing of savings on account of some norms like secondary fuel oil consumption and refinancing of loan, etc.

4. Scope and extent of application {Regulation 2}

4.1 In the draft regulations, it was provided that the regulations would be applicable to all cases where tariff is to be determined by the Commission under section 62 of the Act read with section 79 thereof. After detailed deliberation during finalization of the regulations, the Commission noticed that the provisions of regulations, particularly the operational parameters cannot be applied parri passu in case of the generating stations or units thereof based on non-conventional energy sources. The Commission has decided to come out with a separate regulation for determination of tariff based on non-conventional energy sources. Accordingly, the determination of tariff of generating station based on non-conventional energy sources has been kept out of the purview of the present regulations.

5. Definition (Regulation 3)

5.1 Auditor {Regulation 3(5)}

5.1.1 Regulation 3(5) defines auditor as one appointed by the generating company or transmission licensee in accordance with sections 224 and 619 of the Companies Act, 1956 or any other law for the time being in force. In the draft regulation, a provision was made for auditors appointed in accordance with provisions of section 233 of the

Companies Act. The Commission intended that the cost accountants appointed under section 233B should be made eligible to certify the various documents required under these regulations. However, section 233B has been inadvertently left out. This shall be corrected by following due procedure to reflect the proper intention of the Commission.

5.2 Expenditure incurred {Regulation 3(2)

5.2.1 Draft Regulation 3(2) defined the word 'actually incurred' as any fund i.e. the equity and/or the debt, actually deployed and paid in cash or cash equivalent, for creation or acquisition of assets. However, the term 'actually incurred' which figured in the 2004 tariff regulations are being given various interpretations. In order to avoid ambiguity and assign a proper meaning to the term, the Commission considered it appropriate to change the term 'actually incurred' to 'expenditure incurred' and to limit the allowable expenditure incurred to the extent of actual cash outgo.

5.2.2 Accordingly, the said clause has been rephrased as under:

> **''expenditure incurred'** means the fund, whether the equity or debt or both, actually deployed and paid in cash or cash equivalent, for creation or acquisition of a useful asset and does not include commitments or liabilities for which no payment has been released;"

5.3 Useful life

5.3.1 The gas/liquid fuel based stations comprise of two main components. One set of components are the gas turbine and its auxiliaries which are subjected to high temperatures; and the other set of components namely waste heat recovery boiler, steam turbine, generator and their auxiliaries etc are not subjected to very high temperatures.

5.3.2 So far, the useful life for the gas turbine is being considered as 15 years and that of waste heat recovery boilers, steam turbine etc as 25 years. Historically, the gas turbines were used in aero planes and ships where reliability aspect was very important from the view point of safety and security of life of passengers and crew members. Considering the reliability of the gas turbines, life of gas turbines was considered as 15 years. When gas turbines were used in generation of electricity, the same period was taken as the useful life. However, experience has shown that many of the first generation gas turbines installed in India have already completed 20 years of operation and continue to operate with major overhauls undertaken at regular intervals of 50000 EOH. The major overhaul of gas turbine involves complete renovation of hot gas path which is subjected to very high temperature.

5.3.3 Considering the performance of gas turbines, the Commission has decided that useful life of gas turbine stations should be fixed as 25 years as in case of coal based thermal generating stations. Accordingly, for the purpose of R&M useful life of gas turbines as 25 years has been specified in these regulations.

5.3.4 The Commission has considered 25 years as the useful life in case of the AC and DC sub-stations and 35 years in case of hydro generating stations and transmission lines Keeping in view their actual performance in the past.

5.3.5 Accordingly, clause (42) of Regulation 3 has been inserted as under:

"(42) **'useful life'** in relation to a unit of a generating station and transmission system from the COD shall mean the following, namely:-

(a)	Coal/Lignite based thermal generating station	25 years
(b)	Gas/Liquid fuel based thermal generating station	25 years
(c)	AC and DC sub-station	25 years
(d)	Hydro generating station	35 years
(e)	Transmission line	35 years

6. Application for determination of Tariff {Regulation 5}

6.1 The Commission, in the draft regulation, under 2nd proviso to Regulation 5(2) proposed as under:

> *'Provided that in case of an existing project, the application shall be based on admitted capital cost including any additional capitalization already admitted up to 31.3.2008 and estimated additional capital expenditure for the year 2008-09 and for the respective years of the tariff period 2009-14'*

6.2 The Commission has reconsidered this provision. As per Regulation 18(4) of the CERC (Terms and Conditions of Tariff) Regulations, 2004, the utilities are permitted to approach the Commission for tariff revision on account of additional capital expenditure twice during 2004-09. As the capital cost as on 31.03.2009 shall form the basis for determination of tariff for the control period 2009-14 as per the 2009 tariff regulations, it is imperative that all applications for revision of tariff on account of additional capital expenditure incurred upto 31.3.2009 are considered and decided as per the 2004 tariff regulations before taking up the tariff determination for the next tariff period starting 1.4.2009 . Most of the utilities are in the process of filing their applications for revision of tariff for the period 2004-09 on account of additional capital expenditure. The Commission feels that once these applications are disposed of, the applications for determination of tariff for the next tariff period starting from 1st April, 2009 should be taken up based on the firmed up capital cost as on 1.4.2009.

6.3 Accordingly, the Commission decided that the first proviso to clause (2) of Regulation 5 should be modified as under:

> **"**Provided that in case of an existing project, the application shall be based on admitted capital cost including any additional capitalization already admitted up

to 31.3.2009 and estimated additional capital expenditure for the respective years of the tariff period 2009-14."

6.4 The Commission expects the generating companies and the transmission licensees to file their petitions for tariff determination for the period 2009-14 based on the audited accounts as early as possible,. Till the tariff is determined by the Commission for the period 2009-14 under these regulations, the tariff as applicable as on 31.3.2009 shall continue to apply. The difference between the tariff charged during this period and that which becomes payable as per the tariff determined by the Commission under these regulations shall be settled at the SBI PLR rate of the 1st April of the concerned year.

6.5 Accordingly, the Commission decided to add another clause i.e. clause (3) to Regulation 5 as under:

> "In case of the existing projects, the generating company or the transmission licensee, as the case may be, shall continue to provisionally bill the beneficiaries or the long-term customers with the tariff approved by the Commission and applicable as on 31.3.2009 for the period starting from 1.4.2009 till approval of tariff by the Commission in accordance these regulations:
>
> Provided that where the tariff provisionally billed exceeds or falls short of the final tariff approved by the Commission under these regulations, the generating company or the transmission licensee, as the case may be, shall refund to or recover from the beneficiaries or the transmission customers, as the case may be, within six months along with simple interest at the rate equal to short-term Prime Lending Rate of State Bank of India on the 1st April of the concerned/respective year".

The expression 'long term customer' has been used inadvertently in regulation 5(3), as quoted above. The Commission intended to use the expression 'transmission customer' in the context. This shall be corrected accordingly.

7. Truing up of Capital Cost(Regulation 6)

7.1 The Commission, in Regulation 6(1) of draft regulations had proposed truing up exercise of capital cost as under:

> 'The Commission shall carry out truing up exercise during the terminal year of the tariff period, that is during 2013-14, with respect to the capital expenditure including additional capital expenditure actually incurred up to 31.3.2013 and revised estimated additional capital expenditure for 2013-14, as admitted by the Commission after prudence check,"

7.2 Normally the truing up exercise for all the years in a tariff period should be carried out together. Leaving the truing up exercise of the terminal year (2013-14) to be carried out separately would tantamount to carrying out the same exercise once again during the next tariff period, which is avoidable. As such, the Commission is of the view that instead of carrying out the truing up exercise in the terminal year, the exercise with respect to the capital expenditure including additional capital expenditure actually incurred up to 31.03.2014, as admitted by the Commission after prudence check, should be carried out along with the petition filed for next tariff period.

7.3 Accordingly, the Commission has decided that the clauses (1) to (4) of Regulation 6 should be deleted and in their place clauses (1) to (3) be substituted as under:

> "(1)The Commission shall carry out truing up exercise along with the tariff petition filed for the next tariff period, with respect to the capital expenditure including additional capital expenditure incurred up to 31.03.2014, as admitted by the Commission after prudence check at the time of truing up:

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

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

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

<u>8. Capital Cost (Regulation 7)</u>

8.1 Draft Regulation 8(a) provided as under:

> "(1) Capital cost for a project shall include:
>
> (a) the expenditure actually incurred or projected to be incurred, including interest during construction and financing charges, up to the date of commercial operation of the project, as admitted by the Commission".

8.2 The capital cost includes interest during construction, financing charges and foreign exchange risk variation up to the date of commercial operation of the project. The draft regulation 13 provides that the investors may deploy any amount of equity they want to invest but the return on equity shall be allowed only to the extent of 30% of the capital cost or actual amount of equity, whichever is lower. In case the equity invested is more than 30%, the equity in excess of 30% would be considered as notional loan and it would be serviced at the weighted average rate of interest of the respective utility, as is calculated under the provision of clause 16(5) of the draft regulation. The interest, financing charges and foreign exchange rate variation on actual loan is payable even during the construction period but there being no source of revenue during the construction period, the same is allowed to be capitalized as interest during construction period. Now the question arises whether the equity amount considered as notional loan and deployed during construction period too should be treated in the same manner as the actual loan. Any investment deployed either in the form of equity or debt has a cost to be serviced. The investments made in the form of equity are risk capital carrying higher rate of return and have perpetual flow of return up to the end of the life of the plant. But the loan capital does not enjoy the aforesaid perpetual and higher rate of return. As the equity in excess of 30% of capital cost has been considered as notional loan for the purpose of tariff, the Commission is of the view that the said capital is also entitled for interest during construction, financing charges and foreign exchange risk variation up to the date of commercial operation of the project. Accordingly, the Commission has decided to allow interest during construction, financing charges and foreign exchange risk variation up to the date of commercial operation of the project on the normative loan admitted by the Commission.

8.3 The Commission decided to substitute Regulation 8(1)(a) of the draft regulation as under and renumber as Regulation 7(1)(a):

> "7. Capital Cost. (1) Capital cost for a project shall include:
>
> (a) the expenditure incurred or projected to be incurred, including interest during construction and financing charges, any gain or loss on account of foreign exchange risk variation during construction on the loan - (i) being equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event of the actual equity less than 30% of the funds deployed, - up to the date of commercial

operation of the project, as admitted by the Commission, after prudence check;'

9. Initial Spares (Regulation 8)

9.1 Draft Regulation 9 provided for capitalization of initial spares as under:

> "9.(1)Initial spares shall be capitalised as a percentage of the original project cost, subject to following ceiling norms:
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> (i) Coal-based/lignite-fired thermal generating stations 2.5%
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> (ii) Gas Turbine/Combined Cycle thermal generating stations 4.0%
>
> (iii) Hydro generating stations 1.5%
>
> (iv) Transmission system
>
> (a) Transmission line 0.75%
>
> (b) Transmission Sub-station 2.5%
>
> (c) Series Compensation devices
> and HVDC Station 3.5%"

9.2 In case of thermal generating stations, the same norms for initial spares as specified in the 2004 tariff regulations were proposed in the draft regulations. However, the generating companies in their comments have considered the norms as inadequate and suggested higher norms. NTPC has argued that as availability norms are proposed to be raised from 80% to 85%, the generator will always be under pressure to ensure that availability does not go below 85%. Therefore, norms for spares @2.5% for coal based stations would not be sufficient. NTPC has further submitted that for 500 MW unit, initial spares should be 4% of original project cost and in case of gas/liquid based stations, the norm of 7% should be adopted for advanced class machines. DVC has suggested a norm of 4% for coal based stations whereas NLC proposed the norm of 6% for the lignite based stations. Torrent Power Limited during the hearing has submitted that the in-principle approval granted by the Commission under 2004 tariff regulations should be the basis for allowing capital cost including initial spares.

9.3. The Commission is of the view that actual availability of coal and gas/liquid fuel based stations is in excess of 85% barring few stations like Farakha and Gandhar etc., that too, for certain specific reasons. Moreover, the Commission is not putting any bar on the generators to keep the sufficient inventory as considered necessary by them. But for capitalization of initial spares which are provided to take care of mandatory and insurance spares requirements at the time of commissioning of the project and to arrange for its financing, we are of the view that the specified norms are sufficient and do not call for any further increase. Similarly for the hydro generating stations and transmission systems, the Commission has decided to continue with the existing norms.

10. Capital Cost and Additional Capitalisation (Regulations 7 & 9)

<u>10.1 Projected Capital Cost</u>

10.1.1 As per Regulation 7 of these regulations, capital cost includes the expenditure incurred or projected to be incurred upto the COD, initial capitalized spares and additional capital expenditure incurred or projected to be incurred. It is to be noted that the Commission has adopted a slightly different approach and has allowed generating companies and transmission licensees to make applications for tariff determination based on anticipated additional capital expenditure for the tariff period 2009-14 in order to provide tariff certainty and avoid retrospective tariff revisions and to keep the impact of tariff revision to the bare minimum.

10.1.2 The beneficiaries like UPPCL and MPPTCL have argued that the projected additional capital expenditure should not be accounted for in tariff, especially when the assets have not been put to use. Further, they apprehend that the generating companies/transmission licensees would submit inflated estimates for the purpose of tariff and beneficiaries would have to shell out more tariff which would be adjusted after 4 to 5 years. They have suggested for truing up exercise to be carried out every year. On the other hand, the generating companies like NTPC have expressed concern that it would be difficult to make estimation of additional capitalisation accurately and later adjustments would also lead to disputes.

10.1.3 The Commission has carefully examined the issue again and is of the view that the generating companies/transmission licensees as well as the beneficiaries should appreciate the regulation in its proper perspective. Apart from meeting the intended objective of certainty of tariff and minimal retrospective adjustments, the procedure would have following additional advantages:

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

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

10.1.4 The Commission is of the view that the approach adopted with regard to consideration of the expenditure including additional capital expenditure projected to be incurred for the purpose of determination of capital cost is a win-win situation for all. The Commission has decided to retain the said provisions with regard to capital cost including projected additional capital expenditure in Regulations 7 and 9 of these regulations.

<u>10.2 Admissibility of Additional Capital Expenditure</u>

10.2.1 The draft regulation 10 dealing with the admissibility of additional capitalization by the Commission for the purpose of tariff provided as under.

> "10. Additional Capitalisation.(1) The following capital expenditure within the original scope of work actually incurred or projected to be incurred, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check:
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> (i) Deferred liabilities;
> (ii) Works deferred for execution;
> (iii) Procurement of initial capital spares within the original scope of work, subject to the provisions of regulation 9;
> (iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court; and
> (v) Change in law:
>
> Provided that the details of works included in the original scope of work along with estimates of expenditure, deferred liabilities and the works deferred for execution shall be submitted along with the application for determination of tariff.
>
> (2) The capital expenditure of the following nature after the cut-off date may, in its discretion, be admitted by the Commission, subject to prudence

check:

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

(ii) On account of change in law;

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

10.2.2 The above provision was on similar lines as in the tariff regulations for 2004-09 except for additional capital expenditure on new assets not in original scope of work prior to and after cut-off date, and deferred liabilities and works after the cut-off date. The generating companies in their comments have sought to allow additional capitalization on new assets not in original scope of work and deferred liabilities and deferred works within the original scope after cut off date.

10.2.3 The term deferred liability encompasses various liabilities including deferred credit, liabilities accrued but not due and other contingent liabilities that are likely to be paid by the utilities in future. The Commission is of the view that terms used in these regulations should have definite meaning and use and devoid of ambiguity. The Commission has decided that the phrase ‘deferred liability’ should be substituted by the phrase ‘undischarged liability’ which would mean that even though the work has been executed, the liability for payment for that work has not been discharged.

10.2.4 As regards the generators’ demand to allow deferred liabilities and deferred works executed after the cut-off date, the Commission is of the view that all the works relating to the project within the original scope including colony etc should be completed as early as possible, but not later than cut-off date. In fact the cut-off date has been extended by one more year to take care of the concerns of the generating companies/transmission licensees. The Commission expects that all liabilities and deferred works which could not be settled or completed by the COD of the station, must be settled or completed by the cut-off date. A period of 2 to 3 years is considered reasonable enough to complete all works within the original scope except the works relating to ash pond and ash handling system. Any liability remaining unsettled or work remaining unfinished after the cut-off date could only be because of some dispute or otherwise before arbitration or pending before the court which shall be dealt as per the regulations dealing with additional capitalisation after cut-off date.

10.2.5 As regards new works not within the original scope and expenditure on minor assets, a provision has been made in the regulations dealing with O & M expenses for a compensation allowance starting from 11th year from COD of units in respect of coal/lignite based stations as discussed elsewhere in this SOR.

10.2.6 The generating companies like NHPC , NEEPCO, THDC and NHDC have argued for compensation allowance for additional capitalization for hydro generating stations. NHPC has stated that the additional capitalization is necessary for hydro stations due to heavy damage of under water parts such as runner assembly, guide vanes, thrust bearings due to high silt content. Capital expenditure is also required to be incurred on technological improvements such as computerization, automation, communication, replacement of switchyard equipment and certain hydro mechanical items such as bulk head gates, stop log gates, draft tube gates which need replacement after a particular number of years of service. NHPC has also asked for provision of special allowance to meet expenses on minor assets. NEEPCO has submitted that additional capitalization should be allowed for works taken up during useful life of plant to add to the efficiency in operation and reduction of outages of the plant. Moreover, with such works being taken up, life of plant is also increased and cost of R&M works is reduced when taken up after expiry of useful life of plant. THDC has submitted that to take care of obsolescence in today’s fast developing technological world, certain modifications may be required to be made in the plant for its efficient and smooth operation. Therefore, provisions in the 2004 tariff regulations may be retained. NHDC has also asked to provide for compensation allowance as proposed in draft regulations.

10.2.7 Based on the available data of additional capitalization claimed in respect of NHPC stations, an exercise was carried out to make provision for compensation allowance for hydro generating stations. However, it has been observed that additional capitalization in the form of compensation allowance works out to be very high for hydro generating stations compared to thermal generating stations. The Commission has, therefore, decided to add the following provisions towards additional capitalization for hydro stations:

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

10.2.8 The Commission has also decided to make a similar provision in case of transmission system as under:

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

10.2.9 The Commission is of the view that any additional expenditure incurred on acquiring minor items/assets like tools and tackles, furniture, personal computers, air-conditioners, voltage stabilizers, refrigerators, coolers, fans, washing machines, heat convectors, mattresses, carpets etc. in respect of the hydro generating stations and transmission systems brought after the cut off date shall not be considered for additional capitalization for determination of tariff w.e.f. 1.4.2009. Accordingly a proviso has been added under sub-clauses (iv) and (v) of clause (2) of Regulation 9 of these regulations as under:

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

11. Renovation and Modernisation(Regulation 10)

11.1 Draft Regulation 11(1) dealt with renovation and modernization for the purpose of the extension of life beyond the useful life of the generating station or a unit thereof or a transmission system. First proviso to the said clause provided the generators an alternative option to avail of a "special allowance" as compensation for meeting the requirement of expenses including expenses on renovation and modernization beyond the useful life of the generating station or a unit thereof . Clause 4 quantified the special allowance at the rate of Rs.5 lakh/MW/Year during the tariff period 2009-14 unit-wise from the respective date of completion of the useful life with reference to the COD of the respective generating station. This option for special allowance was subject to two conditions. Firstly, there would be no revision of the capital cost. Secondly, option once exercised will be final and shall not be allowed to be changed.

11.2 NTPC in its comments has submitted that special allowance should be provided @ Rs.14.5 lakhs/MW with provision for annual escalation. The estimate is based on 40% of current cost of plant and machinery (P&M) of Rs.4.1 to 4.5 crore/MW which works out to Rs.1.6 crore/MW. It is assumed that a part of capital expenditure i.e. 20%, 10% and 10% will be invested in the initial three years respectively (mainly that related to Boiler works like tube replacement, APH basket replacement etc.) and considering servicing of the initial capital expenditure as loan (15 year EMI @ 13%) and spreading the remaining investment over 15 years. NTPC has further submitted that switchover from normative special allowance option to full scale R&M option should be permitted. In case, switchover is not permitted, special allowance @ Rs.29 lakh should be allowed. NLC in its comments has argued for switchover to the main provision of R&M if the situation so demands.

11.3 Amongst the beneficiaries, UPPCL has submitted that such an allowance should not be provided to the generating companies as they are already earning exorbitant profit. If at all such allowance is considered necessary, then Rs.1 lakh/MW/Year would be sufficient. TNEB, on the other hand, has not only agreed with the proposal but has also favoured continuation for such an allowance even beyond the tariff period 2009-14. MPPTCL has also agreed in principle for grant of such an allowance but has submitted that the amount should be reasonable and should be worked out in consultation with CEA. GRIDCO has opposed grant of such allowance.

11.4 The Commission has already stated in the Explanatory Memorandum to the draft regulations the reasons for providing such an option to generators in case of coal/lignite based generating stations to facilitate continued operation of well maintained generating stations and to sustain performance at the existing operational level. The Commission had observed in the explanatory memorandum to the draft regulation as follows:

"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 reasonable shape, it should b e continued in operation, and the tariff formulation should support it".

11.5 While specifying compensation of Rs.5 Lakh/MW/Year, the Commission had observed as follows:

"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 incetivise 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".

11.6 The proposal of NTPC for special allowance of Rs.14.5 Lakh/MW/Year with switchover option and Rs.29 Lakh/MW/Year without switchover option is considered to be on the higher side. NTPC during the public hearing has however sought for an allowance of Rs.8 Lakh/MW/Year with annual escalation. The Commission is of the view that a special compensation allowance of Rs.5 Lakh/MW/Year along with annual escalation of 5.72% should be reasonable to incentivise the generators to keep the units running after their useful life. The generators are also given the liberty to come with the detailed R&M proposal before the Commission if situation so demands. In case of gas/lignite based stations, such an alternative is not being considered in the absence of sufficient data in this regard. In any case generating companies have the first alternative available with them to come up with a detailed R&M proposal as and when required.

11.7 The Commission, in its draft regulation, under clause 11(3) proposed that:

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

However, the proviso to draft regulation 7 dealing with capital cost stated as under:

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

From the above two provisions, it was noticed that the words "writing off the original amount of the replaced assets" appearing in draft regulation 11(3) would be redundant as any asset being replaced will be no longer in use and will be taken out of the capital cost at the time of such replacement as per the proviso to draft regulation 7. Accordingly, the words "after writing off the original amounts of the replaced assets" have been deleted. Clause (3) of the Regulation 10 of these regulations has been worded as under:

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

12. Debt-Equity Ratio (Regulation 12)

12.1 The draft regulation *13* proposed funding pattern in the debt-equity ratio of 70:30 for new projects. The Commission intended that the investors should be free to invest fund in the form of equity as per their own investment plans, even beyond 30%. If the equity actually invested in a project was more than 30%, it was proposed that equity in excess of 30% would be considered as normative loan. However, where equity deployed was less than 30%, it was proposed to consider actual equity for determination of tariff. In respect of the existing projects, the Commission proposed to retain the same debt-equity ratio as was approved by the Commission in tariff determination as on 31.3.2009. It was further proposed that the expenditure on additional capital expenditure and renovation and modernization would be serviced in the ratio of 70:30.

12.2 The proposed debt-equity ratio of 70:30 for new projects has got wide acceptance. The beneficiaries like MPPTCL, GRIDCO, UPPCL, BSEB and individual consumers like Er. R. B. Sharma are of the view that debt-equity ratio of existing projects should also be modified to 70:30. UPPCL, BSES *Rajdhani* and TNEB have proposed debt-equity ratio of 80:20 for new projects. KSEB proposed debt-equity ratio of 70:30 for generation projects and 80:20 for transmission projects. OPTCL has proposed a high gearing of 90:10 for all new projects. The generating utilities like THDC and NHDC and the transmission utilities like PGCIL have proposed normative debt-equity ratio of 70:30.

12.3 The Commission after considering the responses and suggestions is of the view that so far as the existing projects are concerned, the investors have made investments in the existing projects on the basis of the provisions of the existing tariff regulations and any change in the debt-equity ratio of such projects would lead to regulatory uncertainty and jeopardize the scenario of investment in power sector. As such the Commission decided not to incorporate any changes in the debt-equity ratio of the existing projects. In keeping with the requirement of tariff policy, the Commission considered it appropriate to include a provision to the effect that equity invested in foreign currency should be designated in *Indian rupees* on the date of investment. The purpose is to ensure that the debt equity ratio remains unaffected by the foreign exchange rate variation and provide regulatory certainty. Accordingly, a second proviso has been added to clause (1) of Regulation 12 pertaining to debt-equity ratio in these regulations:

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

13 Rate of Return on Equity (Regulation 15)

13.1 It was proposed in the draft regulation *15* that the return on equity would be determined @ 14% in terms of the equity base determined in accordance with draft regulation 13. It was also proposed that equity invested in foreign currency should be designated in rupee terms on the date of investment. The responses to the proposed rate of return were varied and divergent.

13.2 NTPC in its submission has claimed 21.5% of post-tax rate of return on equity, supported by a detailed calculation using Capital Assets Pricing Model. For calculation, NTPC considered a risk-free rate of return of 8.5%, applicable to the 10 years Government securities, market premium of 10% and a beta value of 1.0 for power sector. It has also considered 3% additional return to compensate return on equity during construction period. Hydro generators like NHPC, SJVNL, and THDC proposed a post-tax rate of return on equity of at least 18% with 1% additional return for hydro projects because of the higher risk perception. NEEPCO has proposed as high as 30% of post-tax rate of return on equity for north-eastern region. Transmission companies like PGCIL, Power links, Universal Infratech and other companies like Energy Infratech have advocated for allowing at least 18% of post-tax rate of return on equity. CII has also proposed a return of 17% to 18% and consideration of return during gestation period. Private entities like Power Dodson LHPL, Energy Infratech, Avanta Power, CESC, Torrent Power, have proposed a post-tax rate of return on equity of at least 16% considering the financial market scenario. Mr. C. P. Jain *has* endorse*d* the proposal of post-tax rate of return on equity of 16% as SBI PLR was increasing.

13.3 On the other hand beneficiaries like GRIDCO, UPPCL, GUVNL, BSEB, KSEB and individual consumers like Ms. Mallika Sharma Bezbaruah have objected to providing higher return on equity to the utilities. They are of the opinion that the Commission should review the entire benefits available to the utilities along with return on equity and permit recovery of cost of electricity at a reasonable manner. Some of the consumers have even proposed to reduce the return on equity from 14% to 12%. UPPCL, MPPTCL *and Er. Paramjit Singh, consumer* have proposed a pre-tax rate of return of 14% for the new projects and 19% for the existing projects.

13.4 Section 61 (d) of the Electricity Act, 2003 provides that the Commission, while specifying the terms and conditions for the determination of tariff, shall be guided by the principle of *'safeguarding of consumers interest and at the same time, recovery of cost of electricity in a reasonable manner'.* Para 5(3)(a) of the Tariff Policy stipulates that:

> 'Balance needs to be maintained between the interests of consumers and the need for investments while laying down rate of return. Return should attract investments at par with, if not in preference to, other sectors so that the electricity sector is able to create adequate capacity. The rate of return should be such that it allows generation of reasonable surplus for growth of the sector'

13.5 The Commission has thus the mandate to fix a rate of return for equity that will not only attract investment and generate sufficient resources for further growth in the sector but also to take care of the consumers' interest. The interests of the consumers are taken care of in real sense only when quality power is made available for twenty four hours a day throughout the year. This could be achieved only through large capacity addition which in turn will require huge investment in the power sector. Considering the investment pattern of 70:30 debt-equity ratio, the utilities are required to build up sufficient internal accruals so that they are able to meet the target of investing at least 30% of capital cost in the form of equity. A higher investment in the form of equity also helps the entities in negotiating and availing loan at competitive terms and conditions.

13.6 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 sector is at the take off stage at present and there is a need to ensure that the confidence evinced is sustained.

13.7 The rate of return on equity can 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 too, very recently. To calculate the 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 etc, not many generating companies and transmission licensees particularly in the State Sector are listed in the Stock Exchange. As sufficient data in regard to the power sector, particularly scripts traded in the secondary market, are not available, the Commission does not favour to estimate the rate of return by using any of the scientific models.

