BEFORE THE CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Coram:

1. Shri S.L. Rao, Chairman
2. Shri D.P. Sinha, Member
3. Shri G.S. Rajamani, Member
4. Shri A.R. Ramanathan, Member

Petition No.4/2000

In the matter of

Operational norms for thermal generation

Petition No.31/2000

In the matter of

Financial norms for rate of depreciation

Petition No.32/2000

In the matter of

Financial norms for cost of capital

Petition No.34/2000

In the matter of

Surcharge on hydro generation

Petition No.85/2000

In the matter of

O&M cost norms for hydro power stations

Petition No.86/2000

In the matter of

O&M cost norms for inter-State transmission

Petition No.88/2000

In the matter of

O&M cost norms for thermal stations.

The details of the representatives of the parties who attended the hearings in above-noted petitions are contained in Annexure-A attached

Annexure "A"

BEFORE THE CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Coram:

5. Shri S.L. Rao, Chairman
6. Shri D.P. Sinha, Member
7. Shri G.S. Rajamani, Member
8. Shri A.R. Ramanathan, Member

Petition No.4/2000

In the matter of

Operational norms for thermal generation

The following were present :-

1. Shri V.S. Verma, Chief Engineer, CEA.
2. Shri Suresh Chander, Director, CEA
3. Shri A.K. Gupta, Director, CEA
4. Shri Sanjay Sharma, Dy. Director, CEA
5. Shri R.K. Sethi, Dy. Director, CEA
6. Shri S.K.Kassi, Asstt. Director, CEA
7. Dr. I.M.N.Soi, Chief Engineer, HPGCL,
8. Shri Satjit Singh, Dy. Director, PSEB
9. Shri A.K. Mathur, CGM, UPRVUNL
10. Shri R.Suresh, CE(Comml), NLC Ltd.
11. Shri M.Subramanian, DS/Plg, NLC
12. Shri B.N. Ojha, Director (Operation),NTPC
13. Shri S.L. Bajaj, Director, NTPC.
14. Shri M.S. Chawla, DGM, NTPC
15. Shri S.N. Goel, DGM (Comml), NTPC
16. Shri K.C. Mondol, Sr. Mgr.(Comml), NTPC
17. Shri Manoj Saxena, Sr. Mgr., NTPC
18. Shri T.R. Sohal, NTPC
19. Shri M.G.Ramachandran, Advocate, NTPC
20. Shri A.K. Das, GM, Power Grid
21. Shri Bhanu Bhushan, Director (Operation), Power Grid
22. Shri K. Venkateshwar Rao, RE,KPCL
23. Shri V.K. Gupta, SE (ISP), RVPN

Petition No.31/2000

In the matter of

Financial norms for rate of depreciation

The following were present :-

1. Shri Sailesh, AGM, ICRA
2. Shri Deepak, Sr. Analyst, ICRA
3. Shri S.C. Mehta, EE , RSEB
4. Shri R.K. Sharma, ED (Comm.), NHPC
5. Shri P. Kaul, SM (E), NHPC
6. Shri S.K. Aggarwal, GM (Comm), NHPC
7. Shri H.L. Bajaj, Dir. (Comm), NTPC
8. Shri Shyam Wadhera, GM (Comm.), NTPC
9. Shri M.S. Chawla, DGM (Comm), NTPC
10. Shri R. Suresh, CE (Comm.), NLC
11. Shri S. Misra, AGM, GRIDCO
12. Shri P.T. Yohannan, CE, KSEB
13. Shri B. Ravindran, OSD, KSEB

14. Shri G.C. Jain, EE, UPPCL
15. Shri B.K. Saxena, Sr. AE, UPPCL
16. Shri T.C. Sharma, DY.FA, PSEB
17. Shri R.K. Arora, XEN, HVPN
18. Shri Bhanu Bhushan, Dir (O), PGCIL
19. Shri J. Sridharan, ED (F), PGCIL
20. Shri M.D. Ravi, AO, KPTCL
21. Shri S.K. Anantha, AO, KPTCL

<u>Petition No.32/2000</u>

In the matter of

Financial norms for cost of capital

The following were present:

1. Shri Manish Aggarwal, Head (Energy), CRISIL
2. Shri Amit Kumar, CRISIL
3. Shri S.C. Mehta, EE , RSEB
4. Shri R.K. Sharma, ED (Comm.), NHPC
5. Shri P. Kaul, SM (E), NHPC
6. Shri S.K. Aggarwal, GM (Comm), NHPC
7. Shri H.L. Bajaj, Dir. (Comm), NTPC
8. Shri Shyam Wadhera, GM (Comm.), NTPC
9. Shri M.S. Chawla, DGM (Comm), NTPC
10. Shri R. Suresh, CE (Comm.), NLC
11. Shri S. Misra, AGM, GRIDCO
12. Shri P.T. Yohannan, CE, KSEB
13. Shri B. Ravindran, OSD, KSEB
14. Shri G.C. Jain, EE, UPPCL
15. Shri B.K. Saxena, Sr. AE, UPPCL
16. Shri T.C. Sharma, DY.FA, PSEB
17. Shri R.K. Arora, XEN, HVPN
18. Shri Bhanu Bhushan, Dir (O), PGCIL
19. Shri J. Sridharan, ED (F), PGCIL
20. Shri M.D. Ravi, AO, KPTCL
21. Shri S.K. Anantha, AO, KPTCL

<u>Petition No.34/2000</u>

In the matter of

Surcharge on hydro generation

The following were present:

1. Shri Ajit Pudussery, Advocate, NHPC
2. Shri R.K. Sharma, ED (Comm.), NHPC
3. Shri S.K.Agarwal, CE (T), NHPC

<u>Petition No.85/2000</u>

In the matter of

O&M cost norms for hydro power stations

The following were present:

1. Shri Ajit Pudussary, Advocate, NHPC
2. Shri R.K. Sharma, Director (Tech), NHPC
3. Shri V.K. Kanjlia, ED (Comml),NHPC
4. Shri Nain Singh, CE(O&M), NHPC.
5. Shri S.K. Agarwal, CE (T), NHPC
6. Shri Ranjan Mitra, SM(E), NHPC
7. Shri P. Kaul, SM(E), NHPC

8. Shri Vijay Kumar, SM (F&A), NHPC
9. Shri T.K. Mohanty, Mgr.(Law), NHPC
10. Shri J. Saxena, A. Prog (EDP), NHPC
11. Shri B. Chahar, Advocate, PD - Govt. of Sikkim,
12. Shri P.K. Das, Director, Sikkim, Power Development Corp. Ltd., Power Deptt. Govt. of Sikkim.
13. Shri S. Ananthakrishnan, Addl. CE, WAPCOS
14. Shri G.S. Chawla, Addl CE, WAPCOS
15. Shri S.P. Syagi, Expert Consultant, WAPCOS
16. Shri S.N. Balasubramanian, Expert Consultant, WAPCOS
17. Shri Rajindra Singh, Expert Consultant, WAPCOS
18. Shri Jayadev Singh, Consultant, WAPCOS
19. Ms. Manjula P. Madhavan, Sr. Engineer, WAPCOS
20. Shri K.P. Ray, Consultant, NEEPCO
21. Shri D.K. Singha, Sr. Manager (EL), NEEPCO
22. Shri M.M. Majumdar, Sr. Manager (Finance), NEEPCO
23. Shri Bhanu Bhushan, Dir (Opn.), Powergrid
24. Shri K.K. Das, GM (SO), Powergrid
25. Shri H.S. Bedi, Dy. CE, ISB, PSEB
26. Shri V.K. Gupta, SB (ISB), RVPN
27. ***Mr. Christian Guillaud, Engineer, SNC-Lavalin***
28. Shri Gurdial Singh, CE (HE & RM), CEA

Petition No.86/2000

In the matter of

O&M cost norms for inter-State transmission

The following were present:

1. Shri S.K. Dube, ED (Comm.), PGCIL
2. Shri Suresh Sachdeva, GM (Comm.), PGCIL
3. Shri S.S. Sharma, AGM (Comm.), PGCIL
4. Shri P.T. Yohannan, CE, KSEB
5. Shri K.R.Unnithan, EE, KSEB
6. Shri B.S. Seshadri, SE, KPTCL
7. Shri S. Suryaprakasha Rao, CE (Comm.), APTRANSCO
8. Shri Shiv Raj Singh, Addl. CE, MPEB
9. Shri Deepak Kumar Shrivastava, EE (Comm.), MPEB
10. Shri Santosh Kumar, CE (GM), CEA
11. Shri B.K. Jain, Dir (GM), CEA
12. Shri A.P. Verma, Director (GM), CEA
13. Shri A.K. Saxena, Dy.Director (GM), CEA
14. Shri H.S. Bedi, DY. CE, ISB, PSEB
15. Shri V.K. Gupta, SE (ISB), PSEB
16. Shri A.Muthu Narayanan, SE, Elect. Deptt., Pondicherry.

Petition No.88/2000

In the matter of

O&M cost norms for thermal stations.

The following were present:

1. Shri Shyam Wadhera, GM (Comm.), NTPC
2. Shri K.K. Garg, AGM (Comm.), NTPC
3. Shri B. Arya, AGM(F), NTPC
4. Shri R. Suresh, CE(Commercial), NLC
5. Shri M. Nallasivan, Accounts Officer, NLC
6. Shri Shakil Ahmed, AM, NLC
7. Shri T.V. Balakrishnan, Director, DCL
8. Shri Dipak K. Sarkar, CE, DCL
9. Shri B.D. Banerjee, Sr. Executive, DCL
10. Shri Satjit Singh, Dy.Dir. (ISB), PSEB
11. Shri S.C. Mehta, RVPN Ltd, Jaipur

12. Shri V.K. Gupta, SE, RVPN.
13. Shri B.N. Ray, Sr. GM(PP), GRIDCO
14. Shri S.S Nayak, GRIDCO
15. Shri S.P. Angurala, XEN (P&M), DVB.
16. Shri D.K. Kattar, SE(E), DVB
17. Shri N. Raghavendra Rao, SE, Projects, KPTCL

O R D E R

A.R. RAMANATHAN, MEMBER:

PRELIMINARY

1.1 Background

1.1.1 Section 13 of the Electricity Regulatory Commissions Act 1998, (ERC Act) has entrusted the Central Electricity Regulatory Commission (hereinafter called the 'Commission') with the powers and functions to regulate: -

a) the tariff of generating companies owned or controlled by the Central Government;

b) the tariff of generating companies other than those owned or controlled by the Central Government, if such generating companies enter into or have a composite scheme for generation and sale of electricity in more than one state; and

c) the tariff of transmission utilities engaged in inter-state transmission of energy.

1.1.2 As per Section 28 of the ERC Act the Commission is required to determine by regulations the terms and conditions for fixation of tariff under clauses (a), (b) and (c) of Section 13. Section 37 of the ERC Act stipulates that the Commission shall ensure transparency while exercising its powers and discharging its functions.

1.1.3 The Commission assumed the jurisdiction under Section 13 (a) and (b) as referred to above w.e.f. 15th May, 1999. This was the date from which, as per the provisions of Section 51 of the ERC Act, the Central Government notified the deletion of Section 43A(2) of the Electricity (Supply) Act 1948 (ES Act), in respect of tariff of companies falling under sections 13(a) and (b) of the ERC Act. Section 43A(2) which deals with the terms and conditions for sale of power by generating companies to State Electricity Boards was in force until that date. Consequent to the deletion of Section 43A(2) new sets of terms and conditions were required to be notified under the provisions of Section 28 of the ERC Act, as they now fall under the tariff jurisdiction of the Commission.

1.2 <u>Jurisdictional issues</u>

1.2.1 NTPC raised some preliminary jurisdictional issues. Power Grid Corporation of India Ltd. also raised similar objections. The contention of these parties is that the functions and jurisdiction of the Commission are to frame guidelines in matters relating to tariff and to determine tariff guided by national power plans. According to them, the norms and parameters fixed under the notifications issued by the Government of India under section 43A(2) of the Electricity (Supply) Act are part of the national power policy. The national power plans and tariff policy as laid down by the Government of India should be the guiding factor in determining the tariff of generating companies regulated by the Commission.

1.2.2 It is also argued by NTPC that the norms and parameters should be applied to all generating stations in the country irrespective of ownership and sector. Otherwise there would be discrimination; whereas, there should be a “level playing field”. Since the Commission cannot regulate all generating companies the appropriate course for the Commission could be only to advise the Government of

India under Section 13(e) of the ERC Act, 1998 to change the norms. CERC's norms being applicable only to central government owned/controlled undertakings, would not be equitable.

1.2.3 All the jurisdictional issues stated above have been already considered by the Commission in the review petition No.13/2000 filed by NTPC **in which Power Grid is also a party. We have already concluded after elaborate consideration that the Commission has the jurisdiction to fix the norms and determine the tariff accordingly.** Those conclusions on jurisdictional issues may be read as part of this order. Incidentally we have also noted from the records of the Commission that the Central Government while conveying its views on implications of omitting section 43A(2) of the ES Act, 1948 in respect of generating companies referred to in clauses (a) and (b) of Section 13 of the ERC Act 1998 vide their communication No.25/24/98-R&R dated 1.6.1999 addressed to the Commission has stated:

"CERC and SERCs in the States like Orissa and Haryana where Section 43A(2) has been disapplied will, however, be entitled to deviate from such tariff notification issued by the Government. In case of such deviation, reasons will be recorded by the Commission. The Commission will adopt the principles contained in the notification and modify them as the circumstances require. However, the discretion has to be left to the CERC and SERC to follow the norms as they, in exercise of quasi-judicial power, consider just and proper. In doing so, the norms of operation and PLF laid down by the CEA will be a guiding factor and not a binding factor".

1.2.4 NTPC has also raised a new issue which did not find a place in the ABT review petition viz., that their stations both existing and those in the pipeline were approved and given techno-economic clearance by the Central Electricity Authority based on the prevailing norms and guidelines. These projects have also been appraised by financial institutions for viability, profit, capacity for repayment of loans, capacity to generate resources for future investments etc. Change of norms for these stations at this stage will seriously affect their viability and credit rating and in turn will affect the capability to mobilise resources for future investments.

Though the above contention is really not a challenge to the jurisdiction of the Commission, it is a new issue. The crux of the issue is that those stations which were cleared for implementation on certain parameters should be allowed to charge their tariff based on the existing terms and conditions. This objection is an alternative version of the "level playing field" argument, seeking a parallel treatment with the IPPs, since their fixed charges in the tariff are sealed and cannot be changed for a long and specified period. This argument is despite the fact that the Central Government itself in the past had varied the norms though broadly in favour of these public sector undertakings.

1.2.5 This argument will, if accepted, negate the provisions of section 13 of the ERC Act, 1998, which require the Central Electricity Regulatory Commission to promote efficiency and economy through its tariff regulation. The Commission will not be able to determine tariff under the terms and conditions developed by it for promoting efficiency, and economy and apply them to electrical plants or electrical lines licensed, authorised, installed or contracted under the provisions of the existing laws. CERC will have no scope for introducing economy and efficiency measures while regulating tariff for existing stations/lines. The tariff jurisdiction gets totally ousted for all existing plants and lines and will disable the CERC from rationalising the tariff and pursuing promotion of economy and efficiency in the power sector, which the law mandates it to do.

1.2.6 A perusal of the agreements entered into by different State Governments with IPPs shows that their tariff have been virtually frozen based on the parameters laid down by the Government of India vide notification dated 30th March, 1992. As such in their case, scope for continuously improving economy and efficiency does not exist. Solemn agreements have been entered into with the IPPs and State Governments. These IPPs constitute a mere 5% of generation capacity.

1.2.7 **The terms and conditions developed herein by the Central Commission under Section 28 can constitute the basis for tariff of all other generating and transmission companies as well. The Commission is hereby advising the government under Section 13(e) of the ERC Act, 1998, accordingly so that the Government of India can explore the possibility of introducing economy and efficiency in the IPP and State sector as well. We recommend that the tariff terms and conditions framed by this Commission may constitute the guidelines for the State Electricity Regulatory Commissions and state governments. This can bring about a uniformity in approach for the country as a whole. This is however without prejudice to the jurisdiction statutorily conferred on the respective authorities. While doing so, in order to alleviate the apprehensions of IPPs it should, no doubt be ensured that the minimum rate of return is not eroded for no fault of the utilities and the benefits of economy and efficiency are equitably shared. In our view this is a more viable alternative approach instead of making all utilities to fall in line with IPPs, which may not be in the overall national interest.**

1.2.8 Until the creation of the Central Electricity Regulatory Commission in July 1998, bulk electricity tariff of central generating companies were determined through various notifications by the government of India. The decisions relating to various cost items were reflected in the different notifications over a period of time, since 1992. These notifications did not give reasons for different decisions that were notified. The impact of these decisions was difficult to identify. There were recommendations of the CEA on a number of issues which were not accepted by government (e.g. on operational norms, availability levels for transmission etc.).

The Commission has faced immense difficulties in the way of introducing a tariff structure leading to improved efficiency, which should be a continuous process. Adequate and accurate data was not available on a number of issues. The rationale for some earlier government notifications was not available and the Commission could not appreciate why some decisions were taken.

1.2.9 The Commission was determined to look at the tariff structure as a whole and to put in place a comprehensive set of norms and terms and conditions for the electricity sector under its jurisdiction. This has been done after following the due process and reasoning out the conclusions. It expects that these terms and conditions would, over time, serve as signals for the state regulatory commissions as well in their decisions.

1.2.10 The Commission was also desirous of using its tariff regulatory powers to promote investment, competition, efficiency and economy in the sector, and also to improve quality and discipline in the Grid. As such these factors are constantly kept in view in these orders. While the decisions of the Commission on Tariff are spread over several orders, they should be seen as a whole.

1.3 <u>**Consultation paper**</u>

1.3.1 After assuming its tariff jurisdiction, the Commission issued a consultation paper on bulk electricity tariff in September, 1999. The intention was to generate widespread discussion and comments before finalising the terms and conditions for determination of tariff. The Commission called for written comments from all concerned and also held conferences at the headquarters of the 5 Regional Electricity Boards to enable greater inter-change of views. Simultaneously the Commission also initiated expert studies by consultants on the following major elements of tariff:-

a) Return on Capital

b) Depreciation; and

c) Operation and maintenance (O&M) costs.

1.3.2 Other studies on the operating norms of all segments viz., thermal generation, hydro generation, transmission, escalation factors in projecting O&M expenses, were obtained from expert groups and Commission staff. The debate on operational norms for thermal stations was based on the recommendations made by CEA in 1997.

1.4 <u>**Applicability and effective date**</u>

1.4.1 **The terms and conditions as will be notified, shall, apply to all utilities covered under Section 13(a) (b) and (c) of the ERC Act unless specifically stated otherwise. However, it should be remembered that these terms and conditions shall apply wherever cost based tariff is determined by the Commission. These terms and conditions shall be in force for a period of 3 years effective from Ist April, 2001 and reviewable/renewable at the discretion of the Commission.**

1.4.2 The terms and conditions covered by this and other orders of the Commission could have been applied from 15th May 1999. The Commission has already granted either provisional tariff or continuation of existing tariff for stations/lines pending finalisation by it of its tariff norms, terms and conditions. These stations/lines include those:

a) for which the earlier notifications have expired, and are awaiting new notifications;

b) for which the earlier notifications continue to apply for some more time;

c) established on or after 15th May 1999 and have mutual agreements with beneficiary SEB's for charging tariff; and

d) established on or after 15th May 1999 other than (c) above.

The Commission would like to minimise uncertainty and hardship regarding tariff. It would like also to avoid determining tariff retrospectively. Hence the terms and conditions, and norms, notified in these orders shall be applied uniformly to all stations/lines with effect from Ist April 2001. This time gap is required to enable state level beneficiaries to project their Annual Revenue requirements for the year 2001-2002 onwards. The Commission also anticipates that Tariff petitions would be filed sufficiently in advance of Ist April 2001 so that the state level beneficiaries could estimate their requirements in time. **In all cases where the tariff were determined earlier under Government notification or provisionally shall continue to apply till that time. Wherever provisional tariff was determined with partial payment, the same is now confirmed. For instance if 90% provisional payment was allowed, with this order the balance 10% is also confirmed. As such where partial payment was being made while awaiting final determination, full payment shall now be made, on demand by the utilities.**

1.4.3 **If this order creates any unfairness, or hardship, parties may approach the Commission for redressal, within 60 days of issue in accordance with the provisions for review as contained in Regulation 103 of the Conduct of Business Regulation.**

1.5 <u>The Broad Principles</u>

1.5.1 Our consultation paper on bulk electricity tariff has stated that the immediate objective of tariff regulation should be the establishment of a predictable and fair system which rewards efficiency and discourages the cost plus approach to rate making. However the consultation paper also stated that it does not disclose the mind of the Commission on tariff setting. But the following considered views of the Commission were pronounced in the paper: -

a) So long as the Commission and not the market determines the tariff for generation, a two part tariff is necessary for efficient use of generation capacity. (Executive Summary – Page IX).

b) The Commission would determine only the price cap chargeable by the generator leaving it to the buyer and the seller to negotiate the price. (Executive Summary – Page X).

c) The Commission feels that the cost push effect of time of use tariff for bulk power could incentivise distributors to take steps towards more effective demand side management (Executive Summary – Page X).

d) The Commission could consider recommending a mechanism for cross-subsidisation of renewable power through an environmental levy on fossil fuel based generators. (Executive Summary – Page X).

e) The Commission does not intend to depart from the existing practice of defining the tariff base in terms of historical costs, though it would require utilities to provide a simultaneous calculation of marginal costs for the purpose of comparison. (Executive Summary – Page XII).

f) The Commission is inclined to re-adjust the depreciation rates such that the loan repayments are made from the return earned by the investor while depreciation is charged at rates which are related to the actual physical life of an asset. (Executive Summary – Page – XII).

g) Project costs must be known and contractually committed to in advance. This is the system followed for IPPs. Subsequent escalations in costs are to be allowed only under exceptional circumstances. (Executive Summary – Page-XII).

h) The Commission is convinced that its tariff setting regulations and practices must simulate market conditions where monopolistic dominance is unavoidable, and induce competition where possible. (Executive Summary – Page – XIII).

i) The Commission has been vested with powers to enforce its decisions and it intends to use these powers to ensure that an enabling environment is created for efficient and economical transactions in bulk power. (Executive Summary – Page-XIII).

j) The first priority before the Commission will be to extract the efficiencies possible within the existing system before moving to the next stage of market development. (Chapter-III – Page-18).

k) Gradualism with directional incentives will be the motif of the Commission's strategy in the move to markets. (Chapter-III – Page-18).

l) The Commission will endeavour to assure a level playing field on consistency in the applications of basic principles of their tariff determination and a non-distortionary tariff regime which maximises efficiency and pays due regard to the interest of the consumer. (Chapter-IV – Page-32).

