CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Coram:

Shri Ashok Basu, Chairman
Shri K.N. Sinha, Member
Shri Bhanu Bhushan, Member

Petition No. 67/2003
(Suo motu)

In the matter of

Determination of terms and conditions of tariff applicable from 1.4.2004

ORDER
(DATES OF HEARING: 9 & 10.3. 2004)

<u>Preliminary</u>

In exercise of powers conferred under Section 28 of the Electricity Regulatory Commissions Act, 1998, the Central Electricity Regulatory Commission (hereinafter referred to as "the Commission"), had notified the terms and conditions of tariff on 26.3.2001, applicable for the period from 1.4.2001 to 31.3.2004. Fresh terms and conditions of tariff effective from 1.4.2004, therefore, needed to be notified.

2. The Electricity Act 2003, (hereinafter referred to as "the Act") which repealed the Electricity Regulatory Commissions Act, 1998, came into effect on 10.6.2003. The Act enjoins upon the Commission to specify, by regulations, the terms and conditions for determination of tariff after previous publication, based on which the

actual tariff is to be determined. The Commission under Section 79 (1) of the Act, is assigned the following functions, 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, 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 inter-state transmission of energy; and*

(d) *To determine tariff for inter-state transmission of electricity.*

3. Immediately after the Act came into force, a staff discussion paper, (hereinafter referred to as "the discussion paper”) prepared by the staff of the Commission was published in June 2003. The discussion paper flagged tariff related issues and invited suggestions from the stakeholders and other interested persons. A total of 57 organisations/individuals responded to the discussion paper. Before formulating any views, an open hearing was held, by the Commission, from 10^{th} to 12^{th} November 2003 as a step towards the consultative process and transparency. After conclusion of the open hearing, some of the stakeholders again filed their views in writing. On consideration of the submissions made by the utilities and other interested persons in their responses on the discussion paper, at the open hearing and also the views filed thereafter, the Commission prepared the draft regulations on terms and conditions named as the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2004, (hereinafter referred to as “the draft regulations”.) The draft regulations were published on

1.1.2004 for focussed response of the persons interested in the subject matter. A detailed order, giving reasons in support of the provisions made in the draft regulations, was issued on 16.1.2004. A fresh opportunity of open hearing on 9th and 10th March, 2004, was afforded to all concerned. After proper evaluation of the suggestions and comments received on the draft regulations and the views expressed at the open hearing, the Commission has finalised the terms and conditions of tariff and these have been published separately. Through this order, we propose to give our reasons for affecting changes in the draft regulations, or otherwise.

4. In its order dated 16.1.2004, the Commission had emphasised the need for evolving guidelines for the purpose of adopting transparent bidding procedures for all future projects since the transparent bidding process provides an in-built incentive for maximising efficiency. We are informed that the Central Government is already seized of the matter. It is needless to say that the guidelines on competitive bidding, as and when notified by the Central Government, shall be applicable to all cases except the following:

(i) The projects already assigned to PSUs by the Ministry of Power or the concerned State Governments.

(ii) The projects which are proposed to be developed as merchant power plants (Power plants not dependent on long term power purchase agreements)

Even in case of PSUs, comprehensive guidelines for procuring equipments/services/EPC etc., through a competitive bidding route need to be prescribed. This is necessary to ensure that these utilities demonstrate the prudence of their investment and procurement decisions in a fair and transparent manner thereby ensuring best possible deals to the electricity consumers.

5. We now proceed to consider the suggestions and comments received on the draft regulations and our decisions thereon.

Period of validity - Draft Regulation 1 (2)

6. It was proposed that the regulations would remain in force for a period of five years from 1.4.2004, unless reviewed earlier or extended by the Commission. Some of the stakeholders argued that the terms and conditions should be valid only for a period of three years. However, the majority of the stakeholders were of the view that the validity should be for five years. Some of them even argued in favour of still longer period of validity. We have opted in favour of a period of five years. In our opinion, three year period would be too short and could become a cause for heart-burning on the ground that such a short period could lead to regulatory uncertainties. Similarly, we have not opted for a longer period since in our opinion, the power sector has been liberalised only in the recent past and exposed to reforms. We feel that it is necessary to constantly monitor and review issues based on practical experience before long-term terms and conditions could be prescribed. In view of this, we do not propose any change to the provision contained in the draft regulations. Accordingly, the terms and conditions have

been made applicable for a period of five years from 1.4.2004, in the final regulations.

Norms of Operation to be ceilings norms - Draft Regulation 3

7. In the draft regulations, it was proposed that the norms of operation were to be ceiling norms. The generating company or the transmission licensee and the beneficiaries could agree to improved norms of operation within such ceiling. The generators like NTPC, Tata Power, CII, ASSOCHAM, etc. have sought omission of this provision. According to NTPC, it would be difficult to negotiate the same operating parameters with different beneficiaries because most of its generating stations are regional stations selling power to all the states in the region. This would lead to delay in conclusion of PPAs and implementation of project. ASSOCHAM and CII have also supported this view of NTPC. The beneficiaries have not objected to the provision. We are of the view that it is not possible to specify norms for all situations and for technological up-gradations which may be adopted in future by the generators, particularly in case of new generating stations and as such, an enabling provisions was proposed in the draft regulations. In view of this, we have preferred to retain this provision in the final regulations too.

Tax on Income – Draft Regulations 7, 8 and 10

8. The draft regulations provided for recovery of income-tax and maintenance of escrow accounts by the beneficiaries. The Commission concluded that sharing of income-tax by the beneficiaries should continue in accordance with the procedure contained in the Commission's notification dated 26.3.2001 containing the terms and conditions of tariff applicable for the period ending 31.3.2004.

9. Some of the central power sector utilities have suggested that the return on equity itself can be prescribed on pre-tax basis, corresponding to current corporate income-tax rates and also suggested that if the actual incidence of income-tax happens to be higher, the differential should be allowed as "pass through".

10. A suggestion has also been made in the case of hydro power generating stations that the income-tax charged to the beneficiaries could be apportioned on the basis of "annual capacity charges" rather than "annual fixed charges" proposed in the draft regulations. Some of the utilities have raised the issue of deferred tax as an expense under the Accounting Standard 22.

11. The Independent Power Producers have suggested that the income-tax be computed on normative basis and not on actual basis. In addition to tax on income, all the taxes/duties/octroi /cess etc. charged on sale of electricity are

sought to be treated as "pass through" in tariff. It is also suggested that dividend distribution tax may also be allowed as "pass through".

12. The beneficiaries have argued in chorus that income-tax should be paid by the assessee, and, therefore, should not be "pass through" in tariff. In the alternative, it is urged that income-tax liability, if to be borne by the beneficiaries, should be limited to the return on equity component.

13. We have examined the issues relating to income-tax and its recovery mechanism. It is well known that certain incentives are provided for the purpose of income-tax and that the benefits have been availed of by the utilities and through them by the beneficiaries for a long time. It can be seen that any new investment provides tax shields and when claimed at the corporate level it is passed on to the station level. Prescribing a pre-tax return on equity, that too based on the current statutory corporate tax rate would not represent the situation on ground on a year-to-year basis. It is also a well-known fact that some of the utilities did not pay tax for a long period after their incorporation. In the prevailing circumstances, the balance of convenience lies in continuation of the existing methodology for income-tax to be allowed as "pass through".

14. The Commission, however, recognises that the utilities have little incentive for minimising their income tax liability in the scheme in which this is totally a “pass through”. It is also possible that while some (conservative) utilities may be more comfortable with income tax liability being a “pass through”, others may be more

enterprising and be willing to take advantage of tax optimisation possibilities (the benefit of which would ultimately accrue to the power sector as a whole), provided a reasonable return on equity norm is applied for them, on a clear pre-tax basis. The issue has wide ramifications and requires an informed debate. The Commission may initiate a discussion on this issue at an appropriate time, with an idea to giving an option to entities to switch over from the presently specified post-tax ROE norm to an appropriate pre-tax ROE norm from a prospective date.

15. As regards opening of escrow for this purpose, we are of the considered view that it is absolutely necessary to have this escrow mechanism as this liability is arising on the central power sector utilities on behalf of the beneficiaries and the income-tax is being paid in advance by these utilities. We do not have any objection, if any bilateral arrangement can be worked out between the parties by mutual consultation.

16. Accordingly, no changes to the provision contained, in this regard, in the draft regulations have been made.

17. We have revisited the proposal for allocation of income-tax in case of hydro power generating stations and are convinced that sharing of income-tax for hydro power generating stations shall be on the basis of capacity charge, instead of fixed charge as indicated in the draft regulations. The corresponding changes have been made accordingly.

Extra Rupee Liability – Draft Regulation 9

18. The draft regulations proposed that extra rupee liability towards interest payment and loan repayment, “actually incurred” in the relevant year, would be admissible. It also provided for recovery of Foreign Exchange Rate Variation on year-to-year basis as income or expense in the period in which they arise, adjustable on year-to-year basis. The methodology to be adopted for computing the Foreign Exchange Rate Variation after 1.4. 2004 had been proposed after taking into account the different methodologies that were adopted in the past for the purpose of calculating the Foreign Exchange Rate Variation.

19. The Commission has received varied and extensive comments on the provisions relating to Extra Rupee Liability made in the draft regulations. The central power sector utilities have suggested adoption of Accounting Standard 11 (AS 11) which provides for different treatment for the borrowings related to different periods. It has also been suggested that in case of hydro power generating stations, recovery of the Foreign Exchange Rate Variation from the beneficiaries should be in proportion to the annual capacity charges payable by them, these being in proportion to the capacity allocation. Some of the Independent Power Producers have suggested that since the cost of hedging is borne by the generator itself, any benefits accruing on account of such hedging should be allowed to be retained by the generator. A further suggestion has been made that the foreign currency

investment should be regulated by the Commission to control the Foreign Exchange Rate Variation in future.

20. The issue has been considered in the light of the comments received. We are of the view that maintenance of accounts as per Accounting Standard 11 is one thing while allowing Foreign Exchange Rate Variation as "pass through" in the tariff is another. Therefore, the comments received do not have any direct relevance to the provision made in the draft regulations. However, we find that the words “actually incurred” used may not be appropriate in all cases on account of the fact that in almost all past cases, normative debt-equity ratio had been used. In view of this, it is necessary to regulate the Exchange Rate Variation corresponding to the foreign loan included in the normative loan. Accordingly, the provision has been suitably modified to the effect that the Extra Rupee Liability towards interest payment and loan repayment corresponding to the normative foreign debt or actual foreign debt in the relevant year shall be admissible, as the case may be.

Availability - Regulation 11 (v)

21. As per the draft regulations, availability is based on declared capacity. The computation formula for availability provided for gross capacity not in operation (CL) on account of scheduling order given by the concerned RLDC. This provision was kept to take care of "no demand" situation as was the case in the Eastern Region and/or bottled up power due to non-availability of transmission links. It is felt that the "declared capacity" could take care of capacity not dispatched (or even

capacity not in operation) in situations mentioned above. The Commission found that the stipulation provided in the draft regulations was complicated and, therefore, the definition has been revised in the final regulations, as under:

> ***'Availability'*** *in relation to a thermal generating station for any period means the average of the daily average declared capacities (DCs) for all the days during that period expressed as a percentage of the installed capacity of the generating station minus normative auxiliary consumption in MW, and shall be computed in accordance with the following formula:*

$$\textbf{Availability} = 10000 \times \sum_{i=1}^{N} DC_i \,/\, \{ N \times IC \times (100 - AUX_n) \} \%$$

where,

IC = Installed Capacity (Gross) of the generating station in MW
DC_i = Average declared capacity for the i^{th} day of the period in MW.
N = Number of days during the period
AUX_n = Normative Auxiliary Energy Consumption as a percentage of gross generation.

22. Since full capacity charge recovery shall be admissible corresponding to target availability, explanatory note given below draft regulation 11(v) loses its relevance and hence it has been deleted in the final regulation.

Plant Load Factor – Draft Regulation 11(xx)

23. Under clause 11(xx) of the draft regulations, the Plant Load Factor (PLF) for a given period was defined as the percentage of sum of kWh generated at generator terminals of all the units corresponding to scheduled generation to

installed capacity, expressed in kilowatts (kW) multiplied by number of hours in that period.

24. We have discussed the provision for incentive in this order subsequently in paragraphs 142 to 145. The changes, which have been incorporated therein, have necessitated a corresponding change in the definition of Plant Load Factor, for the purpose it is used in these regulations, as under, which has been incorporated in the final regulations:

'Plant Load Factor' or 'PLF' *for a given period, means the total sent out energy corresponding to scheduled generation during the period, expressed as a percentage of sent out energy corresponding to installed capacity in that period and shall be computed in accordance with the following formula:*

$$\mathbf{PLF = 10000 \times \sum_{i=1}^{N} SG_i \,/\, \{N \times IC \times (100\text{-}AUX_n)\}\%}$$

where,

IC = Installed Capacity of the generating station in MW,
SG_i = Scheduled Generation in MW for the i^{th} time block of the period,
N = Number of time blocks during the period, and
AUX_n = Normative Auxiliary Energy Consumption as a percentage of gross Generation.

Norms of Operation for Thermal Generating Stations – Draft Regulation 13

25. The draft regulations specify operational norms of target availability, target Plant Load Factor, station heat rate, auxiliary energy consumption and specific fuel oil consumption for 200/210/250 MW set series and 500 MW set series for the existing as well new generating stations. These norms were specified in due

consideration of flexibility of operation and actual performance of the stations of National Thermal Power Corporation Ltd. and some of the best operating plants of the State Electricity Boards.

26. The Commission, however, had not specified any operational norms, in the draft regulations, for Badarpur TPS owned by the Central Government, Tanda TPS, and Talcher TPS of National Thermal Power Corporation Ltd., having unit sizes of 110 MW/100 MW/60 MW.

27. In so far as Badarpur TPS is concerned, the Central Government has not filed any tariff petition till date for determination of terms and condition of tariff for the Badarpur TPS. As such no terms and conditions could be prescribed in the draft regulations. Terms and conditions of tariff would be prescribed separately, for this TPS, by the Commission, on submission of tariff petition by the Central Government giving relevant data for the previous years.

28. With regard to operational norms for Tanda TPS and Talcher TPS, the Commission had missed the same in the draft regulations through oversight. However, this was covered in the order dated 16.1.2004 and it was observed as under:

> *"There are two generating stations of NTPC, namely Tanda TPS and Talcher TPS which are having steam turbines of 60 MW and 110 MW. The Commission has finalized operational norms for these generating stations of NTPC recently while dealing with tariff petitions on case-to-case basis. Further, these generating stations are undergoing lot of R&M works and the Commission would not like*

to review the operational norms till the R&M works are completed. NTPC is directed to come before the Commission with a proposal on the revised operational norms after the completion of R&M works in these generating stations. As such, we hold that the operational norms of station heat rate, auxiliary energy consumption and specific fuel oil consumption prescribed by the Commission for the year 2003-04 in respect of above two generating stations of NTPC in the tariff orders for the previous tariff period up to 31.3.2004, shall continue to apply during the tariff period 2004-09 also, till R&M work in these stations is completed".

29. Accordingly, the following operational norms, based on the principles enunciated in the order dated 16.1.2004, have now been prescribed in the final regulations in the case of Talcher TPS and Tanda TPS, for the period 2004-09, until such time these are revised on review:

Name of Station	Target Availability	Target PLF	Station Heat Rate Norm (kcal/kWh)	Auxiliary Energy Consumption Norm (%)	Specific Fuel Oil Consumption (ml/kWh)
Talcher TPS/ 460 MW	75%	75%	3100	11.00	3.5
Tanda TPS/ 440 MW	60%	60%	3000	11.00	3.5

Target Availability for Recovery of Full Capacity (Fixed) Charges - Draft Regulation 13(i)

30. Under the draft regulation 13(i), the target availability for recovery of full capacity (Fixed) charges was provided as under:

(a) All thermal generating stations, except those covered under clause (b) below – 80 %.

(b) Generating station of Neyveli Lignite Corporation (NLC) (TPS-II, Stage I&II) – 72 %.

31. During the course of open hearing on 9th and 10th March, 2004, it was argued by the generators that the target availability for coal-based thermal power stations be lowered to 70%. As against this, the state utilities wanted it to be raised to 85%. However, the arguments presented were mere repetition of what was submitted earlier before finalisation of draft regulations. No new facts were brought out by any person/organisation. We, therefore, do not propose to make any changes in the provisions at regulation 13 (i) (a) contained in the draft regulations and have retained the same in the final regulations.

32. While the process of formulating the draft regulations was on, NLC did not furnish any operational data in respect of their power stations viz. TPS-I, and TPS-I (Extension), which is under execution and is commissioned partially. Operational data in respect of TPS-II (Stages I and II), had, however, been furnished but for a period of two years only.

33. From para 30 above, it can be seen that, in so far as Stages I & II of TPS II are concerned, a clear provision has been made under draft regulation 13(i)(b). In so far as TPS- I and TPS-I (Expansion) are concerned, they get covered by draft regulation 13(i)(a) by implication.

34. NLC has indicated during the open hearings on 9th and 10th March, 2004 that each station of NLC has its own dedicated mine and it is not possible to supply lignite from any mine other than the dedicated one. It further indicated the Plant Load Factor (of power plant) that can be achieved at 85% and 100% capacity utilisation factor (of the mines) as under:

Capacity Utilisation Factor of Mines	PLF of Generating Stations		
	TPS-I/Mine-I	TPS-II/Mine-II	TPS-IE/Mine-IE
At 85 %	62.00 %	66.29 %	68.49 %
At 100 %	70.00 %	74.00 %	77.00 %

35. The actual PLF achieved by TPS-I & TPS-II for last 3 years i.e. from 2000-01 to 2002-03 is as follows. No data for TPS-I(Expansion) is available as only one unit has been commissioned recently.