13.8 The Commission also discussed the option of linking rate of return on equity to an appropriate benchmark with a mark up. The rate of return on equity may be linked to an appropriate benchmark like RBI Bank Rate, SBI PLR, Average PLR, 10 yr G-Securities Rate, etc. 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 debt market in India is not yet stable. The Commission feels that unless the debt market stabilizes, it may not be feasible to arrive at an appropriate benchmark rate. This leads to difficulty in linking the rate of return to a benchmark with a mark up.

13.9 It may be noted that in the last five years there has been a rise in the interest rate. The Prime Lending Rate (PLR) of the public sector banks have increased during this period, as is seen from the table given below:

Year	PLR of Public Sector Banks (%)
March 2004	10.25-11.50
March 2005	10.25-11.25
March 2006	10.25-11.25
March 2007	12.25-12.75
March 2008	12.25-13.50
January 2009	12.00-14.00

The interest rate of 10-year Government securities has also increased from 5.1461% as on March 2004 to 7.1197% as on November 2008.

13.10 The Commission allowed rate of return on equity of 16% and 14% for the tariff period 2001-04 and 2004-09 respectively. The PLRs of State Bank of India during 2001 and 2004 were 11.50% and 10.25% respectively. But as on 1st January 2009, the PLR of State Bank of India is 12.25%. After considering the rise in the PLR of the public sector banks, 10-year G-Sec, etc and also in order to help the entities to build up sufficient internal accruals for the purpose of investment in capacity addition and to ensure better cash flow, the Commission considered & deliberated to restore the rate of return at 16% as was existing prior to 1.4.2004. After consultations & deliberations it was decided to increase the base rate from 14% to 15.5% and an additional 0.5% for timely competition as explained below.

13.11 The Commission has taken note of the fallout of time overrun and cost overrun due to delay in completion of the projects. The consumers are not getting the benefits of the projects in time. This is a great national loss. As electricity is the prime mover, the nation will be able to achieve the growth rate of GDP of 8% only if the power sector grows at a rate of about 10%. Non completion of projects in time has a negative impact on the national growth. Keeping all these factors in mind and in order to incentivise the timely completion of projects, the Commission has decided to allow an additional return on equity at the rate of 0.5% to those projects that are completed within time, as stipulated in Appendix-II of these regulations. If the project is not completed within the stipulated timeline for any reasons whatsoever, the additional return of 0.5% shall not be admissible. Accordingly, draft Regulation 15 has been modified as sub-clauses (1) and (2) of Regulation 15 of these regulations as under:

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

(2) Return on equity shall be computed on pre-tax basis at the base rate of 15.5% to be grossed up as per clause (3) of this regulation:

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

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

13.12 In case of projects commissioned on or after 1st April, 2009, an additional return of 0.5% shall be allowed if such projects are completed within the following timeline decided in consultation with CEA:

1. The completion time schedule shall be reckoned from the date of investment approval by the Board (of the generating company or the transmission licensee), or the CCEA clearance as the case may be, up to the date of

commercial operation of the units or block or element of transmission project as applicable.

2. The time schedule has been indicated in months in the following paragraphs and tables:

A. Thermal Power Projects

Coal/Lignite Power Plant

Unit size 200/210/250/300/330 MW and 125 MW CFBC technology

(a) 33 months for green field projects. Subsequent units at an interval of 4 months each.

(b) 31 months for extension projects. Subsequent units at an interval of 4 months each.

Unit size 250 MW CFBC technology

(a) 36 months for green field projects. Subsequent units at an interval of 4 months each.

(b) 34 months for extension projects. Subsequent units at an interval of 4 months each.

Unit size 500/600 MW

(a) 44 months for green field projects. Subsequent units at an interval of 6 months each.

(b) 42 months for extension projects. Subsequent units at an interval of 6 months each.

Unit size 660/800 MW

(a) 52 months for green field projects. Subsequent units at an interval of 6 months each.

(b) 50 months for extension projects. Subsequent units at an interval of 6 months each.

Combined Cycle Power Plant

Gas Turbine size upto 100 MW (ISO rating)

(a) 26 months for first block of green field projects. Subsequent blocks at an interval of 2 months each.

(b) 24 months for first block of extension projects. Subsequent units at an interval of 2 months each.

Gas Turbine size above 100 MW (ISO rating)

(a) 30 months for first block of green field projects. Subsequent blocks at an interval of 4 months each.

(b) 28 months for first block of extension projects. Subsequent units at an interval of 4 months each.

B. Hydro Electric Projects

The qualifying time schedule for hydro electric projects shall be as stated in the original concurrence issued by the Central Electricity Authority under section 8 of the Act.

C. Transmission Schemes: Qualifying time schedules in months

S. No.	Category of Transmission Project	Plain Area	Hilly Terrain	Snowbound area@/ very difficult Terrain
A	765 kV S/C Transmission line	30	36	40
B	+/-500 KV HVDC Transmission line	24	30	34
C	400 KV D/C Quard Transmission line	32	38	42
D	400 KV D/C Triple Transmission line	30	36	40

E	400 KV D/C Twin Transmission line	28	34	38
f	400 KV S/C Twin Transmission line	24	30	34
G	220 KV D/C Twin Transmission line	28	34	38
H	220 KV D/C Transmission line	24	30	34
I	220 KV S/C Transmission line	20	26	30
J	New 220 KV AC Sub-Station	18	21	24
K	New 400 KV AC Sub-Station	24	27	30
L	New 765 kV AC Sub-Station	30	34	$
M	HVDC bi-pole terminal	36	38	-
N	HVDC back-to-back	26	28	-
@ e.g. Leh, Laddakh				
$ No 765 KV sub-Station has been planned in difficult terrain				

Notes

(i) In case a scheme having combination of the above mentioned types of projects, the qualifying time schedule of the activity having maximum time period shall be considered for the scheme as a whole.

(ii) In case a transmission line falls in plain as well as in hilly terrain/snow bound area/very difficult terrain, the composite qualifying time schedule shall be calculated giving proportional weightage to the line length falling in each area.

13.13 The Commission has noticed that the timelines for the coal/lignite-based projects do not mention the word first unit before the words “green field projects” and “extension projects”. This has been noted and shall be corrected.

13.14 The return on equity with respect to the actual tax rate applicable to the generating company or the transmission licensee, as the case may be, in line with the provisions of the relevant Finance Acts of the respective years during the tariff period shall be trued up separately for each year of the tariff period along with the tariff petition filed for the next tariff period.

14. Pre-tax Return {Regulation 15(4)}

14.1 Earlier in the draft regulation, the Commission proposed to retain the post-tax return on equity and tax on the income streams of the generating company or the transmission licensee, as the case may be, from its core business excluding net UI income and incentives was allowed to be recovered from the beneficiaries, or the long-term transmission customer, as the case may be.

14.2 The issue of allowing post-tax rate of return or pre-tax rate of return was raised in public hearing as well as written submissions. The generating companies and transmission licensees are in favor of retaining existing regulation. In other words, they are of the view that all the risks pertaining to tax on income from core business including incentive, efficiency gain, income on UI, etc should be passed on to the beneficiaries. On the other hand, beneficiaries want that income tax burden to the extent of normal return on equity should only be passed on to the beneficiaries and any proportion of income tax on account of income other than return on equity, like income accrued due to efficiency gain, incentive, UI, normative expenditure, etc should be borne by the utilities themselves.

14.3 Under post-tax rate of return on equity the beneficiaries are paying tax on the net income of the utilities and the tax burden is calculated by grossing up. Considering the present tax rate of 33.99% applicable to the company’s form of business, under grossing up methodology, the tax burden becomes almost 50% of the net income of the utility. The beneficiaries are not against refunding income tax to the utilities on the admitted return on equity. The beneficiaries also do not have any objection if the utilities run their business more efficiently and thereby optimize their annual income provided no further cost on account of income tax on income other than admitted return on equity is passed on to them. From the utilities point of view, in a regulated business, the tax burden is reimbursed from the beneficiaries or the consumers on no profit and no loss basis. Consumers pay for the income tax only when it is actually levied on the utilities. In case of any refund of income tax, the same is also passed on to the beneficiaries. Under existing regulation, even the benefit of income tax holiday under section 80IA of the Income Tax Act, 1961 is passed on to the beneficiaries. This benefit of income tax holiday is available to the investors only for development of infra-structure facilities. In case, the passing on the tax burden to the beneficiaries is restricted only to the return on equity component, there is no logic in passing on the benefit of income tax holiday under section 80IA of the Income Tax Act, 1961 to the beneficiaries.

14.4 The Commission, after considering all the views of all stakeholders is of the view that it will be appropriate to move to the system of pre-tax rate of return on equity from the existing post-tax rate of return on equity. Accordingly, the Commission has decided to allow pre-tax rate of return on equity to the utilities. The same shall be calculated by considering the applicable tax rate for the companies for the year 2008-09 as per the relevant Finance Act, as base rate. To give an example:

(i) In case of a generating company or transmission licensee paying Minimum Alternate Tax (MAT) @ 11.33% including surcharges and cess:

Rate of pre-tax return on equity = 15.50/ (1-0.1133) = 17.481%

(ii) In case of a generating company or transmission licensee paying normal existing corporate tax @ 33.99% including surcharge:

Rate of pre-tax return on equity = 15.50/ (1-0.3399) = 23.481%.

14.5 In order to facilitate computation of pre-tax, illustrative examples on the above lines have been given in clause 4 of Regulation 15 of these regulations.

14.6 With this change, the beneficiaries will be required to meet the Income Tax liability limited to the equity of the project, considered for tariff purposes and not on other incomes, such as incentive, profit arising out of efficiency improvement, UI Income and the like.

15. <u>Interest on Loan (Regulation 16)</u>

15.1 It was proposed in the draft regulations that the loan arrived on the basis of debt-equity ratio to be determined as per the provision of draft regulation 13 would be considered as gross normative loan for the purpose of calculation of interest on loan. It was proposed that the normative loan outstanding as on 1.4.2009 would be worked out by deducting the cumulative repayment admitted by the Commission upto 31.3.2009. The repayment for the respective year should be deemed to be equal to depreciation allowed for that year. The interest on loan would be calculated on the normative average loan by applying weighted average rate of interest. The weighted average rate of interest has to be worked out on the basis of actual loan portfolio of the generating company or transmission licensee. In the absence of actual loan portfolio in a particular year, the last weighted average rate of interest and in the absence of any loan, the weighted average rate of interest of the generating company or transmission licensee would be taken into account. The draft regulation further provided for refinancing of loan and sharing of benefits with the beneficiaries in the ratio of 2:1.

15.2 Utilities like NTPC, Gujrat SECL have suggested de-linking repayment from depreciation and provision for a higher rate of depreciation to enable them to meet their cash outflow on account of loan repayment obligations. NHPC and SJVNL have proposed additional depreciation in the current tariff period if cumulative repayment is more than the cumulative depreciation allowed at the beginning of the tariff period. As regards sharing of net benefit on account of refinancing of loan, companies like PGCIL, Power links, Universal Infratech advocated sharing in the ratio of 1:1 while beneficiaries like MPPTCL, KSEB, and OPTCL have proposed that entire benefits be passed on to the consumers. Bangalore SEDCL has proposed a lower ratio of 3:1 for sharing the benefits between the consumers and the utilities and also suggested that swapping expenses should be borne by the utilities only. Torrent power has suggested to consider actual rate of interest instead of benchmarked rate of interest.

15.3 The Commission has considered the views of the utilities and beneficiaries. As regards linking the repayment of loan to depreciation, the Commission feels that the provision should continue for the reasons explained in para 11 of the explanatory memorandum to the draft regulation. As regards the sharing of the benefits, the Commission is of the view that refinancing should be undertaken only if it is beneficial to the consumers and major portion of the benefits should be passed on to beneficiaries while allowing the utilities to retain one-third for the initiative taken by them to refinance the loan. Any cost incurred in such refinancing will be reimbursed by the beneficiaries and the net savings will be shared. Moreover, the changes to the terms and conditions of the loan shall be reckoned from the date of refinancing and will not have any retrospective operation.

15.4 The Commission, in its draft regulation 16(3) proposed the following:
"Provided that if on 1.4.2009, the cumulative depreciation recovered is more than the cumulative normative loan repayment, the repayment for the first year of the tariff period shall be deemed to 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 1.4.2009."

The difference in cumulative depreciation and cumulative repayment has occurred mainly due to the provisions of past regulations specified by the Government of India or the Commission. The Commission has decided to consider the amount of depreciation admitted as the amount of repayment for the tariff period 2009-14. If past provisions are revisited time and again then regulatory uncertainty will be created. As such the Commission has decided to delete this provision.

16. Depreciation (Regulation 17)

16.1 The Commission, in its draft regulation, under clause 17 proposed that:

"17. Depreciation. (1) The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission.

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

(3) Land shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing 90% of the capital cost of the asset.

(4) Depreciation shall be calculated annually, over the useful life of the asset and at the rates specified in the table below:

Sl No	Description of Asset	Useful Life (in years)	Rate for first 15 years (%)	Rate for remaining life (%)
1.	Thermal generating station	25	4.67	2
2.	AC and DC sub-station	25	4.67	2
3.	Hydro generating station	35	4.67	1
4.	Transmission line	35	4.67	1

Provided that in case of the existing projects already in operation prior to 1.4.2009, depreciation shall be recovered in the following manner, namely-

(a) For generating station and transmission system which are in operation for less than 15 years, the difference between the cumulative depreciation recovered and the cumulative depreciation arrived at by applying the depreciation rates specified in this regulation corresponding to 15 years, shall be spread over the period up to 15 years, and thereafter the depreciation shall be recovered at the rates specified for the remaining useful life after 15 years.

(b) For the project in operation for more than 15 years, the balance depreciation to be recovered shall be spread over the remaining useful life.

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

16.2 As per the 2004 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 conditions.

16.3 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.

16.4 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 for the Commission to ensure 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.

16.5 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 the absence of AAD, the amount of depreciation calculated as per the existing methodology will not be enough to meet the loan repayment obligations.

16.6 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.' 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 due to high gearing.

16.7 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 12 years, annual repayment would be around 5.83% 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.

16.8 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.

16.9 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 conditional ties like a ceiling of one-tenth of the normative gross loan. It was noted that in some cases the rate of depreciation plus AAD allowed for tariff purposes exceeded the rate as per Companies Act, 1956 resulting in front loading in tariff.

16.10 The Commission has received number of suggestions from different stakeholders on treatment and calculation of depreciation for the purpose of tariff against the draft proposal. Hydro generators like NHPC has proposed to allow depreciation @5.83% for the first 12 years and spread over the balance depreciable value of the assets over the balance useful life of the assets @1.09%. SJVNL advocated for 5.28% of depreciation and also proposed to allow depreciation against the land for reservoir in case of hydro generating station. Companies like PGCIL, NTPC, Gujrat Industries SEDCL, Universal Infratech, India Energy Forum and individual like Mr. C. P. Jain, ex-CMD of NTPC have proposed rates of depreciation as prescribed in the Companies Act, 1956. Companies like NHDC, NLC, Power Link, GMR, individual like Mr. T. L. Shankar have proposed even higher rate of depreciation, like 6% to 8% during the initial years of the project life. However almost all the beneficiaries like TNEB, Kerela SEB, GRIDCO, MPPTC, UPPCL have objected to the frontloading of tariff and have proposed to link the depreciation rate with the life of the assets as per the existing depreciation schedule. Some of the beneficiaries advocated increasing the life of both the generating plants and transmission system. In view of the past experience that these assets have been giving service for more than the useful life specified in the existing schedule of depreciation the beneficiaries proposed to increase the useful life of the assets by at least 5 years across all assets.

16.11 It is also observed that in case of hydro generating station, the agreement signed by the developers with the State Government for creation of the site have certain provisions in regards to the salvage value to be considered and the developers are not binding themselves under long term power purchase agreement to sale electricity to the tune of 100% percent capacity.

16.12 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 and 350 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 is 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 12 years, 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.

16.13 In a regulatory environment, the Commission has to protect the interest of the consumers while determining tariff and at the same time it is to be seen that the investors are having sufficient liquidity and revenue to meet their commercial commitment. Apart from paying regular dividend to the shareholders the utilities should have sufficient liquidity to cater to the loan repayment obligation. The Commission is aware of the burden of repayment of loan that will accrue over the initial years of the project life. Linking depreciation to the useful life of the assets may not provide sufficient cash flow to the utilities to meet their loan repayment obligation. Normally, the projects are having a debt component of 50% to 70% and are repayable over a period of 12 years. If higher depreciation is allowed over a period of initial 12 years, the debt repayment obligation can easily be met by the utilities. Once the loans are repaid, the benefit of reduced tariff should go to the consumers.

16.14 Accordingly, the Commission feels that the loan repayment period be treated as 12 years for all normative loans and accordingly this repayment period of 12 years be linked to depreciation. For 12 years during which the loan capital would be refunded to the investors in the form of depreciation, the rate of depreciation shall be as specified in appendix-III of the regulation and thereafter the remaining depreciable value shall be spread over the balance useful life of the assets.

16.15 In regard to the rates of depreciation, it has been stated in the Tariff Policy that the depreciation rates for the assets shall be specified by the Central Electricity Regulatory Commission and this rate of depreciation shall be applicable for the purpose of tariff as well as accounting. In fact some of the countries have prescribed Uniform System of Accounts (USoA) for the regulatory entities to bring in uniformity in their system of accounts. Some of the utilities have proposed to adopt the provision of Schedule XIV of the Companies Act, 1956 directly for tariff calculation. Schedule XIV does not have specific rate of depreciation that can be applied directly for generation, transmission and distribution assets used in electricity business. Some of the generating companies are using the rates specified for plants and machineries under continuous operation in schedule XIV to their thermal generating assets for the purpose of accounting whereas hydro generating companies and transmission licensees are applying the depreciation rates specified by the Commission for the purpose of accounting as well as tariff. As per the Companies Act, 1956 the revalued cost of the assets can be the value base for calculation of depreciation whereas for determination of tariff depreciation is calculated on the capital cost admitted by the Commission and do not allow the revalued cost of the assets. The Companies Act, 1956 also allows calculation of depreciation when the asset is ready for use whereas under regulatory system depreciation is calculated only when the asset is put to use. There are also some other differences between the Companies Act, 1956 and regulatory system in calculation of depreciation, like, inclusion of spares in the value base, consideration of salvage value, etc. As the Companies Act, 1956 does not provide specific rate of depreciation that can be applied directly for generation, transmission and distribution assets used in electricity business; it will not be possible to maintain uniformity in calculation of depreciation amongst the various utilities in electricity business.

16.16 It has been the practice since 1948 to specify rates of depreciation for various assets used in electricity business separately either by Government of India or the

Commission. So, in order to bring an uniformity in the rates of depreciation, while providing a higher rates of depreciation during the initial years of useful life of the projects, the Commission decides to specify rates of depreciation for various assets in a separate schedule. The depreciation rates for different assets have been so assigned as to arrive at the weighted average rate approximating 5.28%. The depreciation rates as given in Appendix-III of the regulation have no bearing on the useful life of the projects as defined in regulation 3(42).

16.17 During hearing some of the developers like NHDC, SJVNL, THDC indicated that the land which gets submerged and used for reservoir are not capable of being reclaimed or retrieved and hence cost of such land should be treated as depreciable asset. Normally land is considered to be a non-depreciable asset for accounting purposes. However, due to the peculiar nature of hydro project where the land area gets submerged and land used for reservoir are not available for any other use, the Commission considered the request to be genuine and accordingly decided that land other than the land held under lease and the land for reservoir in case of hydro generating stations shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing the depreciable value of the assets.

16.18 Accordingly, the Commission decides that the provision for depreciation shall be as given below:

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

(2) The salvage value of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of the capital cost of the asset.
Provided that in case of hydro generating stations, the salvage value shall be as provided in the agreement signed by the developers with the State Government for creation of the site:

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

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

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

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

(5) In case of the existing projects, the balance depreciable value as on 1.4.2009 shall be worked out by deducting the cumulative depreciation as admitted by the Commission upto31.3.2009 from the gross depreciable value of the assets.

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

17. Interest on Working Capital(Regulation 18)

17.1 Draft Regulation 18 dealing with interest on working capital made two significant departures from the 2004 regulations. Firstly, receivable was reduced from 60 days to 45 days and the provision for O & M expenses for one month was deleted.

17.2 Most of the utilities objected to these changes proposed in the draft regulation. Utilities like DVC, PGCIL, NEEPCO, THDC, NTPC, NHPC, NHDC, GMR, Gujrat

SECL, MahaGenco, Energy Infratech, Avanta power, other organizations like CII, India Energy Forum, etc and individuals like Mr. C. P. Jain suggested for retention of existing norms, particularly, receivables for 60 days instead of 45 days to align with the rate of rebate proposed in the draft regulation, and O&M expenses of one month in calculation of normative working capital requirement, as otherwise the liquidity position of the utilities would be impaired.

17.3 On the other hand beneficiaries like GRIDCO, BSEB, and consumers like Er. R. B. Sharma proposed further reduction of fuel stock to ½ month in case of pit-head stations and to 1 month in case of non pit-head stations on the ground that in actual practice, the thermal generating stations do not even maintain coal stock of 7 days .

17.4 The Commission has considered the concerns of the utilities. Draft Regulations 34 and 35 dealing with rebate and surcharge provide that a rebate of 1% will be admissible if the payment is made within one month and a surcharge of 1.25% will be levied in case the payment is delayed beyond 60 days. As payments are to be made by the beneficiaries without surcharge within a period of 60 days, it is imperative that the generating companies and transmission licensees are made available with working capital at least for a period of sixty days. In order to bring parity with the provision on rebate and late payment sur-charge corresponding to the provision of receivables in the calculation of normative working capital requirement, is the Commission decided to restore 60 days of receivables in calculation interest on working capital.

17.5 Regarding inclusion of one month of O&M expenses as a part of the working capital requirement, this provision has been there even prior to the Commission came into being. Sudden removal of one month of O&M expenses from working capital requirement may lead to regulatory uncertainty. It may also have impact on the liquidity position of the utilities. Considering all the facts stated above, the Commission decided to include one month of O&M expenses as a part of working capital requirement.

18 Maintenance Spares in Working Capital {Regulation 18(a) to (e)}

18.1 In the draft regulation, the Commission had specified norms for maintenance spares as a percentage of O&M norms to be considered in the computation of interest on working capital. The norms were based on the data furnished by the CPSUs about the consumption of spares and the inventory of stores maintained by them for the years 2002-03 to 2006-07. The following norms for maintenance spares were 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 System	15% of O&M norms.

18.2 Inadvertently in the explanatory memorandum, the norms were stated to be arrived based on the inventory of stores alone maintained by the CPSUs. Many of the beneficiaries have expressed the view that the norms of maintenance spares should be based on consumption of spares. Some of them have submitted that the norms are on higher side.

18.3 In this regard, the Commission would like to clarify that the maintenance spares norms stated in the draft regulations were arrived after considering the consumption of spares and inventory of stores during the last four years. The details of consumption of spares by the coal based stations and gas based stations of NTPC for the years 2004-05 to 2007-08 are given below*:*

Rs.lakh/MW)

Sr. No.	Station	Capacity (MW)	2004-05	2005-06	2006-07	2007-08
1	Dadri (4x210)	840	2.02	2.36	2.45	2.81
2	Kahalgaon (4x210)	840	2.27	3.36	3.74	4.74

3	Unchahar (2x210+2x210+210)	1050	2.12	2.48	2.31	2.52
4	Simhadri (2x500)	1000	2.09	1.21	1.24	1.79
5	Talchar (2x500 + 4x500)	3000	1.41	1.50	3.30	2.06
6	Rihand (2x500 + 2x500)	2000	2.67	2.54	1.70	2.89
7	Korba (3x200+3x500)	2100	1.84	1.97	1.70	2.23
8	Farrakka (3x200+2x500)	1600	0.26	0.34	0.23	3.73
9	Singrauli (5x200+2x500)	2000	2.63	2.59	3.35	3.51
10	Ramagundam (3x200+3x500+1x500)	2600	1.59	1.86	2.62	2.22
11	Vindhyachal (6x210+2x500+2x500)	3260	2.10	2.07	2.40	1.56
12	Badarpur (3x95 +2x210)	705	2.64	4.78	4.62	4.40
13	Talchar taken over (4x60+2x110)	460	3.90	3.27	3.73	4.50
14	Tanda (4x110)	440	3.58	2.98	2.74	4.33
15	Anta (3x88.7+1x153.2)	419.33	4.73	2.25	5.97	1.40
16	Auraiya (4x111.19+2x109.3)	663.36	2.41	2.30	2.21	2.26
17	Dadri (4x130.19+2x154.51)	829.84	1.15	5.17	4.94	9.33
18	Faridabad MW (2X140.827 + 1X149.932)	431.586	0.52	0.70	6.07	2.34

19	KaymkulamMW (GT-2x 116.6 + ST-1x126.38)	359.58	0.75	0.72	0.65	1.74
20	Kawas (4x106+2x116.1)	656.2	5.98	2.46	1.60	2.41
21	Gandhar (3x144.3+1x224.49)	657.39	1.79	2.80	2.86	6.08

18.4 The 4 years average consumption of maintenance spares in the base year 2007-08 considering annual escalation of 5.26% per annum and then escalating the base spare consumption of 2007-08 @ of 5.72% per annum to arrive at maintenance spares consumption in the year 2009-10 for stations having 200/210 MW sets, stations having 500 MW sets and station having mix of 200/210 MW and 500 MW sets are as under:

Sr. No.	**Station**	**Capacity (MW)**	**4 yrs. Average at 2007-08 price level (Rs.lakh/MW)**	**4 yrs. Average at 2009-10 price level (Rs.lakh/MW)**	**O&M Cost Norm (Rs.lakh/MW)**	**% of O&M Cost Norms**
1	Dadri (4x210)	840	**2.59**	**3.28**	18.20	18.02
2	Kahalgaon (4x210)	840	**3.76**			
3	Unchahar (2x210+2x210+210)	1050	**2.54**			
4	Simhadri (2x500)	1000	**1.72**	**2.54**	13.00	19.54
5	Talchar (2x500 + 4x500)	3000	**2.21**			
6	Rihand (2x500 + 2x500)	2000	**2.65**			

7	Korba (3x200+3x500)	2100	**2.09**			
8	Farrakka (3x200+2x500)	1600	**1.16**			
9	Singrauli (5x200+2x500)	2000	**3.24**	**2.49**	15.01	16.59
10	Ramagundam (3x200+3x500+1x500)	2600	**2.23**			
11	Vindhyachal (6x210+2x500+2x500)	3260	**2.21**			
12	Badarpur (3x95 +2x210)	705	**4.41**	**4.93**	31.35	15.73
13	Talchar taken over (4x60+2x110)	460	**4.15**	**4.64**	32.75	14.17
14	Tanda (4x110)	440	**3.67**	**4.11**	26.25	15.66
15	Anta (3x88.7+1x153.2)	419.33	**3.92**			
16	Auraiya (4x111.19+2x109.3)	663.36	**2.48**			
17	Dadri (4x130.19+2x154.51)	829.84	**5.40**			
18	Faridabad MW (2X140.827 + 1X149.932)	431.586	**2.53**	**3.85**	14.8	26.01
19	KaymkulamMW (GT-2x 116.6 + ST-1x126.38)	359.58	**1.03**			
20	Kawas (4x106+2x116.1)	656.2	**3.45**			
21	Gandhar (3x144.3+1x224.49)	657.39	**3.57**			

18.5 The inventory of stores maintained by NTPC during the year 2004-05 to 2007-08 is as under:

Sr. No.	**Station**	**Capacity (MW)**	**2004-05**	**2005-06**	**2006-07**	**2007-08**
1	Dadri (4x210)	840	9.79	8.72	8.22	8.53
2	Kahalgaon (4x210)	840	3.89	4.32	5.34	6.61
3	Unchahar (2x210+2x210+210)	1050	5.73	5.78	6.51	6.92
4	Simhadri (2x500)	1000	5.53	5.40	5.48	6.53
5	Talchar (2x500 + 4x500)	3000	5.36	4.62	7.20	5.30
6	Rihand (2x500 + 2x500)	2000	6.47	6.55	5.78	6.53
7	Korba (3x200+3x500)	2100	4.09	4.20	4.49	4.18
8	Farrakka (3x200+2x500)	1600	6.65	7.66	8.72	8.49
9	Singrauli (5x200+2x500)	2000	5.48	5.41	5.54	6.02
10	Ramagundam (3x200+3x500+1x500)	2600	4.67	4.19	4.25	5.20
11	Vindhyachal (6x210+2x500+2x500)	3260	4.61	4.50	4.80	4.33
12	Badarpur (3x95 +2x210)	705	8.30	7.92	7.27	7.28