1.5.2 **The Commission has kept an open mind on all issues referred to in para 1.5.1 while framing the terms and conditions. It would endeavour to implement these views immediately where feasible. In other cases it will implement them in the future. The Commission does not want to substantially disturb the existing system unless it is convinced of the need for change. The**

Commission has kept in view the twin objectives contained in Section 13(e) according to which the tariff shall be:

(i) **fair to the consumers; and**

(ii) **facilitate mobilization of adequate resources for the power sector**

1.6 **Choice of Methodology**

1.6.1 The two fundamental issues related to the tariff of utilities falling within the jurisdiction of the Commission and as identified in the Consultation Paper are:-

a) The choice of methodology, namely, performance based Rate of Return (ROR), versus Retail Price Index (RPI) minus X; and

b) The choice of tariff base, namely, historical cost base, versus Long Run Managerial Cost (LRMC).

1.6.2 The Commission has already indicated that it does not intend to depart from the existing practices both in respect of the methodology as well as in respect of tariff base. This would be evident from the indications contained in the consultation paper as referred to above against items (e), (j) and (k). This approach has also been appreciated by some of the respondents like KPCL, NHPC, WBSEB, CII, etc. DFID in its comments has clarified that in UK, RPI minus X formulation did not apply to generation costs, as generation in UK was considered to be in a competitive market and not in need of cost determined tariff. During the hearings on matters relating to generation and transmission tariff, none of the parties has objected to the basic approach, namely cost based ROR. Detailed comments were received on the methods of tariff setting from NTPC, APGENCO, PGCIL, PSEB, DFID, CARE, etc. None of these parties has objected to the adoption of the rate of return regulation, combined with performance based regulation. However, different views were expressed with regard to the application of the marginal cost based pricing method, as well as the RPI minus X method. The Commission is convinced that its preliminary **inclination to pursue the performance based rate of return method is broadly acceptable to all concerned. It is also convinced that it may be appropriate to define the tariff base in terms of historical costs instead of long run marginal cost. In view of this widely accepted conviction, the Commission would pursue performance based ROR methodology based on the historical costs. However, as far as tariff arising from competitive bidding are concerned, the Commission will decide separately as to how it will proceed. The Commission will issue its Regulations in regard to competitive bidding separately.**

1.6.3 In the consultation paper the Commission has also underlined the significance of a two part tariff for efficient use of generation capacity. The Commission has already adopted the availability based tariff (ABT) as the appropriate mechanism to bring about grid discipline, to facilitate merit order despatch as well as trading in capacity and energy. WBSEB has come out strongly in favour of the two part tariff in its affidavit. A distinctive feature of the availability based tariff is that it recognises two distinct products, namely capacity and energy. In view of these merits a two part tariff has already been ordered to be adopted by all central sector generating utilities in the Regional Grid within the jurisdiction of the Commission, vide ABT order dated 4th January, 2000 in Petition No.2/99. **Accordingly, the two basic issues as already decided, combined with a two part tariff, will constitute the fundamentals of the terms and conditions which are dealt with here under.**

1.7 General Issues in Tariff Setting

1.7.1 Before taking up the various elements of costs which go to determine tariff, it is appropriate to deal with certain general issues in tariff setting which are applicable to both generation and transmission utilities. Some of these issues are:

a) Tariff entity;

b) Periodicity of tariff setting;

c) Treatment of changes during tariff periods;

d) Retrospective adjustment; and

e) Allocation of common facilities for partially commissioned stations/lines.

These issues can be found mentioned in the Consultation Paper under Chapter 4.

1.7.2 As regards the tariff entity, presently, the generating 'station' is considered as the entity, irrespective of the number of units involved. As regards transmission utility, the tariff entity is the line, though all the lines in a region are ultimately clubbed together to constitute a regional tariff. Powergrid at present gets tariff for even segments of a line determined. This would also be allowed subject to its acceptability by beneficiaries. We understand that invariably this segmental tariff gets merged in the tariff of the line as a whole and eventually in the regional tariff at large.

Different views were expressed by the respondents on the question of the tariff entity. RSEB has supported the determination of generation tariff station-wise. However, for use of costlier fuels at the option of some of the beneficiaries, variable charges of costlier fuels need to be charged to the account of the concerned beneficiaries only. UPSEB has suggested that the tariff should be power house wise in case of generators, and pooled in case of transmission utilities. TNEB is for maintaining generation tariff stationwise. It also stated that the transmission tariff shall be on regional basis. Eastern Region constituents excepting GRIDCO have argued for pooling of fixed costs of NTPC on all India basis, whereas GRIDCO prefers disaggregation station-wise. MPEB also prefers station-wise generation tariff and determination of transmission tariff on regional basis. NTPC has strongly urged that the existing station-wise tariff is a time tested one wherein the tariff is determined on a composite basis with all the individual generating units and associated common facilities operating in an integrated manner. This also provides the operator with the flexibility to achieve economic generation from the station as a whole. The accounts are also maintained for each station. Further, a changeover to any other basis would require complete dismantling of the existing system, with no tangible gains. It has also suggested that it would be appropriate to wait till a strong transmission network is established for power transfers, before considering tariff at national or regional levels. NHPC has also come out strongly in favour of station-wise as against unit-wise tariff. BSEB has also supported the station-wise tariff though the Commission could explore unit-wise tariff. On transmission tariff, PGCIL is in agreement that on certain select levels, segregation from the regional tariff is required, and the same is being done already. DFID has felt that there is little point in splitting costs down too far. IDFC has suggested that the Commission should not resort to regulation of individual generating units, as such micro management adversely impacts the incentives for the operators to aggressively pursue efficiency and interstation competition; it also significantly increases the regulatory burden.

1.7.3 **We find that there has been a general consensus both among the beneficiaries and the utilities regarding continuation of the present system of station-wise tariff for generation, and line-wise aggregated regional tariff for transmission which is approved.** The Commission is not inclined to micro-manage the utilities by going down to unit-wise tariff, nor aggregate the generation tariff to regional or national levels, thereby encouraging cross-subsidisation of stations. It is also felt that all stake holders have well adjusted themselves to the present system of station-wise generation tariff and line-wise aggregated regional transmission tariff. The Commission would prefer to stay away from the tariff determination by expediting market development, rather than looking for micro-management of generating units. As such, in this transition phase to competitive pricing, it is not considered appropriate to disturb the existing concept of the tariff entity. On RSEB’s suggestion of charging variable cost of costlier fuel, the Commission will examine the issue as and when it arises.

1.7.4 In the consultation paper the periodicity of tariff setting was envisaged within a range of 1 to 5 years. The merits and demerits of frequent review of tariff were also brought out. Reactions have been received from the respondents viz. utilities, beneficiaries and others. The eastern region constituents have stated that the PBR norms may be fixed for a period of 5 years and may be reviewed well in time to prescribe the norms for the next 5 years. They have suggested for the incorporation of a clause in the PPAs making review of norms mandatory after every 5 years. It has also suggested that separate tariff may be fixed for stabilisation and post stabilisation period. UPSEB has also concurred that the tariff period should be a period of 5 years as per the present practice whereas TNEB has suggested a revision after every 3 years. PSEB has stated that the periodicity of a revision can be 5 years for thermal and hydro-stations and 3 years for gas based stations. Also the first tariff period of a new project may be kept as 2 years during which the actuals in respect of efficiency, availability and O&M charges could be known and the same may be taken into account for future tariff purposes. MPEB however has opined that ideally, tariff should be revised on yearly basis, but looking at the practical difficulties a period of 3 years may be adopted for tariff revision. Any revision at lesser intervals renders the tariff more unrealistic and unreasonable. NTPC as a generator felt that tariff needs to be fixed for a reasonable period to allow the utilities to take management decisions on long-term basis and to provide stability in commercial transactions. Revision of tariff requires detailed analysis of data and this results in protracted debates. The tariff review mechanism should not be subject to innumerable reviews, adjustments etc. It has suggested tariff setting for 5 years, which takes into consideration a provision for annual adjustment in tariff for fuel escalations, change in capital base, foreign exchange rate variation, working capital, incentives, etc. DFID has stated that if tariff is set for 5 years it is essential to remove the biggest cost from the process i.e. fuel costs, unless they are fixed by contract. IDFC has felt that the gap between two tariff reviews should be long enough to encourage regulated entities to pursue efficiency gains aggressively. It has suggested that initially the review period should be short, and gradually, the gap between the successive reviews can be extended. Enron India Pvt. Ltd. has also concurred with the above views that the period between tariff settings should be long enough for companies to experience the benefits of increased efficiency. It has recommended an initial review after 3 years, with regular reviews at 5 year intervals thereafter.

1.7.5 We have carefully considered all the above views on the periodicity of tariff setting. There has been a substantial agreement on a 5 year review, with a 3 year review at the outset. This review period is in line with the performance based system, which is characterised by the utilities being allowed to improve their efficiency and take the benefit of the same over a reasonable period of time, while establishing their sustainability over time. A frequent review like an annual tariff fixation exercise would be more intrusive and in-advisable in view of the cumbersome process and burden on regulation, apart from minimising motivation to improve. We should also keep in mind the overall objective of regulation, namely, to promote investment. Regulatory interventions should not be a stumbling block to this objective. Some of the constituents were in favour of a 3 year tariff period in favour of which arguments were advanced.

In view of the transition to regulatory regime, a period of nearly 2 years has expired in which the tariff issues could not be fully examined. Certain issues require more indepth study and statutory change. These have to be further examined and the tariff reset. As such, the Commission orders that the terms and conditions now determined, shall continue upto 31st March, 2004. A fresh set of terms and conditions should come into force from 1st April, 2004 onwards. In the interregnum, more detailed analysis may have to be done on operational norms, quantification of risk and return, depreciation, etc.

1.7.6 **The Commission is also concerned about the fairness of the tariff from the point of view of the consumers. In the earlier regime, though a period of 5**

years was envisaged for review, no revision has taken place for more than 7 years. Thereby, the consumers were denied the benefit of improved norms and efficiencies. As such, the Commission stipulates that the utilities shall submit their tariff petitions sufficiently in advance, so that by the time of the expiry of the period viz. Ist April 2004, the new tariff would come into force. Utilities shall also file tariff petitions sufficiently in advance of Ist April 2001 as well. The Commission would also allow the liberty to the beneficiaries to file any petitions in case they could establish that a substantial revision in tariff is warranted. Since most of the fixed costs are tied to project costs, such an eventuality should not arise. To ensure that the utilities are not burdened with fuel cost escalations beyond their control, mechanism for fuel price adjustment for thermal stations is also proposed to be provided.

1.7.7 The Commission in its consultation paper had raised a number of issues on the subject of changes in costs in between two tariff filing periods. These changes may relate to additional capitalisation, foreign exchange rate variation, taxes/duties, fuel price adjustments, etc. The following questions were posed by the Commission in the consultation paper, namely:

- Can the area of uncertainty regarding the passthrough of unavoidable costs be narrowed for the supplier?
- How can the beneficiaries be simultaneously assured that only reasonable cost escalations will be passed through?
- How can costly and time consuming proceedings be avoided?
- Where a beneficiary wishes to challenge the cost escalations passed through by the utility, could the beneficiary pay under protest before it is taken up for consideration by the Commission?

The Commission was concerned about the tariff shocks to the beneficiaries on account of revisions even after setting the tariff for a certain period. It was noted that in certain stations, due to the capital cost not being finalised for over 5 years, a provisional tariff is being followed. In certain cases, substantial additions to the fixed costs over a period of 2 to 3 years were incurred, subsequent to the approval of the revised project cost by the CEA. The beneficiaries are also required to pay bills for taxes actually paid, as well as the effect of foreign exchange rate variation on the value of repayment of loans and interest payments at irregular intervals. In addition, fuel price adjustments through a built in mechanism in the tariff are also done. The beneficiaries have limited scope to pass on such billing to the end consumers, due to the tariff system at retail level not being flexible. The issues regarding changes occurring in between two filing periods and the retrospective adjustment of tariff, are composite issues, which have to be dealt with together. This is because any developments in between two filing periods invariably result in a retrospective adjustment as the matter is considered, approved and then allowed, resulting in a time escalation and subsequent adjustment in tariff. The Commission has already expressed its considered view that retrospective revision should not be allowed other than for unavoidable reasons. The consultation paper has also indicated that it is possible to adopt a principle that once tariff are set, they shall remain in place for some time. This will assure regulatory certainty.

The Commission had the benefit of views from respondents in this regard. The Eastern Region constituents have stated that the price of fuel should be actuals to be verified by the regulator. Enron India has suggested that fuel cost is one unavoidable charge, which may have to be indexed and approved in advance. PSEB has also stated that fuel price changes are acceptable as a passthrough. DFID has suggested that in case the fuel costs are hedged to give price stability, the regulator has to allow all the hedged costs. In the UK, they have not chosen to regulate generation prices because of the concern about allowing passthrough of hedging costs. It was stated that in case of distribution companies which had paid hedging premium for stabilisation of power costs, the same is not allowed as it was not a power purchase cost or payment for power. CII has suggested that in the beginning phase, early tariff reviews would be a practical step to avoid this issue of revision in between two tariff periods. NTPC in its submission has suggested automatic adjustment for fuel costs.

On capital cost, it is contended by NTPC that subsequent adjustment for PSU owned projects is inevitable since the actual capital cost can be either lower or higher than the sanctioned capital cost. For this purpose, it has suggested that the Commission may provisionally include expected justified expenditure and stipulate provisions for automatic adjustment instead of lump sum billing on periodic basis. PGCIL has stated that generally a system is put into commercial operation without waiting for completion of infrastructural facilities, reconciliation of accounts etc. which may take 1 to 2 years after commissioning. As such, retrospective adjustment on account of capital cost is unavoidable. A similar view has been expressed by NHPC. The Eastern Region constituents stated that delay in finalisation of project cost should be discouraged and any retrospective increase should not be allowed. DFID has also expressed concern over these retrospective adjustments. PSEB stated that in view of the direct effect of tariff on merit order and scheduling of daily drawal, hike in tariff retrospectively, would not be in order. Cost over run in projects should not be passed on to the buyers whereas if the completed cost is lower than the estimates the tariff could be revised. Enron India Pvt. Ltd. has pointed out that private investors are not able to get any retrospective adjustments if price structure of investment changes, and they have to take the risk to participate in the market. UPSEB has mentioned that in case gross blocks are added, additional fixed charges can be levied from the month of commissioning to the end of the concerned financial year. TNEB does not accept capital cost additions during the tariff period, or capitalisation of left out expenditures, and the same should be agreed to only in exceptional cases.

On O&M, foreign exchange variation and taxes, the ER constituents have suggested freezing of the O&M expenses with escalation through indexation. PSEB has stated that foreign exchange variations should be permissible but limited to the expenditure on actual debt repayment and actual interest payment, whereas

O&M charges can be escalated at 10% or as per price index. IDFC has suggested that the Commission can disregard implications of events with economy-wide impact such as Y2K compliance, changes in corporate tax, etc. RSEB also agreed with indexation for O&M. It has however suggested that all claims for intermediate reviews should be kept pending till the next review of the tariff, and limiting intermediate reviews to specific passthrough and indexation.

Some of the beneficiaries like eastern region constituents would like to reserve the right to withhold payments in case any cost escalation is disputed.

1.7.8 **The Commission has carefully considered the views of utilities, beneficiaries and others on the above issues. The consensus which emerged from all the submissions is that there should be certainty with regard to the tariff for the period for which it is announced. There is also a consensus that automatic escalation/passthrough should be confined to the minimum. The Commission is in full agreement with the views of parties. It is endeavouring to reduce the scope for passthrough to the minimum, which is appropriately taken care of on items relating to taxation, O&M and foreign exchange variations, which are dealt with separately herein.** As regards capital costs, the situation is somewhat difficult. As the law stands today in respect of PSUs, the required approvals from the Government and clearance from CEA have to be obtained before the commencement of the project, subject to certain limits for which no clearance is required. After the completion of the project, if the actual expenditure or the scope of the project vary beyond certain limits, they are required to be further approved. This process of approval is time consuming, resulting in a provisional clearance, making a subsequent retrospective revision inevitable. Changes in legislation are being contemplated by which the clearance from CEA for projects might be done away with. However, as the law stands today, approvals are inevitable. Still, it is possible to bring about stability in tariff in case a time schedule is worked out by which utilities may submit data to CEA at least 6 months prior to the completion of a project, so that clearance could be obtained sufficiently in time before the tariff for the station/lines is determined. It is hoped that any variations on actual finalisation of accounts thereafter should be minor in nature which could be absorbed by the utility and if substantial, can be taken care of in the next revision. In view of the above, **all utilities seeking determination of tariff in respect of new projects shall submit their applications to us at least 3 months in advance of the anticipated date of completion, along with the project cost as approved by the appropriate independent authorities, other than the Board of Directors of the company.** This project cost will constitute the basis for tariff fixation, and no revision would be entertained till the next tariff period. This direction presupposes that CEA may hereafter, unlike the past, clear capital cost escalations on factors other than the change in scope as well. We would urge upon CEA to consider and deal with the approval of additional capital costs other than those due to change in the scope of the project as well, in the interest of avoidance of tariff shocks down stream. In case of projects exempted from CEA clearance, the Commission would consider accepting a due diligence clearance from any recognised agency.

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

As regards adjustment for fuel cost charges, this is inevitable and has to be built into the tariff mechanism. In this context the comment of DFID is worth noting, that any hedging cost for fuel shall not be allowed; only the actual variations will be taken into account through a built in mechanism which would also meet the requirements of both the utilities and the beneficiaries. This leads us to the question of passing on the fuel supply risk to the consumers. Risk of “take or buy” contracts on supply are being sought to be fastened to the state beneficiaries. **The general principle in this regard shall be that if such a decision is collectively taken by the generator and beneficiaries, the same shall be allowed. If a unilateral decision in this regard is taken the same shall be subject to the decision of the Commission depending upon the prudence of such a decision.**

While we have sufficiently taken care of the apprehensions of the beneficiaries, we are averse to the proposal of withholding payment in case a beneficiary raises a dispute on the charges. This is a dangerous weapon which cannot be allowed to be held by beneficiaries when there is a dispute redressal mechanism in the shape of the Commission. **We strongly reject the proposal to withhold payment on the plea of a dispute and will have to enforce our orders in case this is flouted.**

1.7.9 Another issue, which was identified in the consultation paper, relates to treatment of partially completed/commissioned stations. Since a generating station normally is a multi unit one and since there are common costs and the units/lines are commissioned in stages, there is a specific problem of identifying the capital costs for the commissioned unit. In particular, the proportion of common costs to be charged to the completed units/lines has to be decided. It may also have to be kept in mind that progressive completion of units does not necessarily mean definite capitalisation of cost on a progressive basis. The ultimate capitalisation is bound to be done on the completion of the entire station/line. Therefore this problem is a tentative one till the completion of the entire station/line. In future, all capital costs shall be broken up, into stages and by distinct units forming part of the project. The utility may move the Commission for tariff in respect of the completed units though the station may be incomplete and as such the tariff petition for the station may not be forthcoming. For the future as stated, the project report shall give a stage-wise capitalisation. This equally applies to segments of a line in case of transmission.

1.7.10 Partial capitalisation is not a new issue and had existed even before. It is worthwhile to consider as to how the CEA has handled this problem. From information available it appears that the CEA had also allocated the common facility costs to the completed units on the basis of the capacity completed as against the total capacity of the station. This obviously is an approximation. Any approximation would mean a provisional capitalisation of a part of the project cost related to the unit commissioned with the other part continuing to be considered as “under construction” attracting IDC etc.

This approximation is inevitable for a short period depending upon the schedule of completion of the project. RSEB has contemplated two alternatives for sharing the common cost namely:

a) Common facility to be allocated equally among various units but interest charges on debt of common facility to be charged to tariff.
b) Common facility be allocated to various units in graded manner i.e. first unit having higher allocation, second lower than the first and so on. The grading shall be such that interest on debt of common facility should not eat away the entire ROE.

RSEB has recommended the second alternative. UPSEB has recommended that the entire common cost should be charged in proportion to the capacity of units commissioned with respect to the final output capacity. TNEB has suggested that the cost of common facility should be allocated to the extent of the usage of the common facility at each stage of commissioning. However, as regards interest charges for the period for which the common facility is un-utilised, the same can be written off as one time payment from the revenue account. The Commission is not inclined to accept this proposal as it would militate against the accepted accounting concept of capitalising the interest only on commissioning. PSEB has suggested that in case of partly completed projects only those assets which are required for power generation of the commissioned units can be included for the purpose of tariff. MPEB has mentioned that charging of common cost should be service based. Enron India Pvt. Ltd. feels that solving the issue of linking the recovery of common costs to proportion of plant available commercially would involve unacceptable level of regulatory intervention and filings and encouragement of the construction of unnecessary plant. Weighing the advantages and disadvantages it has suggested that the resolution of this issue should not be taken up by the Commission. A similar opinion has been expressed by DFID with the comment that this would involve detailed review which should be avoided.

1.7.11 **The Commission is of the opinion that the apportionment of common costs is an approximation whatever is the method for it. It is also a temporary problem which would cease as soon as all units are commissioned. Any approximation resulting in over recovery or under recovery of tariff for a short period should ultimately get neutralised over a longer period of time. The Commission would not like to micro manage the system by devising an elaborate mechanism for a purely tentative tariff. It is convinced that no serious dislocation of tariff would take place in case common facilities are apportioned with reference to capacity of the different units and the total capacity of the station/line as is presently being done. As such the Commission considers it a simple and viable solution to distribute the common capital costs on the basis of the installed capacity with reference to total capacity of the station/line in the case of ongoing projects whose project costs have not given the desired breakdown. However, any unfairness or absurdity if noticed shall be decided on case to case basis.**

1.8 <u>The Cost Elements</u>

1.8.1 The various elements of cost in respect of generation and transmission including the classification into fixed and variable elements with reference to generation were considered by the Commission. It is noted that none of the respondents has sought any change in the basic content of the elements of cost in respect of thermal generation and transmission. In a cost based tariff the total outgo subject to the test of prudence would in any case constitute the cost of the product. However, the composition of the items may undergo a change as for instance “interest on loans” and “return on equity” may be clubbed together as return on investment. Similarly if tax is not allowed as a pass through, a pre-tax return may find a place. The O & M charges may get split into various elements like establishment cost, repair and maintenance, and insurance. Thus though there could be a reshuffling of the heads, the items which constitute the fixed and variable cost do not undergo any change. None of the respondents have challenged these heads of cost either. However, the Commission on its own has contemplated that it is possible to ignore the cost base for pricing in off-peak period in case supply exceeds demand so that the market may determine the price. In the reverse situation however the Commission is convinced that in order to prevent any unfair advantage being taken the cost base should act as a cap. In case of hydro generation the classification of fixed and variable cost would undergo a critical examination, as there appears to be an aberration in the classification.