	2000-01	2001-02	2002-03
TPS-I	79.09	79.57	83.31
TPS-II	81.65	81.65	81.57

36. It may be relevant to point out that the norm of 72% for target availability for TPS-II (Stage-I & Stage-II) was specified by the Commission, for the period 2001-04, on account of stated limitation in mine capability to run the station at higher PLF even with 100% of mine capacity utilization. The same was retained by the Commission in the draft regulations. Since no such limitation was indicated by NLC for TPS-1 (Expansion) project commissioned recently, no relaxation in target availability was

considered by the Commission and a target availability of 80% was proposed in the draft regulations.

37. TNEB has submitted that target availability and PLF for incentive may be fixed at 80 % for NLC stations instead of 72%. This, it was argued, is in due consideration of the present system of pooling of cost of lignite from individual mines and pooling of lignite from these mines. According to TNEB, since pooling for cost was being done by NLC, it would, inter alia, imply pooling of physical output from the mines. In its view, therefore, such pooling could make available sufficient quantity of lignite to achieve a PLF of about 86% in all the stations.

38. From para 35 above, it can be seen that both TPS-I & TPS-II are consistently operating at a PLF of around 80 % for the last 3 years. The mines are also operating at a capacity utilization factor of more than 100 %. As such there should not be any problem for NLC in achieving a target availability of 75 % for its stations. We have, therefore, fixed the target availability norm of 75% for lignite-fired stations of NLC i.e. TPS-I, TPS-II (Stage I & II) and TPS-I (Expansion), in the final regulations.

Target Plant Load Factor for Incentive - Draft Regulation 13 (ii) (Based on Scheduled Generation)

39. For the reasons discussed in para 31, we do not propose to make any changes in the target Plant Load Factor for coal based thermal power stations. However, for

the reasons recorded in the Order dated 16.1.2004 for thermal power stations, the target Plant Load Factor for TPS-I, TPS-II (Stages I and II), and TPS-I (Expansion) of NLC, shall be same as their target availability. Accordingly, we have fixed a target Plant Load Factor of 75% in the final regulations, for the purpose of incentives, for the lignite-fired stations.

Gross Station Heat Rate - Draft Regulation 13(iii)(a)
Coal-Based Generating Stations

40. The proposal is in respect of 200/210/250 MW sets as also 500 MW and above sets. This is not applicable to Tanda TPS and Talchar TPS of NTPC. The comments and submissions made by the generating companies, like NTPC, on the one hand and the beneficiaries, on the other, for the applicable category of generating stations are on the lines submitted before the Commission in response to the discussion paper prior to finalization of the draft regulations and have already been considered by the Commission in the order dated 16.1.2004. No new point has been made and as such no changes need to be made to the norms specified in the draft regulations for this category of coal-based generating stations for reasons recorded in the order dated 16.1.2004.

Gross Station Heat Rate - Draft Regulation 13(iii)(b)
Lignite-Fired Thermal Generating Stations

41. In the draft regulations, the following station heat rate normS for the existing as well new lignite-fired generating stations of NLC were proposed:-

"Station heat rate norms applicable to the existing as well as new stations of NLC shall be arrived at using the following multiplying factors on the gross station heat rate norms for the coal-based thermal power generating stations:

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

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

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

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

42. The Commission did not distinguish between the existing TPS-II of NLC and new lignite-fired generating station as no significant change in the technology of the plant and equipment was anticipated. Based on the norms proposed in the draft regulations, station heat rate works out to 2750 kcal/kWh corresponding to 50% moisture and station heat rate norm of 2500 kcal/kWh for the coal-based generating stations. NLC has submitted data for the period April 2001 to December 2002 for the TPS-II, which indicated that the actual heat rate was more than 2750 kcal/kWh. Since there has been improvement in the performance level of TPS-II station compared to earlier years, reasons of high heat rate are not understood. Despite the opportunity available to NLC to explain the reasons, it did not provide any explanation. NLC had agreed on a station heat rate norm of 2960 kcal/kWh for the period 1996-2001 with the beneficiaries as per BPSA signed with them. In terms of the Commission's notification dated 26.3.2001, this heat rate

norm was to be adopted for the period 2001-04. NLC has sought continuation of the same on following grounds:

(i) Stage-I units have logged more than 1 lakh hours of operation and Stage-II units are nearing 1 lakh hours of operation,

(ii) Varying quality of lignite from one mine to other, and

(iii) Extensive modifications to attend to slagging problems due to presence of marcasite in the lignite and consequent loss in heat rate on account of water lance operations, soot blower operations and increase in exit flue gas temperature.

43. NLC has sought to justify the station heat rate norms in the BPSA for TPS-II on the strength of the following calculation:

- Guaranteed Heat Rate (G.H.R.) of turbine 1999 kcal/kWh
- Heat rate deterioration due to

a)	Reheater spray	23.81 kcal/kWh
b)	Water lancing	23.68 kcal/kWh
c)	Soot blowing	17.75 kcal/kWh
d)	Aging	100.0 kcal/kWh
e)	High exit gas	65.10 kcal/kWh
f)	Part load operation	40.0 kcal/kWhr
	Total	270.34 kcal/kWh or 13.52% of GHR

- Boiler efficiency corrected 76.4%
- Design heat rate base is 1999/0.764 = 2616.49 kcal/kWh
- Over all heat rate with correction = 2616.49x1.1352 = 2970.24 kcal/kWh

44. NLC has submitted the operational data of GCV, moisture content in the lignite, PLF achieved, specific lignite consumption, etc. for the period 1998-99 to 2002-2003. The consumption of lignite based on the data furnished by NLC when compared with lignite production from dedicated mine-II and stock position as per

the balance sheet do not match. NLC very clearly stated during the open hearing and in its written submissions that lignite cannot be supplied from any source, other than the linked dedicated mine. Further, there is continuos improvement in GCV of lignite with moisture content remaining nearly around 50% and consistent performance at about 80% PLF. There appears to be ample scope for reduction of station heat rate norms for TPS-II station to 2850 kcal/kWh. This is further supported by the following computation:-

Design turbine cycle heat rate	= 1999 kcal/kWh
Boiler efficiency in case of coal-based generating stations	= 87%
Therefore, Design heat rate for the coal-based generating stations	= 1999/0.87
	= 2297.70 kcal/kWh
Norms of SHR for the coal-based generating stations	= 2500 kcal/kWh

45. Therefore, margin for deterioration (on account of operating conditions like variation in ambient condition, part load operation aging, high exit gas temperature, Re-heater spray, soot blowing, deterioration in condenser vacuum etc.)

= 2500 – 2297.70
= 202.3 kcal/kWh (i.e around 8.1% of the norms)

46. The turbine cycle heat rate and deterioration should be same for the lignite-fired generating stations of same unit size. However, considering the boiler efficiency of 77% in case of lignite-fired boiler, the design heat rate works out to 2596.1 kcal/kWh.

Additional allowance for deterioration (as in case of coal-based generating stations)	=202.30 kcal/kWh.

Therefore,

SHR over the life of the station would be = 2596.1 + 202.30
= 2798.4 kcal/kWh.

Considering additional deterioration on account of water lancing and high exit flue gas temperature due to modification of boiler (0.31 + 1.5%=1.81%)

SHR =2849.05 kcal/kWh
Say 2850 kcal/kWh

We have, therefore, allowed SHR norms of 2850 kcal/kWh, in the final regulations, for the existing TPS-II station of NLC.

47. NLC has also requested for specifying heat rate norms for the TPS-I station having 50 MW and 100 MW sets. The station is supplying power to TNEB. As per the existing BPSA with TNEB, agreed station heat rate norm is 3903 kcal/kWh.

Designed Turbine cycle heat rate for 50 MW set	= 2423 kcal/kWh
Designed Turbine cycle heat rate for 100 MW set	= 2284 kcal/kWh
Weighted average designed Turbine cycle heat rate	= 2353.5 kcal/kWh
Boiler efficiency	= 67.6%
∴ Design heat rate	= 3481.51 kcal/kWh

Considering the deterioration over the life of the station at the rate of 8.1%, the station heat rate over the life of the station = 3763.5 kcal/kWh

48. NLC has submitted that TPS-I is very old with Russian design of 1950s and has front wall firing with hammer type mills, non-membrane type water walls and no re-heater. These units have logged more than 2,40,000 hours of operation. Since the unit size is small and the units have outlived their useful life, deterioration in

heat rate would be higher than 8.1% considered. Considering the deterioration of 50 kcal/kWh for the unit size and additional 70 kcal/kWh for aging, the station heat rate works out to 3763.51 + 50 + 70 = 3883.51 kcal/kWh. Allowing some margin of error, the norm of 3900 kcal/kWh appears to be in order and has been prescribed in the final regulations.

49. For the new station of NLC, namely, TPS-I Expansion, NLC has not objected to the norm of 2750 kcal/kWh corresponding to 50% moisture. As such for the new station no change in the norms is required.

Gross Station Heat Rate - Draft Regulation 13(iii)(c)(i) Gas-based/liquid fuel-based Generating Stations

50. The proposal is in respect of existing gas-based/liquid fuel-based generating stations of NTPC. Some of the beneficiaries like GEB, MPSEB, MSEB have argued that in case of the existing gas-based generating stations of NTPC namely Kawas, Anta, Auraiya and Dadri, relaxed norms have been proposed in the draft regulations as compared to the norms of 2000 kcal/kWh under combined cycle mode and 2900 kcal/kWh under open cycle mode prescribed by the Central Government. It appears that they have not taken note of the fact that these generating stations were given relaxed norms by the Central Government itself but the same have been made comparatively more stringent after due consideration of operational parameters before ABT and performance after implementation of ABT. After taking note of the fact that liquid fuel capacity on Naphtha was not getting

fully dispatched after implementation of ABT, the station heat rate norms were proposed. We are, therefore, of the view that norms as proposed in the draft regulations do not require any change and the same have been provided in the final regulations.

51. GEB has, however, made a point, during the open hearing on 10.3.2004, that all gas based generating stations, including IPPs in the State of Gujarat were expected to get LNG w.e.f. 1.4.2004. After availability of LNG, these stations could get full dispatch. NRLDC report on post - ABT scenario in the Northern Region also indicates that LNG is likely to be available shortly. However, we are not clear about the cost of LNG. The price of LNG is the key factor for the improved dispatches from the liquid fuel-based generating stations. In view of this, we have not made any change in the norms specified at this stage for these generating stations. However, we give liberty to the beneficiaries to approach the Commission for review of operational norms when dispatches from these stations improve due to availability of LNG or otherwise.

Gross Station Heat Rate - Draft Regulation 13(iii)(c)(ii) Gas-based/liquid fuel-based Generating Stations

52. This draft regulation covers new Gas-based/liquid fuel-based generating stations. The following station heat rate norms were proposed by the Commission in the draft regulations:

Combined Cycle Operation	-	1900 kcal/kWh
Open Cycle Operation	-	2755 kcal/kWh

53. Most of the generators like NTPC, Torrent Ltd., ASSOCHAM expressed the view that station heat rate norms of 1900 kcal/kWh in combined cycle mode could only be achieved for advanced class machines and this may lead to limiting the competition in the market. Torrent Ltd has stated that after adjustment of GCV, there would not be sufficient margins for 'E' class & EA/EC/EZ class machines and has suggested that norms could be set at 1950 kcal/kWh.

54. The Commission proposed one norm and optimisation was expected to be done by the generators. However, in view of the comments made by the generators, we have specified two categories of norms, one for 'E' class and EA/EC/EZ class machines and other for advanced class machines as follows:

	E/EA/EC/EZ class Machines	Advanced class machines
Combined cycle operation	1950 kcal/kWh	1850 kcal/kWh
Open cycle operation	2830 kcal/kWh	2685 kcal/kWh

Gross Station Heat Rate - Draft Regulation 13(iii)(c)(iii)
Gas-based/liquid fuel-based Generating Stations

55. This draft regulation covers small gas turbine generating stations. No objections were raised regarding station heat rate norms for small gas turbine generating stations. As such, these norms have remained unchanged in the final regulations.

Secondary Fuel Oil Consumption - Draft Regulation 13(iv)(a)
Coal-based Generating Stations

56. The following secondary fuel oil consumption norms were proposed in the draft regulations:

(1)	During stabilization period	-	4.5 ml/kWh
(2)	Subsequent to stabilization period	-	2 ml/kWh

57. Most of the beneficiaries like GRIDCO, PSEB, RRVPNL, TNEB, UPPCL, etc. have sought to reduce the norms to 1 ml/kWh on the ground that most of NTPC coal-based generating stations are achieving specific fuel oil consumption below 1 ml/kWh. It was argued that the proposed norm of 2 ml/kWh will give undue benefit to the generator with consequent tax liability and this would be against consumer interest and objective for bringing efficiency and economy in the sector. NTPC in

its written submissions has sought to retain the existing norm of 3.5 ml/kWh. However during the open hearing, it has been stated on behalf of NTPC that reducing it further from the proposed 2 ml/kWh will jeopardize safety of operation and grid stability. The oil support is required to be taken in operation under certain conditions like variation in the coal quality, changeover of mills and tripping of the mills to sustain the generation. Any undue cut in the oil consumption should, therefore, be avoided. The Commission has already reduced the specific fuel oil consumption norms during post-stabilisation period from 3.5 ml/kWh to 2 ml/kWh. ABT is in operation in all the regions and the experience of ABT is yet to be evaluated. Under the circumstances, we are not inclined to reduce the norm of 2 ml/kWh proposed in the draft regulations at this stage. This has been retained in the final regulations.

Secondary Fuel Oil Consumption - Draft Regulation 13(iv)(b)
Lignite-fired Generating Stations

58. The following specific fuel oil consumption norm for the TPS-II of NLC was proposed in the draft regulations:

(1) During stabilization period - 4.5 ml/kWh
(2) Subsequent to stabilization period - 3 ml/kWh

59. Norms for the new lignite-fired generating stations were proposed to be same as those for coal-based generating stations. NLC has submitted that the norms

proposed are not adequate for lignite-fired generating stations due to very low calorific value of lignite and very high moisture content, requiring oil support very often. We find merit in the argument of NLC. In view of above, the following norms have been adopted for new as well as the existing lignite-fired generating stations, in the final regulations:

(1)	During stabilization period	-	5 ml/kWh
(2)	Subsequent to stabilization period	-	3 ml/kWh

Auxiliary Energy Consumption - Draft Regulation 13(v)(a)
Coal-based Generating Stations

60. A deduction of 0.5 percentage point compared to the norms for 2001-04, across the board for all coal-based generating stations having 200/210/250 MW series and 500 MW series sets, were proposed in the draft regulations. This was in due consideration of operational performance for the years 2001-03 and giving sufficient margin for operational flexibility.

61. Most of the beneficiaries have sought reduction across the board by 1 percentage point in the norms proposed in the draft regulations. The generators have either sought continuation of the existing norms or to increase them further. The demands of the generators and the beneficiaries cannot be sustained because norms for coal-based generating stations were specified after carefully considering the actual performance of NTPC generating stations. Further, adequate margin for operational flexibility has to be allowed. Hence, the auxiliary consumption

norms for coal-based generating stations having 200/210/250 MW sets and 500 MW sets proposed in draft regulations are retained in the final regulations.

62. The auxiliary consumption norms for Tanda TPS and Talcher TPS of NTPC were not specified in the draft regulations. However, in the order dated 16.1.2004, the Commission had proposed an auxiliary energy consumption norm of 11% for these two stations. The same has been retained in the final regulations.

Auxiliary Energy Consumption - Draft Regulation 13(v)(b)
Gas-based/Liquid Fuel-based Generating Stations

63. None of the parties has raised any objection to the following auxiliary energy consumption norms for the gas-based/liquid fuel-based generating stations proposed in the draft regulations:

Combined Cycle Operation	-	3%
Open Cycle Operation	-	1%

As such, the above norms have been provided in the final regulations.

Auxiliary Energy Consumption - New provision in the Final Regulations
Lignite-fired Generating Stations

64. In the draft regulations, norms of auxiliary energy consumption for lignite-fired generating stations were not proposed. However, in the order dated 16.1.2004, the Commission while making distinction between coal-based generating stations and

lignite-fired generating stations, had proposed norms for auxiliary energy consumption higher by 0.5 percentage point over the corresponding norms for coal-based generating stations. These norms were proposed to be made applicable to new as well the existing lignite-fired generating stations. As such, the existing TPS-II station norm was set to 9.5% as against actual performance of 9.56%. The earlier norm for this station was 10%. NLC has argued, in its submission, that unlike NTPC, it is not provided with any flexibility of operation and has sought to retain norm of 10%. Further, no norms were specified for TPS-I station, which operates on auxiliary energy consumption norm of 12.5% as per the existing BPSA with TNEB. The auxiliary energy consumption for this station was in the range of 10.76% to 12.28% during 1996-97 to 2002-03. In the years 2001-02 and 2002-03, the auxiliary energy consumption has been 11.64% and 11.57% respectively. Providing a margin of 0.5% for flexibility of operation, we have allowed the norms for the existing generating stations of NLC as under and provided the same in the final regulations:

TPS-I	12.0%
TPS-II	10.0%

65. For the new generating station TPS-I (Expansion), NLC have suggested a norm of 9.5% for auxiliary consumption. We are of the opinion that a lignite fired TPS would have an auxiliary consumption higher by about 0.5 percentage point, than a comparable coal-based TPS, due to higher boiler size and, therefore, higher size of various auxiliaries. We, therefore, allow that the auxiliary consumption norm for

new lignite-fired stations, shall be 0.5 percentage point more than the corresponding auxiliary consumption norm for coal-based generating stations. This has been provided in the final regulations.