13	Talchar taken over (4x60+2x110)	460	8.89	8.63	8.40	8.34
14	Tanda (4x110)	440	3.20	3.52	4.26	6.63
15	Anta (3x88.7+1x153.2)	419.33	6.80	6.93	7.00	6.67
16	Auraiya (4x111.19+2x109.3)	663.36	3.85	3.72	3.67	4.16
17	Dadri (4x130.19+2x154.51)	829.84	1.03	2.26	3.30	2.96
18	Faridabad MW (2X140.827 + 1X149.932)	431.586	3.05	3.18	3.03	3.46
19	KaymkulamMW (GT-2x 116.6 + ST-1x126.38)	359.58	5.35	6.02	6.19	6.34
20	Kawas (4x106+2x116.1)	656.2	6.58	6.52	6.37	6.16
21	Gandhar (3x144.3+1x224.49)	657.39	6.88	6.83	6.98	7.24

18. 6 The average inventory of stores in different categories of unit sizes in the year 2009-10 has been worked out following the same methodology as in case of consumption of spares given above and the calculations are as under:

Sr. No.	**Station**	**Capacity (MW)**	**4 yrs. Average at 2007-08 price level**	**4 yrs. Average at 2009-10 price level**	**O&M Cost Norm (Rs.lakh/MW)**	**% of O&M Cost Norms**

			(Rs.lakh/MW)	(Rs.lakh/MW)		
1	Dadri (4x210)	840	**9.57**	**8.03**	18.20	44.12
2	Kahalgaon (4x210)	840	**5.39**			
3	Unchahar (2x210+2x210+210)	1050	**6.71**			
4	Simhadri (2x500)	1000	**6.18**	**7.09**	13.00	54.54
5	Talchar (2x500 + 4x500)	3000	**6.06**			
6	Rihand (2x500 + 2x500)	2000	**6.86**			
7	Korba (3x200+3x500)	2100	**4.58**	**6.21**	15.01	41.37
8	Farrakka (3x200+2x500)	1600	**8.48**			
9	Singrauli (5x200+2x500)	2000	**6.06**			
10	Ramagundam (3x200+3x500+1x500)	2600	**4.94**			
11	Vindhyachal (6x210+2x500+2x500)	3260	**4.94**			
12	Badarpur (3x95 +2x210)	705	**8.35**	**9.33**	31.35	29.76
13	Talchar taken over (4x60+2x110)	460	**9.28**	**10.37**	32.75	31.66
14	Tanda (4x110)	440	**4.68**	**5.24**	26.25	19.98
15	Anta (3x88.7+1x153.2)	419.33	**7.41**	**5.92**	14.8	40.09
16	Auraiya (4x111.19+2x109.3)	663.36	**4.16**			

17	Dadri (4x130.19+2x154.51)	829.84	**2.53**				
18	Faridabad MW (2X140.827 + 1X149.932)	431.586	**3.43**				
19	KaymkulamMW (GT-2x 116.6 + ST-1x126.38)	359.58	**6.44**				
20	Kawas (4x106+2x116.1)	656.2	**6.94**				
21	Gandhar (3x144.3+1x224.49)	657.39	**7.55**				

18.7 It can be seen that average inventory of stores maintained by NTPC stations is much higher than the consumption of spares. The consumption of spares ranges amongst 14.16% to 19.54% of the O&M cost norms in various categories of coal based units. In case of stations having small unit sizes of 100 MW & 60 MW namely Talcher, Tanda and Badarpur, the consumption of spares is on lower side. In case of gas base stations, the average consumption of spares is of the order of 26% of the O&M cost norms. It needs to be appreciated that the generating companies would require to keep an inventory which should be higher than the actual consumption of spares. We are not inclined to be guided by the level of inventory maintained by the NTPC stations. We feel that the margin of about 15-20% over and above the actual spare consumption should be sufficient and reasonable to arrive at the norms for the purpose of considering maintenance spares in the working capital computation. Accordingly, we find that the norms specified by us in the draft regulations are in order. In case of hydro generating station and transmission system, since the spare consumption is less than in the case of coal based generating stations, we are inclined to keep the norms for hydro generating station and transmission system as 15% of the O&M norms.

19. O&M EXPENSES (Regulation 19)

19.1 The draft regulation provided separate sets of norms for the coal/lignite based stations depending upon unit sizes without distinguishing between new and existing stations. In respect of some of the coal/lignite based stations of NTPC namely Talcher, Tanda and Badarpur, DVC namely chandrapura, Bokaro and Durgapurand NLC's TPS-I & TPS-II relaxed norms were specified. For Gas/liquid fuel based combined cycle stations separate norms for small gas turbines and other than small gas turbines were specified. Relaxed norms for Agartala GPS of NEEPCO were specified. For transmission system, norms for lines and substations were specified depending upon voltage level and separate norms for HVDC system.

19.2 The norms were specified after considering actual of thermal generating stations of Central Utilities and some of the generating stations State Utilities and IPPs for the period 2004-05 to 2006-07 and factoring in 45% increase (30% increase for transmission system due to inadvertent mistake instead of 45% increase) in employee cost due to pay revision and considering annual escalation factor of 5.17%. The annual escalation factor was based on the average of last last five years.

19.3 NTPC during the hearing as well as through written affidavit has submitted as under:

(a) Norms should be based on actual for 2005-06 to 2007-08;
(b) Escalation rate should be 7%;
(c) Actual wage hike would be of the order of 64%;
(d) Salary hike should be considered in security expenses also;
(e)Loss in stock, incentive and ex-gracias, prior period adjustment etc should not be disallowed.
(f)The rationalisation of man power is not possible in Talcher & Badarpur and there would be escalation in other heads of expenditure other than employee cost.

(g)The water charges should be allowed on actual separately

19.4 NLC has submitted that norms for 200 MW sets and 500 MW sets should be worked out separately and O&M expenses for 2007-08 should also be considered. They have further submitted that O&M norms for the TPS-I should be worked out separately. They have further submitted that the wage hike provision should be of the order of 55 to 60% and that the escalation rate considered is low. DVC has submitted that the norms specified for DVC stations are very stringent. Regulation should not be applied to DVC stations.

19.5 Beneficiaries on the other hand submitted that the actual of NTPC stations are much higher than the stations of States. Provision of wage revision of 45% is high. Norms for 500 MW are on higher side. It was also submitted that the norms for 200/210/250 MW sets is even higher than the 2.5% of the current cost of the new stations.

19.6 In the light of submissions and concerns of the stakeholders the norms have been reviewed. Since the actual of 2007-08 have been made available by the Central utilities in respect of their stations, there is no problem in considering the actual of 2007-08 also. The actuals and normalized O&M expenses of Central utilities for the years 2004-05 to 2007-08 considered by the Commission are at Annexure-A. For the purpose of normalization, incentive & ex-gratia paid to its employees, donations, loss in stock, prior period adjustments, claims and advances written off, provisions including provisions of pay revision have been excluded.

19.7 As regards escalation rate, Commission at the draft stage considered the average annual escalation rate of 5.17% based on CPI and WPI indices for the five years from 2003-04 to 2007-08. This escalation rate was considered for arriving at the base O&M expenses for the year 2008-09 and the same rate was applied for arriving at norms during the tariff period 2009-14. Where as, only three year data of 2004-05 to 2006-07 was considered for the purpose of norms. The Commission is of the view that the escalation rate should be average of the period for which O&M expenses are being considered for arriving at base O&M expenses in 2008-09 where as for future, trend up to 2008-09 should also be captured.

19.8 In case of thermal generating stations, Commission is considering O&M expenses for the four year period from 2004-05 to 2007-08 since the existing O&M norms were specified w.e.f. 1.4.2004. Hence the annual escalation rate for arriving at base O&M cost at 2007-08 price level has been worked out as 5.26% based on escalation rates for the year 2004-05 to 2007-08. However, for the transmission system, Commission is considering O&M expenses for the five year period from 2003-04 to 2007-08 in order to capture rationalization of manpower. Hence the annual escalation rate for arriving at base O&M cost in 2007-08 has been worked out as 5.17% based on escalation rates for the year 2003-04 to 2007-08. The escalation rate for the tariff period has been arrived at 5.72% after considering the inflation data up to October 2008. The details of escalation rate for the period 2003-04 to Oct 2008 are as follows:

19.9 The last revision of the scale of pay of below Board level and Board level executives and non-unionised supervisors, in Central Public Sector Enterprises was made effective from 1.1.1997. The Government had set up a Pay Revision Committee (2^{nd} PRC) under the chairmanship of Justice M. Jagannadha Rao, Retd. Judge of Supreme Court of India, to recommend revision of pay and allowances for above categories of employees following IDA pattern of pay scales w.e.f. 1.1.2007. The recommendations of the Committee were before the Government for final decision and pending such decision Commission had provided for a normative increase of 45% in the employee cost while arriving at the O&M norms for the thermal and transmission system in the draft regulations. The Government after due consideration of the recommendations of 2^{nd} Pay Revision Committee, have decided vide OM No.2(70)/08-DPE(WC) dated 26.11.2008 on revision of scales and pay w.e.f. 1.1.2007, covering revised pay scales fitment benefit, rate & increments, allowances, performance related pay and the like.

19.10 The CPSUs regulated by us were asked to make their estimation of hike on account of revision of scales of pay. The hike on account of revision of scales of pay estimated by some of the CPSU's are as follows:

NTPC	56%
Power Grid	70%
NLC	73%
NEEPCO	70%

The estimates submitted by NLC and NEEPCO were not supported by the calculations. The estimates of NTPC and Power Grid were however, gone into and it was observed that the increase includes PRP and allowances in excess of 50% of the basic. Further certain facilities like school; hospital facilities etc. at site were not monetized. On all these consideration, estimates of CPSU's appears to be on higher side. Commission after due consideration of various aspects covered in the implementation of pay revision has come to a conclusion that a uniform normative increase of 50% in employee cost would be just and reasonable for all CPSU's.

19.11 NTPC and NLC have pleaded to allow water charges separately as per actual as is done in case of taxes and duties as the State Governments have been frequently enhancing the water charges. The Commission is not inclined to accept that the water charges should be allowed as a pass through on the similar line as taxes and duties. O & M expenses of which water charge is a part has been specified on normative basis. There may be increase in actual expenses in some components and decrease in some other components of O&M. Therefore, the utilities should manage their expenses on O & M as admissible on normative basis in accordance with the regulations.

19.12 Having discussed the issues common to thermal, Hydro and Transmission system, now we now proceed to deal with O&M cost norms specific to thermal, hydro and transmission separately.

20. O&M expenses for Thermal Generating Station {Regulation 19(a) to (e)}

20.1 The Commission had specified following O&M cost norms for the coal/lignite based thermal generating stations of unit sizes 200 MW and above:

(Rs. in lakh/MW)

Year	200/210/ 250 MW sets	300/330/350 MW sets	500 MW sets	600 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

20.2For the generating stations having combination of above sets, the weighted average value for operation and maintenance expenses were to be adopted. For 200/210 MW unit size lignite based stations norms were same as that of similar coal based stations.

20.3 The Operation & Maintenance cost for the purpose of tariff covers expenditure incurred on the employees including gratuity, CPF medical, education allowances etc, repair and maintenance expenses including stores and consumables, consumption of capital spares not part of capital cost, security expenses, administrative expenses etc. of the generating stations, corporate expenses apportioned to each generating stations etc. but exclude the expenditure on fuel i.e. primary fuel as well as secondary and alternate fuels.

20.4 The above norms were based on actual of stations having either 200/210/250 MW sets, 500 MW sets and sets having combination of the 200/210/250 MW and 500 MW sets. The average O&M expenses for the year 2004-05 to 2006-07 were escalated at 5.17% up to 2008-09 and provided with 45% increase in employee cost to arrive at average of 13.77 Lakh/MW in 2009-10. This was divided into two sets of norms, one for 200/210/250 MW set and another for the 500 MW set as 15.70 Lakh/MW and 12.50 Lakh/MW. The beneficiaries have pointed out that the O&M norms for 500 MW sets are higher as compared to actual. As such, we have again reviewed the O&M norms considering actuals of 2004-05 to 2007-08 in each class.

20.5 The other point raised by the beneficiaries was that the O&M norms for 200/210 MW stations of NTPC are much higher than the O&M expenses of similar plants of State Utilities. We have already discussed in the explanatory memorandum to the draft regulations the expenses of Dhahanu and Bhatinda TPS were not comparable because it did not include the corporate expenses. Further we have examined the tariff orders of GERC, TNERC and Tariff filing of APGENCO and have found that the O&M expenses are not comparable with that of NTPC when compared on the basis of operational, performance and efficiency parameters. The stations of APGENCO whose performance is comparable with NTPC, elelment wise comparison was not possible due to difference in salary structure, operation and maintenance practices. In these circumstances, the Commission has relied on the actual expenses of NTPC and NLC. In the 200/210/250 MW category, the O&M expenses of Kahalgaon (4x210 MW) are much higher than the other stations of NTPC and NLC. NTPC has clarified vide their submission dated 27.10.2008 that the O&M expenses in case of Kahalgaon is high on account of higher maintenance expenses of coal mills due to poor quality of coal and additional expenses on chemical treatment of water due to its scaling nature. We have however noticed that the consumption of stores by NTPC and NLC has suddenly jumped in the year 2005-06 and repair and maintenance expenses are abnormally high in 2006-07. Nevertheless, the Commission is of the view that such site specific conditions should not effect the fixation of norms and as such, consumption pattern of kahalgaon can not be considered as representative data while arriving at the O&M cost norms for 200/210/250 MW category. Based on these considerations and after making adequate provision for revision of pay scales, the norms for the 200/210/250 MW series is worked out as 18.20 Lakh/MW in 2009-10.

20.6 In the 500 MW category, the data is available for three stations of NTPC which vary widely. The O&M expenses of Rihand STPS are much higher than the Talcher STPS. O&M expenses of Simhadri STPS are between the two. Considering the data of all the three stations in this category, O&M expenses in 2009-10 is worked out as 11.80 Lakh/MW. Alternatively, considering data of Rihand STPS and Simhadri STPS while leaving Talcher STPS (which has very less O&M expenses), the O&M expenses for 2009-10 works out to Rs.14.05 Lakh/MW. When the Commission applied the above norms of 18.20 Lakh/MW for 200/210/250 MW sets and 11.80 Lakh/MW for 500 MW sets in case of stations having mix of 200/210 MW and 500 MW sets, the average expenses fall short of O&M expenses based on actuals. On the other hand, when we apply the norm of Rs.18.20 Lakh/MW for 200/210/250 MW sets and Rs.14.05 Lakh/MW for 500 MW sets in case of stations having mix of 200/210 MW and 500 MW sets, the average expenses exceed the O&M expenses based on actuals. The Commission has observed that with a norm of Rs.13.00 Lakh/MW, O&M expenses based on norms are close to O&M expenses based on actuals. The Commission is conscious that future thermal generating stations will be dominated by 500 MW and above sets. The Commission has decided to adopt the O&M norm of Rs.13 Lakh/MW for the year 2009-10. In respect of lignite-fired stations using CFBC technology and stations proposed to have 300/330 MW sets, 600/660 MW sets and above, we do not have any credible data. Therefore, for CFBC based lignite fired stations the Commission has decided to allow the same norms as that of coal/lignite based stations. The norms for 300/330 MW sets are between 200/210/250 MW sets and 500 MW set. The O&M norms for the 600/660 MW and above sets are kept at 10% lower than the norms for the 500 MW sets considering economy of scale.

20.7 One of the points raised is that in case of 200 MW series the O&M norms are working out to be more than 2.5% of the current capital cost. The Commission has carefully examined this point. It has been observed that the presumption of O & M expenses @1.5% of capital cost of hydro generating stations and 2.5% of the capital cost of thermal generating stations is no longer valid based on the actual ground realities. It needs to be highlighted that while the capital cost of thermal and hydro projects over the last decades has varied marginally, O&M expenses which have a high weightage of man power, repair and maintenance, and consumables have increased substantially. As discussed in explanatory memorandum of the draft regulation, the man power for the 200 MW series thermal generating stations depends on the number of units where as repair & maintenance cost remains the same in absolute terms. Thus O & M expenses for 200 MW series work out to about 80% to 100% higher than the norms for 500 MW series in Rs lakh/MW terms.

20.8 In view of the above discussion, the following O&M norms are allowed for the period 2009-10 to 2013-14:

(Rs. in lakh/MW)

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

20.9 For the generating stations having combination of above sets, the weighted average value for operation and maintenance expenses were to be adopted. It is also felt that O&M expenses for the extension units of the same type at the same location should not be of the same order. The above norms capture economy of scale for a capacity range of 1000 to 1200 MW on an average. Commission is therefore, providing for following multiplying factors to be applied to the above O&M norms for permissible O&M expenses in respect of future additional units, in respective unit sizes for the units whose COD occurs on or after 01.04.2009.:

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

20.10 To explain the applicability of above provisions, if a 210 MW unit comes into operation during 2009-10 in a station already having four or more 200/210 MW units, then the norm for the extension unit would be calculated as 0.90x Rs. 18.20 lakh/MW. If 500 MW units come up in a station having only 200/210 MW units, then admissible O&M norm for the extension unit would be Rs.13.00 lakh/MW during 2009-10.

20.11 In respect of other stations of NTPC namely, 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, the Commission had proposed following O&M norms based on data of 2004-05 to 2006-07:

(Rs. in lakh/MW)

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

20.12 The NTPC was expected to rationalize man power in their Talcher TPS and Badarpur TPS and considering this no escalation was provide during the tariff period. However, NTPC has submitted that it would not be possible for them to rationalize man power to this extent and that there would be escalation in other heads of the O&M. NTPC has indicated rationalization of man power to the extent of 5-8% in case of Badarpur TPS whereas they have shown their helplessness in case of Talcher TPS. As such, in case of Badarpur TPS no escalation has been considered on the employee cost whereas escalation has been provided on other component of O&M cost. Accordingly following norms have been worked out based on the actual O&M expenses of 2004-05 to 2007-08:

(Rs. in lakh/MW)

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

20.13 As discussed in explanatory memorandum for the draft regulations, the manpower to MW ratio is very high in case of DVC stations. There is scope for rationalization of man power. Considering this, Commission is of the view that in case of Mejia which has 210 MW units O&M norms as applicable to other station of 210 MW units shall apply. However, in case of Bokaro TPS norms as applicable to Badarpur TPS should apply giving them time to rationalize their man power. 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. On the similar lines, following O&M norms are allowed for lignite based Generating stations namely TPS-I of NLC and unit of 125 MW capacity based on CFBC technology:

(Rs. in lakh/MW)

Year	**125 MW sets** using CFBC technology	**TPS-I**
2009-10	24.00	27.00
2010-11	25.37	28.54
2011-12	26.82	30.18
2012-13	28.36	31.90
2013-14	29.98	33.73

20.14 Ms Mallilika Sharma Bezbaruah, a consumer from north-east in her submission has pointed out that the salary and renumeration in O&M claimed by NEEPCO of Rs. 7393.37 Lakh for all projects including corporate office for the year 2004-05 is higher than the amount of Rs. 4083.94 lakh as per the annual report in profit and loss account. The issue has been examined by us and it is found that the amount claimed by NEEPCO in the year 2004-05 on account of salary and remuneration is lower than the salary and renumeration as per annual accounts for 2004-05 after accounting for the expenses charged to profit and loss account in the nature of corporate expenses. The other point raised by Ms Bezbaruah is as to how the incidental expenditure during construction could be apportioned as corporate expenses in profit and loss accounts. This has also been examined and is found that the corporate office expenses have not been booked in any other head. As such, we are relying upon the data furnished by NEEPCO. As regards, her argument that norms for the Agartala should be lower than the combined cycle station of Assam is also not acceptable for the reason that the major repair and maintenance cost occurs in gas turbine hot path and weighted average for CCGT plant comes down.

20.15 For the NTPC and NEEPCO gas/Liquid fuel Based stations considering actual of 2004-05 to 2007-08, following O&M expenses are being allowed

(Rs. in lakh/MW)

Year	Gas based Stations other than small gas turbine combined cycle stations	Small Gas turbines combined cycle stations	Agartala GPS
2009-10	14.80	22.90	31.75
2010-11	15.65	24.21	33.57
2011-12	16.54	25.59	35.49
2012-13	17.49	27.06	37.52
2013-14	18.49	28.61	39.66

21. Compensation Allowance (Regulation 19)

21.1 The draft regulations provided for following compensation allowance in respect of coal/lignite based station.

Years of operation	Compensation allowance (Rs. Lakh/MW)
0-10	Nil
11—15	0.15
15-20	0.35

20-25	0.65

21.2 Generating companies like NTPC have submitted that amounts of compensation allowance are not sufficient to meet the expenditure on new works required for successful plant operation. NTPC and NLC have sought following compensation allowance.

Years of operation	As per NTPC	As per NLC
0-5	0.15	Nil
6—10	0.15	0.1
11--15	0.25	0.2
15-20	0.44	0.35
20-25	0.82	0.65

21.3 NTPC has sought above compensation allowance excluding additional capital expenditure on buildings, road, spares, batteries etc. citing the expenditure in case of Singrauli STPS, though the claims have not supported with any details. The Commission's decision to introduce compensation allowance was based on available data on additional capitalisation in the tariff petitions of NTPC stations. For this purpose expenditure on new assets in the nature of Environment Action Plan (EAP), arising on account of change of law or dealing with design deficiency etc has not been considered.

21.4 In view of the above, the compensation allowance as proposed in the draft regulation has been retained as clause (e) of Regulation 19.

22. O&M EXPENSES OF HYDRO GENERATING STATIONS{Regulation 21(f)}

22.1 At the hearing, the stakeholders raised certain pertinent issues such as actual

O&M expenses are much higher than those allowed by the Commission for new stations, the annual escalation factor is based on last five years average, however, during last six months, inflation rate has jumped exorbitantly from about 5% to more than 11%. It has also came to the notice of the Commission that different methodologies have been adopted by the generating companies while claiming insurances charges in O&M expenses.

22.2 Almost all the hydro generating companies pleaded for increasing percentage of normative O&M expenses from the existing 1.5% of the capital cost up to cut off date, and to consider the cost of rehabilitation and resettlement works in the capital cost for the purpose of O&M component of tariff for new stations, etc.

The submissions of the hydro generating companies are summarized as under :

(a)NHPC:[i] NHPC in its submission has stated that the value of 1.5% of capital cost for computation of O&M expenses of hydro stations needs to be increased because O&M expenses actually incurred are much higher than 1.5%. NHPC has made studies which show that actual O&M expenses incurred by NHPC for the FY 2007-08 in respect of its new stations such as Chamera-II and Dhauliganga are 49% higher than normative in case of Chamera-II and 80.7% for Dhauliganga. Also from the data of normative v/s actual (audited) expenses of existing stations of NHPC, it would be seen that actual expenses are much higher than those allowed by the Commission and increase varying from 20% to 95%.

[ii]The Commission has recognized 45% increase in employees cost on account of pay revision. To give effect to 45% increase in case of new hydro stations which have not yet completed 5 years of operation, the base percentage of 1.5% is also required to be increased by 3%. Therefore, regulation should provide that O&M expenses be allowed @3% of capital cost in case of new hydro projects.

(b)THDC :O&M expenses admissible @ 1.5% of the capital cost as per prevailing Regulations 2004-09 are not even sufficient to meet actual expenses in light of escalated O&M expenses and increased salaries due to wage revision etc. Also, further reducing O&M expenses by excluding cost of R&R works does not seem to be justified. The older projects are proposed to be paid on actual of their average expenditures plus 45% increase in employee cost on account of pay revision whereas new projects have been proposed at 1.5% of capital cost, which would be insufficient to meet the expenses. THDC has further submitted that O&M expenses on storage type projects are more as these projects require more expenditure on the maintenance of reservoir as compared to ROR projects. During 2007-08, Tehri HPP incurred actual O&M expenses amounting to Rs 170.58 crore which works out to 2.45% of final completion cost excluding R&R cost .

(c)NHDC : [i) The provision of exclusion of R&R cost from capital cost for evaluating O&M expenses @ 1.5% is irrational for ISP, which is having very high R&R cost component (Rs. 1878 crore) to the extent of 50% of total project cost including irrigation component. Actual O&M expenses of ISP is coming even more than that allowed in the existing tariff while including R&R cost in the total capital cost. In case R&R cost is excluded then normative rate of O&M expenses needs to be kept at least @ 3% of capital cost with escalation.

[ii) The escalation factor @5.17% considered in the draft regulation is based on average escalation during last five years considering 60% weight age for WPI and 40% for CPI. However, during last six months, inflation rate has jumped exorbitantly from about 5% to more than 11%. Keeping this into consideration, escalation factor may either be fixed on normative basis with reasonable escalation but not less than 8% per annum or it be linked directly with inflation rate at the beginning of each Financial year.

[iii) Fitment benefit @ 45% increase in employees cost on account of pay revision has not been considered for generating stations which shall not be completing five years of operation as on 1.4.2009. This provision needs to be reviewed to allow at par treatment to all generating stations.

(d)SJVNL :R&R cost should be included in the capital cost for O&M purpose as R&R related activities are a continuous process in the project vicinity.

22.3 Based on the information received from various hydro generating companies, details of O&M expenses as approved on the basis of normative 1.5% of approved capital cost on COD and actual O&M expenses incurred after deducting R&R cost, if any, during 2006-07 & 2007-08, has been worked out for new stations. These are summarized in the following table:

O&M Expenses of New Hydro Stations								
Station	COD	Capital cost as on COD (Rs crore)	O&M expenses (Rs. crore)					
			2006-07			2007-08		
			Approved @ 1.5% of capital cost	Actual (Excl & R&R)#	Actual as % of capital cost	Approved @ 1.5% of capital cost	Actual (Excl R&R)#	Actual as % of capital cost
Chamera-II	31.3.2004	1956.06	31.73	44.22	2.26	33.5	49.27	2.52
Dhauli Ganga	1.11.2005	1631.39	24.87	42.23	2.59	25.87	45.90	2.81
Indira Sagar	25.8.2005	1873.07*	45.31$	41.49#	2.21	47.12$	47.53#	2.54
Tehri**	8.7.2008	6951.11*				104.2**	170.6#	2.45
* -Cost of power component excluding cost of R&R works								
$- O&M expenses approved are based on capital cost (Power component) on COD including								

R&R cost
#- Actual O&M expenses are based on capital cost (Power component) on COD excluding R&R cost
** In case of Tehri, O&M cost is provisional as final tariff is yet to be approved

22.4 It would be seen from the above table that actual O&M cost of Chamera-II, Dhauli Ganga, Indira Sagar and Tehri HEPs varied from 2.45 % to 2.81% in the year 2007-08. Thus, it would be reasonable to increase O&M expenditure of new hydro stations to 2% of the capital cost as on the cut-off date,subject to the following conditions:

(a) The capital cost considered shall not include cost of rehabilitation & resettlement works.

(b) For the purpose of normalization, incentive & ex-gratia paid to its employees, donations, loss in stock, prior period adjustments, claims and advances written off, provision for VSR, provisions including provisions of pay revision etc shall be excluded.

(c) Commission had considered the average annual escalation rate of 5.17% based on CPI and WPI indexes for the five years from 2003-04 to 2007-08 and 5.72% per annum for the tariff period 2009-14 which would be taken into account.