1.8.2 The above approach may act as a broad guideline for state level commissions to approve the generation tariff which constitutes a major chunk of the distribution tariff. In the determination of distribution tariff the state level commissions could be facilitated to adopt the generation tariff as determined by the Commission in respect of energy supplied from central generating stations. They may pursue the objective of promoting economy and efficiency in determining the bulk cost, on the same lines. The Commission is thus conscious of the impact of the terms and conditions on the ultimate tariff chargeable to consumers.

1.8.3 Keeping in view the general observations as already made, the procedural framework for tariff petitions is devised which shall be separately notified. We now propose to deal with the major elements of cost influencing the tariff. Based on these findings, the terms and conditions shall be framed which shall also be notified separately. The elements of cost such as Return on Investment (including ROE and Interest on Loan and Working Capital) Depreciation, O&M Cost, Variable Cost, Foreign Exchange Rate Variation, and Corporate Tax, are dealt with herein. In addition, Incentives for exemplary performance are also dealt with. We have also considered the claim of utilities regarding making provision for financial requirements for capacity additions. These are taken up seriatim herein.

2. RETURN ON INVESTMENT

2.1 **The basic issue:**

This part covers return on equity, interest on loans and working capital being significant constituents of fixed cost**.** The cost based rate of return approach to tariff determination necessarily involves identifying and attaching a return on investment allowable to the Utility as an element of Tariff. The investment has invariably a mix of debt and equity. In the past, the mix was normated ranging from 50-50 to 70-30 for PSUS and IPPs respectively. In the market price mechanism, the mix has its implications on the ultimate return on the equity investment. It has also been seen in the past that as the project goes on stream the actual mix has not been the initial normative mix nor repayment of loan necessarily as per original schedule. However, the return on equity has been a constant element in tariff. The actual return on equity was however influenced by a variety factors both operational and financial.

The inevitable choices in a Rate of Return regime before any tariff authority are:

(a) Return on capital employed i.e., total investment; {ROCE)}or

(b) Return on equity i.e. total investment less the borrowing {ROE}

The return on equity could also be considered pre tax or post tax.

The return in either case is to be worked out with two elements viz., rate of return expressed as a percentage and the rate base. The pre-determined rate is to be applied on the admissible rate base to arrive at the quantum of return permissible to be included in the tariff. In the ROCE system, return is influenced by the debt/equity mix and other factors whereas in the ROE system, the return on equity is *per se* a factor simpliciter.

2.2 Consultation paper:

The consultation paper refers to the two variables viz., the rate of return and the rate base. The paper also visualises the two possibilities viz., return on capital employed and return on equity. The paper also identifies the various determinants and classification of risks in quantifying the rate like:

- Country, political, regulatory risk
- Financial, cost-over run, foreign-exchange, interest-rate risk
- Projects size and type (hydro power vs. thermal, transmission),
  Pre or post-construction, fuel-supply and price risk.

Risk may vary with the nature of ownership public vs. private, foreign vs. local. The paper has also envisaged determination of risk premium and appropriate rate of return varying with the characteristics of the investment.

2.3 Consultants Report:

2.3.1 To consider the issues involved affecting the investor and beneficiaries, we requisitioned the services of M/s CRISIL Advisory Services (CAS) to study the cost of capital. This was done in pursuance of the objective of the ERC Act under Section 28 viz., that in the fixation of tariff of generating companies and transmission entities the Commission shall adopt such principles in order that they may earn an adequate return and at the same time they do not exploit their dominant position. The following are the terms of reference for CAS:

(a) Review of the cost of capital allowed so far to electric power utilities (NTPC, NHPC and POWERGRID) in tariff on the basis of actual data over last five years.

(b) Review of the Indian capital markets and the risk weighted cost of capital.

(c) Review of the risk weighted cost of capital from foreign markets, multilateral and bilateral suppliers for Indian companies.

(d) Analysis of the risk profile of the NTPC, NHPC and POWERGRID and Disaggregation of the profile into factors within the control of the NTPC, NHPC and POWERGRID and exogenous factors.

(e) Quantification of the risk profile of NTPC, NHPC and POWERGRID on an Aggregated basis as well as station wise (region wise in the case of POWERGRID).

(f) Ranking of the risk profile of NTPC, NHPC and POWERGRID relative to other power utilities, infrastructure companies and core sector companies in the public and private sector.

(g) Specification of a formula for the determination of an optimum risk weighted cost of capital for NTPC, NHPC and POWERGRID.

(h) Application of the suggested formula to the cost structures of different stations of NTPC and NHPC and regional grids of POWERGRID over the last five years.

(i) Simulation of the income statement and balance sheet of NTPC, NHPC and POWERGRID using the suggested formula over the last five years.

(j) Testing of the suggested formula against the requirements of debt service coverage ratio and any other indicator used by banks and financial institutions (domestic and international) to finance capital investments.

2.3.2 CAS submitted its output in 4 parts covering various aspects during December 1999 – February, 2000 and also submitted a discussion paper in April, 2000. This paper was placed before the central advisory committee as well as a group of experts on the subject wherein CAS was also represented. Subsequently the paper was widely circulated for a public hearing to all those interested in the power sector and opportunity was given to those interested to make their written submissions. Thereafter the matter was heard in detail by the Commission. CAS took note of the comments of members of advisory committee and expert groups and interested parties and submitted a supplementary report considering the views of all parties. "CAS Report", hereinafter refers to the discussion paper.

2.3.3 The CAS report on cost of capital is summarised below:

(a) A cost of capital approach, which does not examine the actual cost of debt and gearing level of a company, is the preferable approach. However, considering the issues in adoption of a benchmark cost of debt, a cost of equity approach (with cost of debt at actuals subject to tests of prudence and usefulness) has been suggested. The computation of cost of equity has been related to the gearing level of the company, which incorporates the merits of the cost of capital approach to some extent.

(b) It is suggested that the business risks, and therefore the returns, be considered the same across all Central Sector Utilities (CSUs). However, the financial risks are different considering the different level of gearing of each CSU. The cost of equity be considered different for each CSU only on account of different levels of gearing.

(c) Differentiation in rate of return on account of vintage of assets (existing assets or new assets), ownership of assets (public or private), and mode of financing (balance sheet or project finance) has not been suggested.

(d) It is suggested that risks in non-core business should not be a consideration in cost of capital calculation.

(e) The cost of equity has been the most contested component of tariff in most countries where tariffs are determined by regulators through a transparent process of public hearings, since there is no foolproof methodology for estimation of cost of equity. It has been suggested that Capital Asset Pricing Model (CAPM) be used for determination of cost of equity.

(f) In the application of CAPM, it is suggested that the latest three to four months' average of yield to maturity on GOI securities with a residual time to maturity of 8 years be considered as the risk free rate of return. Market risk premium be estimated using past BSE 30 index data for last 20 years and using systematic investment plan approach. The business risk of the CSUs be considered similar to the business risks in the listed power sector companies and oil & refining companies in India, for selection of a range of asset beta. The cost of equity of the CSUs using this approach has been shown in section 3 of chapter III of the report.

(g) The rate base on which the rate of return would be applied is an equally important issue. In line with the cost of equity approach, and considering that the cost of equity is calculated based on CAPM, it is suggested that the cost of equity be applied on the adjusted networth to compute the Return on Equity component of tariff. The adjusted networth could be calculated as net fixed assets employed in the business (including capital work in progress) plus statutory investments minus total long term debt.

(h) Preparation of proper balance sheets at the plant / project level, such that they aggregate to the company level balance sheets, is a prerequisite for adopting the method of calculation of cost of equity and rate base as proposed in this report.

(i) It is suggested that a complete review of CAPM formula based on review of the cost of equity should be undertaken every five years. However, the cost of equity level could change from year to year due to changes in gearing. Any review of the cost of equity would need to ensure that the cost of equity to be set after the review would not lead to financial ratios poorer than those typically observed in case of debt instrument with at least an investment grade credit rating, and would not result in sharp increases in the tariff.

(j) The study envisaged application of the cost of capital formula to central sector utilities (CSUs) to simulate their returns for the past and future five years and also testing for impact on the debt service coverage ratio (of the CSUs) and other indicators that are used by banks and financial institutions to finance capital investments. However, complete data required for carrying out this analysis has not been made available to CAS. As a result it has not been possible to carry out such an analysis. This analysis is an important step to be able to arrive at logical conclusions.

2.4 **Major issues:**

2.4.1 The three major issues with regard to rate of return *per se* which arise from the CAS report and which were posed to the parties are:

(a) Whether the rate should be linked to cost of capital or cost of equity;

(b) Whether the risks should be considered the same for private and Public sector;

(c) Whether any differential rate of return on account of vintage of assets or on mode of financing (viz. Balance sheet or project financing) should be considered.

CAS has suggested the following in respect of the above issues:

(a) CERC may adopt cost of equity approach at present. A cost of capital approach may be considered at the next review after examining whether the issues regarding bench marking of cost of debt and of debt equity mix are properly addressed.

(b) The business risk and therefore returns may be considered the same across all CSUs. The cost of equity may be considered different for each CSU only for different levels of gearing. The risk should be considered on a company basis and not on project basis. The nature of ownership – whether public or private – should not be a consideration for cost of equity calculation.

(c) The returns are to be estimated at company level and hence there is no need for distinguishing between old and new assets in determining the rate of return.

2.4.2 The replies filed by some of the parties are varied. As regards cost of capital, though NLC, NHPC and Power Grid Corporation were in favour of the cost of equity approach, NTPC has advocated cost of capital approach as it allows incentive for optimising the return by financial engineering, re-financing, etc. It has suggested a normative debt equity of 70:30 and also suggested bench marking of cost of debt or alternatively to take the actual cost of debt. Cost of capital approach has also been supported by GRIDCO, Orissa for the reason that the era of concessional debt is gradually moving towards market related cost of debt. It has suggested a debt equity ratio of 80:20. Some of the State Utilities like RSEB, UP Power Corporation, APTC and KPTC, however, have suggested that return on equity should be appropriate.

2.4.3 We have considered the views of all the parties. We are in agreement with CAS that the "cost of capital approach is the preferable approach". However, this requires bench marking of cost of debt and of debt equity mix. It has been demonstrated by CAS that the interest rates of CSUs over the last four years have been generally rising, which indicates that the era of concessional financing is coming to a close. On this assumption, if a higher bench mark cost for debt is taken, it is bound to burden the tariff resulting in undue benefit to generating companies in case actual cost is less. The situation regarding interest rates is fluid and needs to be watched. As regards debt/equity mix, the traditional 50:50 debt equity mix has been challenged by state beneficiaries extensively and there are differing views on the adoption of a higher gearing as well. Further, with our objective of not substantially disturbing the existing system without a full conviction for a change, we consider it appropriate to adopt the cost of equity approach for the present, though we consider the cost of capital approach as preferable in principle. The changeover to ROCE could be brought about after interest rates are stablised and bench marking of debt/equity is perfected.

2.4.4 The question of business risks and therefore differing returns for different CSUs is a ticklish one. Though every sector like thermal, hydro and transmission is making out a case that their respective sectors carry more risks than the others, it is equally true that such risks are covered otherwise in the form of a higher rate base or through arrangement between counter parties. CAS has reported that it has carried out a business risk analysis of various plants and examined the actual risk for each of the five CSUs viz., NTPC, NHPC, NLC, NEEPCO and POWERGRID. According to the report, this analysis does not show any clear differentiation between generation sector and transmission sub-sector. It is also necessary to mutually enter into covenants in respect of complimentary arrangements for synchronisation of generation and transmission. A special case was made out by NHPC through a separate application for a distinct rate of return on account of gestation period of hydro projects being more than those of thermal projects; the geological surprises also entail delay in completion of projects. It is further stated that due to location in remote areas, adverse law and order situation, expenditure on security agencies, surplus staff, high expenditure in silt laden locations and additional O&M requirements, there is a need for a distinct rate of return for hydro projects. It has claimed an ad hoc increase of 2 % on ROE on account of these factors. Powergrid in its submission has also made out a case for much higher return on equity for reasons of long gestation period. CAS in its subsequent submissions has made a detailed analysis of the two categories of business risks in general viz., exogenous and endogenous risks. According to CAS, only the exogenous business risk should be considered in risk analysis. These risk again may be of four categories viz., (a) development phase risk; (b) construction phase risk; (c) risk due to down stream/up stream facility not being ready; plus (d) operational risk.

CAS has also attempted to develop a linkage of risk on projects with further ranking for mitigation/sharing in case of hydel generation and transmission. It has also considered the possibility of the asset beta being modified for these risks but has ultimately come to the conclusion that out of the two options of differentiating the return and mitigating or sharing with the consumers the latter option is the only practicable solution. It has concluded that it may be preferable to pass on the risk to the consumers by providing for these risks as and when they devolve rather than providing a premium in the equity returns.

2.4.5 We have given a careful consideration to the above pleas for discriminatory returns based on each sector's risk. We have also kept in view the international practice, though limited, as reported by CAS in this regard. We have also to keep in view the past practice in the sector. The case made out by NHPC and Powergrid is based on special features of their projects which have their impact on the capital cost. A longer gestation period results in blockage of capital with equity fetching no returns during that period though the interest cost gets capitalised. CAS had suggested the inclusion of return on capital work in progress in order to provide the return during gestation period. However, this suggestion is not in line with the accepted accounting principles and procedures. It is also worthwhile to note that NTPC in its detailed submission is of the view that return on equity during construction period is not in accordance with accepted accounting practice. According to NTPC, "This is the world over accepted practice because of the reason that the debtors are not equity owners and the interest thereon starts from the day the loan is drawn. So the interest on loan (is essentially an expense) till the date of commercial operation gets capitalised along with the amount of equity and debt invested. This is the universally accepted accounting practice and the departure from this that too only for the purpose of calculation of tariff may not be correct. Moreover, the acceptability of the approach is to be considered in the light of prevailing accounting standards and we propose that the existing practice of charging only the interest on loans till the date commercial operation should be included in the asset base."

As reported by CAS "in assuming the cost of equity to utility, regulatory bodies rarely use data of that utility alone. Rather, samples of similar utilities are analysed and by choosing appropriate samples the risks of the sector are taken into account for arriving at the cost of capital for the company." For determination of cost of capital, it may be appropriate to rely on the behaviour of investors rather than plant level or sub-sector level returns. However, adequate data on investor behaviour in this regard are not available. In the above circumstances, **Commission considers it appropriate to continue with the existing system of uniform rate for all segments in this sector. It is worthwhile for all utilities to cover themselves for the risks appropriately particularly in the context of the rapid developments in the Insurance Sector. They may come out with the cost implications of such insurance with appropriate data to the Commission. One more possibility within the accepted norms is to issue compulsorily convertible debentures which may carry interest during construction period. However such securities with a commitment to be converted with the specific time frame need to be considered as equity in fixing the debt/equity mix.**

2.4.6 CAS has recommended adjustment of the return on equity for the actual capital gearing on account of perceived higher risk in case of highly geared structure as compared to low geared structure resulting in varying ROE for the different CSUs. This adjustment has been contemplated in estimating risk premium for equity, which is dealt with by us separately. **We are however in agreement that no distinction in return should be made based on ownership. Thus the rate of return should be the same for all CSUs or private inter state plants/lines in a cost based tariff regime. Though this should be the principle, the realities have to be recognised. There had been and still are conscious discriminations between CSUs, IPPs and licensees in the matter of ROE. These discriminations could be ironed out only over a period of time on account of legal and structural impediments for such a course. A distorted comparison, however, of utilities of different genre can not be made in the transition period when the Commission is endeavouring to rationalise the tariff principles. Suitable legislative changes are required to be done to bring all utilities under the jurisdiction of Regulatory Commissions.**

2.4.7 Arguments regarding distinction of return based on vintage of assets are clearly divided on the lines of the utilities and beneficiaries. NTPC and NLC have categorically stated that there should be a uniform rate of return for all assets. According to NTPC, beneficiaries of new projects would be unduly penalised in case a distinction is kept based on vintage. CAS, in its report, has stated that "if a marginal cost of capital approach is adopted, there is no case for differentiating between new and old assets." Further, this would increase the complexity in tariff making by tagging the assets to their date of creation." It has also been argued rightly that the ABT notification does not differentiate between plants by vintage for target availability. Some of the beneficiaries have advocated lower rate of return for old power stations. Some others like TNEB have stated that distinction should be kept based on the source of equity whether it is under plan allocation or from private sources. A look at the relevant clause in Schedule VI of the ES Act indicates that a distinction in fact was kept so far between old and new assets.

A return on investment is not on the vintage of the money invested as such but is on the facility provided through the investment. So long as assets of different vintage provide the same level and quality of service, there is no justification for a differentiated return between the two categories. Further on a ROE approach in the corporate sector, in general, no distinction is made in declaring dividend on equity based on the date of provision of the equity to the company. Even some of the beneficiary states are in agreement that no distinction need be made based on vintage of assets. We have also observed that over the last nearly ten years, the Government of India while determining the tariff of PSUs, has not made a distinction based on vintage even though schedule VI of ES Act advocates this for licensees. We also understand that pricing bodies for other industrial products have not made any distinction in the return on account of vintage of assets. **In the circumstances, we consider it appropriate that no distinction need be made in the return on equity on account of vintage of assets. It should be noted that in respect of SEB's also under section 57 of ES Act, though a moderate return was prescribed, no discrimination based on vintage has been made. Thus, though**

this may be a deviation from the principles laid down in schedule VI, we feel the same is justified. We are conscious that a higher return on more recent assets at high capital cost per unit would have a cascading effect on tariff.

2.5 <u>Reckoning the cost of equity</u>:

2.5.1 CAS report has proceeded to estimate the cost of equity based on its recommendation of return on equity method. The consultants considered four alternatives viz., dividend growth model, price earning ratio, arbitrage pricing model and risk premium models and ultimately suggested the capital asset pricing model (CAPM). After considering and dispensing with the arbitrage pricing models as not preferred one due to the complexity in implementation, the report has explored the risk premium model. Here again, for the purpose of quantification one alternative considered is to estimate the desired return by taking the corresponding return for a foreign company in a similar business and adding thereto the country risk premium for India. For this purpose, the country risk premium was suggested to be worked out as the difference between risk free rates between two countries. However, there underlies an assumption that the relative sector risk position in the two economies are the same. This assumption however, is not realistic. Ultimately, the report has come out with the capital asset pricing model as the recommended model for estimating the return on equity as this has acceptability among regulators in various countries including UK and Australia. A specific pattern for estimation of risk premium has been evolved. In this model quantification of risk (risk premium) involves following:

(a) Estimation of the risk free rate;
(b) Estimation of the expected risk premium for the market as a whole;
(c) Estimation of the particular stock's risks relative to that of whole market.

A brief description of the methodology is given below:

2.5.2 The first step in the calculation is the determination of market expectation of return by equity investors with reference to a 20 year study of the equity index of the stock market. The choice of an index representing a diversified portfolio is based on the reasoning that it should be reflective of how the whole equity market has perceived the return. A longer period has been preferred in order to iron out short term fluctuations as use of long time series hopefully leads to their frequency matching their probability. The time period should be long enough to include various phases of the economy as there are various types of investors active in the market at different points in time. A study of these indices leads to an estimation of the normal market expectation of return on equity on the assumption of systematic investment plan. However, this market expectation should be based on a well diversfied market portfolio even though it is based on the Bombay Stock Exchange, BSE-30 index. The study based on BSE 30, has its own inevitable limitations. However, it can not be helped as there are no other equity indices in India spanning a twenty year period.

This expected return, which was reckoned at 19.2 % from a diversified portfolio of equities incorporates in itself two elements viz., the risk free return and the risk premium. The risk free return has to be separated in order to arrive at the risk premium. For this purpose, the study has worked out the market expectation of risk free return based on the average price of long term Government of India securities of 8 years maturity which gives sufficient liquidity. The study has brought out an estimated risk free return of 11 % based on the price changes of these securities over a period of four months in the stock exchange. There has not been any serious challenge to this rate of 11 %. The risk premium of 8.2% (19.2% - 11%) therefore is with reference to the average risk factor of diversified businesses and also with reference to the respective debt equity mix of various companies. An attempt has been made to adjust the risk premium for the risk associated with the power sector and the debt equity mix of the respective companies. In order to quantify the risk factor of the power sector two alternative indices have been developed based on (a) the data relating to listed power companies and (b) a proxy beta viz., of an industry, which is closer to power sector in terms of risk, viz., refinery sector. These indices are signified by the asset beta of power sector companies and refinery sector companies viz., 0.54 and 0.60 respectively. The beta is arrived at on the assumption that all the assets are financed through equity in the comparison. Thus the asset beta reflects the risk factor of the sector compared to the diversified sectors. This beta is levered to the extent of the actual D/E ratio of each company to arrive at the equity beta for the respective company which is applied on the market risk premium arrived at from the BSE 30 index viz., 8.2%.

2.5.3 Though many of the parties perhaps could not understand the intricacies of beta calculation, NTPC has come out with certain balanced criticisms. It has stated that historical data should be given weightage of only 0.67 instead of the full weightage as done by CAS. It has also argued that the asset beta for power sector should be higher than the proposed value viz., 0.60 on account of greater risk in the power sector than in the refinery sector which has been considered as a proxy for the power sector. It has also further suggested that there should be a cap on the beta up to one and that outliers should be removed from the sample of publicly traded refinery and power sector companies. Though CAS has dealt with these questions raised by NTPC on an intellectual plane, we have not been convinced on the practicability and advisability of the adjustment for individual company's debt/equity ratio, though the principles are theoretically well founded. PGCIL has considered the asset beta of refinery sector as low, as this beta does not reflect the sticky debts position and the power sector companies' asset beta does not reflect the risk in transmission business. We do not recognise in principle the sector specific risk and adjustment for debt/equity. However, in the absence of any other better alternative the working of CAS of asset beta of 0.60 for the proxy sector may be appropriate. Any tinkering with this working would be only biased which we would not like to do. Further there is not much of a difference between power sector and refinery sector's asset beta.

2.5.4 Even assuming a normative mix of debt and equity viz., 50:50 based on the asset beta as recommended the rate of return would be in the range of 20 to 21 % as suggested by CAS. The present return on equity of 16 % was revised by the Government of India from the earlier ROE of 12 % in 1998. There had been a great deal of resistance from the beneficiaries to this increase in ROE to 16 % which prior to 1991 was only 10 %. We find a clear contrast between the existing ROE and rate base as against the ROE and rate base suggested by CAS. No doubt the existing rate base is linked to the liabilities side of the balance sheet whereas CAS has suggested the assets side approach. As at present based on the notification of 30th March, 1992 as well as the tariff notifications of 16.12.1997, the Government of India has adopted a policy of keeping the equity constant throughout the life of the plant irrespective of the depreciation written off. This has been the policy in respect of IPPs presumably as an incentive to sustain the interest of the investor even after the loans are repaid. CAS has recommended reduction in both loan and equity to the extent of the depreciation claimed on the fixed assets in determining the rate base. It is however evident that a conscious decision was taken by the Government to keep the equity constant even after the repayment of the loan. We have to consider the impact of ROE on tariff by taking both the rate and rate base into account.