Stabilization period - Draft Regulation 13(vi)

66. The Commission, in the draft regulations, had proposed that the stabilization period would cease to apply with effect from 1.4.2006.

67. Most of the generators have sought to retain the stabilization period for the entire tariff period. However, we are not inclined to deviate from the provisions made in the draft regulations for the reasons already recorded in the order dated 16.1.2004, and, therefore, we have retained the same in the final regulations

Operational Parameters to be adopted on the basis of norms or actual whichever is less - Additional issue related to norms of operation

68. In the notification dated 26.3.2001, applicable for the tariff determination for the period 2001-04, the following was prescribed (Explanation to Regulation 2.4 of the Notification dated 26.3.2001)

"For the purpose of calculating the tariff, the operating parameters, i.e., the station heat rate, secondary fuel oil consumption and auxiliary consumption, shall be determined on the basis of actual or norms, whichever is lower."

69. The Commission dispensed with this provision, in the draft regulations, for the reasons recorded in the order dated 16.1.2004. Beneficiaries like HVPNL, PSEB, UPPCL, etc. have sought continuation of this provision. The generators like NTPC, APGENCO, IPPs like Tata Power and regulator like KERC etc. are not in favor of continuation of this provision. We are of the firm view that in a performance-based system of regulation, adjustment based on actual is not conducive to efficiency improvements because there would not be any incentive for the generator to improve upon its efficiency of operation, which at the macro level leads to conservation of resources. The concerns of beneficiaries have been taken care of by specifying improved norms, based on prevailing operating conditions. The norms can always be reviewed, from time to time, in the light of technological and operational improvements. In view of this, we have not made any provision, in this regard, in the final regulations.

Capital Cost - Draft Regulations 14, 31 & 50

70. The draft regulations provided that –

"Subject to prudence check by the Commission, expenditure incurred on completion of the project shall form the basis for fixation of final tariff. The final tariff shall be fixed based on the admitted capital expenditure actually incurred up to the date of commercial operation …………"

71. In response to the proposal made in the draft regulations and submissions made during open hearing held on 9^{th} and 10^{th} March, 2004, various suggestions have been made in regard to treatment of capital cost for the purpose of tariff fixation. Some of the stakeholders have suggested stringent mechanism for cost determination in the absence of TEC of CEA. However, no specific model has been presented by the proponents of this view to address the issue.

72. Another school of thought was that a normative approach for determination of capital cost may be adopted for the purposes of fixation of tariff. This, according to the argument presented, would provide comfort to the investors in working out their strategies and investment decisions. This aspect, however, has already been discussed in our order dated 16.1.2004. The Commission would like to move in this direction as soon as reliable data is available. The sum and substance of all the submissions is that the Commission may move away from the capital expenditure and base the tariff on a reasonable project cost. On a query regarding "reasonable project cost" it transpired that such a reasonable cost would flow out of normative approach – an issue already discussed in the order dated 16.1.2004.

73. It has to be kept in view that the power sector has now been liberalised with the enactment of the Act. Generation (except hydro) and transmission projects do not require TEC of CEA. Further, in the case of thermal generation even a licence is not required. According to the submission made before the Commission, if the regulator takes a view only after applying the prudence check, which would be

after the completion of the project, it will introduce an element of uncertainty with regard to acceptance of project cost. The private investors/developers, the central power sector utilities and lenders are likely to be uncomfortable with such uncertainty and would like to have up front acceptance of project cost/tariff before taking any investment decision. The present position is that the regulator can take an appropriate view only after applying the prudence check when tariff proposal is submitted. We do not see any reason as to why the project cost should not be accepted by the Commission, if found competitive and reasonable, irrespective of time of its presentation to the Commission. Therefore, we must allay any doubts. For the present, we can only say that we would watch the system of prudence check by the Commission after the tariff proposals have been submitted for sometime. If the same is found to be inadequate to meet the issue of confidence level of investors, the Commission may review the issue and prescribe suitable revised procedure. For the present, we do not propose to make any changes in the formulation laid down in the draft regulations and have retained the same in the final regulations.

Initial Spares - Draft Regulations 14, 31 and 50

74. In the notification dated 26.3.2001, valid up to 31.3.2004, while the initial spares were provided for inclusion in the capital cost of the projects (Thermal, Hydro and Transmission), no norms had been specified for the same. This was mainly on account of the fact that hitherto, the Central Electricity Authority under the

Electricity (Supply) Act, 1948 had to accord techno-economic approval and the quantum of the spares required was an integral part of the appraisal and approval process. However, in the changed scenario in the context of enactment of the Act, no techno-economic clearance would be available and, therefore, it became necessary to provide norms for initial spares which could be taken as part of the capital cost. The following norms were, therefore, proposed in the draft regulations:

1.	Coal based/Lignite-fired Generating Stations	-	2.5 % of the Plant & Equipment Cost (Draft Regulation 14)
2.	Gas based/Liquid Fuel based Generating Stations	-	4 % of the Plant & Equipment Cost (Draft Regulation 14)
3.	Hydro Power Generating Stations	-	2.5 % of the Plant & Equipment Cost (Draft Regulation 31)
4.	Transmission System	-	1.5 % of the Plant & Equipment Cost (Draft Regulation 50)

75. During the course of submission/open hearing on the draft regulations, the stakeholders have suggested two things, that the percentages as indicated above should be increased and that the quantum of initial spares should be computed with reference to the project cost and not on the plant and equipment cost.

76. It has been argued by the stakeholders that the project cost is clearly known and well identified number whereas there could always be an element of arbitrariness in determining the cost of plant and equipment. We have examined this issue and

agree that the project cost is a well identified number. Further, we have been given to understand that project execution by packages include not only the cost of plant and equipment but also the cost of erection, testing and commissioning. Bifurcation of the two elements, plant and equipment on one hand and erection, testing and commissioning on the other, can pose considerable difficulties. Keeping this in view, we have decided that the project cost and not the cost of plant and equipment would be the basis for determining the cost of initial spares to be included in the capital cost. We do not propose to change the percentages proposed in the draft regulations except for the hydro generation stations, for the reason that there would be an across the board increase of 10%-25 % in the quantum of initial spares once these are determined on the basis of original project cost as against the cost of plant and equipment proposed in the draft regulations. In case of hydro generating stations, plant and equipment cost is of the order of 35 to 40 % of the total project cost, civil cost being higher depending upon the type of plant whether it is purely run-of-river type or pondage or storage type of plant. Therefore, 1.5% of the original capital cost has been allowed for initial capital spares for hydro generating stations. Accordingly, determination of initial spares has been linked to the original project cost in the final regulations, as against plant and equipment cost provided in the draft regulations.

Additional Capitalisation - Draft Regulations 15, 32 and 51

77. The draft regulations stipulated the situations under which additional capitalisation could be allowed. The type of expenditure which would not qualify for additional capitalisation after the date of commercial operation was, however, not prescribed in spite of the issue having been raised by some of the state utilities in their submissions and during the open hearing on 10th, 11th and 12th November, 2003. The issue was again raised by some of the state utilities in their submissions as well as during the open hearing on 9th and 10th March, 2004. The Commission has observed, in various petitions filed by the Central Power Sector utilities for approval of tariff, that expenditure incurred on minor assets, such as, furniture, air-conditioner, voltage stabiliser, refrigerators, TV, washing machines, coolers, fans, heat convectors, mat, carpets, normal tools and tackles etc, have been claimed towards additional capitalisation after the date of commercial operation of the generating station or the transmission system, as the case may be, in spite of the fact that expenditure on such minor items had already been allowed to be capitalised once within the scope of original work.

78. In a cost-plus approach, the Commission has to discourage the tendency of frequent capitalisation of expenditure after the cut-off date per se and on sundry items in particular. It is, therefore, necessary that capitalisation of sundry items of the type mentioned in the previous paragraph is not permitted. In view of this, we have ordered to insert a suitable clause in the final regulations, giving an

illustrative, but not exhaustive, list of items, which would not be allowed to be capitalised after the cut-off date. It is to clarify that the intention is not to prohibit expenditure on such items after the cut-off date. These can always be procured by utilities within their own resources but with clear understanding that the expenditure would not be allowed to be capitalised for the purposes of tariff determination.

Debt-Equity Ratio – Draft Regulations 17, 34 and 52

79. In the draft regulations, debt-equity in the ratio of 70:30 was proposed for the purpose of determination of tariff in case of a generating station or a transmission system, declared under commercial operation on or after 1.4.2004. It was proposed that where equity employed was more than 30%, the amount of equity for the purpose of tariff would be limited to 30% and the balance amount would be considered as loan. Where actual equity employed was less than 30%, the actual equity would be considered for the purposes of determining the tariff. In case of the existing generating stations and the transmission system, debt-equity ratio considered by the Commission for the period prior to 1.4.2004, was proposed to be considered.

80. The central power sector utilities have submitted that the debt-equity ratio of 70:30 could be considered for the projects approved on or after 1.4.2004, as prescribed in the draft regulations. They have further submitted that the debt-equity ratio, for the on-going projects taken up before 1.4.2004, as also the existing stations, be

maintained as per the financial package approved by the competent authority. Further, any advantage or disadvantage of actual debt and equity employed be left to the utilities' account. Commenting on the provision limiting the equity to 30% or actual whichever was less, it was suggested that the return on equity should be allowed at a normative level of 30%, irrespective of the actual equity employed. Some of the central power sector utilities urged that the debt -equity ratio of 50: 50, instead of 70:30, should be prescribed even for the projects commissioned after 31.3.2004 so as to provide adequate resources for power development.

81. The beneficiaries have argued that the Central Government had prescribed a debt equity ratio of 80:20. They, therefore, demanded that a debt equity ratio of 80:20 be prescribed by the Commission also, not only for assets to be approved after 1.4.2004, but across the board, covering the existing assets also. They have based their demand on the fact that the very concept of division of capital between debt and equity on a notional basis of 50:50, irrespective of the actual debt equity ratio employed, was introduced on the basis of K.P. Rao Committee report. They pointed out that in doing so, K.P. Rao had also recommended dilution of equity by the amount of depreciation recovered, once the loan was paid off. However, in the mean time, the Central Government in Ministry of Power issued a notification dated 16.12.1997 applicable for transmission tariff effective from 1.4.1997, wherein a switch over from NFA to GFA concept was made. Accordingly, the equity remained constant through out the balance life of the assets.

82. We have considered the issue very carefully. While we do not find any merit in the

demand of State utilities that the debt equity ratio be maintained at 80:20 on the grounds that it was prescribed by the Central Government, we note that the debt equity ratio of 80:20 prescribed by the Central Government was a minimum ratio and not a must ratio. A careful reading of the Resolution of the Central Government, referred to by the State utilities, brings out clearly that the minimum equity to be deployed was to be 20%. It could be any number between 20% and 100%. Having said that, we hasten to add that the economics of equity to be deployed is a function of rate of interest, availability of funds in the market, willingness and perception of lenders and other factors. It is an intricate exercise. The Commission has prescribed 30% equity as it has been determined by the market in due consideration of various contributing attributes mentioned by us. We, therefore, reject the demand for prescribing a debt-equity ratio of 80:20 and retain the ratio of 70:30 in the final regulations.

83. We now turn to the second demand of state utilities that the new debt equity ratio be applied across the board, to all the assets – existing as well as new. The State utilities have cited recommendations of Shri K.P. Rao regarding notional division of capital in the ratio of 50:50 :: debt : equity along with reduction of the equity by the amount of depreciation once the loan was fully repaid. We are unable to agree with this argument in view of the fact that Ministry of Power notification dated 16.12.97 applicable to POWERGRID, does not provide for such an arrangement. The arrangement resorted to was to change over from the net fixed asset concept following in case of POWERGRID to gross fixed asset concept with effect from

1.4.97. Thereafter a conscious decision was taken to retain the equity constant over the balance life of the assets. Same principle is also contained in the notification issued by Ministry of Power on 30th March, 1992 which was applicable to IPPs. The Commission had consciously adopted this principle in the tariff setting for the period 1.4.2001 to 31.03.2004. This principle is continued by the Commission for the tariff period 1.4.2004 to 31.03.2009 as well. The State Utilities have further argued that the reduction in equity would be in the consumers interest as the ROE is quite high and also it has to be provided through out the life of the assets. They have also argued that single part tariff was in vogue prior to introduction of two-part tariff based on K.P. Rao report, during which time the utilities earned higher profits. It was further argued by them that the notional division of capital cost was done irrespective of deployment of actual debt and equity in the construction of the projects. We have examined these issues in detail and observe that the issues raised are very old and cannot be reset after a long delay especially when in the interim period many changes have taken place by virtue of various notifications issued by Ministry of Power.

84. Keeping these factors in mind, we have decided to fix the debt -equity ratio in all cases at 70: 30 for all the projects, including those declared under commercial operation before 1.4.2004. Where debt-equity ratio other than 70:30 was considered in the past, the equity component would stand reduced to 30% of the capital cost on the date of commercial operation and the balance equity would be treated as notional loan on which notional interest would be allowed. This notional interest would be calculated based on the weighted average interest rate of all the

outstanding loans. The necessary changes in the final regulations have accordingly been made.

85. Further Draft regulation provides for tariff revision on account of additional capitalisation once in tariff period. Commission on reconsideration feels that it may not be adequate and has decided to allow two tariff revisions on account of additional capitalisation during the tariff period including tariff revision after the cut off date.

Interest on Loan Capital – Draft Regulations 18 (i), 36 (i) and 54 (i)

86. It was proposed that interest on loan capital would be computed loan-wise on the outstanding loan arrived at in accordance with the provisions for division of capital cost into debt and equity, duly taking into account the schedule of repayment and actual interest rates. It was further proposed that in case of the existing generating stations or the transmission system, the normative loan outstanding as on 1.4.2004 would be considered as the opening loan and the repayment would be worked out on normative basis. The weighted average rate of interest on loan was proposed to be worked out on the actual outstanding loan and applied to the normative loan for calculation of interest on loan in the respective year. This has been retained in the final regulations.

87. Some of the beneficiaries have raised the issue of swapping of loan and treatment of moratorium period. The beneficiaries have pleaded that in the falling interest rate scenario, it would be appropriate for the generating companies and the

transmission licensees to swap the loans and pass on the benefits to them. The beneficiaries agreed to absorb the cost relating to swapping of loans provided there was an over all saving on interest on loan. On the question of moratorium period, it was pleaded that in the past, the central power sector utilities contracted loans with moratorium periods extending beyond the date of commercial operation, and in all such cases, the interest on loan was passed on to the beneficiaries without considering any repayment during the moratorium period.

88. Both these issues have been examined in detail. The financial health of the beneficiaries is not too good and at the same time the reform process has also to be sustained. The cost of purchasing power from the central power sector utilities and the inter-state transmission charges constitute a sizable portion in the annual revenue requirements of the state utilities. In view of this, any reduction in the purchase power cost should help to boost the financial health of the state utilities. Further, we are of the view that the central power sector utilities are not expected to make any profits on account of swapping of loans, interest on loan, etc. and these items are to be considered only as "pass through" items in tariff. Accordingly, we have decided that the central power sector utilities should make every effort in the direction of swapping of loans as long as it results in net benefit to the beneficiaries and the cost associated with such swapping shall be borne by the beneficiaries. The swapping of loan could be done by the central power Sector utilities and the changes to the loan terms and conditions shall be reflected from the date of such swapping. Any reduction in tariff as a result of swapping of loans shall be passed on to the beneficiaries by the central power sector utilities

with immediate effect. In deciding the issue we were guided by the fact that some the central power sector utilities are already passing the benefit of swapping of loans to the state beneficiaries. The Commission can be approached by any of the parties in case of disputes. However, the beneficiaries shall not withhold any payments, as ordered by the Commission, to the central power sector utilities on account of any dispute relating to swapping of loans. Suitable provisions have been made in the final regulations.

89. We have also applied our mind to the issue of moratorium period after the commercial operation date. The effect of moratorium period is to increase the liability on account of interest on loan. In case the loan is repaid from the date of commercial operation, the interest liability would be going down on a year to year basis. We are, therefore, of the view that the moratorium period only benefits the central power sector utilities at the cost of the beneficiaries. We are keen to correct this situation and accordingly we have decided that in case any moratorium period is availed of by the central power sector utilities, the depreciation shall be reckoned as repayment during such moratorium period and the interest on loan shall be calculated accordingly. This arrangement is equitable to both i.e. the central power sector utilities and the beneficiaries inasmuch as the central power sector utilities would have sufficient cash flows during the moratorium period of loans, while the beneficiaries would get the benefit of reduction in the interest.

Depreciation including Advance Against Depreciation - Draft Regulations 18 (ii), 36 (ii) and 54 (ii)

90. The draft regulations prescribed the methodology for calculation of depreciation and Advance Against Depreciation. Depreciation was to be provided on the basis of historical cost of the asset and calculated annually as per straight-line method after taking into account its useful life. The rates of depreciation were published as part of the draft regulations. It was further proposed that the total depreciation during the life of the generating station or the transmission system would not exceed 90% of the approved original cost, including additional capitalization on account of foreign exchange rate variation up to 31.3.2004. Advance Against Depreciation was proposed to meet loan repayment obligations by considering the repayment period of 10 years.