22.5 Based on the above discussions, the Commission has decided to make the following provisions for Operation and Maintenance expenses of the existing and new hydro generating stations: in clause (f) of Regulation 19 of these regulations:

“(f) Hydro generating station

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

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

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

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

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

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

22.6 The methodology to work out average normalized O&M expenses at 2007-08 price level and arrive at O&M expenses for the year 2009-10 is illustrated with sample data of 'X' Hydro generating station as follows:

(Rs. lakh)

STATION	2003-04	2004-05	2005-06	2006-07	2007-08
X	2500	2700	3000	3500	4000

O&M expenses of each year is normalized @ 5.17% to arrive at normalized O&M expenses at the 2007-08 price level as follows:

FY 2003-04= $(2500)x\ (1.0517)^4$ = Rs. 3058.50 lakh
FY 2004-05= $(2700)x\ (1.0517)^3$ = Rs. 3140.80 lakh
FY 2005-06= $(3000)x\ (1.0517)^2$ = Rs. 3318.20 lakh
FY 2006-07= (3500)x (1.0517) = Rs. 3680.95 lakh
FY 2007-08= (4000) = Rs. 4000.00 lakh

Sum = Rs. 17198.45 lakh

Average normalized O&M at 2007-08 price level= 17198.45/ 5
= Rs. 3440 lakh

The Average normalized O&M at 2007-08 price level so obtained shall be escalated @ 5.72% to arrive at O&M for the year 2009-10 as follows:

O&M for 2009-10 = $(3440)x\ (1.0572)^2$ =Rs. 3845 lakh

Impact of provision of 50% hike in salary shall be considered as follows:

Assuming contribution of 'Employee cost' in the total O&M expenses in the year 2007-08 amounts to 35%,

Employee cost shall be = 3845x0.35= Rs. 1346 lakh

Increase in employee cost after allowing 50% hike due to pay revision shall be = 1346x0.5 = Rs. 673 lakh

Thus, total O&M expenses to be considered for the year 2009-10 shall be = 3845+ 673= Rs. 4518 lakh

22.7 The above O&M expenses for the year 2009-10 shall be escalated further @5.72% per annum to arrive at O&M expenses for subsequent years of the tariff period.

23. O&M Expenses for transmission systems {Regulation 19(g)}

23.1 The methodology for arriving at norms for O&M expenses for transmission system published as provided in the draft notification regulations was explained in the explanatory memorandum. Commenting on these norms, POWERGRID has made following submissions in letter dated 15.10.2008:

(a) In the proposed methodology concept of normalized employee cost was introduced. POWERGRID has stated that instead of considering minimum of actual employee cost and normalized employee cost, the Commission should consider applying normalized employee cost across the board. POWERGRID has stated that at the time of its formation, due to historical reasons, POWERGRID had to absorb manpower from different organizations, which was beyond the control of POWERGRID.the utility. Over the years, this excess manpower could be rationalized by training/retraining and deployment in new projects. This resulted in optimum manpower deployment over the years as brought out in the Explanatory Memorandum. This process will continue in future as well. POWERGRID has prayed that it should be rewarded for improvement in efficiency rather than getting penalized for the same. POERGRID has submitted that by applying normalized employee cost, POWERGRID is not able to recover employee cost for 1129, 849, 615, 312 & 239 employees for the each of the five years considered for the calculation. During the hearing, CMD, POWERGRID mentioned that during recent years, POWERGRIDthe company has undertaken works related to RGGVY under directive from GOI. Considering that these works are for temporary period, POWERGRIDthe company has deployed some manpower from existing O&M strength. He mentioned that this has given an impression that due to efficiency improvement there is reduction in number of employees per km as well as per bay. He said clarified that as of now, total shortage of manpower is about 400. He, however, emphasized that even with existing inadequate manpower, POWERGRID has not compromised with quality and standard of the service.

(b) The concept that O&M cost other than spare cost is proportioned to line length and not circuit length is not correct. This is applicable for line patrolling and corridor clearing only. Other activities like PID will take almost double the time and maintenance activities on double ckt line need for more mobilization and materials compare to single circuit lines. POWERGRID has recommended that concept of O&M cost per ckt-km appears more realistic and straightforward.

(c) POWERGRID has stated that failure of converter transformers is high all over the world and repair cost of converter transformers will always be high and in some cases to the tune of Rs 10 Crs. POWERGRID has pointed out that this type of expenditure has been termed as ‘not normal’ and has been disallowed. It has been requested that either this expenditure should be considered for deriving norms or one time reimbursement of additional expenditure may be allowed.

(d) POWEGRID has stated that failure of most of the equipment like ICT, Reactor etc do not qualify under Self Insurance Policy. POWERGRID has requested that insurance premium for insurance of such equipment should be allowed in O&M expenses or alternatively additional capitalization may be allowed in such eventualities.

(e) POWERGRID has also pointed out few minor errors in calculations for arriving at norms published in the draft notification.

(f) Subsequently, in December 2008, POWERGRID submitted another letter stating that total expenditure incurred for repair of defective Converter transformers under Rihand Transmission system of Northern Region (S No 7476316,6004906, 6004876 and 6004874) is Rs 5238.99 lakhs. Out of Rs 5238.99 lakhs, Rs 3655.00 lakhs has been included in Repair & Maintenance expenses of Northern Region for 2006-07 and the remaining expenditure of Rs 1583.99 lakhs is included in Repair & Maintenance expenses of Northern Region for 2007-08. It is further submitted that Rs 48.22 lakhs is balance anticipated expenditure under this head, which is yet to be incurred

23.2 Powerlinks Transmision Ltd (PTL) has submitted that unlike PTL, POWERGRID is operating substations along with the transmission lines. Hence, POWERGRID enjoys benefit of economies of scale in operation and maintenance of the transmission lines. It has stated that PTL is a single project company with a project which is unidirectional and spread over 1166 Km and requires more project offices to maintain the line. PTL has recommended that a maximum percentage of 1.5% of the Gross Block in case of transmission line and 3% in case of substations subject to actual expenses incurred by the transmission licensee may be allowed as O&M expenditure. PTL has also contended that being a single project company, its corporate office expenses should not be compared with that of the POWERGRID.

23.3 As regards the beneficiaries, Jaipur VVNL has stated that existing norms for 2008-09 are very much on higher side. By applying these norms allowable O&M expenses comes out to be almost double that of the amount allowed by RERC.

23.4 MPPTCL has stated that actual O&M expenditure in WR is much less than expenditure based on proposed norm and beneficiaries of WR would be unnecessarily burdened due to adoption of a national norm. In view of this, a request has been made to prescribe region wise norm based on normalized expenditure.

23.5 BSEB and ShriEr R.B Sharma, consumer have contended that O&M expenses for S/C are very high as compared to D/C configuration and on this premise has requested for continuation of the norm based on ckt-km basis but have supported differentiation based on voltage.

23.6 The Commission has reconsidered the methodology for arriving at O&M norms taking into account comments of the stakeholders as enumerated above. The revised methodology adopted by the Commission for arriving at norms for O&M expenditure for transmission is described below along with reasons for departure from the method proposed in the Explanatory Memorandum for draft notification:

(i) The data of actual O&M expenses submitted by the POWERGRID for the year 2007-08, which was submitted after publication of draft notification, has also been taken into account. Accordingly, five year’s actual O&M

expenses i.e. for the period 2003-04 to 2007-08 has been considered for arriving at norms. It may be recalled that in the absence of the average values of number of bays and line length for a year, values as on 1st April of the next year were used while arriving at norms published in the draft notification. However, since now we have information as on 1st April of 2003 to 1St April of 2008, average value for a year can be calculated by taking average of respective values as on 1st April of two consecutive years. This method has been used for arriving at average values for all the five financial years i.e. 2002-03 to 2007-08. In the draft notification, gradation of the norms was done on the basis of voltage and circuit configuration. While gradation based on circuit configuration has been retained, instead of gradation based on voltage, we have decided to adopt number of sub-conductors as parameter for gradation. There is no doubt that both voltage and no. of sub-conductors impact O&M expenditure for transmission line but in our opinion, the parameter of no. of sub-conductors largely covers impact of voltage as well. This is because entire 132 kV and 220 kV line network is with single conductor (except 156 ckt-kms of Kayamkulam-Edmon D/C line with twin moose conductor). Similarly, entire 765 kV and HVDC line network is with quad conductor. Further, about 50% of the POWERGRID network is at 400 kV level. Most of the upcoming transmission line network will also be at 400 kV and therefore, if only voltage is adopted as parameter for gradation, it will not be able to capture impact of no. of sub-conductors for major part of the ISTS. In order to avoid any confusion as to how bays are to be counted, we would like to lay down following guidelines based on the current practice in this regard:

- For each AC sub-station, there will be one bay for each circuit emanating from or terminating into that sub-station. This means that in case of sub-station having one-and-half breaker scheme, tie breaker will not be counted as bay. Similarly in case of sub-station with two main and one transfer bus scheme, bus coupler and bus transfer breakers will not be counted as bays.

- Each transformer will have two bays- one for HT side and other for LT side.
- Bus reactor will have one bay
- Switchable line reactor will have one bay
- Fixed Series compensation will have one bay
- Variable Series compensation will be considered to have two bays
- Each SVC will be considered to have one bay

Circuit breaker employed for bus sectionalization /extension for each bus will be counted as one bay

Tables 1 and 2 below give details of the average number of AC sub-station bays and average ckt-kms of AC & HVDC lines in commercial operation.

Table 1: Average Number of AC sub-station bays in commercial operation

Region	*2003-04*	*2004-05*	*2005-06*	*2006-07*	*2007-08*
NR	241.00	248.50	277.50	338.00	407.00
WR	108.00	116.50	138.50	161.50	210.50
SR	131.00	143.50	163.50	188.00	214.00
ER	125.00	150.50	178.50	220.00	260.50
NER	106.5	109	109	109	109
Total	711.50	768.00	867.00	1016.50	1201.00

Table 2: Average ckt-km of AC and HVDC lines in commercial operation

Region	*2003-04*	*2004-05*	*2005-06*	*2006-07*	*2007-08*
NR	14529.45	14699.01	16061.34	18214.59	20410.71
WR	10316.65	10419.49	10976.52	11899.28	14113.33
SR	11599.97	12413.54	13537.31	14246.80	14884.96
ER	5839.40	6563.06	7343.01	7891.48	9006.20
NER	4971.94	4994.21	4994.21	4994.21	4779.49
Total	47257.42	49089.32	52912.39	57246.35	63194.69

Note: (1) Each pole of an HVDC lines is considered as one circuit for the present purpose.
(2) Average No. of AC sub-station bays and average ckt-km has been calculated by taking average of the respective figures as on 1st April of the two consecutive years.

(ii) We have decided to prescribe norms on per km basis but with additional gradation based on circuit configuration. Since, the information based on circuit & conductor configuration (together) is not available, this information has been derived indirectly based on line length categorized based voltage & circuit and ckt-kms based on conductor configuration. It was noticed that while submitting information, POWERGRID had inadvertently taken 220 kV D/C Kayamkulam-Edmon line with single conductor. Therefore, necessary correction has been made in the data submitted by POWERGRID. The indirect method used to arrive at ckt-kms based on conductor configuration is as under:

S/C quad ckt-km = 765 kV ckt-km

S/C Triple conductor ckt-km = Nil

S/C twin conductor ckt-km = Total twin ckt-km – D/C twin ckt-km

S/C Single conductor ckt-km = 132 kV S/C ckt-km + 220 kV S/C ckt-km

D/C quad ckt-km = Total quad ckt-km – 765 kV ckt-km

D/C Triple conductor ckt-km = Total triple conductor ckt-km

D/C twin conductor ckt-km = Total 400 kV D/C ckt-km – D/C triple conductor ckt-km – D/C quad ckt-km

D/C Single conductor ckt-km = 132 kV D/C ckt-km + 220 kV D/C ckt-km

Only in case of Southern Region, appropriate change has to be made to take care of the fact that 220 kV D/C Kayamkulam-Edmon line is with twin conductor. When this method is applied, the total ckt-km matches with ckt-km information submitted by POWERGRID, except in Southern Region, where there is a mismatch to the extent of about 65 ckt-km, which is too small and can be neglected.

In case of transmission lines, S/C twin conductor ckt-kms have been used as base and ckt-kms of all other circuit & conductor configurations have been converted to equivalent ckt-kms of S/C twin conductor ckt-km. No differentiation has been made between triple & twin conductor for same circuit configuration, since the population of triple-conductor lines is comparatively very small. Weightage factor for conversion have been used based on our estimate of ratio of O&M expenditure for a particular conductor & circuit configuration vis-à-vis S/C twin conductor. The weightage factors for a bundled conductor with four or more conductors is taken as 1.5 and that for single conductor it is taken as 0.5. Additionally, ratio between O&M expenditure of 1 km of D/C line is estimated to be 1.5 time that of 1 km of S/C line for single conductor and 1.75 time of 1 km of S/C for bundled conductor.

The Commission has decided to adopt voltage as the basis for gradation of norms for O&M expenditure for sub-station as was proposed in the draft notification. However, bays at various voltage levels have been converted to equivalent 400 kV bays. As in case of transmission line, the weightage factors for such conversion are considered based on our estimate of ratio of O&M expenditure of bay at a voltage level as compared to O&M expenditure for a bay at 400 kV.

Table 3 and 4 below give details of number of bays and ckt-kms based on the gradation and equivalent 400 kV bays and equivalent S/C twin conductor ckt-kms.

Table 3: Number of AC sub-station bays

	Actual average No of bays in commercial operation					Weightage Factor	Equivalent No of bays (400 kV) in commercial operation				
	2003-04	*2004-05*	*2005-06*	*2006-07*	*2007-08*		*2003-04*	*2004-05*	*2005-06*	*2006-07*	*2007-08*
765 kV	0.00	0.00	0.00	0.00	2.50	1.4	0	0	0	0	3.5
400 kV	426.50	455.50	508.00	603.50	729.00	1	426.5	455.5	508	603.5	729
220 kV	209.00	229.50	264.50	310.00	366.50	0.7	146.3	160.65	185.15	217	256.55
Up to 132 kV	76.00	83.00	94.50	103.00	103.00	0.5	38	41.5	47.25	51.5	51.5
Total	**711.50**	**768.00**	**867.00**	**1016.50**	**1201.00**		**610.80**	**657.65**	**740.40**	**872.00**	**1040.55**

Table 4:Ckt-km of AC and HVDC lines

	Actual average ckt-km in commercial operation					Weightage Factor	Equivalent ckt-km (twin conductor) in commercial operation				
	2003-04	*2004-05*	*2005-06*	*2006-07*	*2007-08*		*2003-04*	*2004-05*	*2005-06*	*2006-07*	*2007-08*
S/C Quad	562.50	562.50	655.24	1022.17	1471.67	1.500	843.75	843.75	982.87	1533.25	2207.50
S/C Triple	0.00	0.00	0.00	0.00	0.00	1.000	0.00	0.00	0.00	0.00	0.00
S/C Twin	18513.08	19073.23	19676.66	20005.16	20258.61	1.000	18513.08	19073.23	19676.66	20005.16	20258.61
S/C Single	2753.80	2831.53	2871.90	2886.30	2907.55	0.500	1376.90	1415.77	1435.95	1443.15	1453.77
D/C Quad	4669.85	4669.85	4669.85	4669.86	5862.59	1.313	6129.18	6129.18	6129.18	6129.19	7694.65
D/C Triple	1479.68	1479.68	1522.97	1566.26	1566.26	0.875	1294.72	1294.72	1332.60	1370.47	1370.48
D/C Twin	12755.51	13762.23	16588.76	20113.46	24125.65	0.875	11161.07	12041.95	14515.17	17599.27	21109.95
D/C Single	6523.00	6710.28	6927.01	6983.16	7002.37	0.375	2446.13	2516.36	2597.63	2618.69	2625.89
Total	47257.42	49089.32	52912.39	57246.35	63194.69		41764.82	43314.96	46670.05	50699.18	56720.84

(iii)Normalization of O&M expenditure has been done on the same basis as was proposed while formulating norms published in the draft notification. The expenditure that has been actually been incurred by POWERGRID but has been excluded for the process of normalization are described below:

- Abnormal security expenses in NR and NER as reported by POWERGRID
- Electricity charges corresponding to colony consumption by applying ratio of electricity consumption in colony to total electricity consumption.
- Productivity linked incentive, Ex-gratia
- Spikes in O&M expenditure at Rihand HVDC station in 2007-08 and at Dadri HVDC station in 2006-07 and 2007-08, mainly due to abnormal expenditure on repair of converter transformers, have been smoothened by restricting normalized expenses to 20% more than that in previous year.
- Expenditure under the head 'Repair & maintenance' have been reduced in NR to the extent of HVDC O&M expenditure not considered due to smoothening of spikes. Also, expenditure on repair of ICT at Mandola S/S amounting to Rs 324 lakhs has not been considered for

normalization. We understand that this expenditure was required on account on burning of transformer and in our opinion such expenditure has to be met from Self-Insurance reserve. The expenditure on account of events, which are covered under insurance, can neither be allowed under O&M nor can be allowed to be capitalized. This expenditure has to be met from self-insurance reserve.

- Expenditure on petition fee for petitions filed in the Commission amounting to Rs 317 lakh, Rs 276 lakh, Rs 249 lakh and Rs 149 lakh for the years 2004-05, 2005-06, 2006-07 and 2007-08 have been excluded for normalization. It has been decided that during the period 2009-14, petition fee shall be reimbursed separately by the long-term customers of the transmission asset in question.

The Commission would like to clarify that spikes in O&M expenses at Rihand & Dadri HVDC terminals have been smoothened out because in our opinion, probability of such spikes in future is very remote. Such abnormal spikes have to be excluded so that norm does not get distorted due to stray events. However, we clarify that during 2009-14 if it incurs abnormal O&M expenditure for HVDC stations on account of converter transformer failures, POWERGRID will have liberty to approach the Commission with suitable justification for reimbursement of the same.

Table 5, 6 and 7 below give details of the actual regional O&M expenditure, normalized regional O&M expenditure and normalized regional O&M expenditure excluding HVDC stations

Table 5: Actual Regional O&M expenditure

(Rs Lakh)

Region	*2003-04*	*2004-05*	*2005-06*	*2006-07**	*2007-08**
NR	11719.44	12333.18	12650.28	18488.59	19597.11
WR	4909.87	4882.07	5156.46	5837.03	7371.53
SR	8784.95	9112.76	10157.71	10685.67	11338.57
ER	5695.70	5924.48	6607.97	7831.04	9250.07
NER	4646.54	4766.77	4730.28	5086.33	5364.70
Total	35756.50	37019.26	39302.70	47928.66	52921.98

* 'Provision' of Rs 1532 lakh in the year 2006-07 and Rs 11003 lakh in the year 2007-08 towards wage revision in the O&M expenses have not been included in the actual expenditure. The above 'provision' has been apportioned to various regions and corporate Office in the ratio of their respective 'salary & wages' and deducted from the figures submitted by POWERGRID.

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Table 6: Normalized Regional O&M expenditure

(Rs Lakh)

Region	*2003-04*	*2004-05*	*2005-06*	*2006-07*	*2007-08*
NR	10432.30	11497.25	11644.48	13858.22	16430.02
WR	4397.95	4570.37	4873.50	5322.13	6796.95
SR	7748.54	8401.99	9466.56	9629.97	10297.98
ER	4754.24	5436.37	6143.88	7187.54	8298.92
NER	4145.40	4342.53	4367.25	4607.21	4828.82
Total	31478.43	34248.51	36495.66	40605.07	46652.70

Table 7: Normalized Regional O&M expenditure (excluding HVDC stations)

(Rs Lakh)

Region	*2003-04*	*2004-05*	*2005-06*	*2006-07*	*2007-08*
NR	9412.71	10073.69	10337.37	12534.41	14821.36
WR	3960.13	4016.94	4140.24	4544.51	5695.80
SR	5630.30	6501.43	7684.66	7923.06	8586.78
ER	4595.25	5168.66	5873.89	6882.25	8036.03
NER	4145.40	4342.53	4367.25	4607.21	4828.82
Total	**27743.79**	**30103.24**	**32403.42**	**36491.44**	**41968.79**

(iv) Tables 8 and 9 below give details of the manpower deployment per equivalent 400 kV bay and per equivalent single circuit twin conductor ckt-km for the five years.

Table 8: Actual Number of employees for AC sub-station O&M

Region	*2003-04*	*2004-05*	*2005-06*	*2006-07*	*2007-08*
NR	745	768	755	818	803
WR	199	281	281	334	359
SR	447	431	450	443	429
ER	546	553	576	643	775
NER	559	551	515	496	462
Total	2496	2584	2577	2734	2828
Equivalent (400 kV) No of bays	610.80	657.65	740.40	872.00	1040.55
Employees per Equivalent (400 kV) bay	**4.09**	**3.93**	**3.48**	**3.13**	**2.72**

Table 9: Actual Number of employees for AC and HVDC lines

Region	*2003-04*	*2004-05*	*2005-06*	*2006-07*	*2007-08*
NR	456	354	320	365	402
WR	160	162	174	187	168
SR	198	207	217	213	224
ER	158	146	116	178	230
NER	174	158	161	158	148
Total	1146	1027	988	1101	1172
Equivalent (single ckt- twin conductor) ckt-km	41764.82	43314.96	46670.05	50699.18	56720.84
Employees per Equivalent (single ckt-twin conductor) 100 ckt-km	**2.74**	**2.37**	**2.12**	**2.17**	**2.07**

(v) In the Explanatory Memorandum, rationalization in employee cost was proposed based on trend of reduction in manpower per bay and per km of line length. However, we have taken note of the submission by POWERGRID that over the last few years, there has been depletion in the manpower deployment, which has given an impression of efficiency improvement in manpower deployment. Accordingly, we have decided that O&M expenditure considered for formulating norms shall be arrived at from the normalized O&M expenditure by uplifting the employees cost for the years 2004-05 to 2007-08 by keeping manpower per ckt-km and per bay at the same level as in 2003-04. While formulating norms published in the draft notification, direct segregation of normalized O&M expenditure into sub-station and transmission lines was not warranted as norms per bay and per km of line length were obtained by regression analysis with total normalized O&M expenses as dependent variable and line length and number of bays as independent variables. Now we have decided that for the purpose of arriving at norms, total O&M expenses will be apportioned between sub-stations and transmission lines (AC and HVDC lines) in the ratio of 70:30. Table 10 below shows process of arriving at average O&M expenditure per equivalent 400 kV bay and average O&M expenditure per equivalent ckt-km of S/C twin line at 2007-08 price level. These average values serve as the base norm at 2007-08 price level.

Table 10: O&M expenses per equivalent (400 kV) bay and per equivalent (single ckt-twin conductor) ckt-km at 2007-08 price level

(Rs Lakh)

		2003-04	*2004-05*	*2005-06*	*2006-07*	*2007-08*	*Average*
A.	Total Normalized O&M expenses (From Table 9)	27743.79	30103.24	32403.42	36491.44	41968.79	
B.	Normalized O&M expenses allocated to S/S (70 % of A)	19420.65	21072.27	22682.39	25544.01	29378.15	
C	Employee Cost included in B *	9645.25	10287.18	11561.23	11706.16	13720.12	
D.	Compensation factor for staff depletion **	0.00	0.04	0.18	0.31	0.50	
E.	O&M expenditure considered for S/S(B+C xD)	19420.65	21491.09	24708.93	29134.39	36288.65	
F	O&M expenditure escalated to 2007-08 level (escalation 5.17%)	23759.17	24999.65	27329.88	30640.64	36288.65	
G	Equivalent No. of sub-station bays(From Table 3)	610.80	657.65	740.40	872.00	1040.55	
H	**O&M expenditure per equivalent (400 kV) AC bay**	**38.90**	**38.01**	**36.91**	**35.14**	**34.87**	**36.77**
I	Normalized O&M expenses allocated to AC and HVDC lines (30 % of A)	8323.14	9030.97	9721.02	10947.43	12590.64	
J	Employee cost included in I*	4428.47	4088.60	4432.48	4715.01	5685.99	
K	Compensation factor for staff depletion **	0.00	0.16	0.29	0.26	0.32	
L	O&M expenditure considered for AC and HVDC lines (I + J x K)	8323.14	9669.28	11017.32	12185.94	14431.03	
M	O&M expenditure escalated to 2007-08 level (escalation 5.17%)	10182.50	11247.85	12185.95	12815.95	14431.03	
N	Equivalent (400 kV) bays From Table 4)	41764.82	43314.96	46670.05	50699.18	56720.84	
O	**O&M expenditure per equivalent (S/C - twin conductor) ckt-km**	**0.244**	**0.260**	**0.261**	**0.253**	**0.254**	**0.254**

* Excluding corporate employee cost; allocated pro-rata to number of employees

** Compensation factor for staff depletion for a year has been calculated as (No of employees per equivalent bay or ckt-km for that year/ No of employees per equivalent bay or ckt-km for 2003-04 - 1)

(vi) We have noted that O&M expense per 500 MW capacity of HVDC BTB stations are in close range so a uniform norm has been prescribed for HVDC BTB stations. However, in case of HVDC bipole projects namely Rihand-Dadri and Talcher-Kolar, separate stand alone norms have been prescribed because their expenditure per MW capacity were not in close range. The norms for O&M expenses for HVDC BTB stations will be on the basis of per 500 MW capacity as basis as compared to per 100 MW basis as proposed in the draft notification. Normalized O&M expenditure for HVDC stations have been obtained by applying ratio of regional normalized expenditure to regional actual expenditure of the relevant region. However, an exception has been made for Rihand HVDC station in 2007-08 and at Dadri HVDC station in 2006-07 and 2007-08, where normalized O&M expenditure has been restricted to 20% more than value for previous year in order to smoothen out spikes. Correction for employee depletion has been applied in the same manner as in case of AC sub-station and transmission lines. The process of arriving base norm for HVDC stations is captured in the tables 11 to 13 below:

Table 11: Actual O&M expenditure at HVDC stations

(Rs Lakh)

HVDC Terminal	*2003-04*	*2004-05*	*2005-06*	*2006-07*	*2007-08*
Rihand	341.35	541.39	481.44	522.19	1002.81
Dadri	545.93	690.24	561.49	3567.40	2274.08
Vindhayachal BTB	258.11	295.43	377.08	416.50	470.80
Bhadrawati BTB	488.78	591.18	775.83	852.85	1194.24
Talcher	959.07	860.17	551.16	503.74	699.17
Kolar	959.07	602.41	476.41	322.82	537.44
Gazuwaka BTB	483.43	598.76	884.42	1063.55	647.50
Sasaaram BTB	190.47	291.75	290.38	332.62	293.02
Total	**4226.21**	**4471.33**	**4398.21**	**7581.67**	**7119.06**

Table 12: Computation of base norm at 2007-08 price level for HVDC Bipole schemes (Rs Lakh)

	Normalized O&M expenditure					Escalated to 2007-08 level @5.17%					Average at 2007-08 level	
HVDC Station	***2003-04***	***2004-05***	***2005-06***	***2006-07***	***2007-08***	***2003-04***	***2004-05***	***2005-06***	***2006-07***	***2007-08***	*Station wise*	*For the scheme*
Rihand-Dadri Scheme												
Rihand	303.86	504.69	443.16	391.41	469.69	371.74	587.09	490.17	411.65	469.69	466.07	
Dadri	485.97	643.46	516.85	620.22	744.26	594.54	748.50	571.67	652.28	744.26	662.25	**1128**
Talchaer-Kolar Scheme												
Talcher	845.92	793.08	513.66	457.51	635.00	1034.90	922.56	568.14	481.16	635.00	728.35	
Kolar	845.92	555.42	443.99	290.93	488.12	1034.90	646.10	491.09	305.97	488.12	593.23	**1322**

Table 13: Computation of base norm at 2007-08 price level for HVDC Back-To-back Schemes

(Rs Lakh)

	Normalized O&M expenditure					Escalated to 2007-08 level @5.17%					Average at 2007-08 level	
HVDC Station	***2003-04***	***2004-05***	***2005-06***	***2006-07***	***2007-08***	***2003-04***	***2004-05***	***2005-06***	***2006-07***	***2007-08***	*Station wise*	*per 500 MW*
Vindhayachal BTB	229.76	275.41	347.10	312.19	394.71	281.09	320.37	383.92	328.33	394.71	341.68	341.68
Bhadrawati BTB	437.82	553.44	733.26	777.62	1101.15	535.63	643.79	811.03	817.82	1101.15	781.88	390.94
Gazuwaka BTB	426.40	552.06	824.24	958.48	588.08	521.65	642.19	911.67	1008.03	588.08	734.32	367.16
Sasaaram BTB	158.99	267.71	269.99	305.29	262.89	194.50	311.42	298.62	321.07	262.89	277.70	277.70
										Average		**344.37**

(vii) The base norm at 2007-08 price level is escalated at 5.72% per annum to reach to 2009-10 price level. It is estimated that 55% of the sub-station O&M expenditure, 52% of the line O&M expenditure and 30% of the HVDC station O&M expenditure is on account of employee cost. Wage hike of 50% has been applied accordingly in the norms for O&M expenditure. This is shown in the table 16 below:

Table 14: Base Norms for O&M expenditure at 2009-10 price level

(Rs Lakh)

	Norm for O&M expenditure (without considering impact of wage revision) (Escalation Rate= 5.72%)			Norms for 2009-10 after accounting for impact of wage revision
	2007-08	2008-09	2009-10	
O&M expenditure per equivalent (400 kV) AC bay	36.77	38.87	41.09	52.40
O&M expenditure per equivalent (twin conductor) ckt-km	0.254	0.269	0.284	0.358
O&M expenditure per 500 MW of HVDC BTB capacity	344	364	385	443
O&M expenditure for Rihand-Dadri HVDC bipole scheme	1128	1193	1261	1450
O&M expenditure for Talcher-Kolar HVDC bipole scheme	1322	1398	1478	1699

(viii) The norms for AC sub-station and transmission lines (AC and HVDC) for equivalent 400 kV bay and for equivalent S/C twin conductor ckt-km so arrived are then converted to various voltage levels (for sub-stations) and various circuit and conductor configuration (for transmission liners) by applying weightage factors as contained in table 3 and 4. Escalation rate of 5.72% is applied to the norms to arrive at norms for each year of the tariff period 2009-14. Finally, the values obtained for D/C lines have been converted from ckt-km to km basis by doubling them.