2.6 Commission's findings on ROE:

The proposals of the CAS both in respect of rate and rate base have a strong logical foundation. CAS has also replied to the various queries raised by the parties during the hearings on apprehensions and reservations expressed by various parties.

The views of the parties with regard to the methodology for capital asset pricing model have been already set out. The debate on beta adjustments were very academic in nature. The quantification of risk premium based on the equity market study viz., 8.2% has been done for both asset beta

and debt/equity. The implications in the beta adjustments and for risk factor viz., debt/equity are bound to influence the tariff substantially. The net effect of the CAS study is that even if risk free return of 11 % is accepted as justified, the risk premium should be something above 11 %. Even if we proceed on a normative debt/equity of 50:50 the applicable risk premium would be around 9 to 10% as per CAS report. Is this premium justified or not is a difficult question. NTPC has commented on the reservations admitted by the CAS itself. These reservations relate to the impact study on cash flow, debt service coverage ratio, borrowing capacity etc., of the undertakings. While we appreciate the elaborate efforts put in by CAS to quantify risk premium, the following factors which are admitted by CAS, as inevitable do not enable us to confidently adopt the capital asset pricing model and the resultant ROE as recommended by them:

(a) The data on equity market expectation is based on a very limited sample of 30 equity shares of BSE which cannot be taken to be a clear reflection of the equity market expectation and as such the result is not fool proof.

(b) The risk perception with regard to power sector could not be precisely captured in the study for which a more elaborate exercise is still required to be done. This can be seen from the debate on the beta quantification.

(c) The model suggested by CAS lacks stability in as much as it is required to be linked to the actual debt equity of each company periodically. These companies do not have any manouverability to influence the debt/equity mix.

(d) A constant revision of the risk premium based on the behaviour of the equity and debt market would result in regulatory uncertainties which would be a great disincentive for investments in the sector, though the adjustment is contemplated every five years.

(e) The sticky nature of receivables as a factor needs to be tackled at the outset in order to bring out clearly the risk perception of the investor in the sector and it is only thereafter the uncertainties could be better quantified.

(e) Any additional increase in the ROE based on imperfect data may not be in the interest of the beneficiaries as a whole since this has a cascading effect till the final consumer.

(f) It has not been possible for CAS to make impact study due to reasons beyond their control and as such any decision of the Commission would be a shot in the dark without assessing the implications.

In the above circumstances, the Commission considers appropriate to refer any increase in the ROE till a more comprehensive study is undertaken. In the meanwhile, the Commission will explore the possibilities of introducing the concept of return on capital employed which is bound to bring about more stability, motivate the investor and will be more flexible to accommodate any mix of funds. As such, present ROE of 16 % is advisable to be retained for the next tariff period as well. It would however, be ensured that any revision in future would not result in the ROE falling below 16 %. This should assuage the feeling of uncertainty on the part of the investors.

2.7 **Rate Base**:

2.7.1 As already stated, the two elements of the return are the rate of return and the base on which rate is applied. We have already dealt with the first element viz., the rate. Regarding rate base, presently, the practice is to determine the base by proceeding from the original project cost, and dividing the same into a normative debt equity of 50:50. As regards the debt portion the interest as per the loan agreements is allowed as part of the tariff. The repayment schedule is taken as the basis for working out the balance loan on which interest is permissible. It is learnt that in 1992, and later when tariff was notified under section 43A(2) of ES Act for the first time for existing plants/lines, debt and equity on 50-50 basis was taken on their book value on that date. However, for new plants/lines actual project cost was taken. Similar treatment was adopted for transmission tariff also. Thus, it can be noted that after commercial operation starts, as years roll by, the debt/equity is bound to get distorted due to actual mix of debt/equity being different and depreciation and the loan repayment not perfectly matching.

2.7.2 The essential elements in calculating the rate base as at present are:

(a) The approved project cost/book value in case of existing plants/line
(b) The normative debt equity of 50:50
(c) Schedule of repayment of debt

Accordingly the ROE and interest on loan elements are being determined.

As stated above, loan is reduced to the extent of scheduled repayment for Calculating the interest. The tariff notifications do not establish any linkage between depreciation and loan repayment. However, revisions of depreciation rates in 1992 and 1994 give the indication that depreciation and loan repayment were linked. In fact the K.P. Rao Committee Report reinforces the impression that depreciation is first used to repay the loans and thereafter the equity base. However, this was not specifically indicated by the Government in the notifications.

Though there is no comprehensive document describing the present practice adopted for tariff fixation, the above description of the existing system tallies with the working for tariff calculations.

Since the first tariff on the above process was determined in 1992 for a period of 5 years and no further revision of tariff has been done there is no precedent available before us on how return on equity was treated after loans were repaid.

2.7.3 The rate base constitutes the pivot around which all major elements of fixed cost viz., ROE and interest on loan revolve. In order to ensure predictability of tariff the criteria for determining the base should be clear and unambiguous. The base as on date of COD is a fact, which can be certified by Auditors as well. However, the composition of debt/equity in subsequent years may or may not conform to norms. There may be schedules for repayment up front but later deviations may take place. Tariff, however, may get determined on normative scheduled repayment but the actuals may deviate from the norms over time. The tariff authority has to stick to the original project profile and the schedule and has to keep track of numbers in that trail. It should also be noted that in reckoning the base, working capital element should also be taken on normative basis all the time. The fact of the matter is that the base gets reduced to the extent of loan repayment and does not remain constant. Of course any permissible capital additions including on account of exchange rate variations do add to the base.

2.7.4 As against the present practice, CAS report has recommended the determination of rate base every time the tariff is to be decided including at the commencement of project by referring to the balance sheet. The report envisages identification of regulated assets and borrowings so that, from total assets, unregulated assets are deducted and the balance can be either divided into debt/equity on normative basis or by deducting from the total assets the actual outstanding borrowings to reckon the resultant equity.   It has suggested two methods viz., aggregated rate base and disaggregated rate base. In the aggregated rate base method, the total net fixed assets as per the balance sheet is adjusted for net fixed asset (not regulated), capital work in progress (not regulated), investments (non-statutory) and current assets (in excess of norms), which are deducted. This would constitute the rate base funded by debt and equity in the respective proportion for regulated assets. This may be split accordingly as per the normative debt and equity ratio and a composite return on debt and equity put together is worked out. In the disaggregated rate base method, the regulated net fixed assets, current assets capital work in progress and statutory investments are aggregated from which the actual long term loan is deducted to arrive at the adjusted net worth on which the return on equity is to be applied. The basic difference is that in the first method, the normative debt equity is applied whereas, in the second method, the actual long term loan is deducted to arrive at the net worth. Thus in both the cases the net assets as on date is taken but the split is on normative basis in the first case and in the other it is on actual basis. To this extent, the return element would differ. In short, CAS recommends return on fixed assets reduced to the extent of depreciation. CAS has set out detailed illustrations in its subsequent submissions based on the 2nd method.

2.8 Commission's findings on Rate Base Methodology:

2.8.1 The basic feature of the CAS recommendation on determination of rate base therefore is that we should resort to the audited balance sheet of the station/line, each year to determine the tariff of that year. The Commission envisages practical difficulties in relying on the balance sheet as suggested by CAS. It should be kept in mind that tariff is to be determined station wise/line wise. Presently, no audited station wise/line wise (or region wise) balance sheets are available disclosing in a verifiable manner the debt and equity. Further the actual book figures are based on the ground realities

whereas the tariffs are determined on normatives and hence reliance cannot be had on book figures. On a sample study we found that the net block on tariff basis and on balance sheet basis differ. For instance, the adjustments between head office and stations are purely internal on which regulator cannot have a control. There might be inter station transfers of assets and borrowings at corporate level. Exchange rate variations adjusted in the books distort the values of assets, if not approved by Regulators. Moreover, there is bound to be a time lag between the availability of audited balance sheet and the commencement of a year whereas tariff is required to be determined before the commencement of a year. In fact it is preferable to determine Tariff for the full tariff period in advance, subject to permissible additional capitalisation during the tariff period. It is therefore, more appropriate to develop parallel data commencing from commercial operation particularly of assets, debt and equity in order to keep track of the rate base on normative levels. The trail has to be followed independently commencing from approved project cost. These can be certified by the Auditors. Thus the methodology for obtaining rate base has to be different i.e. independent of the balance sheet.

2.8.2 In administrative pricing in all regulated industries (even including under schedule VI of the ES Act, 1948) return is allowed on net assets only. It should also be so under section 43A(2) of ES Act 1948 as well on a normal interpretation read with schedule VI. Hence it would be only appropriate to provide for interest and return on net fixed assets. While doing so, how much of the net fixed asset should be taken as equity and how much as borrowing? In this regard we find that in case of IPPs the equity is kept constant and return is continued to be provided till the life of the plant. Though no justification on record is available for the treatment adopted by the Government as at present, a legitimate assumption that depreciation is used to repay loans is appropriate though this is not borne out by any notification. After the loan is repaid, the balance of net fixed asset is represented completely by equity. There is no justification of providing return on equity not represented by assets. However, this practice has been uniformly advocated by the Government both for IPP and PSUs. The impression we are given is that return on equity should continue to be provided even though the assets are written of. This may be viewed as unwarranted and unfair but this is based on the notification dated 30th March, 1992 and 16th December, 1997 which state that a return of 16 % on subscribed capital relating to the plant shall be provided. `Subscribed capital' has to be justified with the presence of regulated assets to that extent. If non-core investments are present, a return through tariff on such assets can not be recovered for the same. The implication of CAS recommendations is to eliminate such aberrations.

2.8.3 A further anomaly has been created since 1992 by accelerating the depreciation rates ostensibly to augment the cash flow in the hands of utilities. For instance in case of thermal stations the recovery of 90 % of the cost of assets is done in 12 years. After 12 years before which time the loans are repaid the scrap value of 10 % and margin money for working capital would only remain to represent the equity and hence there would be no incentive for the promoter to operate the plant. As such the accelerated depreciation along with 'a return on constant equity base, the burden on tariff both initially and throughout the plant life is enormous. There is need to bring all utilities on par on these two issues with fairness to the beneficiaries. It appears however that these two steps were taken to facilitate loan repayments and incentivise the investors particularly the IPPs. There is need to harmonise the objective of promoting investments and determining a fair tariff for beneficiaries. This requires bringing all the players viz., IPPs, PSUs, Licensees etc., at par for which legislative changes are necessary. In the meanwhile however the objective behind the above two changes cannot be totally lost sight of, and has to be carefully weighed.

2.8.4 NTPC in its written submissions have advocated continuation of the existing method. It would like even the total capital base to be kept constant after the loans are repaid as according to it "though loans are progressively repaid, there is corresponding increase in the reserves which form part of the owners equity". In other words, NTPC has sought a return on the total investments which is akin to a return on capital employed. PGCIL has also advocated that no reduction in the equity should be done for any cash flow on account of depreciation. Both NLC and NHPC have not specifically dealt with maintenance of constant equity.

In contrast to NTPC's observations, state beneficiaries have totally conflicting views. The UP Power Corporation has adversely commented on the accelerated depreciation causing advance recovery of equity resulting in additional source of profit. The Rajasthan State Electricity Board has emphasised that a return on equity should be allowed on actual equity employed, which implies reduction of depreciation recovered over and above the loan repayment. Orissa's Gridco has advocated return on capital employed rather than return on equity which means treating debt and equity together.

2.8.5 The major controversy in rate base relates to the basic approach viz., assets side or liability side. In the liability side approach as is presently being adopted the value of the assets employed becomes irrelevant. The return on the two sources of investment viz., equity and debt are fitted into tariff as per the prescribed rates. Whereas the interest on debt will get reduced from time to time based on the scheduled repayment of the debt, the return on equity is being kept constant. This takes care of the issue of sustaining the investors interest in the plant after the loans are repaid. This is the principle which has been adopted in case of IPPs as well. The KP Rao Committee however had recommended that the return on equity should be reduced once the loans are repaid to the extent of the depreciation allowed.

2.8.6 It is evident that CAS has recommended the assets side approach to determination of rate base whereas NTPC and Power Grid have advocated the liabilities side approach. According to the utilities this is the underlying concept behind tariff notification of the Government of India dated 30th March, 1992 and specifically of the notification dated 16th December, 1997. The distinguishing features of these two approaches are –

(a) In the liability side approach the value of the assets on the ground would be ignored subject to the investments being used in the core activity; whereas in the assets side approach the value of the core assets on the ground are taken for arriving at the base.

(b) As a corollary, in the liability side approach the depreciation is independent of the rate base determination. In other words, depreciation is considered as the amount recovered to be used exclusively for replacement of the assets.

(c) In the liability side approach, the base would get reduced only to the extent of the loan repayment since equity is never repaid except on the dissolution of the company. As such return on equity would be allowed so long as there are assets to generate the revenue. When applied to a station/line 'equity' represents the net worth of the company invested in the project.

(d) The liability side approach provide scope for double counting of the equity in case the depreciation amount instead of being used for replacement of capacity is otherwise used for addition to the capacity. In the assets side approach this situation is averted.

(e) Underlying the assets side approach is the concept of return of equity with option to the investor to reinvest or quit; whereas the liability side approach provides an incentive to the investors to sustain his interest in the operation and motivates in sustaining his capacity and continue to render the service.

2.8.7 From a study of the policy of the Government of India with regard to IPPs it is evident that there was a conscious decision to offer incentives to investors so that they can continue to sustain their plants and operate the services. In case they discontinue they would also lose the return on the hypothetical capital which may not be the actual capital employed. This policy appears to have found its way into the pricing for public sector utilities

also as evident from the notification dated 16th December, 1997 in respect of Powergrid. We consider this as a deliberate policy of the government though not formally communicated under section 38 of the ERC Act. We do not propose to upset this deliberate scheme before a comprehensive study of the implications. We would like to view this as an encouragement in its own way to continue to plough back the cash flow including depreciation in either replacing the capacity and creating additional capacities. Public Sector undertakings so long as they stand committed to the power sector and do not diversify to other sectors without prior approval and proper justification should be entitled to this incentive of a return on the equity employed based on the liability side approach rather than a strict administered pricing approach based on the asset values. As such in all matters of tariff under section 13(a) or (b) or (c) for valid reasons viz., to promote investment in the sector and to plough back the funds within the sector either for replacement of capacity or addition to capacity a return on original equity has to be provided. The Commission will monitor the non-core investment and regulate the return in case of application of funds in non-core activities. We would like to sustain the underlying incentive feature behind the existing policy and would not like to upset the same in view of the need for promotion of investments in this sector. All the same the acceleration of depreciation, needs proper justification though augmentation of cash in flow has an equal and opposite cash out flow effect on beneficiaries. We shall take note of the same while dealing with depreciation.

2.9 General conclusion on ROE:

2.9.1 In view of our conclusion that the present method of reckoning the rate base should be continued the justification for a rate of return beyond 16 % has to be also critically examined. We have already come to the conclusion that there are imperfections in the reckoning of the cost of capital by adopting the capital asset pricing model. We have also concluded that with the adoption of

this model with linkage to the debt/equity of the individual utilities there would be fluctuating rates of return from period to period. Such a situation is undesirable both from the investors' as well as the beneficiaries point of view. This may also be looked with disfavour by lending institutions in particular international institutions. Application of higher rates beyond 16 % on the rate base would result in further burden of tariff on the beneficiaries which is bound to be resisted and may result in further sticky receivables. In the circumstances, we consider it appropriate to leave the present rate of return and the rate base as they are. We however, strongly recommend that the return on capital employed approach should be considered for adoption after a detailed study taking into account the implications of normative debt equity, unstable interest rates, leverage advantage once the loans are repaid and grossing up of taxation. We have the satisfaction that no uncertainty due to regulation and no serious tariff shock on either side would be created by this conclusion of preserving the status quo.

2.10 **Interest on Loan:**

With the adoption of the liabilities side approach to rate base determination, the interest on outstanding loans as a constituent of tariff is not a controversial issue. Before any tariff period it is only necessary to determine with reference to the original loan outstanding, the quantum of interest on the schedule outstanding loan for the forthcoming tariff period. It is necessary to stick to the original loans as per approved project cost and the original schedule of repayment. The contracted interest rate shall be applied on the schedule outstanding loan amount for the ensuing tariff period. In doing so, it is necessary to include in the loan the extent of exchange rate variation on the loan amounts as per our decision elsewhere in this order. Since the loans should be distinctly identifiable, the respective interest rates shall be applied on the scheduled outstanding loans. Thus any bullet

payments or extension of the tenor of the loan shall be exclusively to the account of the utilities concerned. This is in line with the existing practice.

2.11 <u>Interest on working capital</u>:

2.11.1 Working capital is a substantial component of the investment. The project cost should contain margin money for working capital. Thus in determining the return on equity and the interest on loan the project cost should be considered along with margin money for working capital as determined at the project stage. Any introduction of additional margin money for working capital should be with the approval of the Commission.

The elements of working capital have been already identified both in the K.P. Rao Committee Report as well as in the notification dated 30th March, 1992 separately for thermal and hydro stations. In addition the tariff notifications of power grid have also identified the elements of working capital. Though the margin money for working capital is already included in the project cost, the short term funding has to be obtained from banking institutions for which interest has to be paid and the same has to be fitted into the tariff. Both the K.P. Rao Committee and the government notifications have laid down the norms for working capital. The K.P. Rao Committee also debated on the need for a separate provision for working capital cost in view of the tariff earnings providing for depreciation and return on equity which do not involve any cash outgo. However, it was viewed that these cash flows are required for capital addition programmes and hence are not available for meeting the working capital requirements. **Accordingly, inclusion of interest on working capital based on the cash credit rates prevailing at the time of tariff filing is justified. We fully agree with this conclusion of the Committee. As regards the permissible components for the purpose of working capital, we find commonality in the norm for fuel expenses, fuel stocks and O&M expenses between K.P. Rao Committee recommendations and the Notification. As regards secondary fuel oil a limit of 60 days stock has been**

identified as the limit both by K.P. Rao Committee and the notification dated 30th March, 1992. Regarding maintenance spares the notification is more deterministic viz., 1 % of the capital cost. We propose to adopt these norms without change. However, with spares of current value and capital cost of historical value, the utilities are bound to be hampered in their operations for lack of maintenance spares. As such it would be more appropriate to resort to estimating the spares consumption of one year based on the average consumption over the last five years. In doing so, it should be ensured that only those spares which are not capitalised initially but were booked in the revenue account and spares supplied by the plant suppliers as a part of the warranty are taken into account. The norms for working capital in respect of above items in case of hydro stations and power grid as contained in the relevant notifications may be adopted as they are on the same lines as applicable to thermal stations.

2.11.2 As regards receivables, the position as envisaged both in the K.P. Rao Committee and in the tariff notifications prior to 1992 have not come true. Both the documents envisaged an outstanding position of about two months average billing calculated on normative operations. The outstanding position however is alarming and is stated to have crossed the average of six months billing. This situation has been brought about by a combination of factors viz., accelerated depreciation, increased rate of return, deteriorating financial position of SEBs caused by irrational tariff, lower than cost in most cases and mounting non-technical losses. In fact, each utility is justifying their norm for increased rates of return due to the huge outstanding receivables over the norms. One alternative in determining the normative working capital is to increase the norms for receivables in view of the past history. **Another alternative however is to retain the norm as it is and explore measures for enforcing these norms on the beneficiaries. We consider the second alternative as more preferable and as such we propose to sustain the norms for receivables as at present. Since the power to enforce orders on fear of personal penalty is granted to the Commissions, we propose to use**

these measures in the ultimate analysis in case of persistent violations. K.P. Rao Committee had recommended a rebate of 2½ % in case the bills are paid by opening LCs. Alternatively, a rebate of 1 % is contemplated in case the bills are paid within one month of presentation. Keeping in view the reduced interest rates prevailing in the market these are adequate incentives for the beneficiaries to make payments promptly. As such we propose to incorporate these incentives in the payment of bills.

3. DEPRECIATION

3.1 The Concept of Depreciation

3.1.1 Depreciation is an important element of fixed cost as it constitutes roughly about 20 % of the total expenditure of generating companies both thermal and hydro and in case of transmission companies, it constitutes even more than 40 % of the total expenditure. Depreciation, as compared to other elements of cost, is not the cash outgo incurred during a year. It is a fraction of the original cost of the capacity created in the form of a book adjustment which is built into tariff every year and recovered over the years as part of fixed cost. It is a major contributory to the cash flow of utilities.

The definition of depreciation as found in the Accounting Standard of the Institute of Chartered Accountants of India is:

"Depreciation is a measure of the wearing out, consumption or other loss of value of a depreciable asset arising from use, efflux of time or obsolescence through technology and market changes. Depreciation is allocated so as to charge a fair proportion of the depreciable amount in each accounting period during the expected useful life of the asset. Depreciation includes amortisation of assets whose useful life is predetermined." (Accounting Standard 6).

3.1.2 The value of depreciation is normally linked to the historical cost of the depreciable asset though the economic value for evaluating the service is not necessarily the historical cost. In this concept of `economic value' is included the replacement cost of the asset or of a corresponding asset whose services if evaluated as on date would constitute an element of the cost of service. As a result of this, conflicting views on the values are attributed to depreciation viz., it should be related to the historical cost or should be related to the present replacement value or the future replacement value discounted to today's value etc. These discussions did find a place in our exercise as well.

3.2 **Our approach**

3.2.1 We entrusted a study on the depreciation norms to M/s ICRA Advisory Services so that they could study the present practices and recommend the most desirable method in the context of the international practices. The paper presented by ICRA Advisory Services was circulated to all parties concerned and was also discussed in the Central Advisory Committee as well as in the Experts Group specifically constituted for this purpose.

ICRA Advisory Services was represented in all the discussions and have taken note of the discussions.

3.2.2 The recommendations of ICRA are broadly as follows:

(a) the Straight Line Method be followed based on its wide acceptance, price smoothness and the positive effects on utility interests.

(b) Depreciation rates currently prescribed have no relationship with the fair life of the asset. It is proposed that the rates be derived from the fair life assuming a residual value of 10 %. This will result in a reduction of the depreciation rates. The fair life used to determine the rates is as prescribed in the 1994 notification.

(c) It is possible that the life may be lower than the notified life by comparing the asset lives with international norms. It is observed that the internationally prescribed asset lives are higher compared to the Indian norms. While this may be due to differences in operating conditions, it is proposed that the asset lives be determined afresh after a scientific study.

(d) Depreciation base be gradually shifted to an Optimised Depreciated Replacement (ODRC) cost base. The period over which this shift needs to be done can be determined by the utilities and the CERC.