91. The central power sector utilities have argued that depreciation may be specified as per Schedule XIV of the Companies Act, 1956 as a ”continuous process plant” so that the rates of depreciation for the purposes of accounts and tariff computation are uniform. In case of inadequacy of cash for debt repayment, Advance Against Depreciation be also allowed. It is further submitted that the central power sector utilities be allowed to recover up to 95% of capital cost through depreciation since otherwise it will have significant impact on their profit. A suggestion has also been made that depreciation may be allowed as per the Central Government’s notification issued during 1994 under the Electricity (Supply) Act, 1948, since repealed. The central power sector utilities have submitted that

Advance Against Depreciation may be allowed based on total repayment schedule of the loan right from the first year and where depreciation and Advance Against Depreciation together are not adequate to meet loan repayment obligations, refinancing of loan and cost thereof may be considered as “pass through’ in tariff. According to them, after repayment of loan, depreciation recovery in tariff should continue uniformly. On the question of loan tenure for calculation of Advance Against Depreciation, it is stated that if tenure of loan is less than 10 years, the Commission may make some special provisions in such cases for Advance Against Depreciation. It is submitted that the MAT liability would increase in the year when Advance Against Depreciation is claimed, unless the amount of Advance Against Depreciation is considered as Depreciation for tax purposes. In other cases, the tax liability should be allowed as a pass through or Advance Against Depreciation should be permitted as Depreciation by the tax authorities.

92. The beneficiaries have submitted that Advance Against Depreciation may be allowed with minimum loan term of 12 years as per the notification dated 26.3.2001 and should be allowed duly taking into account cumulative recovery of depreciation and cumulative repayments. It is further urged that the central power sector utilities may have to explore the possibility of refinancing of loans to optimise the recovery of depreciation and Advance Against Depreciation. Another pertinent issue raised on behalf of the beneficiaries is whether 90% of the project cost calculated for depreciation should include land cost because the land is not a depreciable asset. It is submitted that the provision of moratorium period in the repayment schedule is not in the interest of the beneficiaries and, therefore, during

the moratorium period the interest liability be limited to the amount arrived at after deducting the depreciation from the total loan.

93. The issues raised have been examined in detail. We take note of the fact that depreciation rates or useful lives of the assets as adopted by a company, if they are different from the rates of depreciation specified in Schedule XIV of the Companies Act, need to be disclosed in the annual accounts. It is also noted that the depreciation rates prescribed under Schedule XIV are generally lower than those specified in the rules framed under the Income-Tax Act.

94. The issues in regard to charging of depreciation raised in response to the draft regulations were earlier raised by the stakeholders while responding to the discussion paper. The Commission in its order dated 16.1.2004 had given the detailed reasons in support of the proposals made in the draft regulations. The same issues are being re-agitated. Traditionally, depreciation has been considered as a part of tariff. Section 43A (2) of the Electricity (Supply) Act, 1948, which enacted provisions relating to terms, conditions and tariff for sale of electricity, *inter alia*, laid down that the tariff for sale of electricity could be determined in accordance with rates of depreciation, etc as may be determined by the Central Government. Presently, the function to specify the terms and conditions of tariff is entrusted to the Commission. Therefore, in our opinion the rates of depreciation provided in Schedule XIV of the Companies Act have no relevance, direct or indirect, with the rates of depreciation for tariff determination, for which purpose

the rates of depreciation, among other things, are to be specified by the Commission.

95. Under Section 61 of the Act the Commission, while specifying the terms and conditions for determination of tariff is to be guided, *inter alia*, by the principles that generation, transmission, distribution and supply of electricity are conducted on commercial principles, which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments; safeguard consumers interests and at the same time ensure recovery of the cost of electricity in a reasonable manner. We consider ourselves to be bound by the provisions of the Act briefly noticed above. We are of the considered opinion that allowing higher rates of depreciation prescribed in Schedule XIV of the Companies Act, apart from distorting allocation of depreciation over the useful life of the asset shall result in front-loading of tariff, which is antithetic to the concept of safeguarding the consumers' interest. To overcome the cash flow problems of the central power sector utilities for meeting loan repayment obligations, we have provided for Advance Against Depreciation. To accommodate shorter tenors of loan, the repayment period of 10 years has been considered. To our mind, this adequately takes care of the needs of the central power sector utilities and no further change is considered necessary. Provisions already made in the draft regulations in this regard are retained in the final regulations.

96. We now examine the issue whether the rates of depreciation prescribed by the Commission can be different from those prescribed under the Companies Act for

the purpose of tariff. The central power sector utilities have argued that for the purpose of accounts they are obliged to follow provisions of the Companies Act. The argument is made to persuade us to adopt the rates prescribed under the Companies Act for the purpose of uniformity. We consider it sufficient to observe that different rates of depreciation are already being allowed for the purpose of accounts and income-tax. This being so, following different depreciation rates for the purpose of tariff is considered fully justified.

97. The central power sector utilities have argued that providing depreciation at a rate lower than the one prescribed under the Companies Act would adversely affect their balance sheet. It is true that for any asset, on stand alone basis, adoption of different depreciation rates would affect the balance sheet in the earlier years, but at the same time would show profit in later years. Since the central power sector utilities have a large number of assets and that too of different vintage, adoption of different depreciation rates for the purpose of tariff and accounts does not necessarily mean that the balance sheet will always be adversely affected since on the revenue side depreciation will be spread over the whole life, while on the expenditure side, depreciation will be front-loaded. Therefore, on an overall basis, the pluses and minuses would even out each other. Law does not take the trifles into account - *lex non curat de minimis*. It is also relevant to note that during the period 1994 to 2001, depreciation has been recovered on an accelerated rate. Therefore, depreciation is unlikely to have any significant impact on the profit and loss accounts.

98. The upshot of the above discussion is that depreciation should be allowed in tariff on straight-line basis over the useful life of the asset and at the rates proposed in the draft regulations. The residual value of the assets shall also be considered as 10% and consequently depreciation should be allowed up to maximum of 90% of the historic capital cost of the asset. Since land is not a depreciable asset, its cost should be excluded from the capital cost while computing 90% of the historic capital cost of the asset. Accordingly, these provisions have been made in the final regulations.

99. While calculating Advance Against Depreciation, the cumulative depreciation up to the year of tariff and the cumulative repayment during the same period shall be the basis for the purpose of calculation of Advance Against Depreciation. Advance Against Depreciation shall be allowed only if the cumulative repayment up to a particular year exceeds the cumulative depreciation up to that year. For this purpose, the concerned utilities shall file the loan details of individual generating stations and the transmission system from the respective date of commercial operation and the cumulative depreciation allowed in the tariff. In case of assets which are transferred, like in the case of POWERGRID, the details shall be furnished on a year-wise basis after the transfer of assets and for the earlier period the position of assets and liabilities shall be clearly brought out as on the date of taking over of the assets. The debt-equity ratio has been decided on normative basis. In all such cases, a comparison will have to be made with regard to the actual repayment and the normative repayment of loan and appropriate

corrections will have to be applied while computing Advance Against Depreciation. A similar provision has also been made in the calculations for interest on loan, in view of the differences between the actual loan and the normative loan. The principles adopted for arriving at repayment of loan for the purpose of calculations of interest on loan and Advance Against Depreciation have to be identical. While Advance Against Depreciation is presently being allowed as a continuation of the practice hitherto, the Commission would like to advise the transmission licensees and generating companies to go in for long term loans and/or for rolling over of loans so as to minimise the requirement of Advance Against Depreciation.

Return on Equity – Draft Regulations 18 (iii), 36 (iii) and 54 (iii)

100. In the draft regulations it was proposed that the return on equity would be 14% for the central power sector utilities as also in the case of Independent Power Producers if payment security mechanism similar to the central power sector utilities was provided by the Central Government. In other cases of Independent Power Producers, the return on equity was proposed at the rate of 16%. It has been argued that the arrangement for payment security mechanism has not come free. It involves huge costs by way of rebates allowed by the central power sector utilities to the beneficiaries and also waiver of a major portion of the surcharge outstanding on the date the payment security mechanism was put in place. Therefore, differential rates of return on equity would not be fair and equitable. It has, therefore, been represented that the Independent Power Producers should not be permitted the return on equity at the rate of 16% under any circumstances.

There is considerable strength in the submission made. Accordingly, the Independent Power Producers also shall be allowed a return on equity at par with the central power sector utilities, at the rate of 14%. Necessary amendments to the draft regulations have been made and incorporated in the final regulations.

Operational & Maintenance Expenses - Draft Regulation 18 (iv)(a) Coal-based and lignite-fired generating stations

101. The normative operation and maintenance expenses, for coal-based and lignite-fired Thermal Power Stations, proposed in the draft regulations were as under:

(Rs. in lakh/MW)

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

Note 1

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

Note 2

In respect of Tanda Thermal Power Station and Talcher Power Station the operation and maintenance norms given hereunder were proposed:

(Rs. in lakh/MW)

Year	Tanda TPS	Talcher TPS
2004-05	9.88	14.12
2005-06	10.28	14.69
2006-07	10.69	15.28
2007-08	11.11	15.89
2008-09	11.56	16.52

102. Observations with respect to specific-type of generating stations are discussed below: -

1. Coal-based Generating Stations

(a) 200/210/250 MW & 500 MW series:

103. For determining the operation and maintenance cost norms for coal-based generating stations in this category, the following methodology was used at the time of preparing draft regulations:

1. Actual operation and maintenance expenses as given by the NTPC for its stations for the period 1995-96 to 1999-2000 was normalised.
2. After normalisation, simple average of the series was obtained, which represents the average normalised expenditure during the mid year, 1997-98.
3. Escalation factor of 10% for the years 1998-99 and 1999-2000 and 6% for the year 2000-01 was used to arrive at the base year (2000-01) O&M expenses.

4. The base year O&M expenses, thus arrived, were escaled @ of 4% for determining, year-wise, norms for the five year period 2004-09.

104. NTPC has sought revision of these coal-based operation and maintenance norms, based on actual operation and maintenance expenses for the period 1998-99 to 2002-03, given below, as against the O&M expenses for the 1995-96 to 1999-2000 used by the Commission, which was available to it. NTPC has also demanded use of an escalation factor of 7% instead of 4% used by the Commission.

Operation and Maintenance expense of NTPC's coal based TPS during the period 1998-03

Year	Capacity (MW)	Actual O&M Cost (In Rs. crore)
1998-99	13160	1049.16
1999-00	13178	1172.56
2000-01	14048	1393.45
2001-02	14580	1443.41
2002-03	14913	1435.24

105. Based on above, the O&M cost per MW would works out to be as under :

Year	Capacity (MW)	Actual O&M Cost (In Rs. crore)	O&M (in RS lakh /MW)
1998-99	13160	1049.16	7.97
1999-00	13178	1172.56	8.90
2000-01	14048	1393.45	9.92
2001-02	14580	1443.41	9.90
2002-03	14913	1435.24	9.62
Weighted average in 2000-01			**9.30**

106. The year-wise expenditure figures submitted by NTPC are raw figures on which no prudence check could be applied by the Commission as NTPC has not furnished the required details in support of its claim. The Commission has, therefore, to use an indirect method to check the validity of norms vis-à-vis the claims of NTPC. To do this, the weighted average of O&M expenses for the period 1998-99 to 2002-2003, (in Rs lakh/MW), as given by NTPC, was worked out, in the mid-year 2000-01. This works out to Rs 9.3 lakh/MW in 2000-01. The Commission had considered a normalised expenditure of Rs 8.35 lakh/MW in the year 2001-02, in the order dated 16.1.2004, as against an actual expenditure of Rs 9.52 lakh/MW. Considering the same normalization ratio of 8.35/9.52 to be applicable to the expenditure now submitted by NTPC, the weighted average normalised figure for 2000-01 works out to be Rs 8.16 lakh/MW (9.30x8.35/9.52). The detailed working for norms for the period 2004-09 is given below:

Years	Escalation rate applied	Norms as worked out	Division of norms in previous column in respective category	
			200/210/250	500
2000-01	-	8.16		
2001-02	4,0%	8.48		
2002-03	4,0%	8.82		
2003-04	4,0%	9.18		
2004-05	**4,0%**	**9.54**	**10.02**	**9.06**
2005-06	**4,0%**	**9.93**	**10.42**	**9.43**
2006-07	**4,0%**	**10.3**	**10.83**	**9.80**
2007-08	**4,0%**	**10.74**	**11.27**	**10.19**
2008-09	**4,0%**	**11.17**	**11.72**	**10.60**

107. In the computation, bifurcation of O&M expenses between 200/210/250 MW and 500 MW series stations has been done on the same principles as in the order dated 16.1.2004.

108. From the above, it can be seen that the norms which were proposed by the Commission in the draft regulations are liberal than the norms as worked out based on the O&M expenses given by NTPC for the period 1998-2003. No revision of the norms prescribed in the draft regulations, therefore, is necessary.

109. NTPC has also sought a higher escalation rate of 7%, as against 4% considered by the Commission based on the following formula:

$0.4\ WPI_n/WPI_1 + 0.6x2.33\ CPI_n/CPI_1$

110. The claim of NTPC is based on the ground that increase in per capita emoluments of the employees of the public sector undertakings during the years 1996-2001 has been 14% as indicated by the Economic Survey of India for 2002-03, as against an increase of 6% in the consumers price index during the same period. Same argument was made by NTPC, before the Commission, during the process of finalisation of operation and maintenance cost norms for the period 2001-04. The argument made at that time is reproduced below:

> *"The weightage accorded to CPI and WPI should be 60 and 40 percent respectively. They have suggested that the overheads (including corporate office allocations) which account for over 34 percent of overall O&M expenses should be linked to CPI.*
>
> *The CPI was not a suitable indicator for indexing employee cost as, in the last three years, increases in employee costs were twice that in CPI. Therefore, 2 times the inflation in CPI should be built into the escalation formula.*

On these grounds they suggested the following escalation formula:

$$0.4\ WPI_n/WPI_1 + 0.6x2.0\ CPI_n/CPI_1$$

111. The argument did not find favour with the Commission. It made following observations in its order dated 21.12.2000 :

> *"The escalation formula suggested by NTPC accords a higher weightage to CPI and requires an escalation of 2 times the increase in CPI for employee related expenditure and overheads. The arguments offered in favour of the proposed formula are not tenable as escalating the employee related O&M costs (linked to CPI) at twice the rate of increase in CPI merely on the ground that this has been the trend in the growth of per capita emoluments in the public sector in the last three years is not justified. If the employee costs are rising at a rate higher than CPI then this should get reflected in their productivity implying thereby that same amount of labour produces more output. This is clearly brought out in the productivity figures published in NTPC annual reports. With the increases in labour productivity, NTPC should be able to reduce its labour requirement. As a result the overall wage bill should not rise at the rate of per capita emoluments. The CPI linked indexation for wages is thus quite fair."*

112. No arguments have been given for the Commission to change its views. The Commission had adopted methodology based on CPI and WPI for the select commodities in the ratio of 4:6 which has been followed in arriving at the escalation rate of 4% and the same be retained in the final regulations.

Operational & Maintenance Expenses - Coal based and lignite based generating stations (Tanda TPS and Talcher TPS having 110/60 MW sets)

Note 1 below Draft Regulation 18 (iv)(a)

113. Note 1 below draft regulation 18(iv)(a) proposed the following norms for O&M expenses for Tanda TPS and Talchar TPS, which were taken over by NTPC from the state utilities. The generating units at these stations are of the capacity of 110 MW and below series.

(Rs. in lakh/MW)

Year	Tanda TPS	Talcher TPS
2004-05	9.88	14.12
2005-06	10.28	14.69
2006-07	10.69	15.28
2007-08	11.11	15.89
2008-09	11.56	16.52

114. The above norms were based on the following admitted operation and maintenance expenses for the year 2000-01 approved in the order dated 28.6.2002 in tariff petition No.77/2001 for Tanda TPS and in the order dated 18.6.2003 in petition No. 62/2000 for Talcher TPS for the tariff period 2000-04. It is to be mentioned that the principles, methodology and limitations in determining operation and maintenance expenses for these stations, for the base year of 2000-01, are discussed in detail in respective orders mentioned above.

Name of the power station	O&M Expenses during 2000-01 in Rs lakh	O&M Expenses during 2000-01 in Rs lakh/MW
Tanda TPS (4x110 MW)	3720	8.45
Talcher TPS (4x60 MW+ 2x110MW)	5557	12.08

115. In the submissions made in response to the proposals made in the draft regulations and during the course of open hearing on 9th and 10th March, 2004, NTPC furnished data of actual operation and maintenance expenses during the years 2000-2001 to 2002-2003, though no such presentation was made earlier during the open hearing on 10th, 11th & 12th November, 2003. The details in this regard are reproduced below:

Year	Tanda TPS (440 MW)		Talcher TPS (460 MW)	
	Actual O&M Cost (Rs. In crore)	O&M (Rs. in lakh /MW)	Actual O&M Cost (Rs. In crore)	O&M (Rs. In lakh /MW)
2000-01	60.25	13.69	72.69	15.80
2001-02	64.07	14.56	82.14	17.86
2002-03	80.31	18.25	97.53	21.20

116. From the above it can be seen that the actuals even for the year 2002-03, as furnished by NTPC, are much higher than norms prescribed under the draft regulations for the year 2004-05 and beyond. Though the Commission has not subjected the data, submitted by NTPC for the period 2000-03, to any prudence check, the intensity of variations does call for a re-look at the norms proposed in the draft regulations. It has also to be kept in view that both the generating stations are under R&M. The impact of R&M on performance and operation and maintenance costs will also have to be factored. Keeping this in view, we have decided that no norms for operation and maintenance expenditure be fixed for these two stations for the tariff period of 2004-09. Instead, it would be determined on case-to-case basis after prudence check by the Commission of actual expenditure during the previous five years or the period of operation under NTPC,

whichever is lower. Accordingly, suitable provisions have been made in the final regulations.