23.7 In view of the above discussion, the following provisions have been made in clause (g) of Regulation 19 of these regulations with regard to O&M expenses of the transmission system:

"(g) Transmission system

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

Table 15 :Norms for O&M expenditure for Transmission System

	2009-10	*2009-11*	*2009-12*	*2009-13*	*2009-14*
Norms for sub-station (Rs Lakh per bay)					
765 kV	73.36	77.56	81.99	86.68	91.64
400 kV	52.40	55.40	58.57	61.92	65.46
220 kV	36.68	38.78	41.00	43.34	45.82
132 kV and below	26.20	27.70	29.28	30.96	32.73
Norms for AC and HVDC lines (Rs Lakh per km)					
Single Circuit (Bundled conductor with four or more sub-conductors)	0.537	0.568	0.600	0.635	0.671
Single Circuit (Twin & Triple Conductor)	0.358	0.378	0.400	0.423	0.447
Single Circuit (Single Conductor)	0.179	0.189	0.200	0.212	0.224
Double Circuit (Bundled conductor with four or more sub-conductors)	0.940	0.994	1.051	1.111	1.174
Double Circuit Circuit (Twin & Triple Conductor)	0.627	0.663	0.701	0.741	0.783
Double Circuit Circuit (Single Conductor)	0.269	0.284	0.301	0.318	0.336
Norm for HVDC Stations					
HVDC Back-to-back stations (Rs lakh per 500 MW)	443	468	495	523	553
Rihand-Dadri HVDC bipole scheme (Rs Lakh)	1450	1533	1621	1713	1811
Talcher-Kolar HVDC bipole scheme (Rs Lakh)	1699	1796	1899	2008	2122

23.8 We have already covered issue regarding failure of converter transformer raised by POWERGRID. With regard to issue of change in self-insurance policy raised by POWERGRID, we would like to state that the coverage of the self-insurance policy has been decided by the POWERGRID itself and we would not like to micro-manage the same. We are only interpreting this policy whenever an issue of capitalization or repair and maintenance of any asset is brought before us. The suggestion of PTL regarding linking O&M expenditure to capital cost has not been found acceptable in the previous tariff period 2001-04 and 2004-09. Reasons for de-linking have also been discussed in detail while finalizing norms for earlier tariff periods. We would not like to revisit the same issue again. With regard to statement of Jaipur VVNL that norms fixed by State Commission is much lower than the norms proposed for ISTS, we can only say that two transmission systems are not straightway comparable. Intra-State system predominantly contains network of 132kV and even lower voltages with mostly single conductor configuration. The issue of regional norm was raised by MPSEB during the last tariff period as well because if framed separately, norm for Western Region would be much lower. This was also settled in the last tariff period and we would not like to revisit the same.

24. Reasons for linking generation incentive to plant availability and for shifting secondary oil cost to capacity charge (Regulation 21)

24.1 A primary objective of specifying a two-part tariff for thermal generating stations is to ensure that they may be scheduled to generate as per "merit-order", without causing commercial conflicts in a multi-ownership scenario. Scheduling as per "merit-order" basically means that when some generating stations or units have to be backed down during off-peak hours (due to system load coming down during those hours below the total available generating capacity in the system, as should normally be the case) the generating stations/units of a higher variable costs should be given a decreased schedule (or should be shut down) while those with lower variable costs should continue with schedules matching their full available capacity.

24.2 For ensuring optimal "merit-order" operation of the whole system, the load dispatch centre needs to know the actual variable costs of all thermal stations for which it is responsible for scheduling. While this would normally be the case in a bundled utility (i.e. where the generating stations and load dispatch centers are owned by the same entity, e.g. a State government), it may not be so in a multi-ownership scenario. In any case, the generating stations would be getting paid as per the specified capacity charge and energy charge rates. Therefore for optimum scheduling from the angle of beneficiaries, scheduling decisions of a load dispatch centre shall have to be based on energy charge rates of the generating stations belonging to other entities. In case the specified energy charge rates differ from the actual variable costs of the respective generating stations, the scheduling decisions would be deviating from the real “merit-order” to that extent. Put another way, the energy charge rate for the different thermal stations should be as close as possible to the actual variable costs of the stations, for optimal operation of the whole system.

24.3 Besides, if the energy charge rate (x paisa/kWh) of a generating station is more than its variable/incremental cost of generation (y paisa/kWh), any reduction of schedule below the declared capacity would cause a financial loss of (x-y) paisa to the generating company for every kWh of the resultant backing down. Since the schedule reduction is for attaining overall economy for the beneficiaries, it would be grossly unfair to expect such financial loss to be absorbed by the generating company (which is in no way responsible for consumers' load profile). The generating company would therefore be justified in protesting against any schedule reduction, even if it is according to "merit-order". The above problem can be easily addressed by making x equal to y.

24.4 The present tariff regulations (2004-2009) are deficient in the above aspect on two counts. One is the provision regarding linkage of incentive with scheduled PLF, and the second is on account of inclusion of secondary oil cost in energy charge rate. These are discussed further herein.

24.5 The present regulations provide for an incentive for the thermal generating stations @25 paisa per kWh for scheduled generation during a year over that corresponding to the normative PLF. In case the schedule is lower than the declared capability, the generating station stands to lose the incentive @ 25 paisa per kWh of schedule reduction for none of its fault. Naturally, the generating company would protest against any such schedule reduction, while it should be readily accepted in case it is according to "merit-order". In effect, the incentive acts like a supplementary energy charge, which inflates the difference between the effective energy charge rate and the actual variable cost, and thereby aggravates the problem described earlier.

24.6 Secondary oil is required to be fired in coal/lignite-fired boilers during start up and shut down of a generating unit, as also for flame stabilization during operation at part load and/or wet-fuel conditions. When a generating unit is operating at a load above about 70%, secondary oil is normally not required to be fired. The coal/lignite-fired thermal units are normally scheduled to operate at full capability, and may be scheduled to back down by 20-30% during off-peak hours, depending on their position in "merit-order" and the system load profile. They are generally not given a schedule which would call for secondary oil firing. As such, as long as a generating unit operates in 70-100% range, its variable cost comprises of only the coal/lignite cost. However, in the present tariff regulations, energy charge rate includes the normative cost of secondary oil as well. As a consequence, the energy charge rate exceeds the actual variable cost by a few paise per kWh. This again has the potential of leading to the problem described earlier.

24.7 The above deficiencies have not caused a serious problem so far because the generating stations to which the present tariff regulations apply have generally been scheduled to their full capability round the clock. Most of the inter-State generating stations falling in the Commission's jurisdiction are pit-head stations, and therefore have comparatively much lower variable costs. Even with the above distortions, their effective energy charge rates are lower than the variable/incremental costs of the load-centre generating stations of the beneficiaries. Even the load-centre stations covered by the present regulations have comparatively lower energy charge rates (due to higher efficiency), and are not required to back down in the present power-deficient scenario. In other words, the problem has remained dormant, but this should not make us complacent about it.

24.8 There are two reasons why the Commission proposes to address these deficiencies in the 2009-2014 regulations. One is that these regulations would be a guiding factor for the State Commissions, who would be specifying the tariffs for intra-State generating stations. The latter being mostly load-centre stations (and consequently having higher variable costs) would have to be regularly backed down. With diverse ownership, commercial disputes and operational dissentions would arise between intra-State entities if the required preventive measures are not taken in advance. By addressing these problems in the 2000-14 regulations, the Commission would be providing the necessary guidance for the State Commissions.

24.9 Secondly, the new regulations have to be forward-looking. They have to be able to cater to a scenario wherein we would have a generation capacity even if not sufficient for meeting the full peak-hour demand, sufficiently higher than the off-peak demand. In such a situation, at least some inter-State generating stations would be scheduled for backing down during off-peak hours. The above described problem would then no longer be dormant and could become very contentious. The Commission would certainly not like to be specifying parameters which have the potential for leading to commercial disputes and operational dissention between entities in its jurisdiction.

24.10 In their written comments and in the oral presentations on 3-4 November 2008, many of the respondents have opposed the Commission's proposals in the above respect. It appears that they have missed the point made in the foregoing explanation, which supplements the explanation under para 25.1 -25.17 in the Explanatory Memorandum issued with the draft tariff regulation on 29.8.2008. Most of the arguments submitted by the respondents with regard to availability based incentive are on the same lines which were submitted by them in response to the discussion paper circulated by the Commission on its website. These arguments have been extensively dealt within the explanatory memorandum to the draft regulations.

24.11 Some respondents appeared to be keener to keep the profits made by Central PSUs under check than to maximize the benefits that could be derived from the capabilities of the Central PSU. The Commission aims to focus on the letter by introducing focused incentives. Further, it is most important that there are no commercial deterrent for any utility to do what it is supposed to do in the larger interest. For example, a generating station backing down as per merit order during off-peak hours must not suffer a commercial loss. It is primarily for this reason that the Commission has decided to move away from PLF-link incentive by adopting availability linked incentive for the thermal generating stations and to shift the secondary oil cost from energy charge to the capacity charge.

24.12 As regards the incentive and dis-incentive rate Commission has observed as follows in para 25.19 of the explanatory memorandum to the draft regulations:

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

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.

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.

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.

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.”

24.13 Accordingly, following provisions were provided in the draft 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:

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

(AFC x NDM / NDY) (0.5 + 0.5 x 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)

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:

24.14 Many of the beneficiaries and state utilities have argued that recovery of incentive as per above formula lead to different incentive for each stations for the same generation level and such distinction between new and old station would lead to tariff shock for the beneficiaries in the 11th year. In this regard, it is clarified that for the reasons stated above in para 1.12 we are providing for such a distinction consciously in over all interest of everyone.

24.15 In view of the forgoing discussion, we are not inclined to make any change in the manner of recovery of fixed charges inclusive of incentive.

24.16 Further as provided in the draft tariff regulation, 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 they may specify annual fixed charge (AFC), normative annual plant availability factor (NAPAF), installed capacity (IC), auxiliary power consumption and energy charge rate (ECR) for such stations.

25. Transit and Handling losses {Regulation 21(7)}

25.1 The Commission proposed the norms for the transit and handling losses of coal/lignite in the draft regulation as under:

1. Pit Head Station - 0.2%
2. Non Pit Head Station - 0.6%

25.2 Most of the beneficiaries and state utilities have submitted during the hearing and in their written submissions that the above norms of transit and handling losses are too stringent and cannot be achieved by them. They have further, submitted that the transit and handling losses in respect of their stations are in excess of 2%. They have serious concerns that the norms as per CERC if adopted by the SERCs would lead to irreparable losses for them. They sought to specify norms for the state utilities as well as in this regard.

25.3 It needs to be appreciated that the CERC is specifying norms based on the data of NTPC stations available with them. The actual transit and handling losses for the year 2004-05 and 2007-08 of NTPC stations are as follows:

Sr. No.	**Station**	**Capacity (MW)**	**COD of last unit**	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**4 yrs. average (%)**
	Non Pit-Head Stations							
1	Dadri (4x210)	840	1.12.1995	0.52	0.66	0.60	0.78	**0.64**
2	Unchahar (2x210+2x210+210)	1050	1.1.2007	0.60	0.60	0.60	0.64	**0.61**
3	Simhadri (2x500)	1000	1.3.2003	0.17	0.54	0.72	0.71	**0.54**
4	Badarpur (3x95 +2x210)	705	1.4.1982	0.56	0.57	0.69	0.77	**0.65**
5	Tanda (4x110)	440	20.2.1998	0.49	0.52	0.40	0.25	**0.42**
6	Kahalgaon (4x210)	840	1.8.1996	0.15	0.21	0.26	0.25	**0.22**
7	Farrakka (3x200+2x500)	1600	1.7.1996	0.33	0.34	0.28	0.20	**0.29**
							Average	**0.48**
	Pit-Head Stations							
1	Talchar (2x500 + 4x500)	3000	1.8.2005	0.02	0.07	0.12	0.20	**0.10**
2	Rihand (2x500 + 2x500)	2000	1.4.2006	0.08	0.05	0.18	0.25	**0.14**
3	Korba (3x200+3x500)	2100	1.6.1990	0.02	0.12	0.28	0.23	**0.16**
4	Singrauli (5x200+2x500)	2000	1.5.1998	0.09	0.10	0.10	0.10	**0.10**

5	Ramagundam (3x200+3x500+1x500)	2600	25.3.2005	0.21	0.23	0.23	0.24	**0.23**
6	Vindhyachal (6x210+2x500+2x500)	3260	15.7.2007	0.18	0.15	0.22	0.23	**0.19**
7	Talchar taken over (4x60+2x110)	460	3.6.1995	0.16	0.26	0.24	0.25	**0.23**
							Average	**0.16**

25.4 It can be seen that average transit and handling losses of pit head stations are of the order of 0.16%. In case of non pit head stations, namely Dadri, Unchahar, Simhadri and Badarpur, the transit and handling losses are of the order of 0.54% in Simhadari to 0.6% in Badarpur. In case of Tanda, Kahalgaon, Farakka, these are much less than other non-pit stations. In case of Kahalgaon & Farakka, the reason for low losses is that these are supplied coal through MGR system but a substantial quantity is also supplied through distant mines. As such, it would not be reasonable to treat these stations at non-pit head stations. The transit and handling losses for non-pit stations like Dadri, Unchahar, Simhadri, and Badarpur in the year 2007-08 ranges between 0.64% to 0.78%.

25.5 In view of this, we are of the opinion that the norms of 0.6% for non pit head station would not suffice and hence we are retaining the existing norm of 0.8%. In respect of pit head stations, norms of 0.2% appear to be in order.

25.6 As regards norms for the state sector projects, the Commission expects the State Commissions to specify suitable norms after due regard to the actual situation and distance involved in the transportation of coal in respect of stations being regulated by them.

26. *C*ompensation for loss of generation from hydro generating station (Regulation 22(6)

26.1 The draft regulation had done away with capacity index and introduced the concept of normative annual plant availability factor (NAPAF). The new formulation also provided for bifurcating fixed charges into capacity and energy charge. However, the provision relating to any shortfall in energy charge due to hydrology failure resulting in actual energy available being less than design energy was not made passthrough.

26.2 The generating companies, namely, NTPC, NHPC, NEEPCO, SJVNL, THDC, etc have submitted that if the hydrological risk is passed on to the generator, it would adversely affect the development of hydro project. It was also argued that any possibility of occurrence of hydrological failure during the initial years would act as deterrent in financial closure of the hydro projects.

26.3 Commission is conscious to the fact that the country needs increased share of hydro capacity from the point of view of meeting peaking capacity as well as on environmental consideration of reducing GHG emissission. As such, commission is providing .for compensating the hydro developers in the first 10 years for hydrological failures in the following manner on a rolling basis:-

(i) In case the energy shortfall occurs within ten years from the date of commercial operation of a generating station, the ECR for the year following the year of energy shortfall shall be computed based on the formula specified in clause (5) with the modification that the design energy for the year shall be considered as equal to the actual energy generated during the year of the shortfall , till the energy charge shortfall of the previous year has been made up, after which normal ECR shall be applicable;

This is explained by following example:

Dhauli Ganga HE station (4x70 MW) of NHPC was commissioned in the year 2005-06. Suppose there is shortfall in annual energy generation during 2009-10 vis-à-vis annual design energy.

AFC during 2009-10= Rs. 265 crore
Annual design energy= 1135 MU
Actual generation = 1000 MU

ECR for 2009-10= 265×10^5 x0.5/ {1135 x (100-1.2)x (100-12)}
= Rs. 1.343 /kWh

Energy charge corresponding to 1135 MU= Rs. 132.5 crore
Energy charge corresponding to 1000 MU= Rs. 116.74 crore

To compensate for energy charge shortfall of Rs. 15.76 crore (corresponding to less generation of 135 MU), ECR for 2010-11 shall be as follows:

AFC during 2010-11= Rs. 250 crore (assumed)
Design energy to be considered for 2010-11= 1000 MU
ECR for 2010-11= 250×10^5 x0.5/ {1000 x (100-1.2)x (100-12)}
= Rs. 1.438 /kWh

Energy charge for 2010-11 shall be payable at this modified ECR till Rs.(125+15.76) crore has been recovered as energy charge during the year. The energy charge rate for the remaining period of 2010-11 would be Rs.1.267/kWh. Normal ECR shall be applicable from the year 2011-12 if there is no energy shortfall in 2010-11; otherwise similar procedure would follow in 2011-12.

(ii) In case the energy shortfall occurs after ten years from the date of commercial operation of a generating station, the following shall apply:

Suppose the specified annual design energy for the station is DE MWh, and the actual energy generated during the concerned (first) and the following (second) financial years is A1 and A2 MWh respectively, A1 being less than DE. Then, the design energy to be considered in the formula in clause (5) of this Regulation for calculating the ECR for the third financial year shall be moderated as (A1 + A2 – DE) MWh, subject to a maximum of DE MWh and a minimum of A1 MWh. Actual energy generated (e.g. A1, A2) shall be arrived at by multiplying the net metered energy sent out from the station by 100 / (100-AUX).

Consider the case of Chamera-I HE station of NHPC:
Annual design energy = 1665 MU
Suppose the actual generation (A1) during 2009-10 is 1500 MU & actual generation (A2) in 2010-11 is 1700 MU

Thus, design energy to be considered in the formula in clause (5) of the Regulation for calculating ECR for the FY 2011-12 shall be moderated as (1500+ 1700-1665)= 1535 MU, to compensate for energy charge shortfall corresponding to less generation of 165 MU in the year 2009-10.

26.4 Further, Commission has provided for recovery of capacity charges as a function of NAPAF. NAPAF is set by the Commission with due regard to the operating conditions of each station like variation in FRL, MDDL and silt level. In case of new stations also, Commission has provided for due consideration of factors like MDDL and rated head. As such the chances of short recovery of fixed charges on account of factors beyond the control of the generating company are remote. Apart from above, a generator can earn extra revenue as capacity charge for declaring availability more than the NAPAF during peak hours. As such, generator is encouraged to provide more peaking support. In order to give comfort to developers for new hydro electric projects, the Commission has given the option of approaching the Commission in advance for fixation of NAPAF.

27. Norms of Operation (Regulations 25)

27.1 The Commission had started the process of finalizing terms and conditions of tariff in Jan 2008 directing the central utilities under its control to furnish the actual operational data from the year 2002-03 to 2006-07 in the specified formats. The Commission intended to review the existing norms for the new and existing stations including specifying of norms for the coal based plants on super critical boiler technology and for the Lignite Based Plants based on Circulating fluidized bed combustion (CFBC) boiler technology . The Commission vide letter dated 3.4.2008 requested CEA to recommend suitable operational norms for the thermal generating stations by July 2008. CEA could make their recommendations only in Sept 2008. In the meanwhile, Commission had come out with draft regulation in Aug 2008 specifying terms and condition of tariff for a five year period 2009-14 including norms for operation on its own in the absence of CEA recommendations.

27.2 The Commission's approach has been so far to prescribe single value norms depending upon unit sizes and type of fuel and technology. In specific cases relaxed norms have also been prescribed when situation so demanded. In the meantime, CEA made its recommendations on operational norms for the thermal generating stations in September 2008. On the request of beneficiaries the operational data submitted by the CPSU's and the CEA recommendations on operational norms were made public on CERC web site.

27.3 The beneficiaries like MPPTCL, UPPCL, RRVUNL, GUVNL; etc have sought for fixing more stringent norms. One of the stakeholders has sought the average of actual should be the norm. On the other hand generators namely NTPC, NLC, NEEPCO and DVC had sought for continuation of the existing norms or relaxed norms in specific cases. Some State generators have sought for more relaxed norms. According to them, norms based on high performing stations when adopted by the SERCs would lead to innumerable losses for them.

27.4 Before dealing with the concerns of the stakeholders, we would like to discuss some of the provisions of the tariff policy notified by Govt of India on 6.1.2006. Some of the provisions are extracted as under:

(a) The Para 1.3 and 1.4 of the tariff policy reads as follows:

"1.3. It is therefore essential to attract adequate investments in the power sector by providing appropriate return on investment as budgetary resources of the Central and State Governments are incapable of providing the requisite funds. It is equally necessary to ensure availability of electricity to different categories of consumers at reasonable rates for achieving the objectives of rapid economic development of the country and improvement in the living standards of the people.

1.4. Balancing the requirement of attracting adequate investments to the sector and that of ensuring reasonability of user charges for the consumers is the critical challenge for the regulatory process. Accelerated development of the power sector and its ability to attract necessary investments calls for, inter alia, consistent regulatory approach across the country. Consistency in approach becomes all the more necessary considering the large number of States and the diversities involved."

Thus, the objectives of tariff policy are to:

(i) Ensure availability of electricity to consumers at reasonable and competitive rates;

(ii) Ensure financial viability of the sector and attract investments;

(iii) Promote transparency, consistency and predictability in regulatory approaches across jurisdictions and minimise perceptions of regulatory risks;

(iv) Promote competition, efficiency in operations and improvement in quality of supply.

(b) The tariff policy in para 5.1 also provides as follows:

"All future requirement of power should be procured competitively by distribution licensees except in cases of expansion of existing projects or where there is a State controlled/owned company as an identified developer and where regulators will need to resort to tariff determination based on norms provided that expansion of generating capacity by private developers for this purpose would be restricted to one time addition of not more than 50% of the existing capacity.

Even for the Public Sector projects, tariff of all new generation and transmission projects should be decided on the basis of competitive bidding after a period of five years or when the Regulatory Commission is satisfied that the situation is ripe to introduce such competition."

Thus tariff policy has laid down a framework for performance based cost of service regulation in respect of aspects common to generation, transmission as well as distribution.

(c) With regards to operational norms, tariff policy provide as follows:

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

(d) The para 5.3 (h)(2)of the tariff policy provide as follows:

"In cases where operations have been much below the norms for many previous years the initial starting point in determining the revenue requirement and the improvement trajectories should be recognized at "relaxed" levels and not the "desired" levels. Suitable benchmarking studies may be conducted to establish the "desired" performance standards. Separate studies may be required for each utility to assess the capital expenditure necessary to meet the minimum service standards."

27.5 In the light of above provisions of tariff policy, the Commission's endeavor is to specify just and fair norms balancing the interest of the beneficiaries as well as the generators to the extent practicable and possible. The Commission is neither in favour of specifying stringent operational norms nor in favour of giving relaxed norms unless conditions warrant such relaxation. Commission is also conscious of the fact that the future procurement of power by the licenceese shall be through competitive bidding. Nevertheless, regulated prices are expected to give price signals for the investors to invest in the Indian power sector. The Commission's approach is to have distinct operational norms depending upon type of technology and fuel, relatable to past performance in case of existing stations duly taking into consideration actual performance level, age of stations, providing for sufficient operational flexibility with system of built in incentive and disincentive mechanism. In respect of new station which would be achieving COD on or after 1.4.2009 operational norms intend to capture the new technological advancements.

27.6 The Commission doesn't consider it right approach to specify actual performance to be made the norms. This would not incentivize the generator to sustain the performance and improved efficiency levels.

27.7 The actual average based on past performance of stations during 2004-05 to 2007-08 has acted as guide for the commission to specify reasonable norms after passing on gains in efficiency over these years to the beneficiaries in the form of improved efficiency and performance norms of aux energy consumption for the next tariff period wherever deemed fit. It is because the SHR and the aux energy consumption of a station are dependent on the PLF of the station. Higher the PLF lower the SHR and Aux. energy consumption signifying more electricity available to the beneficiary in the form of additional generation. This additional generation which requires lot of efforts on the part of generator is at nominal cost by way of incentive and energy charges and effectively reduces the unit cost of electricity to the beneficiaries. Thus passes on the benefit of efficient operation to the beneficiaries directly.

27.8 The Commission is of the view that unlike SHR and Aux energy consumption norm, the specific fuel oil consumption norm is on a different footing. The use of specific fuel oil is necessary for the stable operation of units and the grid. It has been observed in the past that generator is saving much due to improved performance of the station beyond 70%. Whereas, commission does not want to sacrifice the grid stability and unit stability but at the same time would like the savings in specific fuel oil consumption as against norm be shared with the beneficiaries on year to year basis.

27.9 The actual operational parameters for the 2007-08 have also been submitted by the CPSUs. The station wise existing operational norms, actual operational parameters for 2004-05 to 2007-08, average performance parameters, Norms as per draft and norms as recommended by CEA are tabulated in Annexure-B. Various *operational norms are discussed below in the light of CEA recommendations, submissions of the stakeholders and considering the operational data of 2007-08:*

Norms of Operation of Thermal Generating Stations:

***28*. Normative Annual Plant Availability Factor (Regulation 26)**

28.1 The Commission in the draft regulations had raised the Normative Annual plant availability factor (target availability) for the full recovery of fixed charges from 80% to 85% in general for existing as well as new thermal generating stations.In the draft regulations for tariff period 2009-14, Normative Annual Plant Availability Factor (NAPAF) for recovery of fixed charge and for incentive were specified as follow:

(a) All thermal generating stations, except those covered under clauses (b), (c), (d), (e) & (f) - 85%

(b) Thermal generating stations of NTPC Ltd

Talcher TPS	82%
Tanda TPS	82%
Badarpur TPS	82%

(c) Thermal generating stations of Neyveli Lignite Corporation Ltd

TPS-I	72%
TPS-II Stage-I & II	75%
TPS-I (Expansion)	80%

(d) Thermal generating stations of Damodar Valley Corporation (DVC):

Bokaro TPS	75%
Chandrapura TPS	60%
Durgapur TPS	74%

(e) Assam Gas Based Station of NEEPCO :

Assam GPS	70%

(f) Lignite-based generating stations using Circulatory Fluidized Bed Combustion (CFBC) Technology – 80%

28.2 The CEA has recommended the continuation of existing norms for the thermal generating stations. Beneficiaries have sought a norm of 90%. On the other hand NTPC has sought to continue with existing norm of 80% citing problems in coal supply for its generating stations and dwindling coal stock position.

28.3 The Commission had proposed the above norms having due regard to the actual performance of the coal/lignite based stations for the period 2004-05 to 2006-07. The availability of these stations of NTPC and NLC has further improved in 2007-08 except in case of Farakka TPS of NTPC and TPS-I station of NLC. The average availability of stations for the period 2004-05 to 2007-08 having 200 MW sets and above is in the range of around 86 to 97% except Farrakka TPS. These stations are performing at commendable high performance levels consistently for all these years. Problem of coal supply in case of one station at Farakka TPS and specific problem at TPS-I station cannot be a ground for lower norm. At the same time, we are also conscious of the fact that these stations are amongst the best performing stations and setting norm close to such high performance level will not leave them scope for operational flexibility in case of poor supply of fuel, any operational contingency, deterioration in the fuel quality etc. A very high performance norm may also discourage the new investment in the sector as in the regulated regime it may be difficult for them to mitigate any risk for not achieving the specified high performance level. Commission is therefore, convinced that norm of 85% for these stations is just, reasonable and equitable.