3.2.3 The present practice regarding depreciation is that for the purpose of pricing generation and transmission, the Straight Line Method of depreciation at the rates prescribed under the Electricity Supply Act, 1948 is being followed. The rates of depreciation as laid down in the Electricity Supply Act of 1948 underwent changes in 1992 and 1994. The pre 1992 situation is that the depreciation rates and the fair life of the asset as reflected in the Government Notification, were correlated with each other. In other words, the rates of depreciation multiplied by the expected life of the asset would yield 90 % of the value of the asset which is the depreciable value, leaving 10 % as the scrap value. The original cost of the asset got depreciated at a uniform rate over the life of the asset. In 1992, there was readjustment of depreciation rates for some items of assets with readjustment in useful life in some of the assets. In 1994, there was a further steep upward adjustment in the rates with practically no readjustment in the useful life of assets. The net result is that the rates of depreciation averaged to roughly 7.4 % for thermal stations as against 3.4 % before 1992. The correlation between the depreciation rate and the life of the asset was totally cut off. The consequence was that the assets got depreciated as for as tariff is concerned over a shorter period of time than the expected useful life. This brought about a front loading of the tariff in the first 12 years, leaving the balance period, without a depreciation charge in case of thermal stations. Front loading has been done in hydro and transmission also, to a certain extent.

3.3 Legal provisions regarding Depreciation

3.3.1 We have to consider the question of depreciation in the light of the Electricity Supply (ES) Act, Income Tax Act and the Companies Act since all the Utilities we are concerned with are companies registered under the Companies Act. The Electricity Supply Act and the Companies Act, are in line in as much as the latter contains a provision to the effect that companies engaged in generation or supply of electricity except in so far as the said provisions are inconsistent with the provisions of the Indian Electricity Act, 1910 or the Electricity Supply Act, 1948, the provisions of the Companies Act shall apply. If the ES Act, as it does, prescribes a different schedule of rates then the ES Act schedules shall apply. It should also be noted that the Electricity Supply Act as such does not set out the rates but only specifies under section 75A(3) that for the purpose of preparing the statement of accounts referred to in this section the depreciation to be provided every year shall be calculated at such rates as may be specified by Central Government by Notification in official gazette in accordance with the provisions of section 43A(2). Since section 43A(2) is not totally deleted, the schedule notified by the Central Government shall still prevail for preparation of accounts. However, for tariff purposes the Commission can consider appropriate rates for depreciation. We are aware that Electricity Boards and Licensees adopt the schedule as notified by the Central Government under the ES Act. The Commission would like to take a considered view on rates of depreciation. **It recommends to the Central Government that these rates be notified under sections 43A(2), 68, 75A(3) and Schedule VI as well so that there is uniformity at the national level. We are conscious of the implications of our conclusion at all levels.**

3.3.2 As regards Income Tax Act, till the assessment year 1997-98, depreciation was allowed by written down value (WDV) method as per rates prescribed in the Income Tax Act. In respect of assets acquired thereafter, option is available to assesses to follow the WDV method or the method prescribed under the ES Act. As such over a period of time it is hoped that all the 3 enactments would fall in line. However, liberty for tax planning through choice of depreciation method would continue to be available.

3.4 **Issues in Depreciation**

3.4.1 It may be appropriate to list out the major issues in the context of depreciation. These are: (a) Whether the straight line method or any other method of depreciation should be followed? (b) Whether acceleration of depreciation recovery is appropriate for cash flow reasons? (c) What should be the asset base for the purpose of depreciation? (d) Need and methodology for estimating the useful life of the assets? It is necessary to record here that there has been an absolute uniformity of view of all parties - whether utilities or beneficiaries as regards the method of depreciation that it should be a straight line method and not on any other method like the written down value method etc. It has also been pointed out by the consultants in their report that 97 % of the countries of the world are adopting the straight line method for their tariff purposes or for their accounting purposes. **Hence there is no conflict as to what should be the method of depreciation to be charged. The question however is to write off over what period.**

3.5 **Acceleration of Depreciation**

3.5.1 The next question therefore is what should be the rate of depreciation? Conceptually, the rate of depreciation has relevance to the useful life of the asset. Can we delink the rate from the useful life of the asset? In other words, can we complete the depreciation recovery over a shorter period than the effective life of the asset i.e., can it be unevenly loaded? In this connection, it may be noted that one of the objects of charging depreciation is to provide funds for replacement of the assets. Hence it may be argued that the method should be such that adequate funds are generated to replace the exact asset which is extinguished at the end of its life. As such it may be argued that by recovering the depreciable value over a shorter period of time, interest earnings thereon can adequately take care of the inflationary effect when the assets become due for replacement. Yet another dimension of this front loading is the question of tax benefit. Since the front loaded tariff would be coming up in the earlier years of the project when the project may be having a tax holiday, during this period the entire tax benefit could be taken through the revenue flows so that in the subsequent period the revenue flow may be less and the tax impact can also be less. This is the incidental tax advantage which can also augment the cash flow for replacement of the assets. The question to be considered is whether the replacement cost in actuality warrants this front loading.

Another justification for accelerating the depreciation is that lenders' requirement for debt repayment in a highly geared capital structure can only be addressed through accelerated depreciation and hence there is need for front loading of the tariff.

A third justification is that the accelerated depreciation would provide additional cash flow, which can be used for expansion of capacities in a sector which is starved of funds for investment.

3.5.2 Companies in the private sector had been tinkering with depreciation rates and methods in order to manipulate disposable profits for facilitating dividend declaration. Option available on methods were misused, to achieve short term benefits. Balance sheets were dressed up by using depreciation to reflect or conceal sickness of the company. These however are undesirable practices. Depreciation has to be dealt with as understood universally both in concept and methodology.

3.5.3 Our consultation paper on bulk electricity tariffs contains the following on depreciation:

"4.9.9 Treatment of depreciation and asset life – The depreciation rates currently in use are relatively high. Considering accepted asset life, the depreciation rates in use in India have the effect of front loading the tariff. Typical asset lives used internationally are (the quoted figures provide the range of values for utilities in the USA and Canada):

- Hydro power unit 30-40 years
- Thermal (coal) unit 25-30 years
- Transmission lines 25-35 years

This would indicate that depreciation rates in the range 3-4% would be appropriate based on straight line depreciation, versus the 7-8% now used in India. Adoption of more realistic asset lives, linked to the corresponding depreciation rates, would have a downward effect on tariffs. Adoption of more realistic asset lives might also provide pressure to maintain assets in a better condition to achieve such asset life. It may be useful, to review actual asset life of various types of plant in India, as opposed to the notional asset life indicated by the depreciation rates. If asset life in India is actually lower than the international norms, this indicates that the asset replacement is taking place far more frequently than the norms of good utility practice would allow."

3.5.4 The present practice on depreciation for tariff purposes has to be considered in detail. The tariff notification provides that depreciation shall be as notified by the Central Government. Apart from increasing the rates in the schedule in 1992 and 1994, thereby delinking the rates from the estimated useful life, the concept of "advance against depreciation" has also been used in case of hydro sector. The notification provides that in case of hydro stations, the depreciation to be included in capacity charges shall be that as per the schedule or advance against depreciation which shall be linked to 1/12 of the loan amount and further limited to loan repayment during the year. The advance against depreciation and total depreciation in the life of the project shall be limited to 90 % of the capital cost. This is a further front loading beyond accelerated depreciation. NHPC has pleaded that this cash flow should be preserved to enable it to repay the loans.

3.5.5 We have considered all the arguments in respect of front loaded tariff by accelerating the depreciation and advance against depreciation. We also took into account the views of the parties in this connection. NTPC has advanced two major arguments viz, that in the subsequent part of the life of an asset, the repair and maintenance cost viz., O&M increases and efficiency of plant reduces due to ageing and as such in the initial years if the depreciation is accelerated in subsequent years the maintenance cost can constitute an element in the tariff to smoothen the tariff curve. It is also stated in the reply that no concessions have been made to central utilities while accelerating the rates of depreciation in the past. This increase in rate of depreciation is applicable not only to the central public sector undertakings but also to SEBs. Any reduction in depreciation will affect the growth and expansion plan of the sector as a whole and also discourage new investment in the sector.

Neyveli Lignite Corporation has argued that the basis on which the current Indian statutes viz., the Electricity Supply Act and the Companies Act fixed the depreciation rate and its implication require deliberations. Depreciation rate should be based on the presumption of the statute. The concept of lower rates cannot be applied straight away in all the cases, especially in cases like NLC's, first thermal plant, which underwent a life extension programme, after the plant has spent nearly 3 decades of life. The ICRA report has observed based on three years data of central generating stations like NLC and NTPC, that there is no relationship between depreciation and debt servicing. According to NLC, these however, may not be representative data. These plants would have been initially installed long back. Major part of the debts might have been serviced in these plants. These PSUs had the privilege of availing budgetary support from the Government of India in earlier years. In fact projects were funded by GOI by debt and equity in the ratio of 1:1. Once GOI debts are repaid, debt would be replaced by internal resources only. In the event of reduced depreciation debt servicing may not be possible and debt may have to be serviced out of the return on equity. This will result in reduced availability of distributable surplus to the shareholders. This will affect the image of the company and the company may not be able to meet the market expectations in debt raising and market mobilisation of the equity will be difficult because of lower credit rating.

PGCIL has stated that the rate of depreciation should be maintained at the same level as is prevailing today till ODRC is implemented. ODRC is a method of charging depreciation which is recommended by Consultants, which is linked to replacement cost. If calculations are based on economic life of asset the rate will be reduced to half leading to reduction of internal resources by about Rs.343 crores in one year and 1715 crores during the next 5 years for PGCIL, thereby depriving the transmission sector of capital investment to the tune of Rs.8575 crores.

NHPC in their written submission has furnished a note regarding depreciation, advance against depreciation and loan repayment in the case of URI Hydroelectric Project. It has done the calculation of interest based on :-

(i) the actual repayment schedule;
(ii) repayment schedule matching with depreciation + advance against depreciation as per GOI Notification; and
(iii) repayment schedule strictly matching with depreciation rates as existing now.

From this calculation it has concluded that the interest liability will be the maximum if depreciation is allowed strictly in accordance with the GOI depreciation rates in which case the interest amounts to Rs. 2252 crores over the life of the loan. In case depreciation is coupled with advance against depreciation, the interest liability would be Rs. 1455 crores. In case the actual repayment schedule is followed, the interest liability would be only Rs. 1101 crores. From these calculations NHPC has concluded that even with depreciation plus advance against depreciation they had to incur more than Rs. 350 crores towards interest liability from their normal returns besides repayment of principal from the ROE component. In case depreciation is considered only at the level of GOI notified rates, the interest liability NHPC would be maximum and the difference would be of the order of Rs. 1150 crores over the life of the loan besides creating cash flow problem. In view of this, NHPC has insisted on the system of payment of advance against depreciation over and above the normal depreciation to be continued as per the existing GOI Tariff Notification.

3.5.6 The Punjab State Electricity Board in a brief reply has stated that the depreciation rates being derived on a fair life of the asset assuming residual value of 10 % i.e., 90% spread over its useful life is appropriate. However, fair life of the asset as notified by the Government of India in 1994 need to be refixed and relate to international standards. The Rajasthan State Electricity board has stated that the present depreciation rate of 7.84 % has no relationship to the useful life of the asset, which results in a rise in tariff rate, which will also adversely affect the maintenance of the Plants.

The UP Power Corporation Ltd., in its affidavit has stated that increased/accelerated rate of depreciation beyond the rates arrived at on the basis of straight line depreciation method would facilitate CSUs to recover capital before the life of the asset is over. GRIDCO of Orissa, in its affidavit has stated that the depreciation at higher rate may be allowed to generating company in the form of advance depreciation for repayment of debt installments subject to the depreciation plus advance depreciation in any year being limited to the amount of debt installment of that year. In such an event, the total depreciation and advance depreciation so allowed should not exceed the difference in value of the asset and the residual value.

KPTCL in its affidavit has stated that ICRA has suggested depreciation based on the total useful life of the asset which in their opinion would reduce the depreciation rate by about 50% . In view of this reduction, higher depreciation of

0.5% in respect of dams, associated civil structures could be accepted. TNEB has stated that the depreciation rates in India at 7.84 % is on the higher side though the useful life of the assets is almost comparable with other countries where the depreciation rates are between 2.5 % to 3.5 % except the UK where it is 4.4 %. Hence the Commission should consider fixing depreciation rate between 3 % to 5.06% as was existing until 1992 in order to save the SEBs from the burden of paying higher fixed charges to cover the debt servicing. The depreciation rate after debt servicing is over has to be reworked taking into account the balance capital cost to be depreciated. In case the depreciation is continued at the higher rates then interest charges at the commercial rate of borrowing for the difference in amount between the actual depreciation collected and the depreciation as per the straight line method has to be given credit to the beneficiaries.

Shri Bhanu Bhushan, Director (Operations) Powergrid in his personal capacity has come out with an interesting formulation. The depreciation requirement if the life of the asset is taken into account would be a mere 75 paise per annum for every Rs.100/- of investment so that this 75 paise per annum collected along with the interest on that amount would be sufficient enough to get for the company an amount equal to cost less 10 % for scrap value. In other words he has worked out the interest earning on the depreciation amount collected through tariff in order to make up the 90 % cost over the life of the asset. This combined with the recommendation of a rate of return of 16 % and the interest cost on loan over the life of the asset irrespective of whether the repayment takes place during the period of the life of the project or not, should constitute the element of tariff.

3.5.7 We have observed that different approaches with regard to depreciation are being followed by various utilities based on the rates prescribed by the Government of India. In the case of thermal power stations, accelerated depreciation has been allowed thereby recovering the entire depreciation within a period of about 12 years. In the case of hydro projects this concept did not find full favour with the Government and the Government has chosen to provide advance against depreciation in addition, to enable the hydro power project developers to meet their principal repayment obligations. In the case of thermal power stations, ostensibly, the same was achieved by more accelerated depreciation. The rates for transmission system are less than the accelerated depreciation allowed for thermal power projects as the depreciation rates for major components like transmission line was not changed during the revision in 1994. Pursuit of different practices has also resulted in different problems such as increased generation tariff in the case of thermal which probably is also a reason for larger outstanding in their case. Besides there are also problems in the accounting treatment of advance against depreciation. **It is worthwhile to bring about uniformity in the method of charging depreciation across the entire electricity sector covering the thermal and hydro generation as well as transmission. This could be achieved either by providing further accelerated deprecation for hydro and transmission projects or by providing advance against depreciation for repayment of loans in the case of thermal and transmission projects as well. Along with extending advance against depreciation, it is appropriate that the depreciation rates would then have to be linked to the fair life of the various assets. Thus, depreciation rates which were prevailing before 1992 could broadly become the relevant rates subject of course to any revision in estimation of useful life of the asset which was done in 1992 and 1994. This would smoothen out the tariff, reduce tariff shocks due to excessive front loading of tariff, bring uniformity of depreciation rates across various utilities etc. As far as the utilities are concerned, their debt service obligations are to be fully met subject to application of test of prudence with regard to the duration of loan which has been recognised as 12 years in the case of existing hydro stations. The utilities would also do well to manage their finance by resorting to refinancing etc by which they can create opportunities for optimising their financing cost and reduce interest burden, which shall accrue to them exclusively.**

We do recognise that the above may result in some reduction in the cash flow to utilities which are presently using accelerated depreciation. However, no utility shall suffer on account of lack of funds for repayment of loans as the concept of advance against depreciation is a flexible measure. It should be ensured that once the loans are repaid the depreciation rates are readjusted to spread the balance depreciable value over the balance life of the assets.

3.5.8 It is obvious that the accelerated depreciation was introduced in order to facilitate the utilities (a) to replace the assets, which costs more than original assets, (b) provide funds for expansion programmes and (c) for meeting the debt repayment obligations particularly, where the debt equity ratio is very high. The acceleration of the depreciation thus raised some important questions viz., (a) is it not burdening the consumers of today for a promised cheaper power for consumers of tomorrow? (b) to the extent that these funds are used for expansion which is not financially prudent is it not legitimate on the part of the consumers to expect supply at cheaper cost? (c) If accelerated depreciation is the instrument for attracting investment has it really produced results? (d) In the past was the depreciation collected really used for the repayment of the loans or replacement of assets? (e) Is it not legitimate for the consumer to expect that this additional money that is put in by him before the due date of such depreciation should be compensated in the form of interest? It is seen from studies that there is no linkage between depreciation and loan repayment obligations as well as depreciation and the quantum of investment in expansion. On the other hand, the increased quantum of depreciation can be said to be one of the important causes for sticky outstanding of loans from State Electricity Boards since this has been perhaps beyond the capacity of these SEBs to pay.

Another contention of most of the respondents is that with the recovery of 90% of the cost in very short period, the utility can lose interest in the project. In our view this contention has a great deal of significance particularly with the progressive privatisation.

The simple answer to all these questions is to go back to the fundamentals of depreciation viz., spreading the depreciable value over the useful life of the asset. Having done that, it is necessary to address the question of facilitating loan repayment which incidentally benefits the consumers in the form of reduced interest charges. The solution to such problem is “advance against depreciation” subject to test of prudence. As regards fund for replacement purposes, we understand that replacement costs are falling and it is true that inflation rates are very much under control. Moreover, with the collection of depreciation through monthly bills interest is also being earned on the depreciable value. Hence the problem is not as enormous as it is made out.

The argument for adequate cash flow in order to meet debt obligations, cannot be ruled out totally either. After all, the consumer is only asked to pay the additional deprecation within the 90 %, which in any case he is required to pay over the life of the project. The only difference is that the consumer is asked to pay in advance, which he would have otherwise paid over a period of time but with the early repayment of the loan he gets a tariff advantage as well through reduced interest charge.

The argument of NTPC that higher O&M cost at the later part of the life of the assets makes up for the front loading is not tenable as the magnitude of these two items are not comparable. As regards smoothening the tariff, we have now attempted to smoothen the tariff on both depreciation and O&M, subject of course to the inevitable advance against depreciation.

3.5.9 The argument of all utilities that accelerated depreciation would facilitate capacity expansion is unfair to the beneficiaries. This would amount to misapplication of funds. A utility should apart from expanding capacity sustain the existing capacity. Depreciation funds should be used to sustain existing capacity whereas earnings ploughed back should be used for capacity expansion. Though funds can not be set apart in a compartmental fashion, the basic concept can not be lost sight of. However, despite this, we have made separate provision to a moderate extent for capacity expansion also.

3.5.10 Our findings on depreciation as an element of fixed cost are as follows:

(a) Depreciation shall be calculated annually by the straight line method as per rates prevailed prior to 1992 in the schedule as notified under the ES Act.

(b) These rates shall however be changed for revision in useful life in respect of those assets as done in 1992 and 1994.

(c) Thus the rates and the useful life of the assets shall be corelated. A fresh schedule shall be drawn out accordingly.

(d) Wherever any loan repayment as originally scheduled requires additional cash flow above the depreciation allowable, to that extent and subject to a limit of 1/12th of the original loan amount, an amount can be added to the depreciation as advance against depreciation. However, the total depreciation during the life of the project shall not exceed 90 % of original cost. "Original cost" for this purpose includes additional capitalisation on account of foreign exchange rate variation also.

(e) On repayment of entire loan the remaining depreciable value shall be spread over the balance useful life of the assets.

(f) Central Government is advised as per section 13(e) of the ERC Act to revise the depreciation schedule under the ES Act so that

all provisions would fall in line. We are conscious that the effect of this change in schedule would be to revise all electricity rates till the distribution level subject to the jurisdiction of SERCs. However, this will help in rationalisation of tariff thorughout the country. In case of IPPs probably consequent to the PPA this front loading may have to be sustained. Still the financial impact over the life of the project would be nil.

(g) Depreciation is chargeable from the first year of operation (on pro rata basis for operation for part of the year) as against the present practice of a depreciation holiday in the first year.

3.6 **Value base for depreciation**

3.6.1 Depreciation by and large universally is calculated with a value base, which is equal to the historical cost. The consultants have considered three alternative value bases which take us to the third issue viz., what is the asset base for the purpose of depreciation? This question has been addressed taking three different approaches viz., fixed cost base, market value base, economic value base. The cost base approach is either the historical cost or replacement cost. The market value base is either the disposable value or net realisable value. Economic value base is the discounted cash flow or capitalisation of future earnings. The consultants have after analysing the historical cost have proceeded to examine the feasibility of the optimised depreciated replacement cost (ODRC) method. The ODRC method involves assessment of the gross current replacement cost of modern equivalent asset, making adjustment for design, over capacity and redundant asset and then depreciating this optimum gross current replacement cost to reflect the effective working life of the asset from the age of the new asset and estimated residual value at the end of the assets working life. Out of the three methods which are discussed, the historical cost method is the time tested one and is based on records whereas the market value base and economic value base including ODRC do not have any record base. These involve estimations by experts on the value, which can be attached to depreciation with reference to the service that is obtained from the asset. This is highly subjective. The parties have not been able to effectively react on any other value basis other than the historical cost base because on all these matters there is a great deal of subjectivity involved. The historical cost method smoothens the tariff. The consultants have dealt with issues regarding price shocks, economic signalling etc., which though perhaps academically relevant in the present circumstances may not be appropriate to be introduced till these are examined in detail regarding their fool proofness.

3.6.2 On the question of asset base therefore the options with us are either to go for the historical cost base or estimated values which are subjective. We are of the firm view that the depreciation as a time tested concept accepted by accounting bodies universally is the spreading of the original cost over its effective life. Hence we are of the view that the value base for the purpose of depreciation should be the historical cost and not the replacement cost or any other values. Again there are perceptions that subsequent to the opening up of the economy replacement values are tending to decline, despite the inflation in the economy over a period of time. This is a transition period in which it is not advisable to launch any particular method without fully understanding the implications. Therefore we would advocate the continuation of the existing base for the calculation of depreciation namely the historical cost. We are not convinced about the ODRC method since it has already been concluded that primarily depreciation is not a process for collecting money for replacement of the asset but is a process for repayment of the capital in instalments. Still as an incentive the equity base is kept constant. Having taken this view, it would not be proper to shift to a different line of argument.

3.7 **Revision of useful life**

3.7.1 The fourth issue is on estimating the useful life of the asset. Estimation of useful life in the context of depreciation serves a limited purpose of spreading the cost over the life. By merely accelerating the depreciation the useful life of the asset can not be reduced. **A separate assessment of the useful life taking into account technological and other relevant factors has to be made. Since there is a deliberate reduction in the useful life as per schedule in case of some assets we uphold the revision to that extent.**

Though estimation of useful life is of academic importance as there does not appear to be any new developments in the present context, a comparison of the life of assets as reckoned in other countries could be done. This comparison shows that the life span in India is shorter than in many other countries. This probably, may be due to standards of maintenance, quality of fuel, nature of handling, atmospheric conditions etc. No authentic study is available to us to establish the reasons. However, it is true that the life span is shorter than in many other countries. **We consider CEA as the appropriate authority to carry out such a study if considered necessary.**

3.8 **Environmental compliance**

In order to ensure compliance with the environmental regulations, it is necessary to identify those assets relating to environmental protection separately. When tariff is being set, the Commission proposes to examine whether in the past, environmental standards such as pollution levels etc., as prescribed have been complied with during the previous tariff period. In case of non-compliance the Commission will disallow the depreciation on such assets.