Operational & Maintenance Expenses - Draft Regulation 18 (iv)(a) Coal-based and lignite-fired generating stations (Lignite - Fired Generating Stations)

117. NLC, which falls within the regulatory jurisdiction of the Commission, is operating Neyveli Lignite TPS-I having capacity of 600 MW (6x50MW + 3x100 MW) and TPS-II, having two stages – Stage I of 630 MW (3x210) and Stage II of 840 MW (4x210). Of this, TPS-I is dedicated exclusively to Tamil Nadu. Both the stages, that is, Stage I and Stage II of TPS-II are regional stations, supplying power to the beneficiaries of the Southern Region. NLC has not yet approached the Commission for fixing tariff for these stations. The Commission felt handicapped in fixing the norms for operation and maintenance expenses in respect of these stations as NLC did not make available the actual data of operation and maintenance expenses in response to the discussion paper.

118. As has been stated earlier, since TPS-I is dedicated to Tamil Nadu and no tariff petition has been filed so far by NLC for tariff fixation, the Commission did not propose any norms of operation and maintenance expenses for this generating station in the draft regulations. In so far as Stage I and Stage II of TPS-II are concerned, the Commission prescribed norms for operation and maintenance expenses with the assumption that there should not be much variation in the

operation and maintenance expenses of lignite-fired and coal-based units of the same size. This assumption is based on the consideration that on one hand lignite being a softer fuel poses lesser problems in terms of erosion, etc., but it poses additional problem involving increased volume of fuel as also the increased size of the boiler.

119. In response to the draft regulations, NLC hastened to submit data on actual expenditure for a period of four years (1999-2003) as under:

(Rs.in lakh/MW)

Year	TPS-II (St.-I) (3x210 MW)	TPS-II (St.-II) (4x210 MW)	TPS-I (6x50 MW+ 3x100 MW)
1999-00	7.78	7.83	10.86
2000-01	12.66	12.62	19.47
2001-02	9.21	9.19	14.11
2002-03	10.17	10.16	14.95

120. From operation and maintenance expenses data for TPS-I, it may be observed that there is an abnormal increase during the year 2000-01. We are given to understand that this was on account of employee wage revision. The expenditure during the subsequent years, that is, 2001-02 and 2002-03 makes it abundantly clear that expenses of 19.47 lakh per MW include arrears which would have been paid on account of wage revision. Similarly, when break up of the expenditure was looked into, it was found that the amount of bonus more than doubled in the year 2002-03 over the earlier years. Taking all these factors into consideration and finding out an average expenditure which when escalated reveals a figure of 15.20 lakh per MW for operation and maintenance during the year 2004-05.

However, it would be pertinent to point out that sufficient details have not been furnished by NLC to apply prudence check properly and thoroughly. Therefore, we have ordered to adopt, the following operation and maintenance expenses norms for TPS-I, in the final regulations:

(Rs. In lakh /MW)

Year	TPS-I
2004-05	15.20
2005-06	15.81
2006-07	16.44
2007-08	17.10
2008-09	17.78

121. This would be reviewed on yearly basis with reference to actuals, for which purpose NLC shall submit yearly details of O&M expenses latest by 30th September after the close of the financial year on 31st March.

122. In so far as the operation and maintenance expenses for TPS-II are concerned, it is observed that the norms proposed in the draft regulations match with the numbers that could be arrived at on the basis of actuals, which have now been furnished by NLC. Accordingly, operation and maintenance expenses norms as proposed for the 200/210/250 MW series in the draft regulation have been retained for the existing as well as new lignite fired generating stations.

123. Like TPS-I, no proper prudence check could be applied in case of TPS-II also. Therefore, the observations of the Commission in this regard are same as that made at para 121 above, which stipulates that the operation and maintenance expenses would be reviewed on yearly basis with reference to actuals, for which

purpose NLC would submit yearly details of O&M expenses of TPS-II Stage I and Stage II separately.

Operational & Maintenance Expenses - Draft Regulation 18 (iv)(b)
Gas-based and liquid fuel-based thermal power generating stations:

124. The following O & M expenses norms, for gas-based and liquid fuel-based thermal power stations, were laid down in the draft regulations:

(Rs. in lakh/MW)

Year	Gas-based and liquid fuel-based power generating stations other than small gas turbine power generating stations		Small gas turbine power generating stations
	With Warranty Spares of 10 years	Without any Warranty Spares	Without any Warranty Spares
2004-05	5.20	7.80	9.46
2005-06	5.41	8.11	9.84
2006-07	5.62	8.44	10.24
2007-08	5.85	8.77	10.65
2008-09	6.08	9.12	11.07

Note - A separate application could be made to claim abnormal operation and maintenance expenses over and above the allowable operation and maintenance expenses, to be computed in the manner indicated above.

125. NTPC has sought a provision of Rs.14 lakh per MW for the year 2004-05 as against Rs.5.20 lakh per MW for the stations where operational guarantee was provided and Rs.14.26 lakh per MW for other stations as against Rs.7.80 lakh per MW proposed. The operation and maintenance expenses norms were proposed for subsequent years with 4% escalation factor whereas NTPC seeks escalation at the rate of 10 % per annum.

126. GPEC, Tata Power and Torrent Power Ltd. have sought higher operation and maintenance expenses for new generating stations. Torrent Power has sought a minimum of 2.5% of the cost plus insurance at actuals.

127. NTPC has now estimated the impact of free warranty spares for 10 years on the project cost, based on list of warranty spares and their notional cost indicated in the supply contract of the OEM. Accordingly, the amount of spares included in the project cost for Anta, Auraiya, Dadri and Kawas worked out are as follows:

	(Rs. In Crore)
Anta	17.23
Auraiya	20.62
Dadri	25.75
Kawas	19.66

128. Based on this, NTPC has contended that average impact on project cost would be of the order of Rs. 3.3 lakh/MW and additional ROE on this would be of the order of Rs. 0.26 lakh/MW. The actual consumption of warranty spares, for the years 1995-96 to 2000-01 based on the notional value of spares furnished by NTPC in

tariff petitions for the period 2001-04 are as follows:

Name of the Plant (COD of GT-I) Capacity MW	**Capital Cost as on 1.4.2001 (Rs. In crore)**	**Cost of warrantee spares** (**Rs. In lakh**)							% of Capital Cost
		95-96	96-97	97-98	98-99	99-00	00-01	Total	
Anta GPS (4/89) 419.33 MW	451.67	4730	161	29	-	-	-	4920	10.89 %
Auraiya GPS (3/89) 663.6 MW	720.91	2034	1246	656	1236	979	-	6151	8.53%
Kawas GPS (6/92) 650.20 MW	1500.88	-	6814	1055	3151	9438	6394	26852	17.89 %
Dadri GPS (5/92) 829.78 MW	866.32	1625	2877	1078	20	2360	6558	14518	16.76 %
Gandhar GPS (3/95) 657.39 MW	2425.05	-	-	200.45	-	186.6	-	387	0.16%

129. The above values of spares are based on notional values of spares quoted by the OEM in the supply contract. The consumption of spares in case of Gandhar GPS is only Rs. 3.87 crore which is about 0.16% of the total capital base (on 1.4.2001). This is very low considering the consumption of spares in other gas power generating stations of NTPC. There is no uniformity of value of consumption of spares in Gandhar, Anta, Auraiya, Kawas and Dadri GPS. The capital cost of Gandhar GPS is quite high as compared to other gas-based projects of NTPC. It is, therefore, difficult to hold that the project cost quoted by the bidders would not

be including a substantial cost of warranty spares to be supplied free of cost over 10 years period. On this the generator would not only be getting ROE but also getting cost of such spares reimbursed by way of depreciation. In our view the beneficiaries should not be double - charged. In view of this, actual operation and maintenance expenses of these five stations after the warranty period is of no assistance to the Commission in arriving at fair operation and maintenance expenses. In the end, there appears to be no sufficient ground to revise the operation and maintenance expenses norms specified for the stations with supply of warranty spares free of cost for 10 years.

130. As regard the stations with no provisions of such warrantee spares supply free of cost for 10 years, the same was proposed by the Commission based on the current cost of gas-based /liquid fuel-based stations of Rs. 3 crore/MW at 2.5%. The cost of new gas-based project is suggested to be of the order of Rs. 3.5 crore /MW by Torrent Pvt. Ltd. It appears to be based on budgetary offer and not as per actual bids. NTPC has also indicated the project cost of Rs. 3.6 crore /MW for gas-based /liquid fuel-based generating station based on estimates. We are not inclined to accept these project cost figures. We feel that such a high cost close to coal-based projects with high cost of spares would make these plants unviable. Generators should be careful while deciding to go for such projects. The Commission may not allow such high cost in tariff. It has also been noted that the OEM are quoting exorbitant prices for spares after setting up of the station because the generator has no alternative as these spares cannot be arranged from any other source. In this situation there is no guarantee that spares cost

shall not be further escalated by the OEM if the regulators accept higher norms. The Commission would not like to pass on such unreasonable cost-rise to the beneficiaries and the ultimate consumer. This risk has to be borne by the generators themselves and they have to take careful decision in the choice of technology and its make. We feel that with the reduction in duty on spares there should be reduction in cost of spares. NTPC has not furnished actual operation and maintenance expenses for its Faridabad generating station, but has furnished the operation and maintenance expenses of Kayamkulam generating station for the years 2000-01 to 2002-03. It may not be appropriate for the Commission to be guided by the figures of only one station. However, for the existing projects of NTPC, namely Faridabad and Kayamkulam, we grant NTPC liberty to approach the Commission if there are abnormally high O&M expenses on account of spares. In view of above, we are not inclined to accept any change in the operation and maintenance expenses norms for the stations without any free supply of warrantee spares. In case of small gas turbine norms no objection has been raised. In view of this, we do not propose to change the norms already provided in the draft regulations and have decided to retain the same in the final regulations.

Interest on Working Capital – Draft Regulations 18 (v), 36 (v) and 54 (v)

131. Some of the beneficiaries have suggested deletion of interest on working capital from tariff due to the improved liquidity position as a result of the scheme of one time settlement of dues after the tripartite agreement. In our opinion, despite the tripartite agreement, the need for working capital cannot be obviated for the

reason that the tripartite agreement concerns the outstanding dues of the central power sector utilities. Therefore, the provision for working capital as an element of tariff has been retained.

132. For the purpose of interest on working capital, the draft regulations had listed its different components. It was pointed out that the secondary fuel oil was not provided as component of working capital in the case of coal-based or lignite-fired thermal generating stations. Historically, secondary fuel oil is an essential component of the working capital. It was an inadvertent omission in the draft regulations that a provision for secondary fuel oil was not incorporated. Nevertheless, it was included in the order dated 16.1.2004. Accordingly, a provision for secondary fuel oil has been made in the final regulations.

133. Maintenance spares @ 1% of the plant and equipment cost as on 1.4.2004 or the date of commercial operation, whichever is later; was proposed to be another component of the working capital. It is pointed out that the plant and equipment cost as on 1.4.2004 should imply the current capital cost of the plant and equipment. It has been argued that the maintenance spares when procured separately are very expensive and the spares are not available at the price at which they were procured along with the plant and equipment. Accordingly, it had been suggested to link the maintenance spares to 1% of the current capital cost or 1% of the historical capital cost duly indexed for inflation.

134. In the light of the above submission, we are inclined to agree to the proposal of the central power sector utilities. Therefore, a provision has been made for

maintenance spares @ 1% of the historical capital cost indexed at the rate of 6% per annum, which is the average rate. We do not consider it appropriate to link the indexation to actual inflation rates for the reason that different assets of the central power sector utilities are in different stages of their life cycles.

135. The central power sector utilities have also requested for inclusion of start up fuel for one month, fuel conditioners for one month as the components of working capital. We have considered the submission. Start up fuel is normally capitalised and hence not required to be provided for in the working capital.

136. It was proposed in the draft regulations to include receivables equivalent to two months of fixed and variable charges for sale of electricity calculated on target availability also as a component of working capital. The beneficiaries have represented that the receivables may be limited to a period of one month since a surcharge is levied beyond the period of one month. Traditionally, two months receivables have been considered as one of the components of working capital. This is on the premise that bills are raised at the end of one month and payment is made within one month thereafter. In addition, 2% rebate for payment through LC and 1% rebate if payment is made within 30 days is also provided. In view of this, we do not find sufficient justification to take a different view at this stage.

137. In the draft regulations, it was proposed that the rate of interest on working capital would be on normative basis. It would be equal to the short-term Prime Lending Rate of State Bank of India as on 1.4.2004 or on 1st April of the year in which the

generating station or the transmission system was declared under commercial operation, whichever was later. The interest on working capital was proposed to be payable on normative basis notwithstanding that the generating company has not taken working capital loan from any outside agency. It is next contended that the interest rate on working capital should be linked to SBI PLR minus appropriate spread and that payment of interest on working capital should be linked to actual borrowing.

138. We have carefully considered the issues. Since the entire working capital is based on norms, the interest on working capital is also fixed on normative basis by linking it to SBI PLR for short-term borrowings and accordingly no change is required. It is further observed that funds have alternative uses including deployment as equity by the utilities. The provision of SBI PLR linked to short - term borrowing in the existing scenario seems to meet the ends of justice as it is lower than the return on equity. It has been argued by many of the beneficiaries that the interest rate should be linked to short-term lending rate of PFC, which is lower than the SBI PLR. We have decided to benchmark the interest on working capital to the SBI short - term PLR in view of the fact that the lending from PFC may not be adequate to meet the requirements of the entire power sector and commercial borrowings may have to be resorted to.

Energy Charges – Draft Regulation 19

139. Minor discrepancies were found in the formulation provided in the draft regulations. These have been corrected and revised formulation, as under, provided in the final regulations:

(i) Generating stations covered under ABT

Energy (variable) Charges shall cover fuel costs and shall be worked out on the basis of ex-bus energy scheduled to be sent out from the generating station as per the following formula:

Energy Charges (Rs.) = (Rate of Energy Charges in Rs./kWh) x (Scheduled Energy (ex-bus) for the month in kWh corresponding to scheduled generation)

(ii) Generating stations other than those covered under ABT

Energy (variable) charges shall cover fuel costs and shall be worked out on the basis of ex-bus energy delivered / sent out from the generating station as per the following formula:

Energy Charges (Rs.) = (Rate of Energy Charges in Rs./kWh) x (Energy delivered (ex-bus) for the month in kWh)

Where,

Rate of Energy Charges (REC) for both items (i) & (ii) above shall be the sum of the cost of quantities of normative primary and secondary fuel for delivering ex-bus one kWh of electricity in Rs/kWh and shall be computed as under:

$$REC = \frac{100\{P_p \times (Q_p)_n + P_s \times (Q_s)_n\}}{(100-(AUX_n))} \quad (\text{Rs/kWh})$$

Where,

P_p = Price of primary fuel namely coal or lignite or gas or liquid fuel in Rs/Kg or Rs/cum or Rs./litre, as the case may be.

$(Q_p)_n$ = Quantity of primary fuel required for generation of one kWh of electricity at generator terminals in Kg or litre or cum, as the case may be, and shall be computed on the basis of normative Gross Station Heat Rate (less heat contributed by secondary fuel oil for coal/lignite based generating stations) and gross calorific value of coal/lignite or gas or liquid fuel as fired.

P_s = Price of Secondary fuel oil in Rs./ml,

$(Q_s)_n$ = Normative Quantity of Secondary fuel oil in ml/kWh.

AUX_n= Normative Auxiliary Energy Consumption as % of gross generation

Landed Cost of Coal – Draft Regulation 19 (iv)

140. In the draft regulations normative transit and handling losses of coal @ 0.3% for pit-head power stations and 0.8% for rail-fed power stations was proposed. Many state utilities and the Independent Power Producers have stated that the proposed

transit and handling losses were not adequate for their stations. The concern of various stakeholders, particularly that of the state utilities, appears to be that transit and handling losses in their cases if adopted by the respective State Commission would put them to considerable disadvantage. It is to be clarified that the Commission has specified norms for the utilities under its regulatory jurisdiction . It is not possible for the Commission to prescribe universal norms which could cover requirement of different state utilities. The State Commissions will have to prescribe norms as may be necessary and applicable to utilities under their regulatory jurisdiction. In view of this, we do not propose any change in the norms laid down in the draft regulations and have retained the same in the final regulations.

141. Torrent Pvt. Ltd. has urged payment of additional amount of fuel under "take or pay" obligation to be a “pass through” as it is beyond the ambit of the generator. As a principle, we feel that the fuel risk has to be borne by the generator as beneficiaries as well do not have control over fuel supplies. It is the generator who is in best position to handle this risk.

Incentive - Draft Regulation 20

142. In the draft Regulation, the following stipulation was made in regard to incentive payment:

“An incentive shall be payable at a flat rate of 25.0 paise/kWh for generation corresponding to scheduled generation in excess of generation corresponding to target plant load factor.”

143. It would appear that the extra energy on which the above incentive is to be paid at the specified rate is as metered on generator terminals. As we are already moving to ex-bus metering (for availability declaration, scheduling and UI accounting), it would be desirable to meter the energy for incentive purpose also on ex-bus basis. The stipulation under draft regulation 20, in respect of incentive has, therefore, been changed as under:

Incentive shall be payable at a rate of 25 paise per kWh for ex-bus energy corresponding to scheduled generation in excess of ex-bus energy corresponding to target plant load factor.

144. Further, in the present dispensation incentive is linked to PLF. The generators like NTPC, NLC have sought to link the incentive with availability and not to the PLF. According to them, generator can only ensure availability of the station whereas scheduled generation is dependent on demand by the customers. Linking incentive with PLF will amount to providing incentive to generators for action of purchasers. However, most of the beneficiaries are opposed to linking of incentive with availability.