28.4 The beneficiaries have sought for higher availability norm for Badarpur, Tanda and Talcher TPS of NTPC. The commission had kept the lower availability norm for these stations having regard to their vintage. However, Tanda is performing at fairly high level consistently above 90% for the last two years and has still not completed its useful life. As such, we are inclined to set a norm for Tanda TPS at 85%. But in case, of Talcher TPS and Badarpur TPS, we intend to keep the norm same as provided in the draft regulations at 82% for the reasons specified in draft regulation.

28.5 In respect of DVC stations we do not find any reason to set a different availability norm except Mejia TPS 1 to 4. Mejia unit 1 to 4 has improved upon its performance and has achieved a PLF of 90% in 2007-08 but only one year performance is not sufficient to justify the same availability norms as set for other good performing stations which are consistently performing at level above the availability norm of 85%. As such, we are fixing a norm of 82% for the Mejia unit 1 to 4 based on their performance for the year 2006-07 and 2007-08. Other stations namely Bokaro, Chandrapura and Durgapur despite improved performance than the previous years are still short of norms specified by CERC for the year 2008-09 and as such availability norms as specified in draft regulations are being adopted in the final regulation for these DVC stations.

28.6 Similarly in case of lignite based stations of NLC we don’t find that there is a case for review of norms for these stations. In case of lignite stations of NLC, TPS-I (Expansion) is consistently achieving availability and actual PLF level of more than 80%. TPS-II stage-I & II has also been able to achieve availability of more than 75% in 2007-08. But in case of TPS-I Station availability levels has gone further down to 70%

in 2007-08 (Actual PLF). The NLC during the hearing has informed that they have decided to phase out TPS-I units one by one in a phased manner. But the average availability is of the order of 76% and hence we are keeping the availability norm as 72%. With regard to lignite fired stations using CFBC technology are concerned, we found that the availability in initial years was of the order of 76% in case of surat lignite fired station and gradually picked up thereafter. In view of this we are providing for a norm of 75% during first three years of COD and thereafter, retaining a norm of 80%. In respect of the new lignite power stations with PF Boilers, availability norms have been combined with the coal power fire stations at 85%. NLC has expressed that difference in the availability norms of 5% between coal and lignite power stations should be maintained as in the previous Tariff Orders for the period 2004-2009 in view of the difficulties faced in lignite fired boilers. However, it has been decided to retain the draft and specific difficulties if any brought out by NLC could be looked into for suitable modifications.

28.7 As regards target plant load factor for the payment of incentive is concerned, it is not relevant now when the Commission has decided to go for the availability based incentive scheme for the thermal generating stations as provided in draft regulations. This has been discussed separately. In coal/lignite based stations 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.

28.8 The availability of the various Gas/Liquid fuel based generating stations NTPC in the last 4 years i.e. 2004-05 to 2007-08 is as follows:

NTPC's gas based station	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**Average**
Auraiya	82%	91%	90%	81%	86%
Anta	86%	91%	88%	85%	88%
Dadri	89%	90%	85%	84%	87%

Kawas	91%	93%	95%	87%	91%
Jhanor Gandhar	71%	81%	82%	78%	78%
Faridabad	98%	95%	89%	83%	91%
Kayamkulam (RGCCP)	85%	96%	93%	93%	92%

28.9 It can be seen that despite lower performance level in 2007-08, all the above plants of NTPC are maintaining average availability in the range of 86% to 91% except in case of Jhanor Gandhar GPS. The actual PLFs which were much lower than the respective availability during the last 4 years due to the fact that liquid fuel based capacity was not being dispatched by the beneficiaries due to very high cost of liquid fuel namely Naphtha and HSD and high spot prices of RLNG. But due to steep fall in crude prices we expect that this trend will no longer continue in the next tariff period. With the improvement in the despatches on liquid fuel from Kawas station of NTPC, we feel that more gas could be diverted to Gandhar GPS. Further, reduction in prices of spot gas will also enable despatches of capacity on RLNG so that generator like NTPC could arrange for Gas with some certainty. Nevertheless, in case of gas shortage, we have already provided that the generating co. may propose to deliver a higher MW during peak-load hours by saving fuel during off-peak hours. The nodal load dispatch centre may then specify a pragmatic day-ahead schedule for the generating station to optimally utilize its MW and energy capability, in consultation with the beneficiaries. In such a case the DCi shall be taken to be equal to the maximum peak-hour ex-power plant MW schedule specified by the nodal load dispatch centre for that day.

28.10 As such, we are fixing availability norm of 85% for all existing as well as new gas/liquid fuel based stations.

28.11 The actual availability for the period 2004-05 to 2007-08 as achieved by Small Gas turbine stations of NEEPCO is as below:

Station	2004-05	2005-06	2006-07	2007-08	Average
Assam GPS	78%	72%	72%	69%	**73%**
Agartala GPS	83%	97%	94%	93%	**92%**

28.12 It is observed that the Target Availability of 80% could not be achieved by the Assam GPS from 2004-05 to 2007-08. It is because the station is not getting required quantity of gas for availability declaration of 80%. Further, as brought out in our explanatory memorandum with draft regulation that the allocation of 1.0 MCMD of gas on firm basis and 0.4 MCMD on fall back basis is sufficient for sustaining a generation level of the order of 70% only. 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 is of the view that there is a case for relaxation of target availability norm for the Assam GPS station. However, the average availability of the station is about 73% for the years 2004-05 to 2007-08 despite availability of 70% (Actual PLF) in the year 2007-08. As regards, provision regarding conserving gas during off peak hours and using it during off-peak hours in consultation with beneficiaries due to gas shortage may be a difficult option for Assam GPS due to supply of gas from scattered wells, through short pipelines which do not have any capacity for gas storage (line pack), Considering all these aspect, a target availability norm of 72% is allowed for the tariff period 2009-14 as against 70% provided in the draft regulation.

28.13 In case of Agartala GPS, the station is able to achieve an average availability of 92% in last three years i.e. 2005-06 to 2007-08 and there is no gas supply problem. As such, a target availability norm of 85% is allowed for the Agartala GPS.

28.14 *For the new small gas turbine stations, the target availability norm for the full recovery of fixed charges and payment of incentive shall also be 85%. Accordingly, following availability norms are specified:*

“ (i) Normative Annual Plant Availability Factor (NAPAF) for recovery of fixed charge and for Incentive

(a) All thermal generating stations, except those covered under clauses (b), (c), (d), (e) & (f) - 85%

(b) Thermal generating stations of NTPC Ltd

Talcher TPS	82%
Badarpur TPS	82%

(c) Thermal generating stations of Neyveli Lignite Corporation Ltd

TPS-I	72%
TPS-II Stage-I & II	75%
TPS-I (Expansion)	80%

(d) Thermal generating stations of Damodar Valley Corporation (DVC):

Mejia TPS Unit-I to IV	82%
Bokaro TPS	75%
Chandrapura TPS	60%
Durgapur TPS	74%

(e) Gas Based Station of NEEPCO :

Assam GPS	72%

(f) Lignite-fired Generating Stations using Circulatory Fluidized Bed Combustion (CFBC) Technology –

1. First three years from COD – 75%
2. From next year after completion of 3 years of COD – 80%."

29. Gross Station Heat Rate {Regulation 26(ii)}

29.1 Coal/Lignite based thermal generating stations :CERC had tightened the Gross station heat rate norm in the draft regulation for existing as well as new 500 MW units from 2450 kCal/kWh to 2400 kCal/kWh. The SHR norm for lignite based stations continued to be linked to SHR norm of coal based station with correction factor for moisture content. Separate norms were specified for 600 MW and above sets based on super critical boiler technology and lignite based stations based on CFBC technology.

29.2 So far as existing stations commissioned before 1.4.2004 are concerned, CEA has recommended continuation of existing norms. In respect of new generating stations commissioned after 1.4.2004, CEA has departed from earlier practice of specifying single value norms according to the unit sizes and class of turbines in case of gas based stations. CEA has recommended for specifying Station heat rate norms with a multiplying factor of 6% over the design heat rate in respect of coal/lignite fired stations and 5% over the design heat rate in respect of gas based stations and 2% over the SHR norm of gas based stations for liquid fuel firing.

29.3 It may be appreciated that CERC had specified Operational norms having regard to the actual of 2004-05 to 2006-07 in the absence of CEA recommendations. CEA before making its recommendations has gone in to operational performance of not only CPSUs but has also considered operational performance of generating stations of State Utilities as well. CEA has also deliberated upon various operational aspects and operation margins. The CEA recommendation that design heat rates quoted by the manufacturer or based on the quotations of manufactures are more representative numbers taking in to account all site specific conditions; quality of coal, etc definitely has a merit. The operating margin of 6% for the coal based stations and 5% for the gas based stations over the design heat rate are after due consideration of actual of a class of best performing stations including stations of State Utilities . However, to safeguard against the misquoting of design heat rate, CEA has also recommended following ceiling design turbine cycle heat rate and boiler efficiency depending upon domestic or imported coal as fuel:

Steam parameters at Turbine inlet		**Maximum Turbine cycle heat rate**
Pressure Kg/cm2	MST/RST (Deg C)	(kcal/kWh)
150	535/535	1955
170	537/537	1910 (with MD-BFP), 1950 (with TD-BFP)
170	537/565	1895(with MD-BFP), 1935(with TD-BFP)
247	537/565	1860(with MD-BFP), 1900(with TD-BFP)
247	565/593	1810(with MD-BFP), 1850(with TD-BFP)
Fuel		**Minimum Boiler Efficiency (%)**
Sub -bituminous Indian coals		85%
Bituminous Imported coal		89%

29.4 In view of this we are accepting CEA recommendations with following modifications as discussed below:

(a) In respect of existing units, CEA has recommended that existing norms may be allowed to continue. NTPC has also submitted SHR data of its 500 MW units in the stations having mix of 200/210 MW and 500 MW units which averages to 2405 kCal/kWh. However, having regard to actual heat rate data and actual PLF data of NTPC stations for 2004-05 to 2007-08, Commission is of the view that improvement in SHR norm is on account of improved in PLF in year to year basis except few stations. CEA has also recognized that the NTPC units are operating near 100% of their MW rating. Such a performance consistently is really very credit worthy and beneficiaries has gained tremendously with extra generation at nominal incentive plus energy charges effectively reducing their per unit cost. However, sustaining of such high performance level may not be sustained always thus calling for providing some margin for operational flexibility. The present margin for operational flexibility is of the order of 2-3% in respect of coal based stations. As for as 500 MW sets (including those commissioned between 1.4.2004 to 31.3.2009) are concerned, these units are relatively new and are expected to maintain current performance levels, and as such, for these stations there is scope for tightening of SHR norm for 500 MW unit by about 25 kCal/kWh still giving them operational flexibility to deal with variation in fuel quality and fuel supply constraints etc. As such, we are fixing a SHR norm of 2425 kCal/kWh (instead of 2400 kCal/kWh as proposed in draft) for the existing 500 MW units and passing on the benefit of efficiency gain to the benficiaries. In respect of 200/210/250 MW sets, which are relatively old and near completion of their useful life, the performance level is expected to be lower due to R&M activities, a point made by the NTPC. As such, in respect of 200/210/250 MW sets we are retaining the norms as 2500 kCal/kWh.

(b) In respect of NTPC stations namely Tanda TPS and Talcher TPS, it is felt that there is further scope of reduction of heat rate norm by about 25 kCal/kWh having regard to their actual heat rate data for the period 2004-05 to 2007-08. In respect of Gandhar GPS, NTPC has sought for relaxation of norm to 2080 kCal/kWh due to water injection to control NO_x. However, considering actual performance we feel that a norm of 2040 kCal/kWh would be sufficient. Similarly, in case of Assam GPS due to non availability of gas, we are relaxing the SHR norm to 2400 kCal/kWh as provide in the draft regulations based on actual performance data as it is not possible for the NEEPCO in NE region to arrange gas from any other alternate source. In respect of Agartala GPS, we are providing for tightening of SHR norm to 3500 kCal/kWh from the present 3580 kCal/kWh considering its actual performance. With regard to DVC existing stations as provide in the draft regulation, we are specifying same norms as applicable in 2008-09 as these stations are yet to achieve norms specified for 2008-09. However, Commission would be taking stock of the actual performance of these stations and would review the DVC norms as and when considered necessary.

(c) In respect of new coal/lignite based thermal generating units, Commission is of the view that the SHR norms could not be set based on the actual performance of high performing units leaving them no scope for operational flexibility. As such, Commission is providing for a 0.5% additional margin over the design heat rate and accordingly, providing for a margin of 6.5% above the design heat rate as the SHR norm for the new coal/lignite based stations. Further, to safeguard against the misquoting of design heat rate, as suggested by CEA we are providing that the design heat rate should not exceed the following values in respect of units depending upon their temperature and pressure ratings:

Pressure Rating (Kg/cm2)	150	170	170	247	247
SHT/RHT (0C)	**535/535**	**537/537**	**537/565**	**537/565**	**565/593**
Type of BFP	**Electrical Driven**	**Turbine driven**	**Turbine driven**	**Turbine driven**	**Turbine driven**
Max Turbine Cycle Heat rate (kCal/kWh)	**1955**	**1950**	**1935**	**1900**	**1850**
Min.Boiler Efficiency					
Sub-Bituminous Indian Coal	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**
Bituminous Imported Coal	**0.89**	**0.89**	**0.89**	**0.89**	**0.89**
Max Design Unit Heat rate (kCal/kWh)					
Sub-Bituminous Indian Coal	**2300**	**2294**	**2276**	**2235**	**2176**
Bituminous Imported Coal	2197	2191	2174	2135	2079

(d) It can be seen that the CEA had provided for ceiling of minimum boiler efficiency for imported coal as well. All the existing stations were designed for domestic sub -bituminous Indian coals. But due to deteriorating quality and shortage of coal, NTPC has started blending imported coal with domestic coal in some of its power stations. This is with a view to move towards design coal. As such, there should not be any confusion regarding use of imported coal for the blending with domestic coal in the existing stations. Since such, blending is unlikely to improve the guaranteed boiler efficiency which is given for a designed coal. We shall therefore, be guided by the design coal for which guarantees have been given by the supplier while adopting the efficiency parameters for the domestic coal or the imported coal as the case may be.

(e) It may also be possible that the manufacturers may offer a machine whose pressure and temperature ratings may not exactly match with the pressure and temperature ratings specified above. In such a situation, the ceiling design heat rate of the nearest class shall be taken for determining the norm.

(f) It may also be possible that unit heat rate has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers. In such a situation, the unit design heat rate shall be arrived at by using guaranteed turbine cycle heat rate and boiler efficiency.

(g) It may also be possible that one or more units of a station achieve COD prior to 1.4.2009 and other units may achieve COD on or after 1.4.2009. The units achieving COD prior to 1.4.2009 then shall be called existing units. Then a question may arise whether the units of same type could have different norms. In order to deal with such a situation, it is provided that in such a situation, the heat rate norm for units achieving COD prior to 1.4.2009 as well as units achieving COD on or after 1.4.2009 for the tariff period shall be lower of the heat rate norms arrived at by above methodology and the norms for the existing units.

(h) In case of lignite fired stations, ceiling design heat rates shall be up graded using factor for moisture content.

(i) In respect of units where the boiler feed pumps are electrically operated, the design heat rate shall be 40 kCal/kWh lower than the design heat rate specified above with turbine driven BFP.

(j) As regards gas/liquid fuel based stations are concerned, margin specified by CEA of 5% of design heat rate for gas based stations and 2% above it for liquid fuel firing (7.1% of design heat rate) already provide for sufficient operational flexibility.

29.5 Accordingly following operational norms are specified in clause (ii) of Regulation 26 of these regulations for the thermal generating stations:

"(ii) Gross Station Heat Rate

A. **Existing Thermal Generating Station**

(a) Existing Coal-based thermal generating unit(s), other than those covered under clauses (b) and (c) below

200/210/250 MW Sets	**500 MW Sets (Sub-critical)**
2500 KCal/kWh	2425 kCal/kWh

Note 1

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

Note 2

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

(b) Thermal generating stations of NTPC Ltd.:

Badarpur TPS	2825 kCal/kWh

Talcher TPS	2950 kCal/kWh
Tanda TPS	2825 kCal/kWh

(c) Thermal generating stations of Damodar Valley Corporation (DVC):

Bokaro TPS	2700kCal/kWh
Chandrapura TPS	3100 kCal/kWh
Durgapur TPS	2820 kCal/kWh

(d) Lignite-based thermal generating stations

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

(i) For lignite having 50% moisture: 1.10

(ii) For lignite having 40% moisture: 1.07

(iii) For lignite having 30% moisture: 1.04

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

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

TPS-I 4000 kCal/kWh

TPS-II 2900 kCal/kWh

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

(i) Existing generating stations of NTPC Ltd and NEEPCO

Name of generating station	Combined cycle (kCal/kWh)	Open cycle (kCal/kWh)
Gandhar GPS	2040	2960
Kawas GPS	2075	3010
Anta GPS	2075	3010
Dadri GPS	2075	3010
Auraiya GPS	2100	3045
Faridabad GPS	2000	2900
Kayamkulam GPS	2000	2900
Assam GPS	2400	3440
Agartala GPS		3500

B. **New Thermal Generating Station**

(a) Coal based and lignite based thermal generating unit(s)
= 1.065 X Design Heat Rate of the unit(s) (kCal/kWh)

Where the Design Heat Rate of a unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR, zero percent make up, design coal and design cooling water temperature/back pressure.

Provided that the design heat rate shall not exceed the following design heat rates depending upon the pressure and temperature ratings of the units:

Pressure Rating (Kg/cm2)	**150**	**170**	**170**	**247**	**247**
SHT/RHT (0C)	**535/535**	**537/537**	**537/565**	**537/565**	**565/593**
Type of BFP	**Electrical Driven**	**Turbine driven**	**Turbine driven**	**Turbine driven**	**Turbine driven**
Max Turbine Cycle Heat rate (kCal/kWh)	**1955**	**1950**	**1935**	**1900**	**1850**
Min.Boiler Efficiency					
Sub-Bituminous Indian Coal	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**
Bituminous Imported Coal	**0.89**	**0.89**	**0.89**	**0.89**	**0.89**
Max Design Unit Heat rate (kCal/kWh)					
Sub-Bituminous Indian Coal	**2300**	**2294**	**2276**	**2235**	**2176**
Bituminous Imported Coal	2197	2191	2174	2135	2079

Provided further that in case pressure and temperature parameters are different from above ratings, the ceiling design heat rate of the nearest class shall be taken:

Provided also that where unit heat rate has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers, the unit design heat rate shall be arrived at by using guaranteed turbine cycle heat rate and boiler efficiency.

Provided also that if one or more units achieve COD prior to 1.4.2009 then the heat rate norm for those units as well as units achieving COD on or after 1.4.2009 for the tariff period shall be lower of the heat rate norms arrived at by above methodology and the norms as per the regulation 29 (ii) A (a).

Provided also that in case of lignite fired stations, ceiling design heat rates shall be up graded using factor for moisture content given in sub clause (1) of clause (ii) A(d) of this regulation.

Note: In respect of units where the boiler feed pumps are electrically operated, the design heat rate shall be 40 kCal/kWh lower than the design heat rate specified above with turbine driven BFP.

(b) Gas / Liquid based thermal generating unit(s)/ block(s)

= 1.05 X Design Heat Rate of the unit/block for Natural Gas and RLNG (kCal/kWh)
= 1.071 X Design Heat Rate of the unit/block for Liquid Fuel (kCal/kWh)

Where the Design Heat Rate of a unit shall mean the guaranteed heat rate for a unit at 100% MCR and at site ambient conditions; and the Design Heat Rate of a block shall mean the guaranteed heat rate for a block at 100% MCR, site ambient conditions, zero percent make up, design cooling water temperature/back pressure."

30**. Secondary fuel oil consumption {Regulation 26(iii)}**

30.1 Specific fuel oil consumption norm was reduced by the Commission from 2.0 ml/kWh to 1.00 ml/kWh for the coal based stations and 1.5 ml/kWh for lignite based stations whether new or existing, having 200MW sets and above in clause (iii) of Regulation 26 of draft Regulations. Relaxed norms were specified for some of the generating stations of NTPC, DVC, NLC and NEEPCO.

30.2 While MPPTCL and UPPCL have urged for reducing the secondary fuel oil consumption to 0.4 ml/kWh and 0.5ml/kWh respectively, TNEB and Energy Infratech Pvt Limited have pitched for retention of the existing norms. NTPC has argued for 1.5 ml/kWh for 500 MW sets, 2 ml/kWh for 200/210 MW sets. NLC has asked for 3 ml/kWh for TPS-I(Expansion), TPS-II(Expansion) and Barsinghar CFBC. DVC has asked for 2 ml/kWh for Mejia TPS. Concerns have also been shown by the RLDCs/NLDC that reduced norms should not come in the way of optimal grid operation for fear of more oil consumption.

30.3 CEA has recommended a Specific fuel oil consumption norm of 0.75 ml/kWh in respect of existing coal fired generating stations and 1.25 ml/kWh for lignite fired generating stations. It has been seen that the specific fuel oil consumption in respect of NTPC coal based stations has been much lower than 0.75 ml/kWh recommended by CEA except in case of Farakka TPS.

30.4 The Commission is of the view that the generators should not be discouraged to take oil support when necessary which is important from the boiler safety and grid security point of view. Commission is, therefore, providing for a norm of 1.0 ml/kWh but with a provision for sharing of savings with the beneficiaries on account of actual consumption being lower than the norms in the ratio of 50:50. Similarly in respect of lignite based stations we are providing for a norm of 2.0 ml/kWh and relaxed norm of 3.5 ml/kWh for TPS 1 station of NLC. In case of lignite fired generating stations, CEA has recommended a norm of 1.25 ml/kWh. CEA is of the view that CFBC boiler does not require oil support at low load operations. As such, we are accepting CEA's recommendations in this regard. In case of DVC also relaxed norms of 2008-09 are being allowed. The savings in oil consumption shall also be shared by these stations with the beneficiaries in the 50:50 ratios. Accordingly, following specific fuel oil norms are provided in clause (iii) of Regulation 26:

" (iii) Secondary fuel oil consumption

(a) Coal-based generating stations other than at (c) below

: 1.0 ml/kWh

(b) (i) Lignite-fired generating stations except stations based on CFBC technology and TPS-I : 2.0 ml/kWh

(ii) TPS-I : 3.5 ml/kWh

(iii) Lignite-fired generating stations based on CFBC technology : 1.25ml/kWh

(c) Coal-based generating stations of DVC"

Mejia TPS Unit I to IV	2.0 ml/kWh
Bokaro TPS	2.0ml/kWh
Chandrapura TPS	3.0 ml/kWh
Durgapur TPS	2.4 ml/kWh

31. <u>Auxiliary Energy Consumption {Regulation 26(iv)}</u>

31.1 In respect of aux. energy consumption norms, CEA has recommended norms depending upon type of cooling tower i.e. induced draft cooling towers and natural draft cooling towers and open cycle cooling. Moreover, for steam driven BFP, CEA has recommended norms with reduction of 2.5%. In respect of gas /liquid fuel fired generating stations CEA has recommended continuation of same norm of 3% for combined cycle operation and 1% for open cycle operation. For lignite fired stations based on CFBC technology, CEA has recommended a norm of 10.5% with induced draft cooling towers and 10% for natural draft cooling towers and open cycle operation. We find that CEA norms are conforming to the actual consumption of CPSUs generating stations. As such, we are accepting CEA recommendations in this regard.

However, in case of Barsingsar lignite fired stations of NLC based on CFBC technology, CEA has reviewed the norm and has recommended a norm of 11.50%. Considering the actual of Surat lignite station and additional pumping of water required for Barsinghsar station, we have accepted the norm of 11.5%.

31.2 In view of the above discussion, the Commission has specified the following norms for auxiliary energy consumption clause (iv) of Regulation 26 of these regulations:

<u>“(iv) Auxiliary Energy Consumption</u>

(a) Coal-based generating stations except at (b) below:

		With Natural Draft cooling tower or Without cooling Tower
(i)	200 MW series	8.5%
(ii)	500 MW & above	
	Steam driven boiler feed pumps	6.0%
	Electrically driven boiler feed pumps	8.5%

Provided further that for induced draft cooling towers, above norms shall further be increased by 0.5% point.

(b) Other Coal-based generating stations:

(i)	Talcher TPS	10.5%
(ii)	Tanda TPS	12.0%
(v)	Badarpur TPS	9.5%

(vi)	Bokaro TPS	10.25%
(vii)	Chandrapura TPS	11.50%
(viii)	Durgapur TPS	10.50%

(c) Gas Turbine/Combined Cycle generating stations:

(i) Combined cycle 3.0%

(ii) Open cycle 1.0%

(d) Lignite-fired thermal generating stations:

(i) All generating stations with 200 MW sets and above:

The auxiliary energy consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (iv) (a) (i) & (ii) above. For lignite based stations based on CFBC technology, auxiliary energy consumption norms shall be 1.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (iv) (a) (i) & (ii) above.

(ii) Generating stations up to 125 MW sets using CFBC technology: 11.50%

(iii) TPS-I, TPS-II Stage-I&II and TPS-I (Expansion) of Neyveli Lignite Corporation Ltd.:

TPS-I 12.0%

TPS-II 10.0%

TPS-I (Expansion) 9.50%

32. Lime stone Consumption Norm for lignite fired station of NLC using CFBC technology

32.1 In so far as lime stone consumption for lignite-based generating station using CFBC technology is concerned, the Commission had specified a norm of 0.05 kg/kWh based on RERC order and had provided for factoring in this in the fixed cost. CEA on the Commission's request has gone into the quality of lignite to be fired in the up coming stations of Barsingsar & TPS-II (Expansion) of NLC and has recommended specific norms depending upon the sulpher content in lignite to be fired. On this consideration, the Commission has decided to provide for specific norm rather than a general norm which may vary depending upon sulphur content in the lignite. Accordingly, following norms of lime consumption in respect of following stations of NLC using CFBC technology have been adopted:

Barsinghsar : 0.056 kg/kWh.

TPS-II (Expansion) : 0.046 kg/kWh

33.0 <u>Norms of Operation of Hydro Generating Stations</u>

33.1 <u>Normative Annual Plant Availability Factor(Regulation 27)</u>

33.1.1 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 Hydro electric Development Corporation and Damodar Valley Corporation were directed to furnish 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. 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 assessed. Chamera-I and Chamera-II stations of NHPC which had consistent performance in terms of providing peaking capability during last 4-5 years and where plant availability is not affected by silt are considered as benchmark stations. Normative plant availability factor (NAPAF) of these stations has been considered at 90%.

33.1.2 Normative annual plant availability factor (NAPAF) of various hydro generating stations shall be determined based on following criteria /guidelines:

(i) Storage and pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8% and where plant availability is not affected by silt : 90%

(ii) In case of Storage and pondage type plants with head variation between Full Reservoir Level and Minimum Draw Down Level of more than 8% and where plant availability is not affected by silt, the month wise peaking capability as provided by the project authorities in the DPR (approved by CEA or the State Govt.), shall form basis of fixation of NAPAF.

This has been explained with the following example of Tehri HE project of THDC, as per submission of the generating company.

Installed capacity : 4x250 MW

Month	Expected Avg. of daily 3-hour peaking capacity
April	701
May	448

June	497
July	544
August	990
September	1000
October	1000
November	1000
December	1000
January	1000
February	693
March	605

Weighted average of expected daily peaking capability= 790 MW

Peaking capacity is based on the assumption that one unit shall be under annual maintenance during month of May, July, February and March.

Considering 2% allowance on plant capacity on account of forced outages during the year, expected average peaking capacity= 770 MW

Thus, NAPAF= 770/1000= 77%

(iii) Pondage type plants where plant availability is significantly affected by silt, a margin of 5% has been allowed and NAPAF shall be 85%

(iv) In case of purely Run-of-river type plants, NAPAF shall be determined plant wise, based on its 90% dependable 10-daily inflows pattern as approved in the DPR of the project.

(v) A further allowance may be made by the Commission while determining the NAPAF under special circumstances i.e. abnormal silt problem or other operating conditions and known plant limitations.

(vi) Keeping in view the difficulties faced in North East Region, a further allowance of 5% may be allowed for plants already in operation or likely to be commissioned in N.E. region.