4. OPERATION & MAINTENANCE COST (O&M)

4.1 Key Issues

4.1.1 Operation and maintenance cost (hereinafter referred to as O&M) broadly refers to the expenditure incurred on employees, administrative overheads and repair and maintenance of the generating station/transmission system. The existing practice for fixing O&M norms follows a two-step approach. First, the base level of O&M expenditure (which is specified as a fixed proportion of capital cost) is determined. Subsequently the base is escalated every year over the tariff period on the basis of an escalation norm.

Thus, the two key issues in the review of norms of O&M expenses are:

(a) How much should the utility be allowed to charge under the O&M head i.e. the base level of O&M?

(b) What should be the escalation factor for this base year O&M?

4.1.2 The process followed for the revision of the norms involved the following steps:

(a) Commissioning of studies for guidance on issues relating to O&M norms which was circulated to all the stakeholders:

- M/s DCL and WAPCOS were appointed consultants for Benchmarking Industry's best practice for O&M costs and escalation characteristics of such costs for thermal power generation using international and domestic data and preparing a Proposal for Operating Cost norms including O&M norms for Hydro Power Stations respectively.

- For the transmission systems no study was commissioned but extracts of the report of the Expert Committee on framework to facilitate Private Investment in Transmission Projects were circulated

(b) CERC Staff Discussion Papers on issues related to escalation formula for O&M expenses:

- Review of Escalation formula for O&M Expenses of Power Generating Stations
- Review of Annual Escalation Formula for O&M Costs of Transmission Systems

(c) Public hearing where the stake holders presented and defended their viewpoint

(d) Synthesis of the entire process from steps (a) through (c) to arrive at norms.

4.2 Existing guidelines and the need for revision and related issues

4.2.1 The guidelines for O&M expenses of thermal and hydro stations and transmission systems have changed from time to time. The existing guidelines are documented in Table-1 below:

Table-1 ***Norms for Fixing the Base level of O&M Expenses and its Escalation***

S. No	**Utility**	**Base**	**Escalation**
THERMAL STATIONS			
1(a)	NTPC	For coal based stations 2.5 percent of the current capital cost which is the cost approved by CEA in the year of fixation of tariff of a similar project	10 percent escalation each year 10 percent escalation

1(b) 1(c)	IPPs NLC	For gas based stations 2.5 percent of capital cost 2.5 percent of the actual capital expenditure of thermal plants or 2 percent of actual capital expenditure of ceiling on capital expenditure provided in the PPA plus actual expenditure on Insurance (GOI notification dated 30/3/1992) Actual O&M expenditure of the terminal year of previous tariff period.	each year On the basis of a weighted price index mutually agreed upon between Board and the Generating Company. 10 percent per annum
HYDRO STATIONS			
2)	NHPC	1.5 percent of the approved capital expenditure as per GOI notification dated 30/3/1992	On the basis of a weighted price index mutually agreed upon between the Board and the Generating Company.
TRANSMISSION SYSTEM			
3)	POWERGRID	1.5 percent and 2 percent of the actual capital expenditure at the time of commissioning of transmission system in the plain area and hilly area respectively. (GOI notification 16/12/1997)	Escalation as per the weighted price index with 60 percent weightage to Wholesale Price Index and 40 percent to Consumer Price Index

4.2.2 For the thermal generating stations, the K.P. Rao Committee (1992) (Section VIII, page 18) had suggested the continuation of the existing practice of computing O&M expenses. It recommended that in the tariff period of 5 years, for the first year permitted O&M should be 2.5 percent of current capital cost which should be subject to 10 percent escalation for remaining four years of the tariff period. The report had further suggested that these norms should be revised after five years giving due consideration to the actual level of O&M expenses in the preceding years. The revision of norms has been pending since 1997.

4.2.3 One striking aspect of the escalation factors prescribed in the existing GOI norms is that while NPTC is permitted an annual escalation of 10 percent in the O&M costs, POWERGRID and NHPC are allowed annual escalation on the basis of weighted indices of the Consumer Price Index (CPI) and the Wholesale Price Index (WPI). The use of different escalation factors for different utilities should be justified, failing which this anomaly needs to be corrected. Further, the weights attached to WPI and CPI should, to the extent possible, reflect the cost increases in the components of O&M expenses. These issues have been discussed in detail in the CERC Staff Discussion Papers.

4.2.4 The principle of fixing the base level of O&M expenses as a percent of capital cost is fraught with the problems of measurement of capital cost of generating stations/transmission systems of old vintage. In the case of old generating stations of NTPC, principle of current capital cost is used for computing the base level of O&M expenses for a given tariff period. The current capital cost is defined as the capital cost in the year of fixation of tariff for a similar project. This method of computing the current capital cost is not appropriate as it is not directly related to the project for which it is being computed and can lead to distortions.

4.2.5 In the case of Central hydro stations of NHPC, the base O&M is computed as a fixed proportion of the approved capital cost at the time of commissioning of the project. The base level of O&M thus obtained is escalated each year on the basis of permitted escalation factors. So, the principle of current capital cost is not adopted in the case of NHPC stations. The use of differential approach to measurement of capital cost in different Central Government utilities needs to be examined. The possibility of computing the base level of O&M without reference to capital cost in the case old generating stations also needs to be explored.

4.2.6 The revision of O&M norms should consider the efficacy of the existing norms for computing the base level of O&M expenses and the escalation factors. To be fair to both the utilities and the beneficiaries, the review of O&M expenses should not only examine the adequacy of existing norms in compensating the O&M costs incurred by the utilities, but also the prudence of such expenses.

4.2.7 In what follows, the revised norms for computing the base level of O&M and escalation formula after a careful deliberation of the findings of the consultants, Staff Discussion Papers of the Commission and the views of the stake holders for Central Thermal Generating Stations (NTPC and NLC and NEEPCO), Central Hydro Stations (NHPC, NEEPCO) and Inter-state Transmission System (ISTS) are set out.

4.3 O&M for Thermal Sector

4.3.1 The report of M/s DCL (dated 25.08.2000) was circulated to the concerned parties and views of the respondents to the petition were heard. The consultants have made an attempt to benchmark international best practices of O&M costs for US and 16 other countries. The domestic benchmarking has been done on the basis of a select sample of 7 NTPC stations, 2 state level stations and 2 NLC stations. M/s DCL have expressed reservations about international benchmarking of O&M expenses.

For computing O&M expenses, they have suggested two alternatives:

(a) They contend that 2.5 percent of capital cost is insufficient to cover the O&M expenses of coal based stations and have recommended computation of O&M expenses at 2.8 percent of the escalated capital cost which is computed using a linear function estimated from the past data. For the gas-based stations DCL report is inconclusive.

(b) The second alternative of computing O&M costs links it to the generation costs.

The novelty of their approach is that it does not require the use of an escalation factor for computing year to year O&M expenses.

4.3.2 NTPC's response with regard to benchmarking international best practice was that comparison with US was not tenable due to different conditions prevailing in the two countries and differences in the quality of coal. The superior quality of US coal reduces the maintenance expenditure of power plants. NTPC disapproved of DCL's proposal of linking O&M expenses to generation cost.

For the gas-based plants, NTPC stated that the current capital cost obtained through DCL's method overstates the capital cost as the data used pertains to old plants which had higher capital cost. The capital cost projected on the basis of this data leads to an overestimate of capital cost, and hence a lower O&M to current capital cost ratio. NTPC suggested that 3.5 percent of the current capital cost should be allowed as O&M expenses for coal based generating stations. For the gas-based stations, they suggested a normative base for O&M at 5 percent of capital cost on the basis of their own analysis.

For annual escalation NTPC argued that:

- 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:

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

- NTPC also requested that in view of the steep increases in water charges in recent times, the increase in water charges beyond what is permitted in O&M should be allowed as a pass through in the tariff.

4.3.3 NLC disagreed with DCL's proposal of linking the O&M costs to Generation cost/fuel cost. They suggested that operating cost of both the mine and power station should be viewed in totality as they are an integrated unit.

NLC has suggested three alternatives for computing O&M expenses:

(a) 3.0 to 3.25 percent of the current capital cost should be allowed as O&M expenses. The current capital cost is to be obtained by the method suggested by DCL consultants.

(b) As an alternative, base O&M may be fixed on a normative base with a provision of 10 percent annual escalation.

(c) O&M expenses to be divided into major components viz. wages, spares and consumables with each escalation in component being arrived on the basis of RBI indices.

4.3.4 All the state utilities viz. TNEB, RVPNL, PSEB, GRIDCO and UPPCL disagreed with the findings and recommendations of DCL consultants of linking the O&M to the generation costs. TNEB argued that DCL' recommendations were based on select NTPC stations and hence were likely to be biased. TNEB, GRIDCO, PSEB and UPPCL suggested a continuation of existing norms for computing the base level of O&M expenses. RVPNL suggested while fixing O&M norms the NTPC's actual expenditure on O&M should be analysed. PSEB raised doubts about the comprehensiveness of the study conducted by DCL and the reasoning offered for the alternate proposal of linking O&M cost to generation cost. UPPCL suggested that the escalation formula given in the GOI notification of 30.3.1992 and the price indices used in the formula should be modified to reflect the requirement of electricity industry. RVPNL agreed with the escalation formula suggested in the CERC Staff Discussion Paper.

4.3.5 After a careful perusal of the documents circulated and hearing the views of various parties, we feel that:

- **There are serious limitations in the proposal of DCL consultants and they may not be accepted because:**

  - **It is based on a scrutiny of data pertaining to select NTPC stations. Thus, the conclusions reached are not sound.**

  - **DCL's alternative proposal of linking O&M costs to generation cost/fuel cost has not found acceptance with any party. The major limitation of this approach is that it will allow different O&M expenditure to similar plants depending upon whether they are at the pithead or at the load centre.**

- NTPC's proposal for fixing the O&M expenses at 3.5 and 5.0 percent of current capital cost for coal and gas-based stations also relies on data for select plants which may not be truly representative and is fraught with the problems of measurement of capital cost.

- 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.

- NLC's proposal of fixing base O&M cost at 3 to 3.25 percent of current capital cost too is plagued with the problems in the measurement of current capital cost. It is however noteworthy that despite lignite being a very inferior variety of coal, NLC's proposal for fixation of O&M norms for both the base and its escalation are lower than those proposed by NTPC.

4.3.6 The Commission is convinced that linking the base level O&M expenses to the capital cost is not appropriate as there are unresolved issues of measurement of the capital cost itself. Thus, the efficacy of the base on the basis of capital cost is questionable. The approach adopted in this order is based on following tenets:

- **The base level of O&M should not be computed as a given proportion of capital cost but should be derived on the basis of actual O&M expenses in**

the last five years after ironing out the spikes and abnormalities in the year-wise data.

- **Any abnormal expenses incurred by utilties in operating and maintaining their plants should not get reflected in the norms but should be dealt with separately on a case by case basis through separate petitions. This will provide an opportunity to all the stakeholders to assess the merit of claims on the basis of these expenses in a transparent way.**
- **Escalation in O&M should be on the basis of a weighted price index of CPI and an index of those components of WPI which mimic the non-employee costs of power generating stations.**

4.3.7 The Base O&M expenses shall be calculated as given in Box 1.

Box 1. Computation of Base level of O&M expenses

The average of actual O&M expenses for the five-year period (1995-96 to 1999-2000) should theoretically correspond to 1997-98. Thus, by escalating it twice preferably on the basis of price indices it can be pulled up to 1999-2000 level will serve as the base.

$BO\&M2000_i = AVO\&M_i \times (1.10)^2$

Where $BO\&M2000_i$ = Base level O&M for 1999-2000 for ith generating station

$AVO\&M_i$ = Average O&M costs from 1995-96 to 1999-2000 for the ith generating station

The $AVO\&M_i$ has been escalated twice by 10 percent, which is the permissible escalation for NTPC.

The base level of O&M expenses derived using the above methodology has following advantages:

- **It does not rely on current capital cost estimates, computation of which is both difficult and controversial.**

- **It uses actual O&M expenses of the utilities to arrive at a normative base for O&M.**

- **The averaging of data smoothens the impact of spikes in O&M expenses on the normative level for 1999-2000.**

4.3.8 During the hearing, NTPC had argued their actual O&M expenses were in excess of what was provided for in the tariff. In this scenario, the proposed method based on actual O&M expenses and the escalation norm of 10 percent per annum will result in a base for 1999-2000 which is in excess of what they are currently permitted in the tariff. But it will be less than the actual O&M expenses incurred in 1999-2000 as the O&M expenses had been growing at the rate of over 15 percent per annum much higher than the normative escalation rate of 10 percent per annum.

Thus, the base level of O&M expenses for NTPC stations will lie between what they are permitted as per the existing norms and what they are actually incurring. As the commission has not carried out any test of prudence on the actual O&M expenses incurred by NTPC, this norm is justified. In future however the test of prudence shall be applied wherever 'Actual" are taken as the base.

The base level of O&M for NLC and NEEPCO obtained through the above method will similarly be impacted by the trends in actual escalation of O&M expenses vis-à-vis the permissible escalation.

4.3.9 For escalating the base O&M expenses of generating stations, the approach discussed in CERC Discussion Paper dated June 2, 2000 is proposed to be adopted. The approach improves upon the existing escalation norms in the following ways:

- **The overall WPI includes some items that are not associated with O&M expenses of the generating station e.g. agricultural commodities. An index of those components of wholesale prices (WPIOM) closely associated with O&M expenses that reflects the 'non-employee cost' better than overall WPI is used.**
- **The employee related expenditure is linked to the Consumer Price Index for Industrial workers (CPI_IW). One may note that CPI is available separately for a given basket of goods and services consumed by a defined group of population viz. Agricultural Labourers (CPI_AL), Urban Non-manual Employees (CPI_UNME) and Industrial workers (CPI_IW). The coverage of CPI_IW extends to factories, mines, plantations, railways, public motor transport undertakings, electricity generation and distribution establishments and ports and docks. It is, therefore, more suited for measuring the increases in cost of living of employees of the power sector.**
- **The annual escalation factor is expressed as a weighted average of inflation in CPI and WPIOM- a special index of those components of WPI which are related to O&M operations of the generating stations. The allocation of weights has been done on the basis of the share of various components in the overall O&M cost and each component is linked to the appropriate price index.**

4.3.10 The special index of wholesale prices for power generating utilities (WPIOM) includes relevant groups/sub-groups of WPI. WPIOM is obtained as a weighted average of relevant components (Box 2) selected from disaggregated WPI series (1993-94=100).

Box. 2. Computation of WPIOM

COMMODITIES	**WEIGHT**
1. Lubricants	0.16367
2. Cotton Cloth	0.90306
3. Jute, Hemp and Mesta Cloth	0.37551
4. Paper & Paper Products	2.04403
5. Rubber & Plastic Products	2.38819
6. Basic Heavy Inorganic Chemical	1.44608
7. Basic Heavy Organic Chemical	0.45456
8. Paints Varnishes & Lacquers	0.49576
9. Turpentine, Synthetic Resins, Plastic materials etc	0.74628
10.Matches Explosives & Other Chemicals	0.94010
11. Non-Metallic Mineral Products	2.51591
12. Basic Metals Alloys & Metals Products	8.34186
13. Machinery & Machine Tools	8.36331
14. Transport Equipment & Parts	4.29475
All the Above (WPIOM[1])	**33.47307**

[1] $WPIOM = \dfrac{\sum_{i=1}^{14} wiWPIi}{\sum_{i=1}^{14} wi}$ where *WPIi* is the wholesale price index of the ith commodity and *wi* is the respective weight

Although WPIOM is not published as a separate category yet it can be easily constructed from the disaggregated WPI data that is available with the same frequency as the overall WPI. The principal advantage of WPIOM is that it is a better proxy for the non-employee O&M expenses of power generating stations than WPI for all-commodities.

4.3.11 To work out a reasonable weighting pattern the structure of O&M costs across NTPC and NLC was examined. It may be noted that the allocation of corporate expenses on the basis of CPI and WPI-related categories has been done for NTPC as they had provided the breakup of such expenses. However, the disaggregation of data provided for other administrative expenses is limited to only 7 NTPC stations which may not be representative. Thus, these expenses have been put under WPI-related costs. After an analysis of the structure of O&M costs of both NTPC and NLC the following escalation formula has been derived.

$0.4 \times INFL_{CPI} + 0.6 \times INFL_{WPIOM}$

where:

$INFL_{\mathbf{CPI}}$ **=** Inflation in CPI_IW

$INFL_{\mathbf{WPIOM}}$ **=** Inflation in WPIOM

4.3.12 The regulated entities shall include in their Tariff petition details of yearwise actual O&M cost data for the last five years duly certified by Statutory Auditors. The data should exclude all abnormal expenses such as account of water charges. In the case of new stations which were not existing for a period of five years the base O&M will be fixed with reference to the actual capital cost (2.5 percent of capital cost) duly escalated at the rate of 10

percent to bring it to 1999-2000 level. The capital cost of new stations is well known and its measurement is not an issue. The utilities shall provide a breakup of O&M expenses by major categories for the last five years 1995-96 to 1999-2000, duly certified by the statutory auditor.

4.3.13 The average escalation factor for the last five years (1995-96 to 1999-2000) on the basis of the escalation formula specified above has been rounded off to 6 percent. The utilities shall escalate their Base O&M for the tariff period at 6 percent per annum. A deviation of the escalation factor computed from the actual data that lies within 20 percent of the above notified escalation factor (which works out to be 1.2 percentage points on either side of 6 percent) shall be absorbed by the utility. Deviations beyond this limit will be adjusted on the basis of the actual escalation factor for which the utility will have to come to the Commission with a petition. The escalation factor of 6 percent applies only to the current tariff period.

4.4 O&M for Hydro Sector

4.4.1 The analysis of various hydro stations by WAPCOS, both of NHPC and the state utilities, indicates that existing norms wherein the base level of O&M expenses is fixed at 1.5 percent of capital cost are justified. They further pointed out that O&M expenses of NHPC stations are higher due to overstaffing. The O&M staff deployment in all the NHPC stations (except Uri) exceeded the norms worked out in the 9th Five Year Plan document.

WAPCOS also pointed out that comparison with hydro stations in developed countries was not meaningful as they were designed for unattended and remote operation and hence had lower O&M expenses. They however suggested that additional O&M expense may be allowed for the stations affected by insurgency on a case by case basis only if the concerned state had failed to meet the security requirements of these stations.

On the basis of the structure of O&M costs of 29 hydro stations, the following escalation formula was suggested:

$$Xn = Xo\ (0.07+0.87CP(n)/CP(o) + 0.06\ WP(n)/WP(o))$$

Where Xo and Xn are O&M expenses in the first and the nth year
CP(o) and CP(n) are the CPIs in the first and the nth year
WP(o) and WP(n) are the WPIs in the first and the nth year

It may be noted that while CPI related costs have been provided a very high weight of 87 percent, no escalation has been provided for insurance expenses.

4.4.2 For working out the escalation formula the Staff Discussion Paper suggests an approach similar to that adopted for thermal generating stations.

- The escalation formula was suggested on the basis of the structure of O&M costs.

- As an alternative to the use of overall WPI in the escalation formula, use of WPIOM as suggested for thermal stations (Box 2) is adopted.

4.4.3 NHPC expressed its reservations about the findings of the consultant and contended that O&M expenses as percent of capital cost varied from 1.25 in Uri to 5.04 in Loktak. The permissible level of O&M expenses were thus insufficient. They suggested that they should be allowed to recover 2 percent of the capital cost under the O&M head plus the actual expenses on security.

NHPC acknowledged the problem of overstaffing but pointed out that it was due to the tardy process of redeployment of staff from completed projects owing to socio-political compulsions and difficulty in retrenchment. They, however, contested the observations of the consultant regarding overstaffing made on the basis of 9th FYP.

They stated that their sanctioned staff was very much within the norms recommended by CEA task force sub group IV-1985 and NHPC O&M norms Committee constituted in 1989. They also stated that staff employed in the completed NHPC stations had come down by 2069 in 1999-00 over the previous year. This is reflected in a fall in their O&M expenses by about Rs 69 crores in the corresponding period.

Responding to the Commission's query on the reasons for higher O&M expenses in their stations, NHPC pointed out that security expenses in the plants located in insurgency prone areas and siltation problem in Salal, which were beyond their control, inflated their O&M expenses.

NHPC disagreed with the escalation formula proposed in the WAPCOS report and the CERC Discussion Paper. Their basic objection relates to the use of CPI and WPI in escalating the O&M expenses which they contend cannot adequately take care of escalation in O&M costs. They have suggested that O&M expenses should be escalated by a minimum of 10 percent.

4.4.4 UPPCL suggested that the escalation formula should:

- De-escalate the insurance component of O&M expenses
- Not escalate administrative expenses like rent, travelling, consultancy expenses

PSEB agreed with the recommendation of WAPCOS on permitting O&M expenses at 1.5 percent of capital cost. They however argued that for hydro projects with long term storage, O&M expenses should be permitted at only 0.4 percent of capital cost as has been observed in Dehar and Bhakra projects. They further pointed out that there was no need to reimburse additional security expenses as requested by NHPC as this was taken care of by the respective states in which the projects were located. PSEB agreed with CERC's Discussion Paper's methodology of calculating the escalation factor but recommended that weights accorded for inflation in WPI and CPI should be changed to 0.65 and 0.35 respectively.

4.4.5 The Commission recognizes the problems associated with the measurement of capital cost of old projects and the computation of base O&M expenses as a proportion of fixed cost. This issue was widely debated in the hearings. NHPC's attempt to prove that actual O&M expenses as a percentage of capital cost are insufficient is not very appropriate as the measurement of capital cost is faulty. They have inflated the original capital cost (the capital cost at the time of commissioning of the project) by 6.5 percent per annum to arrive at year-wise estimates of capital cost.

There is no justification for using the factor of 6.5 percent for compounding the capital cost. This factor is an average of weighted average inflation in CPI (industrial workers) and WPI (for the manufacturing sector) during 1994-95 to 1999-2000. This was documented in the CERC Staff Discussion Paper to study the impact of one of the options of the proposed escalation formula.

4.4.6 In view of these problems in the measurement of capital, an alternative of computing the base level of O&M on the basis of actual O&M expenses in the last five years after ironing out the spikes and abnormalities in the year-wise data is proposed for hydro stations. The methodology is as indicated in Box 1. It may be noted that for hydro stations, the permissible escalation factor for O&M expenses is worked out on the basis of a weighted average of WPI and CPI. We have however adopted the escalation factor of 10 percent per annum for bringing the five-year average corresponding to 1997-98 to 1999-2000 level to maintain uniformity across sectors.