145. The issue of linking the incentive to PLF or availability was not debated threadbare in the recent hearings and as such, we would like to continue with the existing dispensation of incentive based on PLF. The Commission may, however, like to

revisit the issue for a more informed debate after evaluating the experience of ABT. ABT has been implemented in all regions only recently. Some more time would be required for evaluating the experience. This should not be construed as regulatory uncertainty. Also, the issue is of much greater significance for the load centre and liquid fuel-based power stations, which may be required to back down regularly due to their higher variable cost. It would be prudent for the State Electricity Regulatory Commissions, in whose jurisdiction most of such power stations would fall, to examine this issue pragmatically.

Development Surcharge – Draft Regulations 21, 39 and 58

146. The draft regulations proposed levy of development surcharge on the beneficiaries at the rates of 5% of the capacity charges for thermal power generating stations, 5% of the capacity charges and primary energy charges for hydro power generating stations and 10% of the transmission charges for the transmission system. The draft regulations attached a number of conditions on the use of the development surcharge by the concerned utilities. The development surcharge was proposed to supplement the efforts for generation capacity additions of over 1,00,000 MW by the year 2012, along with matching requirements in the transmission sector. The Commission reiterates its earlier view that the entire investment needs could not be met through retained earnings or development surcharge as there was always a limit up to which an expansion programme could be supported by earnings from the existing capacity.

147. The central power sector utilities have sought exemption of income-tax on the development surcharge and have also pleaded for withdrawal or relaxation of the conditionalities proposed by the Commission on its use. It is also urged by some of them that instead of levying the development surcharge, the Commission should provide recovery of depreciation based on provisions of the Companies Act.

148. The beneficiaries have argued against levy of the development surcharge. According to the beneficiaries, the central power sector utilities should raise their requirements of funds through the capital market as the levy imposes additional burden on them, which they are unable to sustain. They have argued that with the enactment of the Act, thermal generation has been liberalised and de-licensed and accordingly the generating capacity additions could be achieved through sources other than the central power generating utilities. The changing scenario would imply that the off take from the central power sector utilities may vary in future depending upon the development of the sector through the sources outside the central power sector utilities. With the provision of open access in the transmission and distribution, they have further argued, it may be difficult to properly justify levy of the development surcharge. The question of competence of the Commission to levy the development surcharge in exercise of its powers to specify the terms and conditions of tariff has also been raised by some of the stakeholders.

149 The development surcharge was introduced by the Commission for the first time in its order of 21.12.2000 for the tariff period commencing on 1.4.2001. The Commission had considered the legal basis for levy of the development surcharge. It was only after proper consideration that the Commission had decided to impose the development surcharge. However, some of the beneficiaries have filed appeals/petitions against this decision of the Commission, which are presently pending before the Hon'ble High Court of Delhi. In view of the fact that a superior court is already in seisin of the question of jurisdiction of the Commission to order levy of the development surcharge as a part of tariff, we restrain ourselves from recording any opinion on the question.

150. The Commission in its order of 21.12.2000 had opined that the development surcharge should be exempt from levy of income-tax. Accordingly, the Commission took up the matter with the Central Government. However, the Central Government has not yet taken any decision on this recommendation made by the Commission. We find that the central power sector utilities are not enthusiastic about continuation of the development surcharge unless exempted from payment of income-tax and till such time the conditions imposed on the use are relaxed. The beneficiaries have also opposed the concept, though introduced with a laudable object. In view of the fact that the concept has not found general acceptance among the central power sector utilities and the state beneficiaries, its continuation is considered unnecessary. Further, as we have noted above, the

development surcharge had been provided for in order to support the future capacity addition programmes.

151. The Act lays emphasis on promotion of competition, promoting private investment, development of market, removal of subsidies, charging of electricity based on cost of services etc. In this changing environment, the Commission feels that the levy of development surcharge has lost its significance and, therefore, abandoned the proposal to levy the development surcharge for the tariff period commencing on 1.4.2004. The corresponding provisions have been omitted in the final regulations.

Declared Capacity & UI treatment for AG > DC - Draft Regulations 22 and 41

152. In the draft regulations, as per regulation 11 (xi), Declared Capacity or DC was defined to mean the capability of the generating station to deliver ex-bus electricity in MW declared by the generating company in relation to any period or time block duly taking into account the availability of fuel.

153. Draft regulation 22 (2) further provided:-

> *"In case the declaration of its capability by the generating station is on lower side and the actual generation is more than the declared capacity, UI charges due to the generating station on account of such extra generation shall be reduced to zero and the amount shall be credited towards UI account of beneficiaries in the ratio of their capacity share in the generating station."*

154. The explanation under the definition of Declared Capacity in the existing CERC notification dated 26.3.*2001* stating that *"the Declared Capacity shall not exceed*

the installed Capacity" had already been deleted in the draft regulation, thus removing any restriction in declaring generation capability by generator.

155. The generators have sought provision of a band of 2% to 5% for generation above DC, in which any excess generation should not get paralised. This has also been the subject matter of the petitions filed by NTPC and NLC for removal of difficulty under ABT. It has been stated that it is not possible to keep the generation constant, due to variation in operating conditions, free governor mode of operation etc. and generator has no control over such variation. The variation could be above schedule of generation (SG) as well as below SG. When schedule of generation is below DC, then generator gets paid at UI rate for extra generation up to DC. But when schedule of generation is equal to DC, then for any variation above SG, generator does not get any UI where as for variation below SG, generator has to pay UI, resulting in financial loss to them which is not fair. They have pleaded that such inadvertent variations should not be treated as gaming.

156. The provision in the draft regulation 22 (2) was basically to prevent gaming. POWERGRID has, however, submitted during the hearing that RLDCs are in a position to keep a check on any gaming on this account. The Commission has also come to the conclusion that if a generator under-declares, then such lower declaration shall reduce its schedule and the incentive and energy charge payable shall also be less due to less generation schedule. If on the other hand, the generator tends to over-declare then chances of his incurring UI charges increase. Further any variation due to frequency response has to follow the droop

characteristic of machine in FGMO and any unhealthy variation could easily be detected by RLDCs. POWERGRID/ RLDCs had also submitted that the Commission may allow a higher band in a time block of 15 minutes, say 2-5% above DC but limit it at 1% over a day. Any variation up to this limit should not be construed as gaming and UI should be allowed to the generator. In case of any variation beyond above limits, RLDCs should investigate and ensure that there is no gaming. In case gaming is found, no UI should be admissible to the generator. As such, the provision in the draft regulation 22(2) has been amended and incorporated in the final regulations as under:

(i) *"Any generation up to 105% of Declared Capacity in any time block of 15 minutes and averaging up to 101% of the average Declared Capacity over a day shall not be construed as gaming, and generator shall be entitled to UI charges for such excess generation above the scheduled generation (SG).*

(ii) *For any generation beyond the above prescribed limits, the Regional Load Despatch Centre shall investigate so as to ensure that there is no gaming and if gaming is found by the Regional Load Despatch Centre, the corresponding UI charges due to the generating station on account of such extra generation shall be reduced to zero and the amount shall be adjusted in UI account of beneficiaries, in the ratio of their capacity share in the generating station."*

157. Corresponding provision in case of hydro power generating stations has also been made and incorporated in the final regulations.

UI Rates - Draft Regulation 22

158. A ceiling rate of 600 paise/kWh is stipulated in draft regulation 22(1). While many of the beneficiaries have sought a reduction of the ceiling UI rate , PSEB has welcomed the move (i.e. a raise from 420 paise/kWh to 600 paise/kWh) during the

open hearing on 10.3.2004. For the reasons recorded in the order dated16.1.2004 which still remain valid, we are not inclined to make any change in the UI scheme as contained in regulation 22 (1) of the draft regulations.

159. Corresponding provision in the case of hydro power generating stations has also been made and incorporated in the final regulations.

Rebate - Draft Regulations 23, 42 and 59

160. In the draft regulations a rebate of 2% for payment through letter of credit was proposed. The reasons for proposing 2% rebate through the letter of credit have also been elaborated in the order dated 16.1.2004. Some of the beneficiaries have pleaded for rebate of 2.5% instead of 2% proposed in the draft regulations. We consider it all the more reasonable to link the rebate to the prevailing interest rates, which have been reduced considerably in the recent past. In view of this, no change to the proposal made in the draft regulations regarding rebate has been made.

Late Payment Surcharge – Draft Regulations 24, 43 and 60

161. Late Payment Surcharge has been proposed @ 1.5% per month in the draft regulations. Most of the beneficiaries have pleaded for charging of the Late Payment Surcharge @ 15% per annum as prescribed in the tripartite agreement. We are of the view that the Late Payment Surcharge is a penal provision and as such has got to be more stringent than the provisions regarding rebate. We have,

therefore, decided to levy the Late Payment Surcharge @ 1.25% per month. Even after this change, the Late Payment Surcharge is higher than the rebate.

Scheduling, Metering & Accounting - Draft Regulation 25

162. Stations such as Simhadri, Kayamkulam, Faridabad, Tanda and Talcher TPS which are contracted to supply power to the State in which they are situated, are despatched by the respective State Load Dispatch Centres (SLDCs) and not by RLDCs. This aspect was not clear in the draft regulations. Accordingly, following note to this effect has been added in the final regulations, under the head 'Scheduling' as well as under the head 'Metering and Accounting':

> *"In case of a generating station contracting to supply power only to the State in which it is located, the scheduling, metering and energy accounting shall be carried out by the respective State Load Dispatch Centre."*

Trading of un-requisitioned capacity by the generator - Draft Regulation 28(iii) and 47(iii)

163. The Commission in clauses (ii) and (iii) of the draft regulations 28(ii), has recognised the first right of beneficiaries on the allocated capacity under ABT since it is mandatory for the beneficiaries to bear the capacity charges irrespective of drawal by them. It has, however, come to our notice that beneficiaries are not requisitioning their allocated capacity fully and are also not allowing generators to market such un-requisitioned capacity, thereby preventing such capacity from

becoming available in the grid. It is apparent that the stipulation at para 5.7.4 in the Commission's order dated 4.1.2000 has not been sufficient.

164. Under the circumstances, NTPC has requested for allowing trading of such un-requisitioned capacity without any agreement with or permission from the beneficiaries. In order to ensure that such un-requisitioned capacity does not get blocked and becomes available in the grid, the Commission allows trading of such un-requisitioned capacity by the generators on interruptible basis. By this the Commission means that the generator's right to trade exists until the schedule is revised by the beneficiary with advance notice as per the scheduling provision in the regulations and IEGC and subject to fulfillment of other legal requirements. Accordingly, suitable provision has been incorporated in the final regulations.

165. The corresponding provision in the draft regulation 47 (iii) for hydro power generating stations has also been modified and incorporated in the final regulations

Maximum Available Capacity - Draft Regulation 29 (xviii)

166. In the draft regulations, Maximum Available Capacity for pondage and storage type generating stations was defined as :

> *" The maximum capacity in MW, the generating station can generate with all units running, under the prevailing conditions of water levels, flows and with 100% gate openings, over the peaking hours of next day."*

Some of the stakeholders have raised apprehensions with regard to the percentage of gate openings mentioned in the above definition of Maximum Available Capacity. It has been submitted that to achieve maximum output of the machine, including overloading allowed as per design gate opening will not necessarily correspond to 100%. Rather in many cases 100% gate opening could be injurious to the generating machine. Therefore, it is pleaded that the definition of Maximum Available Capacity needs to be reviewed and modified.

167. We have been informed that gate openings in respect of hydro power generating stations vary from plant to plant and have been prescribed at different percentage by the manufacturer of the turbine equipment so as to achieve the maximum generator output. Therefore, it is not mandatory to specify the particular gate opening percentage in the above definition. We have, therefore, modified the definition of Maximum Available Capacity as follows :

(a) Run-of-river power stations with pondage and storage type power stations

> *“ The maximum capacity in MW, the generating station can generate with all units running, under the prevailing conditions of water levels and flows, over the peaking hours of next day.”*

The peaking hours for this purpose shall not be less than 3 hours within a 24-hour period.

(b) Purely run-of-river power stations

“ The maximum capacity in MW, the generating station can generate with all units running, under the prevailing conditions of water levels and flows over the next day.”

Norms of Operation - Draft Regulation 30

168. Note below the draft regulation 30 (i) stipulates

> *" Full Capacity Charges shall be recoverable if the station achieves capacity index of 90% in case of purely run-of-river stations and capacity index of 85% for pondage and storage type generating stations. However, for the 1st year of operation of a newly commissioned hydro power generating station, normative capacity index shall be 85% for purely run-of-river and 80% for pondage or storage type hydro power generating station for recovery of full capacity charges".*

169. The above note is considered deficient to the extent that it does not provide for recovery of capacity charge at various levels of operation. To remove this deficiency, the note has been revised as under:

> *"There shall be pro rata recovery of capacity charges in case the generating station achieves capacity index below the prescribed normative levels. At Zero capacity index, no capacity charges shall be payable to the generating station"*

Sale of Infirm Power – Draft Regulation 33

170. The draft regulation 33 proposed that "any revenue earned by the generating company from sale of infirm power shall be taken as reduction in capital cost and shall not be treated as revenue". The hydro power generators, at the open hearing held on 10th March, 2004, pleaded that the rate of infirm power, prior to the

commissioning of the generating units of the station should be specified. They submitted that presently they had to negotiate the rate with beneficiaries each time a generating unit was put on trial runs prior to its commissioning which led to protracted negotiations each time, but could be avoided if the Commission prescribed a pre-determined rate. The utilities have proposed that the rate of infirm power may be fixed as the primary energy rate prevailing in the region from time to time. In due consideration of above submission, the provision has been amended as under and incorporated in the final regulations:

> *"Sale of Infirm Power: Any revenue earned by the generating company from sale of infirm power, shall be taken as reduction in capital cost and shall not be treated as revenue. The rate for infirm power shall be same as the primary energy rate of the generating station."*

Computation of Capacity Charges- Draft Regulation 35

171. The note under the draft regulation 35(i), read as under:

> *"When the capacity charge is negative, this amount shall be set to zero. The capacity charges shall be calculated on annual basis and shall be billed on monthly basis in Rs/kw/month in proportion to the allocated capacity."*

172. In case of an old hydro power generating station, a situation may arise when the primary energy charge becomes higher than the annual fixed charges and thus capacity charge would be a negative value. In such a scenario, to avoid recovery more than the annual fixed charges of the generating station in that year, the note has been amended to read as under:

> *"Recovery through primary energy charge shall not be more than annual fixed charge".*

Operation and Maintenance Expenses – Draft Regulation 36(iv) (Hydro Power Generating Stations)

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

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

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

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

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

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

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

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

175. We take note of the apprehension of the hydro power utilities that operation and maintenance cost of a hydro power generating station is site-specific and any two hydro power generating stations of same capacity may not have same operation and maintenance cost. Apart from this, remote location of the hydro power generating stations together with siltation problems encountered by most of them are subject to higher operation and maintenance cost. Thus, normative operation and maintenance expenses as proposed in the draft regulations may not be

adequate to maintain the operation and maintenance quality and may affect adversely the performance of hydro power generating stations. We have, therefore, decided that operation and maintenance expenses of hydro power generating stations shall be worked out in the following manner:

(a) The operation and maintenance expenses including insurance for the existing generating stations which have been in operation for 5 years or more in the base year of 2003-04 shall be derived on the basis of actual operation and maintenance expenses for the years 1998-99 to 2002-03, based on the audited balance sheets, excluding abnormal operation and maintenance expenses, after prudence check by the Commission.

(b) The average of actual operation and maintenance expenses for the years 1998-99 to 2002-03 considered as operation and maintenance expenses for the year 2000-01 shall be escalated at the rate of 4 percent per annum to arrive at the operation and maintenance expenses for the base year 2003-04.

(c) The operation and maintenance expenses for the base year 2003-04 shall be escalated further at the rate of 4 percent per annum to arrive at permissible operation and maintenance expenses for the relevant year.

(d) In case of new hydro power generating stations, which have not been in existence for a period of five years, the operation and maintenance expenses shall be fixed at 1.5 per cent of the capital cost as admitted by the Commission in the year of commissioning and shall be escalated at the rate of 4 percent per annum from the subsequent year to arrive at the operation and maintenance expenses for the base year 2003-04. The base operation and maintenance expenses shall be further escalated at the rate of 4 percent per annum to arrive at permissible operation and maintenance expenses for the relevant year.

176. For the generating stations commissioned during the tariff period (2004-05 to 2008-09), the base operation and maintenance expenses shall be fixed at 1.5 percent of the actual capital cost as admitted by the Commission in the year of commissioning and shall be subject to an annual escalation of 4 percent per annum for the subsequent years.

Primary Energy Rate – Note below Draft Regulation 37

177. In the note below the draft regulation 37, the rate of primary energy in the North-Eastern region was proposed as 90% of the lowest variable charge of the central sector thermal power generating stations of the Eastern Region plus transmission charges (Paise/kWh) of the Eastern Region.

178. It is noted that the primary energy rate in other regions, except for pumped storage generating stations, was 90% of the lowest variable charges of the central sector thermal power station of that region. The transmission charges were not added in other regions as was proposed for North-Eastern Region. The reasons for this peculiarity have been discussed in detail in the Commission's order dated 11.4.2002 in petition No.87/2001 of Ranganadi H.E. project of NEEPCO.