(vii) When head variation between FRL and MDDL is more than 8%, following multiplying factors shall be applied:

Multiplying factor for
head variation = (Head at MDDL/Rated Head) x 0.5+ 0.52

33.1.3 NEEPCO brought to the notice of the Commission following inherent operational problems faced in respect of Kopili-I, Khandong, Kopili-II and Doyang HE projects:

(i) Installed capacities of Kopili (200 MW), Khandong (50 MW) & Kopili-II (25 MW) could never be achieved due to more than expected head loss in HRT. Practically, maximum generation from Kopili-I, Khandong, Kopili-II stations are 196 MW, 44 MW and 22 MW respectively with all units running during high hydro period, whereas due to wide variation of head, the output of these stations are much below the rated output during lean season.

(ii) In case of Doyang the design FRL is EL 333 M. However, local population have been objecting to raise the reservoir level beyond EL 325 M, thus practically achievable FRL is 325 M resulting in loss of maximum power output.

(iii) Keeping in view the above practical difficulties faced by NEEPCO, the NAPAF of the above stations has been arrived at in the following manner and also considering the multiplying factor when head variation between FRL & MDDL is more than 8%.

a) KOPILI HEP (4 x 50 MW) has an FRL of 609.6 m, MDDL of 592.85 m, TWL of 267.0 m and a rated head of 326.5 m. However, due to increased head loss in the head race tunnel (HRT), the net head available at FRL is only 302.91 m (92.8% of the rated head). It would be reasonable to allow for this in NAPAF for the generating station, since it constitutes a permanent operational limitation. The station has no silt problem, and its head variation from FRL to MDDL is only 5.5%, for which the bench mark NAPAF is 90% (considering normal machine outages and operating conditions). With an allowance of 5% for the difficulties faced in NER, the NAPAF for this generating station may be specified as 90 x 0.928 x 0.95 = 79.34% (rounded off to 79%).

b) KHANDONG HEP (2 x 25 MW) has an FRL of 719.3 m, MDDL of 704.3 m, TWL of 611.0 m and a rated head of 99.0 m. One 25 MW unit has been installed under Kopili – Stage II to operate in parallel with the Khandong HEP, due to which the HRT head loss has substantially increased, and net head available at FRL (when all three units are operating) is only 85.38 m (86.2% of the rated head). This is a permanent operational limitation, and needs to be allowed in NAPAF determination. Further, the head variation from FRL to MDDL is 17.6%, much in excess of the head variation considered in bench mark NAPAF of 90%, and a margin of 6.8% need be allowed for the same. Taking these factors into account and allowing 5% for difficulties faced in NER, the NAPAF for this generating station would work out to 90 x 0.862 x 0.932 x 0.95 = 68.7% (rounded off to 69%). This would also be applicable for Kopili – Stage II (1 x 25 MW).

c) DOYANG HEP (3 x 25 MW) has a design FRL of 333.0 m, MDDL of 306.0 m, TWL of 252.5 m and rated head of 67.0 m. However, due to objections of local population, the reservoir level is being restricted to 325.0 m, at which the net head available is 65.59 m (98% of rated head). Further, the head variation from restricted FRL to MDDL is 29%, for which an allowance of 12.5% should be made in NAPAF. Considering these factors and allowing 5% margin for difficulties faced in NER, the NAPAF for this generating station would work out to

0.90 x 0.98 x 0.875 x 0.95 = 73.3% (rounded off to 73.0%)

33.1.4 Based on the above, the Normative Annual Plant Availably Factor (NAPAF) of the hydro generating stations shall be as follows :

Station	Type of Plant	Plant Capacity (MW)	NAPAF (%)
NHPC			
Chamera -I	Pondage	3x180	90
Baira siul	Pondage	3x60	85
Loktak	Storage	3x35	85
Chamera-II	Pondage	3x100	90
Rangit	Pondage	3x20	85
Dhauliganga	Pondage	4x70	85
Teesta-V	Pondage	3x170	85
Dulhasti	Pondage	3x130	90
Salal	ROR	6x115	60
Uri	ROR	4x120	60
Tanakpur	ROR	3x31.4	55
NHDC			
Indira sagar	Storage	8x125	85

Omkareshwar	Pondage	8x65	90
THDC			
Tehri Stg-I	Storage	4x250	77
SJVNL			
Nathpa Jhakri	Pondage	6x250	82
NEEPCO			
Kopili Stg - I	Storage	4x50	79
Khandong & Kopili stg-2	Storage	3x25	69
Doyang	Storage	3x25	73
Ranganadi	Pondage	3x135	85
DVC			
Panchet	Storage	2x40	80
Tilaiya	Storage	2x2	80
Maithon	Storage	3x20	80

33.1.5 Based on the submission of the stakeholders, Commission has decided that recovery of capacity and energy charges shall be on 50:50 basis for all hydro plants. Hence there is no need to specify the Capacity Charge Apportionment Factor (CCAF).

34. CALCULATION OF TRANSMISSION SYSTEM AVAILABILITY

34.1 In the tariff regulations for 2004-2009, the availability of a transmission system (for payment of transmission charges and incentive) is required to be worked out through formulae in which

(i) A transmission line circuit has a weightage proportional to its length and surge impedance loading (SIL), for working out the weighted average availability of transmission lines.

(ii) A transformer / bus reactor has a weightage proportional to its MVA / MVAR rating, for working out the weighted average availability of transformers / bus reactors.

(iii) Transmission line circuits, transformers and bus reactors have weightages proportional to their respective numbers in a transmission system, in computation of the system's overall availability.

34.2 While the same procedure for transmission system availability calculation had been proposed in the draft tariff regulations for 2009-2014, the Commission has observed two drawbacks in the above scheme, as discussed below.

(a) SIL has no direct relationship with the power carrying capability of a transmission line. For example, SIL of a 400 kV line with twin Moose conductors is 515 MW, and a 400 kV line with quad Bersimis conductor has an SIL of 691 MW (1.34 times of the former), whereas the latter can easily carry twice the amount of power. Further, SIL loses its significance totally in case a line has a shunt reactor or series compensation. SIL is therefore not a suitable criterion for weightage in line availability.

(b) In the overall availability determination for a transmission system, line lengths, SIL and transformer/ bus reactor ratings do not figure, and the three groups get a weightage only according to their numbers. In other words, a transformer or a reactor ultimately has the same weight as a line circuit, irrespective of their size or length.

34.3 To overcome the above drawbacks, a new formula has been specified in Appendix –IV for calculation of transmission system availability in a composite manner. Factors have been applied such that a 315 MVA transformer would have the same weightage as a 200 km long D/C line with twin conductors, and a 50 MVAR switched reactor would have one-fourth the weightage of a 315 MVA transformer. The transmission lines shall have a weightage proportional to their circuit – km and number of sub-conductors (to which the current carrying capacity is directly proportional). Voltage has been omitted by design for the present, to deliberately enhance the weightage for 220 kV and 132 kV lines (as they are critical for supply to beneficiaries), and to suppress the weightage for 765 kV lines (since they presently carry power much below their capability). The Commission may review and modify the formula when the situation changes in future.

34.4 We are conscious of the fact that clause 6 of the procedure for calculation of availability prescribed in Appendix-IV requires that in case of acts of god as also in case of grid disturbance not attributable to the transmission licensee, the outage hours attributable to these events have to be subtracted from the total outage duration as well total hours during the month for the affected elements, yet the formulae in clauses 3 and 4 envisage total hours to be same for all elements. Since such events are rare, it was thought that the basic formula can be simplified for normal application. If in any month certain elements are affected by aforesaid events, Member Secretary of the RPC concerned shall subtract from the denominator, outage hours attributable to the aforesaid events multiplied by weightage factor for that element. For example if due to an act of god (such as cyclone) one 300 km D/C quad conductor line is under outage for 40 hours, not only these outage hours will not be counted in outage hours for that element appearing in the numerator, from the denominator (as calculated based on prescribed formula) figure equal to 600 x 4 x 40 i.e. 96000 will be deducted. It is needless to mention that if an element is kept under operation using ERS, this element will be considered available.

34.5 We recognize that there are many other aspects of transmission system operation which also have an impact on the system reliability, but which are not included in the computation of transmission system availability, to keep the latter simple. Some of these are :

i) Outages of individual equipment which can be bypassed through provisions in the scheme design, e.g. circuit breakers, and which can be isolated without restricting power flows, e.g. shunt reactors, series capacitors, sub-station busbars.

ii) Outage of individual equipment for which a stand-by has been provided as a prudent practice, e.g. protective relays, a spare single-phase transformer for a 3-phase bank.

iii) Restoration of a line on emergency restoration system (ERS).

34.6 In all these cases, redundancies provided for enhancing system security get encroached upon, and it is expected that the transmission licensee would exercise due diligence in the matter on his own, i.e. without having to be induced through a commercial incentive to minimize the outage period.

34.7 Frequency of tripping of a transmission element, more so if the tripping is caused by relay mal-operation, etc., also has an adverse impact on system security. The Commission may consider incorporation of tripping frequency (in number of trippings in a year) in the formula for calculating transmission system availability, after a detailed exercise in due course.

Availability of HVDC System

34.8 A uniform availability norm of 95% was specified for all HVDC schemes whether bipole or back-to-back, in the tariff regulations for 2004-2009, and was also proposed in the draft for 2009-2014. PGCIL has represented that such a norm is too high, and would be difficult to achieve on a sustained basis. The matter has therefore been reviewed. It has been observed that the back-to-back HVDC stations have generally achieved on annual availability of well over 95%. The average availability achieved for the four-year period from 2004-05 to 2007-08 is 96.34% for Sasaram (1 x 500 MW), 98.20% for Gazuwaka (2 x 500 MW), 97.42% for Bhadrawati (2 x 500

MW) and 98.64% for Vindhyachal (2 x 250 MW). An availability norm of 95.0% for these is therefore reasonable. On the other hand, the two bipole HVDC schemes, Rihand – Dadri (2 x 750 MW) and Talcher – Kolar (2 x 1000 MW) have experienced longer outages, and have achieved average availability of only 91.71% and 95.81% respectively, over the same four year period. It would therefore be reasonable to specify an availability norm of 92.0% for these, which would also allow the required time for cleaning of line insulators (not applicable in back-to-back HVDC).

35. FERV(Regulation 40)

35.1 Generation and transmission utilities are of the opinion that both the cost of hedging and impact of FERV should be allowed as a pass through without imposing any condition of attributability. NTPC proposed that FERV prior to date of commercial operation should be allowed to be capitalized. They also proposed amendment of para 14(3) of the proposed regulation as '… to the extent…..has not hedged the foreign exchange exposure….' instead of '…is not able to hedge….'.

35.2 On the other hand beneficiaries like TNEB, JVVNL, and AVVNL have suggested that FERV or the cost of hedging is to be allowed to the extent of actual foreign currency loans only. TNEB also suggested that, in line with Tariff Policy, FERV should not be allowed. KSEB apprehended that hedging of foreign loan may not be advantageous to the beneficiaries. CESC proposed that decision to going for hedging or not should be left to the utilities; as hedging may not always be beneficial and depends upon the market vagaries. Reliance energy has suggested that the Commission should specify the circumstances under which FERV would not be attributable to the utilities.

35.3 The Commission has decided that the provisions on FERV as given in the draft regulations does not call for any revision or modification.

36. Special Provision relating to DVC (Regulation 43)

36.1 Damodar Valley Corporation in its comments to the draft terms & conditions of tariff regulation has submitted that the Corporation is a statutory body constituted under the Damodar Valley Corporation Act, 1948. The Corporation is governed by the provisions of section 79(1)(a) to (d) of the Electricity Act, 2003 in so far as activities of generation and transmission of electricity are concerned. It has been submitted that following special provisions may be made in the regulations in view of the special status of DVC:

The power systems of DVC involving generation, transmission and distribution activities are integrated and cannot be viewed independently for separate determination of the annual revenue requirements of each of the generating stations and transmission and distribution systems. Moreover, DVC is following an integrated manner of finance, budget and accounts as per the provisions of the DVC Act, 1948. The format and other details required under the tariff regulation should be allowed to be given to DVC with the necessary modifications based on integrated finance, budget and accounts maintained by DVC and further entire operation of generation, transmission and distribution systems.

The Appellate Tribunal for Electricity in its judgement dated 23.11.2007 in Appeal No. 273 of 2007 and other related appeals has held that Part-IV, section 27 to 47 of the DVC Act will have continued application and therefore the said provisions of the Act should be given effect to while framing the regulations for terms and conditions of tariff. DVC has suggested that a proviso should be inserted to Regulation 1 of the draft regulations in order to ensure that provisions of DVC Act and the Electricity Act are read in a consistent manner as per the decision of the Appellate Tribunal for Electricity.

“Provided further that these Regulations in so far as Damodar Valley Corporation constituted under the Damodar Valley Corporation Act, 1948 (Act XIV of 1948) is concerned will be applied with such modification as may be required to give effect to the provisions of Part IV, Sections 27 to 47 of the said Damodar Valley Corporation Act, 1948 and as per the decision of the Appellate tribunal for Electricity dated 23.11.2007 in Case No. 273 of 2006 and the provisions of these Regulations which are inconsistent with the provisions of the above Part IV of the Damodar Valley Corporation Act, 1948 shall not be given effect to."

36.2 On the first issue that the tariff of the DVC for generation, transmission and distribution should be determined in an integrated manner, the Commission is of the view that it is only concerned with determination of tariff for generation and inter-state transmission of electricity in terms of section 79(1)(a) to (d) read with section 62(1)(a)&(b) of the Electricity Act, 2003. Distribution of electricity completely falls under the domain of the respect State Commissions. This has been made amply clear in the Commission's order dated 3rd October, 2006 determining the tariff for DVC for the period 2004-06. With regard to the submission of information in an integrated manner for determination of tariff, we are of the view that even though DVC is maintaining accounts in an integrated manner, it is not difficult to segregate the accounts in respect of electrical energy into generation, transmission and distribution. Section 62(2) of the Electricity Act requires that the Appropriate Commission may require a licensee or a generating company to furnish separate details as may be specified in respect of generation, transmission and distribution for determination of tariff. The terms and conditions of tariff regulation provides for separate formats for submission of information in respect of generation and interstate transmission of electricity. Therefore, DVC should submit the required information in terms of the regulations separately for generation and interstate transmission of electricity and no special dispensation can be allowed to DVC on this account.

36.3 The Appellate Tribunal for Electricity in its judgement dated 23.11.2007 has interpreted the fourth proviso to section 14 of the Act. The said proviso reads as under :

"Provided also that the Damodar Valley Corporation, established under sub-section (1) of section 3 of the Damodar Valley Corporation Act, 1948, shall be deemed to be a licensee under this Act but shall not be required to obtain a licence under this Act and the provisions of the Damodar Valley Corporation Act, 1948, in so far as they are not inconsistent with the provisions of this Act, shall continue to apply to that Corporation:"

36.4 The Tribunal after detailed examination of the provisions of the Electricity Act and the DVC Act has come to the conclusion that the fourth proviso to section 14 clearly implies that only such of the provisions of the DVC Act which are inconsistent with the Electricity Act shall not apply. The Central Commission cannot frame regulations for determination of tariff of DVC which are inconsistent with the provisions of the DVC Act that do not collide with the Electricity Act. In other words, the Commission is required to frame terms and conditions of tariff regulation which will accommodate such of the provisions of the DVC Act which are not inconsistent with the Electricity Act, 2003.

36.5 The Tribunal in para 89 of the judgement has stated that the Legislature, expected that the Central Commission while framing regulations under the Electricity Act, 2003 will take care of such provisions of the DVC Act not inconsistent with the Act. The provisions of the DVC Act which are not inconsistent with the Act shall continue to apply. In para 91 of the judgment held that the regulations under the Act are to be read in addition to and not in derogation of any other law (i.e. provisions of Part IV of DVC Act) for the time being in force that means the Regulations, 2004 formulated by the Central Commission need to be read along with the provisions of Part IV of DVC that relate to the power-object of DVC. Relevant provisions of Part IV are quoted in the following sections:

"SECTION 30: Liabilities of participating Governments to provide Capital to the Corporation:

The Participating Government shall, as hereinafter specified, provide the entire capital required by the Corporation for the completion of any project undertaken by it.

SECTION 31: Payment by participating Government on specified date:

Participating Government shall provide its share of the capital on the dates specified by the Corporation and if any Government fails to provide such share on such dates the Corporation may raise loan to make up the deficit at the cost of the Government concerned.

SECTION 32: Expenditure on objects other than irrigation, power and flood control:

The Corporation shall have power to spend such sums as it thinks fit on objects authorized under this Act other than irrigation, power and flood control and such sums shall be treated as common expenditure payable out of the Fund of the Corporation before allocation under Section 33

SECTION 33: Allocation of expenditure chargeable to project on main objects:

The total expenditure chargeable to a project shall be allocated between the three main objects, namely, irrigation, power and flood control as follows, namely:

i. Expenditure solely attributable to any of these objects, including a proportionate share of overhead and general charges, shall be charged to that object, and

ii. Expenditure common to two or more of the said objects, including a proportionate share of overhead and general charges, shall be allocated to each of such objects in proportion to the expenditure which, according to the estimate of the corporation, would have been incurred in constructing a separate structure solely for that objects less any amount determined under clause (1) in respect of that object.

SECTION 34: Capital allocated to irrigation:

The total amount of capital allocated to irrigation shall be shared between the Provincial Governments as follows, namely:

i. The Government concerned shall be responsible for the capital cost of the works constructed exclusively for irrigation in its Province; and

ii. The balance of capital cost under irrigation for both the Provinces of Bihar and West Bengal shall be shared by the Provincial Governments in the proportion to their guaranteed annual off-takes of water for agricultural purposes:

Provided that the divisible capital cost under this clause shall be provisionally shared between them in accordance with their previously declared intentions regarding their respective guaranteed off-takes and any payments made accordingly shall be adjusted after the determination of the guaranteed off-takes.

SECTION 35: Capital allocated to power:

The total amount of capital allocated to power shall be shared equally between the three Participating Governments.

SECTION 36. Capital Allocated to flood control:

The total amount of capital up to fourteen crores of rupees allocated to flood control shall be shared equally between the Central Government and the Government of West Bengal and any amount in excess thereof shall be the liability of the Government of West Bengal."

SECTION 37: Disposal of profits and deficits:

(1) Subject to the provision of sub-section (2) of Section 40, the net profit, if any, attributable to each of the three main objects, namely, irrigation, power and flood control, shall be credited to the participating Governments in proportion to their respective shares in the total capital cost attributed to that object.

(2) The net deficit, if any, in respect of any of the objects shall be made good by the Governments concerned in the proportion specified in sub-section(1):
Provided that the net deficit in respect of flood control shall be made good entirely by the Government of West Bengal and the Central Government shall have no share in such deficit.

SECTION 38: Payment of interest:

The Corporation shall pay interest on the amount of the capital provided by each Participating Government at such rate as may, from time to time, be fixed by the Central government and such interest shall be deem to be part of the expenditure of the Corporation.

SECTION 40: Provision for depreciation and reserve and other funds:

(1) The Corporation shall make provision for depreciation and for reserve and other funds at such rates and on such terms as may be specified by the Auditor General of India in consultation with the Central Government.

(2) The net profit for the purpose of section 37 shall be determined after such provision has been made.

36.6 The Tribunal has discussed in detail the provisions of the DVC Act which are both consistent and inconsistent with the Electricity Act and has come to the conclusion that the provisions of the DVC Act that are not in conflict with the Electricity Act, 2003, particularly sections 38, 39 and 40 of the DVC Act which have tariff implications have to be given effect.

36.7 On specific grounds of appeal, the Tribunal has given the following directions:

a) Debt-Equity Ratio: The DVC Act is silent about adopting any specific Debt Equity Ratio for financing of projects. In the interest of equity and fairness, all old projects of DVC commissioned prior to 1992 be assigned debt-equity ratio of 50:50 and the recent projects be assigned debt-equity ratio of 70:30 as specified in the 2004 regulations. [Para A-8 of the Judgement]

b) The capital infused by the participating Governments is in the nature of equity capital and for the purpose of determination of tariff, the same should be eligible for return on equity. [Para A-14 of the Judgement]

c) The DVC Act envisages the projects to be built only on capital contributed by the participating Governments and any deficit in the capital amount is to be made good by taking loan on behalf of the participating Government. The debt taken will attract interest. The average interest rate of repayment payable during the tariff year is to be applied on 50:50 normative debt capital for tariff purposes. The excess of equity over the normative debt-equity ratio shall be considered as interest bearing debt and serviced accordingly. [Para A-16 of the Judgement]

d) The Central Commission has worked out a sum of Rs.1534.49 crore to create Pension and Gratuity Contribution Fund with the stipulation that 60% thereof shall be recovered through the tariff and the remaining 40% to be contributed by the DVC. The decision of the Commission is not backed by any justification and the entire cost is allowed to be recovered through tariff. However, the recovery should be staggered in a manner that it does not create tariff-shock to consumers. [Para D-1 of the Judgement]

e) The expenditure incurred by DVC on objects other than irrigation, power and flood control be allocated to these three heads as per sections 32 and 33 of DVC Act and expenditure so allocated to power object, should be allowed to be recovered through the electricity tariff. [Para E-12 of the Judgement]

f) Sinking funds established with the approval of Comptroller and Accountant General of India vide letter dated December 29, 1992 under the provision of Section 40 of the DVC Act is to be taken as an item of expenditure to be recovered through tariff. [Para E-15 of the Judgement]

g) Depreciation – The Electricity Act does not make any provision for factoring rate of depreciation in tariff determination. Accordingly, DVC Act in so far as depreciation is concerned, not inconsistent with the Act and shall continue to apply to the Corporation. The Central Commission is directed to adopt rate of depreciation as prescribed by Comptroller and Accountant General of India for computation of tariff for the assets based on the principles outlined in Para F-3 of the Judgement. [Para F-2 and F-4 of the Judgement]

h) Operation and Maintenance expenses – The Tariff Regulations, 2004 notified by the Commission generally provide for a 4% increase in O&M expenses annually. The same shall be adopted in case of DVC also to offset additional burden on the Appellant due to inflationary measures. [Para GH.5 of the Judgement]

i) Expenditure incurred on repair, renovation and modernization aimed at extending the useful life of the assets would be eligible, subject to prudence check, for capitalization and would be eligible for recovery through tariff once the assets are again put to use. [Para J.2 of the Judgement]

36.8 Keeping in view the provisions of the DVC Act and the judgement of the Appellate Tribunal for Electricity, the following special provisions have been made:

a) Capital cost – The expenditure allocated to object power in terms of sections 32 and 33 of the DVC Act to the extent of its apportionment to generation and interstate transmission shall form the basis of capital cost for the performance of determination of tariff. As investment on head office, regional office, administrative and technical centres of DVC have been allowed to be capitalized, the same has also been considered in case of DVC.

b) Debt-equity ratio of the projects of DVC commissioned prior to 1992 has been kept as 50:50 and the projects commissioned thereafter has been kept as 70:30.

c) The rate of depreciation as stipulated by Comptroller and Accountant General of India in terms of section 40 of the DVC Act have been adopted for computation of depreciation of generating station and interstate transmission system of DVC.

d) The sinking fund established under section 40 of the DVC Act has been considered as item of expenditure to be recovered through tariff. However, it is seen that DVC has not reflected the sinking fund as an item of expenditure in its annual report. Keeping in view the spirit of the judgement, the sinking fund shall qualify for recovery through tariff, only if it is considered as an item of expenditure.

36.9 Other directions of the Tribunal are consistent with the general provisions of the regulations and therefore no specific provision has been made in respect of DVC. The Commission has filed an appeal before the Supreme Court challenging the judgement of the Appellate Tribunal for Electricity which is still pending. Therefore, the special provision related to DVC shall be subject to the outcome of the similar appeals filed in the Supreme Court

36.10 Accordingly, the Commission has made special provisions for DVC in Regulation 43 as under:

"43. **Special Provisions relating to Damodar Valley Corporation**. (1) Subject to clause (2), these regulations shall apply to determination of tariff of the projects owned by Damodar Valley Corporation (DVC).

(2) The following special provisions shall apply for determination of tariff of the projects owned by DVC:

(i) Capital Cost: The expenditure allocated to the object 'power', in terms of sections 32 and 33 of the Damodar Valley Corporation Act, 1948, to the extent of its apportionment to generation and inter-state transmission, shall form the basis of capital cost for the purpose of determination of tariff:

Provided that the capital expenditure incurred on head office, regional offices, administrative and technical centers of DVC, after due prudence check, shall also form part of the capital cost.

(ii) Debt Equity Ratio: The debt equity ratio of all projects of DVC commissioned prior to 01.01.1992 shall be 50:50 and that of the projects commissioned thereafter shall be 70:30.

(iii) Depreciation: The depreciation rate stipulated by the Comptroller and Auditor General of India in terms of section 40 of the Damodar Valley Corporation Act, 1948 shall be applied for computation of depreciation of projects of DVC.

(iv) Funds under section 40 of the Damodar Valley Corporation Act, 1948: The Fund(s) established in terms of section 40 of the Damodar Valley Corporation

Act, 1948 shall be considered as items of expenditure to be recovered through tariff.

(3) The provisions in clause (2) of this regulation shall be subject to the decision of the Hon'ble Supreme Court in Civil Appeal No 4289 of 2008 and other related appeals pending in the Hon'ble Court and shall stand modified to the extent they are inconsistent with the decision."

37. Sharing of Transmission Charges

37.1 The draft Regulation 33 has been redrafted but the basic philosophy remains more or less same. This philosophy is generally in line with Commission's order dated 28.03.08 in petition 85/2007 (in the matter of sharing of charges and losses for ISTS) and proposals contained in the staff paper on "Arranging Transmission for New Generating Stations, Captive Power Plants and Buyers of Electricity". Based on the latter, the Commission intends to come out with draft regulations on the issue of connectivity, and long-term and medium term access in due course. Commission has also undertaken a separate study on sharing of transmission charges with the assistance of a consulting agency. Conclusions derived from this study along with final regulations on connectivity and long-term and medium term access may necessitate amendment to these regulations.

37.2 The Commission has also noticed that an inadvertent error has crept in the sub-clause (a) of clause(1) of Regulation 33. In the second sentence of the said sub-clause, the word "no" has to be replaced by the words "at least one". This shall be corrected.

37.3 The Commission has also decided that the income from the open access customers shall be disbursed directly to the long-term customers rather than reducing it from transmission charges payable by long-term customers. As such, existing provision relating to this has been deleted.