4.4.7 For escalating the base O&M expenses of generating stations, the approach discussed in CERC Discussion Paper dated June 2, 2000 has been adopted. It involves the computation of WPIOM and weights to be accorded to CPI and WPIOM. Computation of WPIOM has been discussed in **Box 2.**

4.4.8 To work out a reasonable weighting pattern, the structure of O&M costs of six NHPC stations was examined. The sub-categories of O&M expenses were regrouped into two broad groups of expenses viz. CPI-related expenses and WPI-related expenses. CPI-Related expenses include Employee cost, Travelling expenses, Rent and Insurance and 50 percent of corporate management expenses. As the break up of corporate management expenses is not available these were apportioned equally between CPI and WPI related expenses on the basis of trends in NTPC and PGCIL data. WPI-Related expenses include, Repair and Maintenance, Consumption of stores and spares, Electricity charges, Printing and Stationery, and other expenses. On the basis of the above, the escalation factor for the hydro sector is specified as:

Escalation Factor = 0.55 x $INFL_{CPI}$ + 0.45 x $INFL_{WPIOM}$

where:

$INFL_{CPI}$ = Inflation in CPI for industrial workers
$INFL_{WPIOM}$ = Inflation in WPIOM

The weightage given to inflation in CPI is lower than that proposed by WAPCOS due to following reasons:

- **Whereas the weighting pattern devised by WAPCOS was based on O&M data of state level hydro power stations, the above weights have been worked out on the basis of data of six NHPC stations.**

- **Although the CPI-related expenses accounted for over 57.0 percent of overall O&M expenses in the five year period spanning 1995-96 to 1999-2000, their weight was rounded off to 0.55. This is justified as due to redeployment of staff in NHPC stations, the share of CPI-related expenses is expected to drop even further.**

The weights attached to CPI and WPI are marginally different from that proposed in the CERC Discussion Paper as with the availability of disaggregated O&M data further refinement of weights was done.

4.4.9 The regulated entities shall include in their Tariff petition details of yearwise actual O&M cost data for the last five years duly certified by Statutory Auditors. The data should exclude all abnormal expenses on account of:

- **Security expenses on account of insurgency**
- **Problems due to abnormal siltation as noticed in Salal and Bairasul**
- **Impact of over staffing. There has been a significant redeployment of staff from completed projects of NHPC to those under construction during 1999-2000. This led to a drop in O&M expenses in 1999-2000. Therefore, the norms based on past data of actual O&M expenses will overestimate the normative base. NHPC is hereby directed to adjust the O&M data downwards under the assumption of employment level as in 1999-2000. This implies that the employee remuneration for the past data should be adjusted on the basis of employment in 1999-00.**

4.4.10 In the case of new stations which were not existing for a period of five years the base O&M will be fixed with reference to the actual capital (1.5 percent of capital cost) cost duly escalated at the rate of 10 percent to bring it to 1999-2000 level. The capital cost of new stations is well known and its measurement is not an issue. The normative base for 1999-2000 will be worked after purging the O&M data of the impact of abnormalities pointed out

above. This will partly overcome the problem of imprudent expenses and other project specific problems which may be transitory in nature in getting embedded in the normative base of O&M. The utilities may file a separate petition with justification of their demand for reimbursement of abnormal expenses. As the Commission has not carried out any test of prudence on the actual O&M expenses incurred by the utilities, this norm is justified. In future however the test of prudence shall be applied wherever 'Actuals" are taken as the base. The utilities shall provide a breakup of O&M expenses by major categories for the last five years 1995-96 to 1999-2000, duly certified by a statutory auditor.

4.4.11 The average escalation factor for the last five years (1995-96 to 1999-2000) on the basis of the escalation formula specified above has been rounded off to 6 percent. The utilities shall escalate their Base O&M for the tariff period at 6 percent per annum. A deviation of the escalation factor computed from the actual data that lies within 20 percent of the above notified escalation factor (which works out to be 1.2 percentage points on either side of 6 percent) shall be absorbed by the utility. Deviations beyond this limit will be adjusted on the basis of the actual escalation factor for which the utility will have to come to the Commission with a petition. The escalation factor of 6 percent applies only to the current tariff period.

4.5 O&M for Transmission Sector

4.5.1 The analysis in the Expert Committee Report is based on the actual O&M expenses of POWERGRID and SEBs. The report acknowledges that O&M expenses of the transmission system will depend upon a number of factors which include system configuration, voltage level, terrain, availability target and the age of assets. Their findings are as follows:

The Expert Committee does not make any clear recommendation for fixing the base level of O&M expenses of the transmission system. Their finding of O&M expenses at 1.5 percent of capital cost is based on data for 400 kV lines which dominate the transmission system of POWERGRID.

4.5.2 The discussion paper reviews the existing escalation formula, scope for its improvement and suggests alternative. The proposed escalation factor is based on Consumer Price Index and an index of components of WPI relevant for the transmission systems.

4.5.3 POWERGRID pleaded that the new norms should be fair to the consumers while ensuring adequate returns to POWERGRID. They further contended that:

- Permitted O&M expenses as per the existing norms are insufficient. They have stated that O&M expenses recoverable through transmission tariff do not cover the actual O&M expenses.

- O&M costs of some SEBs are less than 1 percent of capital cost as they do not include auxiliary consumption and insurance charges in their O&M expenses.

- Distinction should be made between hills and plains in fixing base O&M expenses.

- The expenditure on security personnel in militancy prone areas of J&K should be reimbursed over and above the norms for O&M expenditure.

- Power drawn for auxiliary consumption of sub-station/HVDC station should be payable by SEBs over and above O&M expenses.

- They agreed with the escalation formula proposed in the CERC Staff Discussion Paper. They however expressed apprehension that construction of new index of wholesale prices will lead to certification problems and may create controversy.

- That no efficiency factor should be specified for O&M expenses as efficiency element is already covered in the form of availability based disincentive as per GOI notification dated 16/12/1997.

During the hearings Commission directed POWERGRID to provide:

(a) Reasons for significant increases in the components of O&M in recent times
(b) Details of O&M expenses in hills and plains to get a better idea of the impact of terrain on the nature and extent of O&M expenses.

PGCIL clarified that the abnormal increases in O&M expenses in recent times was on account of addition of new capacity and that as a proportion of the gross block (which is the completed cost of transmission system) they have remained constant during the last three years. They also explained that significant increases in the employee costs in the recent past was on account of improvement in salary structure.

PGCIL did not submit O&M details of the hills and plains separately for substantiating their demand for higher O&M in hilly regions. They however submitted O&M expenses as a proportion of gross block in the NER hilly terrain where they were shown to range from 3.95 percent to 5.96 percent from 1997-98 to 1999-2000.

4.5.4 TNEB, MPEB and PSEB are of the opinion that base O&M expenses should be of the order of 1% of the Capital Cost. KPTCL and APTRANSCO have expressed agreement with the existing norms of base O&M expenses as stipulated in GOI Notification dated 16.12.1997. RVPNL and PSEB are in agreement with the recommendation of the Expert Committee that O&M expenses should be 1.5% of the Capital Cost. PSEB is also of the opinion that no distinction should be made on the basis of terrain while fixing the base O&M expenses. UPPCL have pointed out that the weighted average of sub-station costs and line costs works out to 1.39% and not 1.5% of capital cost as suggested by the Expert Committee.

MPEB pointed out that POWERGRID is paying MPEB only 1 percent of capital cost as O&M expenses for its bays (terminal equipment) installed in MPEB's S/S at Bhilai, Indore, Sarni and Korba (W). In view of this, MPEB argued that it is possible to restrict O&M costs to 1 percent of capital cost if the transmission system is timely and efficiently maintained. MPEB has therefore, suggested that O&M expenses should be fixed at 1 percent of capital cost.

On the issue of escalation of O&M expenses, TNEB, KSEB, PSEB, DVC and APTRANSCO have expressed agreement with the CERC Staff Discussion Paper. KSEB, however, does not want higher weightage to be accorded to CPI as was suggested in CERC staff paper. UPPCL has contended that insurance expenses should be de-escalated and no escalation should be allowed on administrative expenses like rent, traveling and consultancy expenses. KPTCL have suggested that escalation should be restricted to 5% per annum.

4.5.5 After carefully reviewing the views expressed by various stakeholders the Commission has decided to follow the approach of using actual O&M data for computing the base level. However the method followed for computing the base O&M in thermal and hydro sectors cannot be applied to the transmission sector without suitable modifications. The annual data on the O&M expenses of transmission system at the regional level consists, among other things, of increases in O&M expenses on account of network expansion. Therefore, a part of the growth in O&M expenses is likely to be on account of expansion of the transmission system/sub-system.

The method of averaging the O&M expenses and then incrementing it by a suitable escalation factor to bring it to a given base year will not account for increases in O&M expenses due to network expansion and hence will underestimate it.

4.5.6 In view of these problems, a variant approach is adopted. If the O&M expenses on substations and lines were separately available for each region, these should be normalized by dividing them by line length and number of bays in each region respectively. This will then be used to derive the base O&M for lines and substations a sum of which would give the base level of O&M for 1999-2000. If such data is not available the following proxy can be used:-

O&M expenses in region will be apportioned to the sub-stations and lines on the basis of 30:70 ratio as mentioned above in the Expert Committee Report. Let OML and OMS be the O&M expenses apportioned to lines and substations respectively. These should then be normalized as shown below:

OMLL = OML/Line Length

OMBN = OMS/Number of bays

It may be noted that number of bays in a region has been used to normalize the O&M expenses of substations. The five year averages of the normalized O&M expenses adjusted for inflation for two years (1998-99 and 1999-2000) can serve as a norm for O&M expenses per unit of line length and per transformer. The method of averaging the data smoothens the impact of any yearly spikes in the data and corrects for the impact of addition of new lines. These averages multiplied by line length and the number of bays in 1999-2000 will give the normative/permissible level of O&M expenses for 1999-2000. Thus,

BOMLL=AVOMLL x LL99-00 x $(1.10)^2$

BOMBN=AVOMBN x BN99-00 x $(1.10)^2$

Where;

BOMLL and BOMBN are the base levels of O&M (for 1999-2000).

AVOMLL and AVOMBN are 5-year averages of OMLL and OMBN respectively.

LL99-00 and BN99-00 are the line length and number of transformers in 1999-2000.

The normative base for 1999-2000 is the sum of BOMLL and BOMBN.

It may be noted that for the transmission systems, the permissible escalation factor for O&M expenses is worked out on the basis of a weighted average of WPI and CPI. We have however adopted the escalation factor of 10 percent per annum for bringing the five-year average corresponding to 1997-98 to 1999-2000 level to maintain uniformity across sectors.

4.5.7 For escalating the base level of O&M expenses of transmission systems, the approach discussed in CERC Discussion Paper dated June 2, 2000 has been adopted. It involves the computation of WPITR and weights to be accorded to CPI and WPITR. WPITR is an index of those components of wholesale prices that mimic the non-employee costs of the transmission systems better than the overall WPI. It is computed as a weighted average of relevant components (listed below) selected from disaggregated WPI series (1993-94=100).

COMMODITIES	WEIGHT
1. Cotton Cloth	0.90306
2. Paper & Paper Products	2.04403

3. Rubber & Plastic Products	**2.38819**
4. Paints Varnishes & Lacquers	**0.49576**
5. Turpentine, Synthetic Resins, Plastic Materials etc	**0.74628**
6. Non-Metallic Mineral Products	**2.51591**
7. Basic Metals Alloys & Metals Products	**8.34186**
8. Machinery & Machine Tools	**8.36331**
9. Transport Equipment & Parts	**4.29475**
All the Above (WPITR[2])	**30.0931**

4.5.8 To work out a reasonable weighting pattern the structure of O&M costs of the transmission system of POWERGRID was examined. The sub-categories of O&M expenses were regrouped into two broad groups of expenses viz. CPI-related expenses and WPI-related expenses.

CPI-Related expenses include Employee cost, Training and Recruitment, Communication expenses, Travelling expenses, Rent and Insurance.

WPI-Related expenses include, Repair and Maintenance, Power charges, Printing and Stationery, and other expenses.

On the basis of the average share of CPI-related and WPI-related expenses for the period 1995-96 to 1999-2000, the following escalation formula was devised.

Escalation = $0.55 * INFL_{CPI}$ + $0.45 * INFL_{WPITR}$

where:

$INFL_{CPI}$ = Inflation in CPI for industrial workers

$INFL_{WPITR}$ = Inflation in WPITR

---

[2] $WPITR = \frac{\sum_{i=1}^{9} wiWPIi}{\sum_{i=1}^{9} wi}$ where WPI_i is the Wholesale Price Index for the ith sub-group and w_i is its respective weight

It may be noted that weight of CPI-related expenses is higher than that reported in the Staff Discussion Paper. This is because corporate office expenses were treated as WPI-related. Subsequently, with the breakup of corporate office allocations made available by PGCIL, it was possible to apportion it to CPI and WPI related costs as mentioned above.

4.5.9 During hearing KSEB had contented that giving higher weightage to CPI related expenses may be detrimental to the health of SEBs as it may translate into higher provision of O&M expenses. This is not necessarily true. Although in the past on the average inflation in CPI has been higher than in WPI, yet there have been periods when inflation in CPI was lower than WPI e.g. during 1999-2000 average inflation in CPI at 3.2 percent was marginally lower than WPI at 3.5 percent.

4.5.10 The regulated entities shall include in their Tariff petition details of yearwise actual O&M cost data for the last five years duly certified by Statutory Auditors. The data should exclude all abnormal expenses such as on account of insurgency. The normative base will thus be computed after removing the impact of abnormalities This will partly overcome the specific problems that may be transitory in nature getting embedded in the normative base of O&M. **The O&M expenses on account of network expansion shall be computed on the basis of normative O&M expenses per unit of line length or bays as the case may be. The per unit normative O&M expenses will be escalated to bring them up to the level of the relevant year with the escalation at 10 percent upto 1999-2000 and 6 percent after that. As the Commission has not carried out any test of prudence on the actual O&M expenses incurred by the utilities, this norm is justified. In future however the test of prudence shall be applied wherever 'Actuals" are taken as the base. The utilities should file a separate petition with justification of their demand for reimbursement of abnormal expenses. The utilities should provide a breakup of O&M expenses**

by major categories for the last five years 1995-96 to 1999-2000, duly certified by a statutory auditor.

4.5.11 The average escalation factor for the last five years (1995-96 to 1999-2000) on the basis of the escalation formula specified above has been rounded off to 6 percent. The utilities shall escalate their Base O&M for the tariff period at 6 percent per annum. A deviation of the escalation factor computed from the actual data that lies within 20 percent of the above notified escalation factor (which works out to be 1.2 percentage points on either side of 6 percent) shall be absorbed by the utility. Deviations beyond this limit will be adjusted on the basis of the actual escalation factor for which the utility will have to come to the Commission with a petition. The escalation factor of 6 percent applies only to the current tariff period.

4.6. Conclusion

4.6.1 In principle the new norms described above follow a two-step approach as in the earlier norms. First, the base is computed. Next, it is escalated each year using a suitable escalation factor. Yet, significant improvements have been carried out over the existing norms.

4.6.2 The method of linking base of O&M expenses to capital cost of old generating stations was not found to be appropriate as the measurement of capital cost itself is difficult and controversial. In the alternative proposed, base of O&M will be computed on the basis of the averaging technique (see Box 1) applied to the actual O&M expenses of the utilities after ironing out abnormalities such as the impact of insurgency, abnormal siltation in hydro plants, sudden spikes in water charges etc.

4.6.3 The data used for computing the normative base will thus be sanitized of the impact of such data abnormalities. If these abnormalities are due to conditions beyond the control of the utility, the utility can be suitably compensated through the transparent mechanism of public hearing of their petitions in this regard. The difficulty of applying this approach to the O&M expenses of transmission systems is acknowledged and suitable modifications are made in the approach.

4.6.4 Whether or not this method of computing the base will cover the actual O&M costs incurred by utilities will depend upon the pattern of annual increases in their O&M expenses. If the O&M costs have been increasing at a rate which is in excess of permitted escalation, the utilities may not fully recover their actual O&M costs but it will be higher than what the existing norms permit and vice versa. As the Commission has not been able to apply test of prudence to the O&M data furnished by utilities, it is not justified to compensate abnormal increases in the O&M expenses of utilities.

4.6.5 The new norm for escalation of O&M charges is an improvement over the existing norms as it considers the impact of both the CPI and a refined index of WPI on the escalation formula.

- The refined index is constructed from those components of wholesale prices that mimic the ‘non-employee’ O&M costs of the utilities.
- The weights accorded to CPI_IW and refined index of WPI have been worked out on the basis of share of CPI-related and WPI-related costs in overall O&M expenses.

5. VARIABLE COST AND OPERATIONAL NORMS FOR THERMAL GENERATION

5.1 Background of Variable Charges

5.1.1 The need for laying down efficiency norms relating to operational requirements of Central Sector Utilities received the necessary attention of the Commission. The Consultation Paper on Bulk Electricity Tariff while dealing with efficiency and operational cost norms raised the following question:

> **"*under a regulated tariff regime, how can a regulator ensure that the norms being used for judging performance and thus allowing incentives or imposing disincentives, are challenging, without being burdensome for the utility? How should incentives be set, so that they induce continuous improvements in the efficiency of supply and demand?*"**

5.1.2 It will be necessary to mention here that there is no variable cost in the case of hydro generation or transmission systems. Practice of splitting the fixed cost into capacity charge and energy charge has been adopted in the case of hydro generation. This issue has been dealt with in detail in the Commission's orders on Petition No.17/2000 and 85/2000.

5.1.3 It may be mentioned that the tariff of Central Generating Stations was on a single part basis before 1992. This was found to be unsatisfactory for proper grid operations. The Committee constituted then under Shri K.P. Rao went into the subject and recommended a two part tariff. This consists of fixed charges and variable charges. The issue relating to the fixed charges has already been covered earlier. Presently the subject which is being discussed now relates to the variable charges. At the outset, the various aspects relating to the computation of variable charges are discussed below:

- The computation of variable charges is directly related to the station heat rate and the price and Gross Calorific Value (GCV) of the fuel. Adjustment for heat input by secondary fuel oil in the case of thermal power stations is to be made for calculation of consumption of coal. Thus the two important parameters which govern the variable charge are the quantity of fuel based on the heat rate and GCV of fuel, and the price of fuel. We propose to deal with these two aspects in detail as follows:

5.2. **Price of fuel**:

5.2.1 In the case of NTPC, the tariff notification issued by the Government of India indicates the weighted average price of coal as well as secondary fuel oil. This notification also refers to the actual landed cost incurred by the generating company for procurement of coal, oil, gas or naphtha. The method of calculation of the landed cost of fuel does not appear clearly either in the tariff notification issued by the Government for NTPC or in the notification dated 30th March 1992 issued by the Government of India. **The Commission, therefore, directs the generating companies in general to furnish the calculations for landed cost of various fuels including the inventory maintained at the power stations at the time of tariff petitions.** It is quite likely that the coal sector may move away from the administered price mechanism and also may be opened to private sector and the generating companies may have to enter into legally enforceable contracts for fuel supplies. As far as possible, the fuel supply arrangements shall be made on competitive basis. The fuel supply arrangements shall also take into account the fuel quality besides the quantity and the price factors.

5.2.2 The situation is different in the case of NLC wherein they operate an integrated lignite mine. NLC has explained that lignite can neither be stored in large quantities nor can it be transported over long distances. Accordingly, the mining operations are totally matched with the requirements of the thermal power stations which are located very close to the mines. This being so, NLC is following a transfer price mechanism for arriving at the variable charge. In view of the peculiar situation in which NLC is operating, the Commission would have liked to review the transfer price mechanism so that the ultimate cost of power charged to the customer is fair and reasonable.

5.2.3 **In the mean time, the present system of transfer price mechanism may continue to be followed**. **The Commission intends to examine the same in future and directs NLC to furnish the details of transfer price mechanism for the Commission's examination at the time of submission of tariff petition.**

5.3. <u>Operational Norms:</u>

5.3.1 The quantity of fuel for billing purposes discussed earlier is also directly related to the operational norms. The Commission initiated a suo-moto Petition No.4/2000 based on CEA norms of 1997. The present petition relates to fixing of these norms. It may be mentioned that the K.P. Rao Committee recommendations also contained the operational norms relating to station heat rate, secondary fuel oil consumption, auxiliary energy consumption etc. besides other parameters. The recommendation of the K.P. Rao Committee was in the context of Central Generating Stations. However, based on this report, the Government of India in their notification dated 30.3.1992, incorporated these norms and applied it to the IPPs. This original notification of 30th March 1992 has also undergone several amendments from time to time.

5.3.2: K.P. Rao Committee Report had also suggested that the operational norms should be reviewed and revised after a period of five years taking into account the actual experience. Central Electricity Authority subsequently issued OM in 1997 containing the operational norms for various new power plants. This document was circulated by the Commission in January 2000. A subsequent supplementary note was also received from the CEA in February 2000 which indicated that these norms could be made applicable even to the existing power plants. This was also circulated by the Commission in February 2000. These documents formed the basis for the suo-moto petition No.4/2000 initiated by the Commission for examining the thermal operational norms.

5.3.3: The Commission while issuing the suo moto petition also decided to appoint CEA as Consultants to assist in the finalisation of the Operational Norms, besides required assistance during the hearings. This was done keeping in view that the CEA constitutes a reservoir of technical expertise in the power sector and their advice would be material in the matter.

5.3.4: In response to these documents forming part of the Petition, the interested parties pleaded before the Commission during the hearings held on 8th and 9th May 2000. During the proceedings, the learned Counsel for NTPC Shri M.G. Ramachandran, made legal submissions questioning the jurisdiction of the Commission. The arguments relating to the norms given in the Review Petition of 13/2000 on the ABT Order dated 4.1.2000 were repeated by him. His arguments and the Commission's decisions are contained in our Order relating to the Review Petition. They equally hold good at this point and may be referred to.

5.3.5 S/Shri Shyam Wadhera and L.M. Kapur made technical submissions on behalf of NTPC. The submissions made by the representatives of NTPC were substantially different from the submissions of the Consultants as they have considered different operating margins for various operating conditions. During these hearings, Shri H.L. Bajaj, Director of NTPC made the suggestion that a group of experts may be constituted by the Commission who may discuss all the issues and submit its report to the Commission to facilitate the Commission in taking a decision. The Commission in its Order dated 9.5.2000, in view of the voluminous technical information which need to be sifted and in order to narrow down the areas of conflict, constituted an expert group with the concurrence of the parties. The expert group was Chaired by Shri V.S. Verma, Chief Engineer, CEA with a representative each of NTPC and NLC and Shri Bhanu Bhushan, Director PGCIL as Members and Chief (Finance), CERC as an Observer. SEBs were allowed to participate in the discussions and fully cooperate with the Group. The expert group sought additional information from NTPC, NLC etc. It was stated by the Chairman, Expert Group that while most of the information was furnished by these generating companies, the details regarding auxiliary oil consumption, station-wise auxiliary power consumption actual coal consumption etc. were not furnished by NTPC.