179. At the open hearing held on 10th March, 2004 the representative of Department of Power, Govt of Tripura pleaded that after implementation of ABT in North-Eastern Region, the two-part tariff is in force. In the two-part tariff, the lowest variable charge (i.e. energy charge) of central sector power stations in North-Eastern Region is based on Assam Gas-Based Power Station of NEEPCO. The energy charge of AGBPP during 2003-04 was 40.53 paise/kWh as approved by the Commission vide order dated 10.10.2003 in Petition No. 33/2003. Thus, the primary energy rate of hydro power generating stations in the region based on 90% of the lowest variable charge of central sector thermal stations of the region, works out to 36.48 paise/ kWh, which is much lower than the rate of 50.32 paise/kWh allowed by the Commission for Kopili HEP for the year 2001-02, based on the lowest variable charge of the thermal stations in the Eastern Region and transmission charges of the Eastern Region .

180. In view of the submission of the representative of Tripura State, we feel that working out the primary energy rate for hydro power generating stations in North-

Eastern Region based on the 90% of the lowest variable charge of the thermal stations in the Eastern Region and adding to it the transmission charges of the Eastern Region are no more relevant after implementation of ABT in North-Eastern Region. Therefore, the rate of primary energy for all hydro power generating stations, except for pumped storage generating stations, shall be taken as the lowest variable charge of central sector thermal power stations of North-Eastern Region. In view of this, the note below the draft regulation 37 has been deleted.

Primary Energy Charge – Draft Regulation 37 (2) and (3)

181. As per the draft regulation 37 (2), primary energy charge is to be computed as follows:

Primary Energy Charge = Saleable Primary Energy (Ex-bus)
x Primary Energy Rate/(1-r)

182. During the open hearing held on 10th March, 2004, it was pointed out that as per the draft regulations, the primary energy rate for all hydro power generating stations, except for pumped storage generating stations, has been taken as 90% of the lowest variable charge of the central sector thermal power generating stations of the concerned region and primary energy charge is computed based on the above formula. However, in the above formula if the primary energy rate is divided by (1-r), where r represents 12% free energy to the home state as per

policy of the Central Government, the actual primary energy rate would become more than the lowest variable charge of the region. Thus, it was suggested, the proposal made in the draft regulations needed a fresh look.

183. We concur with the views expressed and, therefore, the draft regulation 37 (2) and (3) dealing with the rate of primary energy and secondary energy has been modified as under and incorporated in the final regulations:

> *"(2) Rate of primary energy for all hydro electric power generating stations, except for pumped storage generating stations, shall be equal to the lowest variable charges of the central sector thermal power generating station of the concerned region. The primary energy charge shall be computed based on the primary energy rate and saleable energy of the station.*
>
> *Provided that in case the primary energy charge recoverable by applying he above primary energy rate exceeds the Annual Fixed Charge of a generating station, the primary energy rate for such generating station shall be calculated by the following formula:*
>
> $$\text{Primary energy rate} = \frac{\text{Annual Fixed Charge}}{\text{Saleable Primary Energy}}$$
>
> *(3) Primary Energy Charge = Saleable Primary Energy x Primary Energy Rate*
>
> *Secondary Energy Rate shall be equal to Primary Energy Rate.*
> *Secondary Energy Charge = Saleable Secondary Energy x Secondary Energy Rate."*

Incentive/disincentive – Draft Regulation 38(i)

184. It was proposed that the incentive, in the case of hydro power generating stations, would be payable when capacity index exceeded the normative capacity index of

90% for purely run-of-river type hydro power generating stations and 85% for pondage or storage type hydro power generating stations. It was further provided that incentive would accrue up to a maximum capacity index of 100%. When capacity index achieved was less than the normative value, disincentive would be deducted from the annual fixed charges paid or payable on pro rata basis of the capacity index value. The last sentence of this regulation, that is, "when capacity index achieved is less than the normative value, disincentive shall be deducted from the Annual Fixed Charge paid or payable to the generating company on pro-rata basis of the capacity index value", becomes redundant in view of modifications carried out in the draft regulation 30 as discussed above. The provision has, therefore, been modified as under:

> *"Incentive shall be payable in case of all the generating stations, including in case of new generating stations in the first year of operation, when the capacity index (CI) exceeds 90% for purely run-of-river power generating stations and 85% for run-of-river power station with pondage or storage type power generating stations and incentive shall accrue up to a maximum capacity index of 100%."*

Date of Commercial Operation or COD – Draft Regulation 48 (ix)

185. The draft regulation proposed that the date of commercial operation would not be a date prior to the scheduled date of commercial operation mentioned in the transmission service agreement unless mutually agreed to by all the parties.

186. POWERGRID has pointed out that BPTA is required to be signed before the investment approval. Therefore, it may not be possible to stipulate the date of commercial operation in the BPTA/TSA. During the period between the Standing

Committee clearance and final project approval, there may be change in scope of work and revision in the project completion schedule. Therefore, the project completion schedule as contained in the project approval document, should be taken as reference.

187. We agree that the scheduled date of commercial operation should be as mentioned in the investment approval in case of projects executed by POWERGRID. However, for other licensees, the reference to the scheduled date of commercial operation has to be drawn from the Implementation Agreement/ Transmission Service Agreement. In view of this, the proviso to the definition of date of commercial operation has been amended as under and incorporated in the final regulations:

> *"Provided that the date of commercial operation shall not be a date prior to the scheduled date of commercial operation mentioned in the Implementation Agreement or the Transmission Service Agreement or the investment approval, as the case may be, unless mutually agreed to by all parties."*

Auxiliary Power Consumption in the sub-station – Draft Regulation 49 (i) (b)

188. It was proposed in the draft regulations that if Central Government made appropriate allocation for auxiliary energy consumption for HVDC sub-stations, the variable charges would be included in operation and maintenance charges and fixed charges for the same would be borne by the beneficiaries of the region in case of intra-regional assets and by the beneficiaries of connected region in case of inter-regional assets.

189. POWERGRID has objected to recovery of fixed charges for the allocated power to meet auxiliary consumption for HVDC sub-stations from beneficiaries of both the regions. It has stated that it would be difficult and cumbersome for central generating station to recover the charges from the beneficiaries of the other regions to whom there is no allocation.

190. BSEB has expressed that auxiliary consumption in HVDC stations is very less (500 KVA) and hence it is practically difficult to allocate share for the same from ISGS. In view of this, BSEB has suggested that the auxiliary consumption may be treated as supply from SEB/DISCOM in whose area HVDC station is situated and the same should be recovered as operation and maintenance expenses by the POWERGRID.

191. In view of the above discussion, we are in the agreement with the suggestion of BSEB that the capacity charges as well as energy charges for the allocation to meet auxiliary energy consumption in HVDC station should be paid for by the transmission licensees as part of operation and maintenance expenses.

192. In a strict sense, the proposal in the draft regulations was not an operational norm as it only stipulated method of recovery of charges for auxiliary consumption. Therefore, the heading of operational norm has been omitted over this provision.

Target Availability – Draft Regulation 49 (ii)

193. The draft regulation proposed the target availability of 98% for recovery of full transmission charges.

194. POWERGRID has stated that as per Annual Maintenance Programme (AMP) schedule, minimum 168 hours of preventive maintenance is required for HVDC sub-stations which brings down the availability to 98.08%. Similarly, considering the duration of preventive maintenance of other systems as per AMP, the availability of regional transmission system will be much less than 98%. POWERGRID has proposed that:

(i) Normative availability may be considered as 95% for threshold for incentive, or

(ii) Normative availability of 97% may be considered for AC lines. However, the disincentive threshold may be kept at 95%. For HVDC system including HVDC lines, the incentive may be payable above 95% availability @ 1% of the equity for every 1% rise in availability.

195. POWERGRID has further contended that transmission lines, especially older ones like Singrauli and Rihand transmission system, are subjected to much higher fog and environmental pollution than for which they are planned and designed. With the increase in environmental pollution level, the need for maintenance of transmission lines like frequent cleaning of insulator is increasing. Therefore, the target availability of 98% should not include time for scheduled maintenance. It

has also suggested that the regulation should appropriately include factor of aging while fixing the target availability.

196. Power Links Transmission Ltd. has contended that size of POWERGRID net work is in far excess of the size of the network, which will be owned by JVC/IPTC. Therefore, the target availability should be reduced to 95%. Shri P Rajamani has suggested that instead of calculating availability for the whole system, minimum availability should be stipulated for each section.

197. The Commission in its order dated 16.1.2004 had rejected the request for separate treatment of HVDC assets. The Commission had taken a view that the target availability of 98% had been fixed based on actual availability of regional transmission system for the past period which takes into account availability of HVDC as well as AC assets and if a separate lower target availability for HVDC was to be specified, the target availability for HVAC assets would have to be enhanced. The Commission had also anticipated that this procedure would be more cumbersome without the corresponding benefits. More importantly, POWERGRID had not submitted any factual details to substantiate its claim for lower availability for HVDC system. However, POWERGRID vide its letter dated 16.3.2004 have, *inter alia*, submitted details of availability for HVDC back-to-back station as well as HVDC links. The analysis of the data submitted by

POWERGRID is given below:

Region/Project	Year						Average Availability	Capacity (MW)
	1997-98	1998-99	1999-00	2000-01	2001-02	2002-03		
Northern Region								
Vindhyachal HVDC BTB	96.91	98.36	98.21	97.24	99.13	97.69	97.92	500
Rihand-Dadri HVDC link	87.16	94.57	95.24	81.35	90.99	87.34	89.44	1500
Western Region								
Chandrapur HVDC BTB	95.23	98.85	97.41	99.1	99.87	96.41	97.81	1000
Southern Region								
Gajuwaka HVDC BTB				98.95	98.98	90.04	95.99	500
Total								3500

Wt Average Availability = 93.98

Note: Data for those years has been considered when the system is in operation for full year after the date of commercial operation (COD).

198. We have noted that actual availability for HVDC assets is of the order of 94%. This is a matter of concern, particularly in view of the submission made by the POWERGRID that as per recommended AMP, the scheduled outage corresponds to non-availability of 1.92% only. HVDC assets have been created with massive investment and if the inter-regional links with HVDC back-to-back station and HVDC links are not available as per expectations, such investment remains under-utilised. In view of this, we have decided that the target availability for HVDC assets shall be 95%. According to report of the expert committee constituted by the Central Government to suggest framework to facilitate private investment in transmission projects, which submitted its report in 1997, the experience of SEBs

and POWERGRID indicate that on an average three outages, each of eight hour duration in a year, are sufficient for carrying out maintenance of a EHV sub-station and line. We are, therefore, not inclined to lower target availability for AC system from the proposed level of 98% in view of the past performance of the POWERGRID system as also the requirement of scheduled outage of only about 0.27% for AC system.

199. As already mentioned, in the order dated 16.1.2004 it was stated that if the target availability for HVDC system was reduced, the target availability for AC system would have to be enhanced. However, the calculations for the year 2000-01 for the Northern Region show that if the target availability for HVDC system (4 elements) and AC systems (144 elements) is fixed at 95% and 98% respectively, the overall availability works out to 97.92%. Thus, the impact of specifying a separate availability of 95% for HVDC systems is negligible on the overall availability.

200. In order to discourage continued operation without having regard to preventive maintenance, it was proposed in the draft regulations that no incentive shall be payable above the availability of 99.75%. This shall continue for AC system. On the same lines, no incentive shall be payable for HVDC assets beyond the target availability of 98.5%.

201. The procedure for calculation of the transmission system availability enclosed as Appendix –III of the draft regulations has been modified in view of the separate target availability for AC and HVDC systems.

Operation and Maintenance Expenses – Draft Regulation 54 (iv)

202. In the draft regulations, operation and maintenance expenses per ckt-km of line length and per bay for the Western Region as allowed in the tariff period 2001-03 were used as the benchmark. However, the values for normative operation and maintenance expenses for the year 2000-01 were escalated @ 4% to reach a value for the year 2003-04 as the actual escalation was of the order of 4% during these years. The Commission had also allowed a "catch-up period" of 4 years (from 2003-04 to 2007-08) for Eastern, Southern and Northern Region to achieve this benchmark with escalation of 4%.

203. POWERGRID has stated that it is not possible to plan transmission system with higher redundancy due to resource constraints. This calls for adoption of modern technology to maintain the assets to enhance their availability. Therefore, more liberal approach needs to be adopted for operation and maintenance expenditure. POWERGRID has also objected to equalization of normative operation and maintenance expenses in all the regions. In its opinion, the normative operation and maintenance expenses can never be equal in the different regions due to-

   (i) Different network configuration (No. of sub-stations and MVA capacity vis-à-vis circuit kilometers) and aging of the transmission lines.

   (ii) Geographical reasons.

204. POWERGRID has stated that such equalization is unfair to POWERGRID since employee-cost constitutes 60% of the total operation and maintenance cost which

is beyond its control. In view of the above, POWERGRID has suggested that 3 or 5 years moving average along with normal escalation may be adopted to set norms for operation and maintenance expenses on regional basis. Alternatively, operation and maintenance norms may be derived on national basis taking weighted average of all the regions. It has also requested for notification of O&M norms for North-Eastern Region.

205. POWERGRID in affidavit dated 30.1.2004, has stated that separate O&M norms for transmission elements like HVDC converter station, bi-pole, FSC, TCSC, Series Reactor have not been given. In its opinion, O&M expenses for these elements should be based on actuals to encourage adoption of new technology.

206. According to Powerlinks Transmission Ltd (PTL), the earlier stipulation of O&M expenses equal to 1.5% of the capital cost was just sufficient to meet the actual O&M expenses. However, the same has been proposed to be reduced substantially in the draft regulations. PTL has cited the example of Tala-Transmission System with 2343 kms as length and Rs.1220 crore as cost. As per earlier norms, O&M expenses work out to Rs.18.3 crore i.e. Rs 0.781 lakh per ckt km as against Rs.0.346 lakh per ckt km for the year 2004-05. Further, the lenders insist for insurance during operation which causes an additional burden. Hence, PTL has suggested that O&M expenses should be 1.5% and 2% of capital cost for all new projects for plain and hilly terrain respectively. If not, the additional cost of insurance should be included in the tariff.

207. TNEB has observed that the proposed norms for O&M expenses per ckt-km and per bay are based on the norms approved by the Commission for the current tariff period 2001-04. TNEB has contended that O&M expenses allowed by the Commission are on higher side and work out to more than 150% of O&M expenses allowed by the Central Government in 2000-01 and are more than the rate allowed for thermal generating equipment with rotating parts.

208. PSEB has suggested that O&M expenses should be kept at 1.5% of the capital cost.

209. DVC has suggested that initially average actual expenses per ckt. km and per bay should be used with a gradual switch over to normative basis. DVC has contended that it has large number of pensioners and this liability should be considered while deciding normative O&M expenses.

210. GRIDCO has observed that two sets of O&M norms have been suggested, one for POWERGRID lines and other for lines owned by other licensees and these norms converge in the year 2008-09. GRIDCO has contended that this will encourage inefficient operation in POWERGRID system. It has, therefore, suggested that only one norm should be adopted with a view to encourage efficiency. It has further submitted that separate norms for separate category of transmission lines, that is, 132 KV, 220 KV, 400 KV and S/C, D/C may be prescribed.

211. GEB has requested that CTU should provide computation on the impact on each of the beneficiary State so as to enable it to assess the impact of such a revision.

212. Before proceeding further on the issue of O&M expenses, we would like to point that while arriving at per ckt-km and per bay norms for different regions during the tariff period 2001-04, the total O&M expenses in the region were divided in the ratio of 70:30 for transmission lines and sub-stations, respectively. We feel that application of ratio of 70:30 for all the regions needs review as different regions have different proportion of lines and sub-stations. Such segregation results in inconsistent values of O&M expenses per ckt-km and per bay for different regions. We are of the opinion that in the absence of separate booking of O&M expenses for sub-stations and lines, the ratio of employees deployed for maintenance of sub-stations and lines can be used for such segregation.