Sd/-	**Sd/-**	**Sd/-**	**Sd/-**	**Sd/-**
(S.JAYARAMAN)	**(R.KRISHNAMOORTHY)**	**(BHANU BHUSHAN)**	**(RAKESH NATH)**	**(DR.PRAMOD DEO)**
MEMBER	**MEMBER**	**MEMBER**	**MEMBER (EO)**	**CHAIRPERSON**

Dated:- 3rd February, 2009

Annexure-A

Actual and Normalised O&M expenses for the thermal generating stations of NTPC, NLC and NEEPCO

	Raw data as Claimed/as furnished				Data after Normalisation			
Station	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2004-05**	**2005-06**	**2006-07**	**2007-08**
200/210/250 MW Sets								
Dadri Coal(4x210)	10896	12262	12713	16780	10204	11280	11259	13544
Rs. Lakh/MW	12.97	14.60	15.13	19.98	12.15	13.43	13.40	16.12
Unchahar (2x210+2x210+1x210)	11800	12196	12215	18587	10992	11214	10658	15324
Rs. Lakh/MW	14.05	14.52	13.70	17.70	13.09	13.35	11.95	14.59
Kahalgaon (4x210)	11648	13263	15063	19325	11554	13171	14279	16618
Rs. Lakh/MW	13.87	15.79	17.93	23.01	13.75	15.68	17.00	19.78
NLC TPS-I expension (2x210)	3176	3582	4280	5186	3090	3470	4201	4506
Rs. Lakh/MW	7.56	8.53	10.19	12.35	7.36	8.26	10.00	10.73
NLC TPS-II stage-I (3x210)	7180	6998	7285	9985	6917	6673	7062	8115
Rs. Lakh/MW	11.40	11.11	11.56	15.85	10.98	10.59	11.21	12.88
NLC TPS-II stage-II (4x210)	9573	9330	9713	13311	9221	8897	9417	10818
Rs. Lakh/MW	11.40	11.11	11.56	15.85	10.98	10.59	11.21	12.88
500 MW Sets								
Rihand St-I&II(4x500)	11671	15694	17678	25934	10914	14158	16010	21584

Rs. Lakh/MW	11.67	11.95	8.84	12.97	10.91	10.78	8.01	10.79
Simhadri (2x500)	8191	8875	9518	13144	7582	8240	8402	10673
Rs. Lakh/MW	8.19	8.87	9.52	13.14	7.58	8.24	8.40	10.67
Talcher (2x500+4x500)	14200	19198	21630	27254	13232	17689	19134	21934
Rs. Lakh/MW	6.43	6.78	7.21	9.08	6.00	6.24	6.38	7.31
Mix of 200/210/250 MW & 500 Sets								
Vindhyachal (6x210+4x500)	19260	19894	23256	33811	18316	18556	21001	27715
Rs. Lakh/MW	8.52	8.80	9.59	10.85	8.10	8.21	8.66	8.89
Korba (3X200+3X500)	19094	21203	23210	28592	18149	19975	21090	23291
Rs. Lakh/MW	9.09	10.10	11.05	13.62	8.64	9.51	10.04	11.09
Farakka (3x200+2x500)	20413	22902	23681	28980	18980	21143	20833	23318
Rs. Lakh/MW	12.76	14.31	14.80	18.11	11.86	13.21	13.02	14.57
Singrauli (5x200+2x500)	19834	21380	24664	30130	18420	19735	22393	25,307
Rs. Lakh/MW	9.92	10.69	12.33	15.07	9.21	9.87	11.20	12.65
Ramagundam (3x200+3x500+1x500)	19221	23295	27960	33684	18208	22053	25396	27452
Rs. Lakh/MW	9.11	8.96	10.75	12.96	8.63	8.48	9.77	10.56
Badarpur(3x95+2x210)	18573	17606	22255	23094	11165	15532	14946	20145
Rs. Lakh/MW	26.34	24.97	31.57	32.76	15.84	22.03	21.20	28.58
Tanda (4x110 MW)	7632	8128	8641	11162	7169	7487	7851	9064
Rs. Lakh/MW	17.35	18.47	19.64	25.37	16.29	17.01	17.84	20.60

Talcher takenover(4x60+2x 110)	10959	10539	12053	14743	8863	9374	10196	11221
Rs. Lakh/MW	23.82	22.91	26.20	32.05	19.27	20.38	22.16	24.39
NLC TPS-I (6x50+3x100)	9901	10085	10415	14059	9467	9583	10063	11292
Rs. Lakh/MW	16.50	16.81	17.36	23.43	15.78	15.97	16.77	18.82
Gas/Naptha								
Anta (3x88.7+1x153.2)	6810	5678	5065	5287	6484	5399	4546	3645
Rs. Lakh/MW	16.24	13.54	12.08	12.61	15.46	12.88	10.84	8.69
Auraiya (4x111.19+2x109.3)	6012	6179	6118	7142	5823	5926	5617	6022
Rs. Lakh/MW	9.06	9.32	9.22	10.77	8.78	8.93	8.47	9.08
Dadri (4x130.19+2x154.5 1)	5697	8896	9558	15087	5425	8627	9103	10836
Rs. Lakh/MW	6.87	10.72	11.52	18.18	6.54	10.40	10.97	13.06
Faridabad (2X140.827+1X149 .932)	2977	3265	6279	5606	2831	3097	5989	4709
Rs. Lakh/MW	6.90	7.56	14.55	12.99	6.56	7.18	13.88	10.91
Kawas (4x106+2x116.1)	8975	7504	7124	10714	8749	7159	6505	8127
Rs. Lakh/MW	13.68	11.44	10.86	16.33	13.33	10.91	9.91	12.38
Gandhar (3x144.3+1x224.49)	4910	6573	6510	10876	4752	6316	6092	9732
Rs. Lakh/MW	7.47	10.00	9.90	16.54	7.23	9.61	9.27	14.80

Kaymkulam (2x 116.6+ 1x126.38)	3237	2950	3462	6072	3176	2880	3199	4960
Rs. Lakh/MW	9.00	8.20	9.63	16.89	8.83	8.01	8.90	13.79
NEEPCO								
Assam (6x30+3x37)	4628	4101	5358	8583	4281	3970	4540	5685
Rs. Lakh/MW	15.90	14.09	18.41	29.50	14.71	13.64	15.60	19.54
Agartala (4x21)	1329	1968	2288	2877	1202	1945	2213	1757
Rs. Lakh/MW	15.83	23.43	27.24	34.25	14.31	23.15	26.34	20.92

Thermal generating stations **Annexure-B**

Avaibility: Existing norms and New norm

Station	**COD**	**Present norm**	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	**Average**	**Norm in Draft**	**Norm recommended by CEA**	**New Norm**
Dadri Coal(4x210)	1.12.1995	**80%**	92%	93%	96%	95%	98%	100%	97%	**85%**	80%	**85%**
Kahalgaon(4x210 MW)	1.8.1996	**80%**	72%	84%	84%	92%	92%	91%	90%	**85%**	80%	**85%**
Unchahar (2x210+2x210+1x210)	1.1.2007	**80%**	72%	71%	73%	77%	96%	99%	86%	**85%**	80%	**85%**
Rihand St-I&II(4x500)	1.4.2006	**80%**	98%	91%	90%	97%	93%	104%	96%	**85%**	80%	**85%**
Talcher (2x500+4x500)	1.8.2005	**80%**	74%	82%	82%	87%	92%	96%	89%	**85%**	80%	**85%**
Simhadri (2x500)	1.3.2003	**80%**	NA	94%	95%	94%	94%	91%	94%	**85%**	80%	**85%**
Singrauli (5x200+2x500)	1.5.1988	**80%**	92%	90%	91%	89%	84%	92%	89%	**85%**	80%	**85%**
Korba (3X200+3X500)	1.6.1990	**80%**	91%	90%	93%	88%	91%	97%	92%	**85%**	80%	**85%**
Farakka (3x200+2x500)	1.7.1996	**80%**	NA	70%	71%	85%	85%	84%	81%	**85%**	80%	**85%**
Ramagundam (3x200+3x500+1x500)	25.3.2005	**80%**	92%	90%	94%	92%	92%	93%	93%	**85%**	80%	**85%**
Vindhyachal Super Thermal Power Sation (6x210+4x500)	15.7.2007	**80%**	87%	85%	91%	94%	94%	99%	94%	**85%**	80%	**85%**
Badarpur(3x95+2x210)	1.4.1982	**75%**	NA	NA	NA	91%	90%	92%	91%	**82%**	80%	**82%**
Talcher takenover(4x60+2x110)	3.6.1995	**80%**	56%	68%	80%	88%	88%	86%	86%	**82%**	80%	**82%**
Tanda (4x110 MW)	20.2.1998	**80%**	NA	NA	NA	NA	91%	94%	92%	**82%**	80%	**85%**
NLC TPS-I (6x 50 +3x100)	21.2.1970	**75%**	N.A.	N.A.	N.A.	N.A.	N.A.	63%	63%	**72%**	75%	**72%**
NLC TPS-I (Expansion) 2x210	5.9.2003	**75%**		70%	88%	96%	101%	100%	96%	**80%**	80%	**80%**
NLC TPS-II (Stage-I) 3x210	23.4.1988	**75%**	83%	74%	71%	72%	53%	77%	68%	**75%**	75%	**75%**
NLC TPS-II (Stage-II) 4x210	9.4.1994	**75%**	80%	81%	73%	75%	69%	78%	74%	**75%**	75%	**75%**
Mejia (3x210+210)	12.10.2004	**80%**	NA	NA	NA	NA	NA	NA	NA	**85%**	80% with progressive improvement	**85%**
Bokaro (3x210)	August,1993	**75%**	NA	NA	NA	NA	NA	NA	NA	**75%**	75% with progressive improvement	**75%**
Chandrapur (3x130+3x120)	March,1979	**60%**	NA	NA	NA	NA	NA	NA	NA	**60%**	60% with progressive improvement	**60%**
Durgapur TPS (1x210+1x140)	Sep.,1979	**74%**	NA	NA	NA	NA	NA	NA	NA	**74%**	74% with progressive improvement	**74%**

Actual PLF												
Station	**COD**	**Present norm**	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	**Average**			
Dadri Coal(4x210)	1.12.1995	**80%**	82%	84%	93%	92%	96%	98%	95%			
Kahalgaon(4x210 MW)	1.8.1996	**80%**	68%	81%	83%	89%	89%	92%	88%			
Unchahar (2x210+2x210+1x210)	1.1.2007	**80%**	67%	70%	74%	77%	96%	98%	86%			
Rihand St-I&II(4x500)	1.4.2006	**80%**	88%	91%	91%	85%	92%	92%	90%			
Talcher (2x500+4x500)	1.8.2005	**80%**	73%	82%	82%	84%	90%	94%	88%			
Simhadri (2x500)	1.3.2003	**80%**	NA	88%	93%	88%	92%	89%	91%			
Singrauli (5x200+2x500)	1.5.1988	**80%**	92%	89%	90%	88%	84%	92%	89%			
Korba (3X200+3X500)	1.6.1990	**80%**	89%	89%	93%	87%	90%	96%	91%			
Farakka (3x200+2x500)	1.7.1996	**80%**	64%	68%	69%	82%	81%	84%	79%			
Ramagundam (3x200+3x500+1x500)	25.3.2005	**80%**	92%	89%	91%	86%	89%	90%	89%			
Vindhyachal Super Thermal Power Sation (6x210+4x500)	15.7.2007	**80%**	86%	82%	90%	92%	93%	93%	92%			
Badarpur(3x95+2x210)	1.4.1982	**75%**	85%	88%	88%	87%	86%	86%	87%			
Talcher takenover(4x60+2x110)	3.6.1995	**80%**	73%	82%	82%	84%	90%	86%	86%			
Tanda (4x110 MW)	20.2.1998	**80%**	58%	75%	86%	86%	91%	92%	89%			
NLC TPS-I (6x 50 +3x100)	21.2.1970	**75%**	83%	84%	81%	76%	76%	70%	76%			
NLC TPS-I (Expansion) 2x210	5.9.2003	**75%**		54%	88%	84%	89%	89%	87%			
NLC TPS-II (Stage-I) 3x210	23.4.1988	**75%**	83%	74%	72%	70%	57%	82%	70%			
NLC TPS-II (Stage-II) 4x210	9.4.1994	**75%**	80%	80%	72%	72%	73%	81%	75%			
Mejia (3x210+210)	12.10.2004	**80%**	60%	73%	73%	80%	85%	90%	82%			
Bokaro (3x210)	August,1993	**75%**	56%	49%	45%	48%	60%	71%	56%			
Chandrapur (3x130+3x120)	March,1979	**60%**	17%	20%	29%	31%	33%	36%	32%			
Durgapur TPS (1x210+1x140)	Sep.,1979	**74%**	36%	54%	48%	59%	67%	54%	57%			

GHR: Existing norms and New norm

Station	COD	Present norm	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	Average	Norm in Draft	Norm recommended by CEA	New Norm
Dadri Coal(4x210)	1.12.1995	**2500**	2465	2462	2434	2421	2414	2393	2416	**2500**	2500	2500
Kahalgaon(4x210 MW)	1.8.1996	**2500**	2480	2460	2453	2444	2433	2420	2437	**2500**	2500	2500
Unchahar (2x210+2x210+1x210)	1.1.2007	**2500**	2459	2458	2451	2430	2410	2394	2421	**2500**	2500	2500
Rihand St-I&II(4x500)	1.4.2006	**2430**	2392	2385	2376	2337	2360	2352	2356	**2380**	COD before 2004-2430 and after 2004-6% over design heat rate	2405
Talcher (2x500+4x500)	1.8.2005	**2450**	2406	2414	2400	2376	2368	2322	2367	**2400**	COD before 2004-2450 and after 2004-6% over design heat rate	2425
Simhadri (2x500)	1.3.2003	**2450**	2438	2404	2375	2361	2355	2358	2362	**2400**	2450	2425
Singrauli (5x200+2x500)	1.5.1988	**2475**	2410	2410	2413	2401	2401	2397	2403	**2450**	2475	2462.5
Korba (3X200+3X500)	1.6.1990	**2464**	2412	2419	2402	2379	2372	2375	2382	**2429**	2464	2457
Farakka (3x200+2x500)	1.7.1996	**2469**	2474	2478	2530	2442	2434	2419	2456	**2438**	2469	2453
Ramagundam (3x200+3x500+1x500)	25.3.2005	**2462**	2441	2442	2425	2406	2378	2375	2396	**2423**	500 MW:COD before 2004-2450 and after 2004-6% over design heat rate	2442
Vindhyachal Super Thermal Power Sation (6x210+4x500)	15.7.2007	**2476**	2456	2458	2430	2400	2393	2382	2401	**2439**	500 MW:COD before 2004-2450 and after 2004-6% over design heat rate	2454
Badarpur(3x95+2x210)	1.4.1982	**2885**	2803	2789	2788	2765	2751	2750	2763	**2825**	2885	2825
Talcher takenover(4x60+2x110)	3.6.1995	**2975**	3144	3000	2924	2914	2904	2886	2907	**2975**	2975	2950
Tanda (4x110 MW)	20.2.1998	**2850**	3137	2846	2758	2753	2749	2740	2750	**2850**	2850	2825
NLC TPS-I (6x 50 +3x100)	21.2.1970	**3900**	3925	3933	3981	3992	3920	3917	3953	**4000**	3900	4000
NLC TPS-I (Expansion) 2x210	5.9.2003	**2750**		3000	2848	2769	2751	2751	2780	**2750**	2750	**2750**
NLC TPS-II (Stage-I) 3x210	23.4.1988	**2850**	3031	3011	2886	2884	2895	2881	2887	**2900**	relax norm may consider	**2900**
NLC TPS-II (Stage-II) 4x210	9.4.1994	**2850**	2879	2883	2860	2874	2891	2867	2873	**2900**	------ Do-----	**2900**
Mejia (3x210+210)	12.10.2004	**2500**	3217	3285	2969	2575	2514	2509	2642	**2500**	2500 with progressive improvement	**2500**
Bokaro (3x210)	August,1993	**2700**	3651	3703	3744	3366	3290	3202	3401	**2700**	2700 with progressive improvement	**2700**
Chandrapur (3x130+3x120)	March,1979	**3100**	4479	3595	3378	3324	3228	3142	3268	**3100**	3100 with progressive improvement	**3100**
Durgapur TPS (1x210+1x140)	Sep.,1979	**2820**	3556	3569	3491	3169	3069	2953	3170	**2820**	2820 with progressive improvement	**2820**

Auxilary Power Consumption: Existing norms and New norm

Station	COD	Present norm	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	Average	Norm in Draft	Norm recommended by CEA	New Norm (station wise)
Dadri Coal(4x210)	1.12.1995	9%	8.00%	8.05%	7.35%	7.39%	7.45%	7.26%	7.36%	8.50%	8.50%	8.50%
Kahalgaon(4x210 MW)	1.8.1996	9%	9.56%	9.64%	8.88%	8.51%	8.58%	9.28%	8.81%	8.50%	9.00%	9.00%
Unchahar (2x210+2x210+1x210)	1.1.2007	9%	8.76%	8.93%	8.58%	8.37%	8.18%	8.05%	8.30%	8.50%	9.00%	9.00%
Rihand St-I&II(4x500)	1.4.2006	8.00%	8.03%	7.65%	7.98%	7.30%	6.49%	6.57%	7.08%	7.50%	7.50%	7.50%
Talcher (2x500+4x500)	1.8.2005	7.50%	7.11%	7.49%	6.82%	5.75%	5.39%	5.20%	5.79%	7%	6.50%	6.50%
Simhadri (2x500)	1.3.2003	7.50%	6.01%	6.18%	5.65%	5.65%	5.56%	5.85%	5.68%	7%	6.00%	6.00%
Singrauli (5x200+2x500)	1.5.1988	7.75%	6.86%	6.92%	6.96%	7.11%	7.24%	6.96%	7.07%	7.25%	7.25%	7.25%
Korba (3X200+3X500)	1.6.1990	7.93%	6.15%	6.68%	6.59%	6.52%	6.11%	6.06%	6.32%	7.43%	7.21%	7.21%
Farakka (3x200+2x500)	1.7.1996	7.56%	8.02%	8.16%	8.50%	7.00%	6.67%	6.83%	7.25%	7.06%	6.94%	6.94%
Ramagundam (3x200+3x500+1x500)	25.3.2005	7.85%	6.50%	6.63%	6.89%	6.40%	6.21%	6.16%	6.41%	7.35%	7.08%	7.08%
Vindhyachal Super Thermal Power Sation (6x210+4x500)	15.7.2007	8.28%	7.00%	7.19%	7.01%	7.06%	7.13%	6.40%	6.90%	7.58%	7.47%	7.47%
Badarpur(3x95+2x210)	1.4.1982	11%	9.15%	9.68%	9.04%	8.84%	8.05%	7.91%	8.46%	9.50%	11.00%	9.50%
Talcher takenover(4x60+2x110)	3.6.1995	10.50%	11.47%	10.73%	10.58%	10.07%	10.19%	10.15%	10.25%	10.50%	10.50%	10.50%
Tanda (4x110 MW)	20.2.1998	12%	13.84%	12.88%	12.00%	11.92%	11.34%	11.11%	11.59%	12%	12.00%	12%
NLC TPS-I (6x 50 +3x100)	21.2.1970	12%	11.57	11.51	11.41%	11.27%	11.55%	13.48%	11.93%	12%	relax norm may consider	12%
NLC TPS-I (Expansion) 2x210	5.9.2003	9.50%		9.78	9.05%	9.08%	8.47%	9.14%	8.93%	9%	9.5	9.50%
NLC TPS-II (Stage-I) 3x210	23.4.1988	10.00%	9.70	9.69	9.85%	9.68%	9.40%	10.87%	9.95%	10%	relax norm may consider	10%
NLC TPS-II (Stage-II) 4x210	9.4.1994	10.00%	9.63	9.40	9.74%	9.75%	9.73%	10.86%	10.02%	10%	relax norm may consider	10%
Mejia (3x210+210)	12.10.2004	9%	12.81%	10.94%	11.02%	10.58%	10.47%	10.22%	10.57%	9%	9% with progressive improvement	9%
Bokaro (3x210)	August,1993	10.00%	11.54%	11.80%	11.48%	11.34%	11.11%	10.95%	11.22%	10.00%	10% with progressive improvement	10.00%
Chandrapur (3x130+3x120)	March,1979	11.50%	18.56%	15.75%	12.23%	11.54%	11.22%	10.76%	11.44%	11.50%	11.5% with progressive improvement	11.50%
Durgapur TPS (1x210+1x140)	Sep.,1979	10.55%	14.26%	11.95%	12.82%	11.67%	11.05%	11.46%	11.75%	10.55%	10.55% with progressive improvement	10.55%

SFC: Existing norms CEA and New norm

Station	COD	Present norm	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	Average	Norm in Draft	Norm recommended by CEA	New Norm
Dadri Coal(4x210)	1.12.1995	**2**	0.44	0.17	0.16	0.21	0.11	0.11	0.15	**1**	0.75	**1**
Kahalgaon(4x210 MW)	1.8.1996	**2**	0.63	0.54	0.53	0.41	0.61	0.18	0.43	**1**	0.75	**1**
Unchahar (2x210+2x210+1x210)	1.1.2007	**2**	0.64	0.50	0.43	0.36	0.27	0.24	0.33	**1**	0.75	**1**
Rihand St-I&II(4x500)	1.4.2006	**2**	0.22	0.22	0.17	0.25	0.17	0.10	0.17	**1**	0.75	**1**
Talcher (2x500+4x500)	1.8.2005	**2**	0.46	0.83	0.65	0.50	0.27	0.23	0.41	**1**	0.75	**1**
Simhadri (2x500)	1.3.2003	**2**	NA	0.66	0.23	0.19	0.19	0.27	0.22	**1**	0.75	**1**
Singrauli (5x200+2x500)	1.5.1988	**2**	0.18	0.23	0.30	0.31	0.44	0.26	0.33	**1**	0.75	**1**
Korba (3X200+3X500)	1.6.1990	**2**	0.24	0.21	0.11	0.11	0.10	0.11	0.11	**1**	0.75	**1**
Farakka (3x200+2x500)	1.7.1996	**2**	1.78	1.94	2.42	0.94	0.90	0.88	1.28	**1**	0.75	**1**
Ramagundam (3x200+3x500+1x500)	25.3.2005	**2**	0.21	0.23	0.17	0.24	0.19	0.22	0.20	**1**	0.75	**1**

Vindhyachal Super Thermal Power Sation (6x210+4x500)	15.7.2007	**2**	0.21	0.18	0.16	0.15	0.14	0.18	0.16	**1**	0.75	**1**
Badarpur(3x95+2x210)	1.4.1982	**2.6**	0.42	0.30	0.33	0.34	0.42	0.40	0.37	**1**	0.75	**1**
Talcher takenover(4x60+2x110)	3.6.1995	**2**	1.60	1.55	0.78	0.40	0.44	0.48	0.52	**1**	1.25	**1**
Tanda (4x110 MW)	20.2.1998	**2**	2.12	0.99	0.74	0.62	0.40	0.44	0.55	**1**	1.25	**1**
NLC TPS-I (6x 50 +3x100)	21.2.1970	**3**	3.62	1.42	3.03	3.46	3.43	3.68	3.40	**3.5**	3	**3.5**
NLC TPS-I (Expansion) 2x210	5.9.2003	**3**		5.42	1.57	1.38	1.07	0.92	1.23	**2**	1.25	**2**
NLC TPS-II (Stage-I) 3x210	23.4.1988	**3**	3.66	0.79	1.21	0.92	1.53	1.07	1.18	**2**	2	**2**
NLC TPS-II (Stage-II) 4x210	9.4.1994	**3**	2.73	0.41	1.05	1.08	0.89	1.00	1.01	**2**	2	**2**
Mejia (3x210+210)	12.10.2004	**2**	6.29	5.20	4.85	3.25	3.92	2.72	3.69	**2**	2 with progressive improvement	**2**
Bokaro (3x210)	August,1993	**2**	5.93	4.01	3.59	3.14	2.39	1.18	2.58	**2**	2 with progressive improvement	**2**
Chandrapur (3x130+3x120)	March,1979	**3**	0.35	4.94	2.61	0.95	1.83	2.09	1.87	**2**	3 with progressive improvement	**2**
Durgapur TPS (1x210+1x140)	Sep.,1979	**2.4**	13.19	9.57	7.29	3.36	3.15	4.83	4.66	**3**	2.4 with progressive improvement	2.4

Gas/Naptha

Avaibility: Existing norms and New norm

Station	**COD**	**Present norm**	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	**Average**	**Norm in Draft**	**Norm recommended by CEA**	**New Norm**
Anta (3x88.7+1x153.2)	1.3.1990	**80%**	88%	87%	86%	91%	88%	85%	88%	**85%**	80%	**85%**
Auraiya (4x111.19+2x109.3)	1.6.1990	**80%**	87%	89%	82%	91%	90%	81%	86%	**85%**	80%	**85%**
Dadri (4x130.19+2x154.51)	1.3.1994	**80%**	83%	88%	89%	90%	85%	84%	87%	**85%**	80%	**85%**
Faridabad (2X140.827+1X149.932)	1.1.2001	**80%**	79%	96%	98%	95%	89%	83%	91%	**85%**	80%	**85%**
Kawas (4x106+2x116.1)	1.9.1993	**80%**	82%	88%	91%	93%	95%	87%	91%	**85%**	80%	**85%**
Gandhar (3x144.3+1x224.49)	1.11.1995	**80%**	64%	58%	71%	81%	82%	78%	78%	**85%**	80%	**85%**
Kaymkulam (2x 116.6+ 1x126.38)	1.3.2000	**80%**			85%	96%	93%	93%	92%	**85%**	80%	**85%**
Assam CCGT (6x30+3x37.3)	1.4.1999	**80%**	66%	77%	78%	72%	72%	69%	73%	**70%**	80%	**70%**
Agartala open cycle (4x21)	1.8.1998	**80%**	NA	91%	83%	97%	94%	93%	92%	**85%**	80%	**85%**

Actual PLF												
Station	**COD**	**Present norm**	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	**Average**			
Anta (3x88.7+1x153.2)	1.3.1990	**80%**	75	75	76	76	80	73	76			
Auraiya (4x111.19+2x109.3)	1.6.1990	**80%**	73%	73%	71%	74%	79%	68%	73%			
Dadri (4x130.19+2x154.51)	1.3.1994	**80%**	72	70	75	74	77	70	74			
Faridabad (2X140.827+1X149.932)	1.1.2001	**80%**	71	74	84	78	75	68	76			
Kawas (4x106+2x116.1)	1.9.1993	**80%**	73	68	49	50	63	63	56			
Gandhar (3x144.3+1x224.49)	1.11.1995	**80%**	47	56	70	78	79	68	74			
Kaymkulam (2x 116.6+ 1x126.38)	1.3.2000	**80%**	67	67	20	11	36	53	30			
Assam CCGT (6x30+3x37.3)	1.4.1999	**80%**	40%	62%	63%	68%	71%	66%	67%			
Agartala open cycle (4x21)	1.8.1998	**80%**	77%	77%	78%	87%	89%	88%	85%			

GHR: Existing norms and New norm												
Station	**COD**	**Present norm**	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	**Average**	**Norm in Draft**	**Norm recommended by CEA**	**New Norm**
Anta (3x88.7+1x153.2)	1.3.1990	**2075**	2017	2085	2058	2067	2032	2067	2056	**2075**	2075	**2075**
Auraiya (4x111.19+2x109.3)	1.6.1990	**2100**	2072	2096	2079	2089	2068	2206	2110	**2100**	2100	**2100**
Dadri (4x130.19+2x154.51)	1.3.1994	**2075**	1970	1998	1982	1967	1947	2003	1975	**2075**	2075	**2075**
Faridabad (2X140.827+1X149.932)	1.1.2001	**2000**	1935	1909	1875	1885	1904	1926	1897	**2000**	2000	**2000**
Kawas (4x106+2x116.1)	1.9.1993	**2075**	1996	2017	1998	2008	1987	2017	2002	**2075**	2075	**2075**
Gandhar (3x144.3+1x224.49)	1.11.1995	**2000**	1934	1958	1997	2018	2026	2049	2022	**2000**	2000	**2040**
Kaymkulam (2x 116.6+ 1x126.38)	1.3.2000	**2000**	1977	1980	1972	1986	1960	1959	1969	**2000**	2000	**2000**
Assam CCGT (6x30+3x37.3)	1.4.1999	**2250**	2736	2329	2417	2322	2376	2400	2379	**2400**	2400	**2400**
Agartala open cycle (4x21)	1.8.1998	**3580**	3637	3582	3437	3370	3463	3366	3409	**3500**	3500	**3500**

Auxilary Power Consumption: Existing norms and New norm												
Station	**COD**	**Present norm**	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	**Average**	**Norm in Draft**	**Norm recommended by CEA**	**New Norm**
Anta (3x88.7+1x153.2)	1.3.1990	3%	2.87	2.56	2.73	2.52	2.13	1.91	2.32	**3%**	3%	**3%**
Auraiya (4x111.19+2x109.3)	1.6.1990	3%	1.89	1.91	1.81	1.80	1.80	2.08	1.87	**3%**	3%	**3%**
Dadri (4x130.19+2x154.51)	1.3.1994	3%	2.72	2.57	2.52	2.32	2.20	2.24	2.32	**3%**	3%	**3%**
Faridabad (2X140.827+1X149.932)	1.1.2001	3%	2.11	2.19	1.97	2.31	2.27	2.45	2.25	**3%**	3%	**3%**
Kawas (4x106+2x116.1)	1.9.1993	3%	1.76	2.22	2.40	2.19	1.74	1.62	1.99	**3%**	3%	**3%**
Gandhar (3x144.3+1x224.49)	1.11.1995	3%	2.22	2.33	2.03	1.95	1.95	2.09	2.01	**3%**	3%	**3%**
Kaymkulam (2x 116.6+ 1x126.38)	1.3.2000	3%	2.16	2.3	4.03	6.18	2.6	2.36	3.79	**3%**	3%	**3%**
Assam CCGT (6x30+3x37.3)	1.4.1999	3%	3.23%	2.83%	2.94%	2.88%	2.86%	2.67%	2.84%	**3%**	3%	**3%**
Agartala open cycle (4x21)	1.8.1998	1%	1.77%	1.42%	0.89%	0.40%	0.58%	1.99%	0.97%	**1%**	1%	**1%**