213. Subsequent to open hearing on 9th and 10th March 2004, we have collected information about the employees' deployment for the operation and maintenance of sub-stations and lines from POWERGRID, which is tabulated below:

S.No.	**Region**	**% of employees deployed for**	
		Sub-station	**Transmission lines**
1.	Northern	67	33
2.	Western	58	42
3.	Southern	72	28
4.	Eastern	74	26

214. POWERGRID has also submitted data on O&M expenses for the years 2000-01, 2001-02 and 2002-03 vide its letter dated 16th March 2004 after deducting the

items disallowed by the Commission for the tariff period 2001-04 such as incentive, ex-*gratia*, donation, provision, bad debt written off, arrears for pay revision prior to 31.3.2000 (already included in the last tariff period) and abnormal security expenses. Based on these O&M expenses, details of line length and bays during various years submitted by POWERGRID vide letter dated 19.03.2004 and by applying the ratio tabulated above, the calculation of per ckt-km and per bay for various regions for the last 5 years are given below:

Northern Region

(Rs in lakh)

Items	1998-99	1999-2000	2000-01	2001-02	2002-03
OM (Normal O&M expenses)	6569.44	7038.24	9914.27	9946.07	10946.15
OML (O&M for lines)= 0.33 X OM	2167.92	2322.62	3271.71	3282.20	3612.23
OMS (O&M for substation) = 0.67XOM	4401.52	4715.62	6642.56	6663.87	7333.92
LL (Average line length in the Region)	10690.72	11672.09	12938.14	13475.65	13634.72
BN (Average number of bays in the Region)	184.0	200.5	231.5	251.0	262.5
AVOMLL(OML/LL)	0.203	0.199	0.253	0.244	0.265
AVOMBN(OMS/BN)	23.921	23.519	28.694	26.549	27.939

Western Region

(Rs in lakh)

Items	1998-99	1999-2000	2000-01	2001-02	2002-03
OM (Normal O&M expenses)	3136.76	3905.44	5313.95	4330.79	4389.52
OML (O&M for lines)= 0.42 X OM	1317.44	1640.28	2231.86	1818.93	1843.60
OMS (O&M for substation) = 0.58XOM	1819.32	2265.15	3082.09	2511.86	2545.92
LL (Average line length in the Region)	7674.50	8424.50	9180.00	9192.00	9342.00
BN (Average number of bays in the Region)	101.5	109.5	119.0	121.0	127.5
AVOMLL(OML/LL)	0.17	0.19	0.24	0.20	0.20
AVOMBN(OMS/BN)	17.92	20.69	25.90	20.76	19.97

Southern Region

(Rs in lakh)

Items	1998-99	1999-2000	2000-01	2001-02	2002-03
OM (Normal O&M expenses)	3724.36	4701.71	5512.63	4222.01	6211.18
OML (O&M for lines)= 0.28 X OM	1042.82	1316.48	1543.54	1182.16	1739.13
OMS (O&M for substation) = 0.72X OM	2681.54	3385.23	3969.09	3039.85	4472.05
LL (Average line length in the Region)	6112.71	6518.88	6847.04	6884.30	9088.01
BN (Average number of bays in the Region)	78.0	93.0	106.0	106.5	149.0
AVOMLL(OML/LL)	0.17	0.20	0.23	0.17	0.19
AVOMBN(OMS/BN)	34.38	36.40	37.44	28.54	30.01

Eastern Region

(Rs in lakh)

Items	1998-99	1999-2000	2000-01	2001-02	2002-03
OM (Normal O&M expenses)	4236.53	4347.00	4956.41	4205.92	4404.14
OML (O&M for lines)= 0.26 X OM	1101.50	1130.22	1288.67	1093.54	1145.08
OMS (O&M for substation) = 0.74X OM	3135.03	3216.78	3667.74	3112.38	3259.06
LL (Average line length in the Region)	4574.20	4708.70	4754.35	5028.00	5508.50
BN (Average number of bays in the Region)	91.0	92.5	93.0	95.0	120.5
AVOMLL(OML/LL)	0.24	0.24	0.27	0.22	0.21
AVOMBN(OMS/BN)	34.45	34.78	39.44	32.76	27.05

215. The values of O&M expenses per ckt-km and per bay so obtained for different regions have been escalated @4% per annum to bring them at 2002-03 price level. These values are tabulated below:

O&M expenses in Rs in lakh per ckt-km at the 2002-03 price level

Year	SR	NR	WR	ER
1998-99	0.199	0.237	0.199	0.281
99-2000	0.225	0.224	0.214	0.270
2000-01	0.249	0.274	0.260	0.292
2001-02	0.177	0.254	0.208	0.229
2002-03	0.190	0.265	0.200	0.210

O&M expenses in Rs in lakh per bay at the 2002-03 price level

Year	SR	NR	WR	ER
1998-99	37.40	27.98	20.96	40.30
99-2000	38.67	26.46	23.27	39.12
2000-01	40.50	31.04	28.01	42.66
2001-02	29.68	27.61	21.59	34.07
2002-03	30.01	27.94	19.97	27.05

216. On the reconsideration of the issue, we are of the opinion that single value of O&M expenses per ckt-km and per bay can and should be specified as norms for all the regions. Arithmetic mean of various values will not yield appropriate norms in view of the widely scattered values as may be seen from table above. This is so because arithmetic mean gets affected by extreme values. To take care of this problem, we have decided to use "mode", which is another measure of central tendency, to arrive at the norm. Mode is “the value occurring most frequently in a

series (or group) of items and around which the other items are distributed most densely". The above values of O&M expenses per ckt-km are converted into following frequency distribution for calculation of mode:

Frequency distribution of O&M expenses per ckt-km at 2002-03 Price level

Class		Frequency
Lower Limit	Upper Limit	
0.17	0.20	5
0.20	0.23	6
0.23	0.26	4
0.26	0.29	4
0.29	0.32	1

217. The mode is calculated as per following formula:

Mode = L + {C* d1/(d1+d2)}

Where L = Lower limit of modal frequency
C= Class interval
d1 = Difference in frequency of modal class and the preceding class
d2 = Difference in frequency of modal class and the succeeding class

It may be seen from the above table that modal class is 0.20-0.23 having highest frequency of 6.
Therefore L= 0.20, C= 0.03, d1= 1, d2=2
and mode = 0.21

Similarly, the frequency distribution for O&M expenses per bay at the 2002-03 price level is as under:

Frequency distribution of O&M expenses per bay

at 2002-03 Price level

Class		Frequency
Lower Limit	Upper Limit	
19	24	4
24	29	6
29	34	3
34	39	3
39	44	4

In this case L= 24, C= 5, d1= 2, d2= 3 and

Mode = 26

Therefore, the norms at the 2002-03 price level for these four regions would be Rs.0.21 lakh per ckt-km and Rs 26 lakh per bay. These values when escalated @ 4% per annum yield following yearly norms:

Norms for O&M expenses per bay and per ckt-km

	Year				
	2004-05	2005-06	2006-07	2007-08	2008-09
O&M expenses (Rs in lakh per ckt-km)	0.227	0.236	0.246	0.255	0.266
O&M expenses (Rs in lakh per bay)	28.12	29.25	30.42	31.63	32.90

218. One may get impression that adoption of single norm may result in higher payment by transmission customers of some regions while it may result in reduction of

charges for some other regions. However, this is not necessarily true as for all the regions the actual values of O&M expenses per ckt-km and per bay (at 2002-03 price level) have been more than the respective norm for O&M expenses at least for one year out of the five years. Further, increase in O&M expenses for some regions due to adoption of a single norm may be justified as POWERGRID may redistribute resources among various regions as well as in the various activities (construction/ O&M) to arrive at their optimal distribution. These norms can, however, straightway be applied to other inter-State transmission licensees. In so far as the higher O&M expenses for adoption of newer technology as sought by POWERGRID, the Commission may consider the same on case to case basis, if approached with proper justification. The Commission has departed from the capital cost based norms for O&M expenses in the tariff period 2001-04 with ample justification and therefore we are not inclined to go back to the same as sought by PTL and PSEB. The example given by PTL is not valid simply because the earlier norm of O&M expenses (as 1.5% of the capital cost) was suitable for a large transmission system having mix of sub-stations and transmission lines. But, O&M expenses in case of transmission system comprising only of transmission lines is expected to be much less as most of the equipment are located in sub-stations. We are not inclined to agree to the suggestion of PTL that insurance should be payable separately. The private entrepreneurs are expected to achieve higher efficiency in operation so that they can meet the additional expenditure on account of insurance. We make it clear that we have prescribed norms based on POWERGRID's expenses, which operates the network at 220 KV, 400 KV and at

HVDC level. These norms, therefore, may have to be suitably moderated when being applied to other transmission networks operating at lower voltage levels.

219. In so far as norm for North - Eastern Region is concerned, the subject matter has already been dealt in the order dated 16.1.2004. There would be no change in this position till norms are prescribed for this region.

Payment of Transmission Charges – Draft Regulation 55

220. The draft regulations proposed as under:

> *"Full annual transmission charges shall be recoverable at 98 percent target availability. Payment of transmission charge below 98 percent shall be on pro-rata basis. The transmission charge shall be calculated on monthly basis. In case of more than one beneficiaries of the transmission system, the monthly transmission charges leviable on each beneficiary shall be computed as per the following formula.*

$$\text{Transmission Charges} = \frac{\mathbf{TC}}{\mathbf{12}} \times \frac{\mathbf{MB}}{\mathbf{MS}}$$

Where TC = Annual Transmission Charges payable by the beneficiaries.

MB = Capacity allocation from Central sector generating stations to each beneficiary individually plus contracted power.

MS = Total Capacity from Central sector generating stations plus total contracted power. "

221. In the above, it would be seen that two aspects have been dealt with. One is the computation of transmission charges and the other is its sharing. We feel that for sake of clarity, the two need to be handled separately. Accordingly, we have

provided separately for payment of transmission charges and sharing of charges for intra-regional assets.

222. However, in accordance with the Commission's notification dated 30th January 2004 on open access in transmission system, the long-term customers are required to share only balance transmission charges after accounting for recovery from the short-term transmission customers. Further, the formula in the existing notification does not make it clear that transmission charges for all the intra-regional projects are to be pooled and such pooled charges are to be shared by the long-term customers. In view of this, the revised formula for sharing of transmission charges shall be as under:

Transmission Charges for intra-regional system payable for a month by a long-term transmission customer of that transmission system

$$= \left(\sum_{i=1}^{n} \left(\frac{TCi}{12} \right) - TRSC \right) X \frac{CL}{SCL}$$

Where

TCi = Annual Transmission Charges for the i^{th} project in the region.

n = Number of projects in the region

TRSC = Total recovery of transmission charges from Short-term transmission customers for the regional transmission system in accordance with the Central Electricity Regulatory Commission (Open Access in Inter-State Transmission) Regulations, 2004.

CL = Allotted Transmission Capacity to the long-term transmission customer

SCL = Sum of the Allotted Transmission Capacities to all the long-term transmission customers of the regional transmission system.

Incentives – Draft Regulation 56

223. The draft regulations did not propose any change in the provision for incentive contained in the notification dated 26.03.2001, which stipulates a slab system for availability-based incentive. The incentive is 1% of the equity for every 0.5% rise in the availability above 98% (except for the target availability in the range of 99.51 to 99.75% for which incentive @1% of equity has been allowed).

224. We have noticed one particular problem in the existing slab-based system of incentives - it leads to sudden jump in the incentive at the boundary of the slabs even though the boundary points are not milestones in terms of degree of difficulty in achieving the availability. To alleviate this problem, we have directed implementation of a continuous linear incentive regime. The rate of incentive shall be *pro rata* to the full transmission charges above the target availability of 98% for AC system and 95% for HVDC system. The formula for calculation of incentive shall be as under:

Incentive = [Annual Transmission Charges] x
[Annual Availability Achieved – Target Availability] /
Target Availability

Where

Annual Transmission Charges shall correspond to the intra-regional assets or for a particular inter-regional asset, as the case may be.

As directed earlier, incentive shall not be payable above 99.75% for AC system and above 98.5% for HVDC system.

Sharing of transmission charges for inter-regional assets including HVDC system by the beneficiaries - Draft Regulation 57

225. The draft regulation proposed that the transmission charges for inter-regional assets should be shared in the ratio of 50:50 by the two contiguous regions. It further proposed that these transmission charges would be recovered from the beneficiaries by pooling 50% of transmission charges for such inter-regional assets with the transmission charges for transmission system of the respective region for facilitating further recovery from various beneficiaries within that region.

226. WBSEB has expressed that the charges for inter-regional lines should be pooled with the charges for regional assets for their recovery.

227. POWERGRID has stated that sharing of charges in 50:50 ratio, may not be justified and fair in case of development of dedicated inter-regional transmission system. It has cited the example of Eastern Region and contended that further development of power projects in the Eastern Region for supplying power to beneficiaries in other regions would burden Eastern Region constituents who would not be availing any benefit from such projects. In case of inter-regional assets, which are not dedicated and where bi-directional flow of power is expected, there should be

commitment of sharing of 50:50 charges by contiguous regions. However, for the actual transfer of power the importing region should compensate the exporting region to the extent of utilisation by way of paying wheeling charges.

228. BSEB has suggested that 50% of the transmission charges for inter-regional assets should be borne by all the beneficiaries of central sector power stations in Eastern Region.

229. KSEB has sought more clarity in the provision relating to sharing of transmission charges for inter-regional assets. It has suggested that only those beneficiaries who actually utilise the system out of the geographical area of the region need to share the charges.

230. We believe that charges for inter-regional assets should be shared by the beneficiaries within the two connected regions only. Our interpretation of the provisions in the draft regulations as well as in the notification dated 26th March, 2001 was to this effect only. However, we have noted that due to semantic confusion, this provision may be interpreted differently. This aspect has, therefore, been clarified by inserting mathematical formulation in the notification as given below :

Transmission Charges payable for a month by a long term-customer within the region for the inter-regional assets connected to that region

$$= 0.5 \times \left\{ \frac{TCj}{12} - RSCj \right\} \times \frac{CL}{SCL}$$

Where

TCj = Annual Transmission Charges for the particular inter-regional asset connected to the region.

RSCj = Recovery of Transmission Charges from the short-term customers for the particular inter-regional asset connected to the region in accordance with the Central Electricity Regulatory Commission (Open Access in Inter-State Transmission) Regulations, 2004.

CL = Allotted Transmission Capacity to the long-term transmission customer in the regional transmission system in which it is located.

SCL = Sum of the Allotted Transmission Capacities to all the long-term transmission customers of the regional transmission system in the regional transmission system in which it is located.

231. We would like to clarify application of this formula with an example given below:

Say, there are three long-term customers A, B and C within a region R_1 having Allotted Transmission Capacities of 2000 MW, 2500 MW and 3500 MW respectively. Also a long-term customer D located in another region R_2 has been allotted transmission capacity of 1000 MW from the regional transmission system of R_1. Now, if Rs 60 crore is the annual transmission charges for an inter-regional line, the transmission licensee should get Rs 5.0 crores in any month. Further, if the same inter-regional line between R_1 and R_2, is used by short term customers, during any month and a recovery of Rs 1.0 crores is made, on this account, from those short-term customers, during that month, the charges for the inter-regional line payable by A, B and C for that particular month will be as under:

Charges payable by A = 0.5 x [(60/12) - 1] x [2000/(2000+2500+3500)]
= Rs 0.5 crore

Charges payable by B = 0.5 x [(60/12) - 1] x [2500/(2000+2500+3500)]
= Rs 0.625 crore

Charges payable by C = 0.5 x [(60/12) - 1] x [3500/(2000+2500+3500)]
= Rs 0.875 crore

Total charges payable
by the long-term = [0.5 + 0.625+ 0.875] = Rs 2.0 crore
Customers in the region R_1

In the same manner, the long-term customers in the region R_2, will also share Rs 2 crore among them in that month.

Thus, total charge receivable
By the transmission licensee = Rs (1.0 +2.0 + 2.0) crores
During the month in question
= Rs 5.0 crores

Changes required in view of the Notification dated 30.01.2004 on the issue of Open access in inter-State transmission

232. The Commission had issued orders on 14th November 2003 and 30th January 2004 on the open access in inter-state transmission. Based on these orders, the terms and conditions for open access in inter-state transmission were notified on 30th January 2004. In the said notification, transmission customers have been divided into two categories; namely the short-term customers and long-term customers. The notification on open access in the inter-state transmission mainly deals with procedural aspects related to open access for short-term as well as long-term customers and rate payable by the short-term customers. As per this notification, the balance transmission charges after accounting for recovery from the short-term customers is to be shared by the long-term customers. However, the draft regulations, stipulates the methods of computation of annual transmission charges as well sharing of the balance transmission charges after accounting for recovery from the short-term customers. Thus, the draft regulations particularly the portion pertaining to inter-state transmission and the notification on open access in

inter-state transmission are complementary to each other. In order to have cohesiveness in these two sets of regulations, the following modifications in the draft regulations have been incorporated

(i) Insertion of definitions of Allotted Transmission Capacity, the long-term transmission customers and the short term transmission customers as per the notification dated 30th January, 2004.

(ii) Definition of "Beneficiary" has been deleted and term beneficiary, wherever appearing has been replaced by the long-term transmission customer.

(iii) As per the notification dated 30.1.2004, the existing beneficiaries having firm allocation in the central generating stations are to be treated as the long-term customers. The definition of contracted power shall be modified as under :

> *'**Contracted Power'** means the power in MW which the transmission licensee has agreed to carry or which the transmission licensee is required to carry as per firm allocation from ISGS outside the region or the long-term agreement between the importing and exporting utility.*

(iv) Recovery from short- term customers shall be taken into account while stipulating method of sharing of transmission charges.

Deviation from the Norms specified in the Notification

233. The draft regulations did not contain any provision for deviations from the norms proposed. Some of the Independent Power Producers pleaded for such a provision on the ground that it would provide necessary leeway for the parties to negotiate terms and conditions, which could be more attractive than the norms. It has also been pointed out that a similar provision existed in the notification issued by the Central Government on 30.3.1992.

234. We have given our anxious thought to the submission made. In the draft regulations it was proposed that the norms of operation were to be ceiling norms, but this would not preclude the generating company or the transmission licensee, as the case may be, and the beneficiaries from agreeing to improved norms of operation. Thus, the proposals contained in the draft regulations afforded the opportunity to the parties for negotiations on the operating norms. We feel that the liberty to negotiate should also be available on other normative parameters being notified since it is likely to prove beneficial to the end consumer and that is the mandate of the law under which the Commission is established and its functioning. However, it has to be ensured that tariff arrived at as a result of negotiation on different parameters should be lower than that may be determined under the norms. Therefore, the method of testing and examining whether such changes are improvement over the norms has to be specified. Accordingly, the following additional provision has been incorporated in the terms and conditions notified:

> The tariff for the sale of electricity by a generating company may also be determined in deviation of the norms other than the norms regarding target availability and plant load factor specified in these regulations subject to the conditions that:
>
> (a) The over all per unit tariff of electricity over the entire life of the asset, calculated on the basis of the norms in deviation does not exceed the per unit tariff calculated on the basis of the norms specified in this Notification.
>
> (b) Any such deviation shall come into effect only after the same has been approved by the Commission.

235. We may clarify that either the generating company, the transmission licensee or the beneficiaries may approach the Commission for obtaining approval for the deviations.

Other Additional Provisions

236**.** Similarly, the provisions regarding relaxation and removal of difficulties are made to rectify any anomalous situations not envisaged presently.

Sd/-	Sd/-	Sd/-
(BHANU BHUSHAN)	**(K.N. SINHA)**	**(ASHOK BASU)**
MEMBER	**MEMBER**	**CHAIRMAN**

New Delhi dated the 29th March 2004