5.3.6 It was brought out by the Chairman, Expert Group that the major area of difference was the application of the margins (correction factors) for actual operating conditions. The generators have indicated certain correction factors without any diversity factor. It should be appreciated that all the variations may not be occurring simultaneously on one side on all the units and throughout the year. It was also explained by the Chairman, Expert Group that if all the deviations as proposed by the generators are taken into account, the gross heat rate figure for turbine and boiler would result in a number which is in excess of the present norms in existence i.e. 2500 K. Cal/kwh which is the heat rate projected at PLF of 68.5% as per the K.P. Rao Committee Report. That would be a retrograde step. The verification of heat rate was also stated to be not possible as the actual coal consumption figures were not made available. In view of the basic differences in the opinion of various members of the Expert Group, no consensus could be achieved with regard to various margins or correction factors relevant for different conditions.

5.4 **Key Issues in Operational Norms**

The following key issues relating to the operational norms came up during the hearing on the subject:

5.4.1 **Issue No. 1 : Settlement period:**

Settlement period is the time span reckoned for computation of variable charges. The draft operational norms of CEA which were circulated to the Commission indicated settlement period of one hour or other agreed period which was later clarified as 15 minutes settlement period to match with the ABT order. It was argued by the NTPC that this would create numerous disputes and could lead to delays and non-payment of dues by the SEBs. It was argued that the heat rate norms should not vary on a day to day or hour to hour basis. On the other hand, the Consultants (CEA) argued that these calculations would not have to wait for the actual energy flows from the special energy meters and could be done based on the schedules. The final report of the Chairman of the Expert Group was that the settlement period could be on daily basis. The generating companies however argued in favour of one normative heat rate on an annual basis. Accordingly the Expert Group could not reach an agreed solution in the matter.

5.4.2 **<u>Issue No. 2 : Specific secondary fuel oil consumption</u>**

The draft norms of CEA specified Specific secondary fuel oil consumption as 1.0 ml/kwh for coal and 3.0 ml/1kwh for lignite based power stations. NTPC argued in favour of retention of the existing norm of 3.5 ml per kwh especially in view of the actual characteristics. It was put forth emphatically by the NTPC that efforts on the parts of generating companies to be within the oil consumption levels as specified in the draft norms would result in dangerous situation leading to furnace pressurization and even accidents endangering the human life. It was also contended by the NTPC that with introduction of ABT, there will be higher partial load cycling on the machine. This would seriously hamper the stability in operation and machines will have to be shut down considering merit order operation and restarted depending upon the requirement of the grid. This would lead to increased secondary oil consumption. Hence NTPC was not in favour of any reduction of the existing level i.e. 3.5 ml per kwh. NLC also presented their case on similar lines and indicated that average secondary fuel oil consumption is 2.24 ml/kwh. The Chairman, Expert Group agreed with the draft norms of the CEA except in the case of lignite and the norm was reduced to 2.0 ml/kwh from 3.0 ml/kwh recommended by CEA. It may be seen that there was a substantial disparity of views and hence no meeting ground in the matter.

5.4.3 **Issue No. 3 : Auxiliary energy consumption**

The draft norms circulated stipulated auxiliary energy consumption of different values for various types of plants and systems. Subsequently the report of Expert Group dispensed with the correction for part load operation and of the values given by the CEA were reduced by 0.5%. The final figures for auxiliary consumption are in the range of 6 to 8.5% for various types of plants. The NTPC argued that the existing norms as per GOI notification dated 30th March, 1992 should be retained. NLC sought an Auxiliary Energy Consumption of 10.5%. It is relevant to point out that the details of actual consumption were not furnished by NTPC. The State Electricity Boards during the arguments suggested that the colony power supply, construction power supply etc. should be excluded from assessment of Auxiliary Energy Consumption. The points raised by the SEBs would be kept in view for action at an appropriate time. As things stand, again there is no meeting ground available on the subject from which a consensus could emerge on the issue.

5.4.4 **Issue No. 4: Heat rate and upgradation factors for existing generating stations**

Heat rate also involves determination of 'margins'. This refers to allowable deviations or correction factors over certain parameters of operation during actual operating conditions over the generated norms. Nineteen different factors were considered by the Expert Group as well as NTPC and NLC for coal/lignite stations which affect the turbine cycle heat rate. The details are contained in the reports of the consultants and the separate report given by the NTPC, NLC, etc., available with the Commission. However, a comparison of the margins or the correction factors indicate that while the generating companies have sought a margin of over 10%, the margins considered by the experts in the range of 4%.

In the case of gas/liquid fuel based stations, the margins shown by the NTPC are 10.28% and 12.45% for open cycle and combined cycle operations while the recommended margins by the Chairman of the Expert Group are 4% and 3.91% respectively. NTPC further argued that in the case of existing power stations at Anta, Auraiya, Dadri, Kawas and Gandhar station heat rates allowed by CEA vide their letter dated 18.3.1996 were higher than the corresponding GOI norms of 30.3.1992 for both simple cycle and combined cycle operation.

From the above, it could be seen that in the case of coal fired power stations, the major area of dispute seems to be the margins or the correction factors. There is no agreement on this issue. In the case of gas turbine power plants, only NTPC operates such power plants in central sector and there is no agreement in the Expert Group with regard to the margins to be allowed for arriving at the heat rate figures of Gas turbine power stations as well. Reconciliation of extreme positions taken by the Chairman of the Expert Group and the rest on the margins is not possible in the absence of authentic data relating to actual performance of power plants relating to heat rate. This information is not readily available.

5.4.5 **Issue No. 5: Heat rate and upgradation factors for new generating stations**

The Chairman, Expert Group has recommended the station heat rate norms for new coal/lignite based stations and gas/liquid fuel based stations. NTPC had expressed a view that in case of new power plants, they might be able to comply with the norms as the new power stations could be established in accordance with the norms but the margins as suggested by them should necessarily be provided.

In the case of gas based power projects the draft norms covered only three categories (based on size of gas turbines). However, this has now been divided into 5 categories based on size of gas turbines to accommodate smaller gas turbines as well.

5.4.6 **Issue No. 6 : Boiler efficiency**

The consultants/generators identified eight items as affecting the boiler efficiency. While the generators have sought correction factors of 3.72% (NTPC) and 4.471% (NLC). Chairman of the Expert Group recommended 0.296% and 0.813% respectively. Accordingly the formula for boiler efficiency calculations will change. Subsequently, NLC also suggested the removal of hydrogen factor from the boiler efficiency calculations due to which some additional changes would also be required. From the foregoing, it could be observed that no final view was reached on boiler efficiency parameters in the Expert Group. Resolution of this would call for a detailed study after receiving authentic data.

5.4.7 **Issue No. 7 : Commercial operation date**

The expert committee could come to a consensus on this issue and decided that the completion of trial run could be the commercial operation date (COD) for central generating stations as per the existing practice.

5.4.8 NEEPCO is operating gas turbines in the capacity range of 21 MW to 30 MW with associated steam turbines. NEEPCO in their petition No. 5/2000 and 6/2000 for their gas turbine projects at Agartala and Assam respectively have adopted the GOI tariff notification dated 30th March, 1992. These tariff petitions are for provisional tariff. NEEPCO is presently operating these plants at much lower PLF for various reasons as enumerated in our orders in respect of those petitions referred above. NEEPCO is directed to examine this issue in detail and approach the Commission within a period of 3 months with performance guarantee and actual operational data. In the meantime, the Commission expects to receive the advice of CEA with regard to low operating levels of NEEPCO power stations. The operational norms for these NEEPCO power stations with smaller size units swill be finalised by the Commission after receipt of relevant petitions from NEEPCO establishing the station heat rate duly taking into account performance guarantee test figures, actual operation data, etc. The petition shall cover all other operating parameters as well.

5.5 <u>Commission's Findings</u>

5.5.1 It would be seen from the foregoing that there has been considerable divergence of opinion on the draft norms of the CEA, on the one hand and the norms asked for by the central generating companies. To resolve the matter the Expert Group was set up by the Commission. The Expert Group itself was constituted on a suggestion made by the NTPC during the hearings. Ultimately it turned out that the report of the Expert Group was only the opinion of Shri V.S. Verma, Chairman. Certain other members of the committee chose to differ and went ahead to submit a separate report. The two reports – one by Shri V.S. Verma and the other by the rest of the members of the Expert Group – took extreme positions on all major issues concerning the operational norms and hence defied a solution, more so in view of the complexity of the technical matter. It was also seen that there was an apparent reluctance on the part of the utilities to part with vital data which would have helped in resolving the matter. The stand taken by them during the hearing was that the data, which they have, cannot be treated as authentic.

5.5.2 During the hearing, the NTPC argued that new norms should be applied only to the new power plants. For the old plants, the existing norms as contained in the Government of India notification dated 30th March 1992 should be continued. It would not be possible for the Commission to decide on the matter unless a cost benefit analysis is made for making efficiency improvements through practically implementable norms in such cases. Such a study should cover aspects relating to technology, effect of renovation and modernisation of the old plants etc. This calls for maintenance of proper data on the vital aspects by the utilities.

5.5.3 **In view of above, the Commission directs the NTPC, NLC and NEEPCO to maintain accurate and verifiable data relating to heat rate, cost consumption, secondary fuel oil consumption, PLF, availability, auxiliary power consumption etc. They are also directed to furnish the same to the Commission on a quarterly basis within 30 days expiry of each quarter so that these details could form the basis for further examination of the norms during the next tariff review.**

In the meantime the Commission issues the following further directions in the matter:-

a) **The operational norms except for PLF/Availability, as contained in the prevailing Govt. of India tariff notifications issued under section 43 A(2) in respect of each existing plant of NTPC shall continue for a period of 3 years w.e.f. 1.4.2001**

b) **In case of existing plants and the new plants of NTPC for which no tariff notification of Govt. of India exists but PPA's have been signed, the operational norms, except for PLF/Availability, shall be governed by the Power Purchase Agreements entered into with the beneficiaries for a period of 3 years w.e.f. 1.4.2001.**

c) **In case of new plants of NTPC for which neither GOI tariff notifications nor PPAs exist, the operational norms except for PLF/Availability as contained in the GOI tariff notification dt. 30.3.92 as amended shall apply for a period for 3 years w.e.f. 1.4.2001. However, the parties may agree to improved norms by mutual agreement.**

d) **The operational norms, except for PLF/Availability for NLC Stage II stations 1 & 2 as contained in NLC's present agreement with the beneficiaries shall continue for a period of 3 years w.e.f. 1.4.2001.**

e) **PLF/Availability and incentives for all the central generating stations shall be governed by separate norms issued by the Commission.**

f) **NEEPCO shall approach the Commission with suitable petition for fixing of norms for smaller gas turbine based power stations being operated by them within a period of 3 months from the date of this order with necessary supporting data.**

g) **All the Central Generating Companies are also directed to furnish the information as indicated in para 5.6 of this order in time so that the Commission will take up the revision of norms on expiry of 2 years so that the new norms may be put in place before the next tariff review.**

6. Foreign Exchange Rate Variation

6.1 Historical Perspective

In normal administered pricing regime the risk of exchange rate variation has to be borne by the investor. In case of licensees, in charging the tariff as per schedule VI of ES Act, 1998, since expenses which are of a revenue nature are only admissible and as such exchange rate fluctuations do not feature in the pricing in strict terms. This facility of protecting exchange rate risk has been extended to IPPs. In case of power sector projects generally, utilities have been totally protected from this risk both on interest payment and on repayment of loans. Exchange Rate fluctuation on repayment is basically not a revenue expenditure but has revenue implications. In a completely competitive market the scope for passing on such risks automatically to the beneficiaries would not exist. This system of passing on the risk however, has been accepted over the years and there has not been any resistance from the beneficiaries. In fact there has been a general consensus before us that this risk should be protected and built into the tariff.

6.2 Issues Involved

6.2.1 In the consultation paper, we referred to the issue of dealing with changes between tariff filing periods. Exchange rate variation is one such change. Exchange rate variation causes a major escalation in cost both on account of repayment of loan and on account of interest on the loans.

6.2.2 CAS in its report raised three issues regarding exchange rate variation viz., (a) whether the returns to a foreign investor need to be protected for exchange rate variations?; (b) should higher returns be permitted to compensate for foreign exchange variation risk?; and (c) would real returns be protected if protection for inflation is provided? On the first issue, CAS concluded that though in other sectors investments are being made without exchange rate risk protection, the power sector being closely controlled and since the investors have non-recourse mode of financing, the protection is essential. As regards the higher return as an alternative, the premium required could be significantly high making the tariffs impractical. On the third issue, though it may be able to achieve some balance, due to the lack of interest rate parity it may not ensure the required risk free return to the investor.

6.2.3 The question of exchange rate variation has to be addressed separately in respect of equity and debt. In case of sale of shares in open market, no protection on equity investment should be provided since the investor is making the investment in equity with clear knowledge. However, in case of joint venture projects or direct investments, in foreign currency this may be part of the package in order to attract the investments wherein the protection has to be considered. NTPC has suggested that protection on equity may be provided upto the extent of the prescribed level of equity and not beyond. With regard to debt, there is no difference of opinion on the protection. In this connection, NTPC has opined that it may be advantageous to provide on a normative basis for exchange risk in case of debt, which in other words means, borrowing beyond normal level need not be protected. PGCIL has also opined that variation may be allowed but on monthly basis. This will facilitate prompt and regular payment. Though we directed PGCIL to provide more details about their experience on the extent of foreign exchange variation, it has only submitted a list of beneficiaries with outstanding dues on account of Foreign Exchange Rate Variation, which does not throw any light on the extent.

6.2.4 CAS, in its recommendation, has favoured full protection for both debt and equity. However, the methodology for protection has not been spelt out, which is dealt with below. It has also not given any specific recommendation on a higher return to compensate for forex risk. **Keeping the past practice in mind, we consider that foreign exchange risk needs protection. This is agreeable in principle to the beneficiaries also. The protection, as far as debt is concerned, has to be allowed both on account of principal repayment and interest to the**

extent not already included in the tariff which is decided up front. The methodology can be put in position so that actual quantification could be done and charged to beneficiaries without seeking formal approval once again.

6.3 **Methodology**

6.3.1 Regarding the methodology for escalation, in case of debt, we find two different practices in NHPC and NTPC. In the former case, the entire burden of rate variation falls at the time of repayment of the loan; whereas in the latter case a revaluation on each balance sheet date is done thereby correspondingly increasing the value of the fixed asset so that consequent return, interest and depreciation are charged to tariff. Charging the return variation at the time of repayment is more harmful particularly, if there are bullet repayments or there is a progressive devaluation of the Rupee. Such a practice gives a big tariff jolt. Hence the practice adopted by NTPC which is also in accordance with the Accounting Standards of the Institute of Chartered Accountants of India (AS-11) is advisable and should be adopted. The present practice is to charge depreciation on the additional capitalisation and also charge interest and ROE on the normative basis of debt/equity mix of 50:50. The variation to be charged for the 1st year is 50% of the number as it is reckoned at the end of the year. This treatment avoids tariff shocks and is commendable. The ultimate impact on tariff should be to the extent of return on equity, interest on loan and depreciation as if the increase in asset is an additional investment. **In order to ensure uniformity all utilities shall follow this practice in future. We are conscious that change over to this method in case of NHPC may create a liquidity problem as suitable source of finance has to be found for the actual repayment. However, since 50 % of the escalation is treated as equity, there is a leverage provided to the utility which should incentivise NHPC to change over to the new system. We understand that NHPC was adopting the system of annual revision but switched over to the system of charging at the time of repayment since 1997-98. As already stated**

this system is not advisable as it gives a tariff jolt to the beneficiaries and is also not in accordance with the accounting standard.

The methodology suggested above is also tax neutral. Any adjustment in tariff on account of interest on the additional loan amount and on account of depreciation would get allowed for taxation purposes, thereby leaving only the return to get taxed which in any case has to be borne by the beneficiaries. In the methodology followed by NHPC the tax neutrality is doubtful.

Any exchange rate variation on non-project financing or on account of normal purchases may have to be absorbed through the allowed O&M Cost and Return and can not be additionally passed on to the beneficiaries. Presently such a practice has not come to our notice either. As regards exchange risk on interest payment the variation has to be recognised at the time of payment of interest, which can not be helped. However, the same can be spread over subsequent year's billing, though payment of interest on half yearly basis may be the normal practice. The variation on account of interest of previous year shall be chargeable next year. The variations in principal and interest should be limited to the extent of permissible loans only. This shall be communicated before the commencement of each financial year, duly authenticated.

As regards exchange rate variation on equity in case of floatation of equity, it cannot be a charge on the tariff. However, any rate variation on project financing in foreign currency should ensure the dollar/Foreign Currency return as per the agreement and to the extent of the permissible equity. **Hence any exchange rate variation to the extent of the dividend paid out on permissible equity contributed in foreign currency subject to the ceiling of permissible return has**

to have an element of exchange rate risk which has to be built into the tariff. This as and when paid may be spread over the 12 month period in arrears. This is at present is irrelevant in case of CSUs. Any joint venture however may attract this treatment if the case falls under cost based tariff fixation. In the final analysis exchange rate variation both on loan (including interest) and dividend shall be allowed subject to the normative debt/equity on pro rata basis. This is in line with the Government of India Notification as well.

6.5 **Procedural Simplication**

In our consultation paper we raised the issue of how can costly and time consuming procedures can be avoided on escalations of tariff. Presently petitions are being filed every time exchange rate variations are claimed. This can be clearly avoided. Once the principles for escalations are settled, the utilities have to get their data verified by the Auditors of the company both on account of repayment and interest and forward the same to the beneficiaries annually for information and continue to charge the tariff accordingly. It is unnecessary to file separate petitions in this regard. This procedure will facilitate beneficiaries in including the same in their annual revenue requirements. If beneficiaries have any objection to the charge they may file a petition before the Commission.

7. TREATMENT OF CORPORATE TAX IN TARIFF

7.1 Concept of Pre Tax Return

The consultation paper took note of the fact that due to the post tax return, currently retro active adjustment of tariff is required to be done. It was also stated that the Commission will consider the possibility of establishing a pre tax rate of return which would eliminate the need for this adjustment.

A pre tax rate of return is possible either by fixing the return on capital employed (ROCE) or by determining the return on equity pre tax instead of post tax. The question of ROCE has been already discussed and the Commission is of the view that it may not be practicable to be implemented immediately. However, the Commission shall further explore the possibility of determining ROCE in the next 3 years time. A pretax return on equity would mean grossing up the tax rate which is considered herein, as an alternative to pass through of actual tax.

7.2 Present Practice

7.2.1 The K.P. Rao committee has proceeded on the basis of the provisions of the Electricity Supply Act, 1948 that taxes, if any, are to be treated as expenses and as such a pass through. Accordingly, the committee contemplated recovery of actual tax paid on profits as part of tariff in the course of the year and to adjust any over or under recovery on year to year basis for which a statement has to be made available certified by the Auditors. The report also contemplates allocation of tax liability to respective stations in proportion to the capacity commissioned at the beginning of the year. The report has not dealt with the concept of grossing up of the rate of return with a notional tax rate as this was not contemplated in the Electricity Supply Act.

7.2. Based on the above, the practice adopted by NTPC is to charge to the beneficiaries the tax actually paid by the company. In fact NTPC is billing the advance tax actually paid from time to time the burden of which was felt by beneficiary states. This was expressed during the hearings before us. The advance tax recovered is subsequently adjusted for any under or over recovery consequent to the assessment as finalised. The tariff impact is not smooth.

7.2.3 The tariff notification dated 30th March, 1992 contemplates computation of annual fixed charge with an element towards taxation. We consider this as most desirable in order to bring about tariff smoothness. The tax element should be computed according to the Notification as per actuals on (a) 16 % return on equity; (b) extra rupee liability on account of foreign exchange rate variation in computing the return on equity not exceeding 16 % in the currency of the subscribed capital. (c) The amount of grossed up tax i.e. payable and actually paid under (a) and (b) above. Any under or over recovery to be adjusted every year. It is also specifically stated the tax on other income streams accruing to the company shall not constitute a pass through component in tariff. Thus no other tax liability besides the above like tax on incentives, other incomes etc., can be passed on through Tariff. This provision in the notification is being applied to IPPs only and not to PSUs. For them the alternative system suggested by K.P. Rao committee is followed. **The procedure as being applied in the case of PSUs as at present is comparatively simpler with no grossing up provision and we propose to adopt the same with further simplification in order to avoid bulk billing and to ensure a smooth tariff profile.**

As already noted grossing up of tax was contemplated in the 30th March, 1992 notification. The need for grossing up is that for example if the tax on 16 % return on equity is included as an element of tariff then the same would constitute a part of the profit of the company on which tax is again to be paid. This is double taxation on the beneficiaries. NTPC instead of doing the grossing up is billing the actual tax to the parties as tariff. The merit of this alternative is that the benefit of tax holiday and other concessions are undoubtedly passed on to the beneficiaries whereas in the tariff notification of 30th March, 1992 this aspect has not been specifically ruled. In the system adopted by the PSUs the beneficiaries are defacto assessees. In case of IPPs as already noted tax on all other streams of income including incentives along with tax benefits as applicable may accrue to the generating company whereas in case of PSUs the actual tax liability including tax on incentives excepting on non-core activity if any are passed on to the beneficiaries. There is abundant clarity in the system as applied to PSUs. On a study of the actual average rate of tax paid by NTPC in the last two years, we find that there is not much of a difference between the scheduled rate of tax and the actual rate of tax. **In the circumstances, both grossing up the return and passing through the actual tax become neutral effectively and, the latter is simpler and justifiable on record. We therefore propose to adopt the existing system which may have to be reconsidered, only when the concept of return on capital employed is considered and adopted. The Commission is in favour of a pre-tax return in principle in order to incentivise the utilities on tax planning. However, since the ROCE is still to be explored, instead of grossing up the tax, the present system, being simpler, can be continued.**

7.3 Proposed System

7.3.1 A major grouse in the existing system however is the tariff shock and unpredictability in as much as lump sum billing is done as and when advance tax is paid. This should be avoided. A way out has been suggested by NTPC in this regard. It has stated that “estimated income tax liability which could be assessed for various years of the tariff period could be built into the fixed charges at the time of tariff fixation and these amounts could be adjusted at the end of each financial year based on actual income tax liability. Thus the customer utilities would be required only to make marginal adjustments in respect of the income tax liability towards power purchased from the central sector utilities each year.” This suggestion has to be considered keeping in view the continuous ongoing relationship. Subsequently, NTPC made further submissions in which it has suggested that grossing up of the income tax would be a preferred option as it ensures price smoothness of tariffs over a period of time. As an alternative, it has suggested that an additional monthly tariff payment to the extent of the tax attributable to the estimated net income to be generated may be permitted. It has also suggested the establishment of a "tax escrow account" into which SEBs shall pay each month an amount more or less equal to the monthly instalment corresponding to the tax amount as certified by the auditors. The tax escrow account should be an interest bearing account maintained in a scheduled bank and all amounts of interest shall be credited to that account. NTPC should be authorised to withdraw the amounts for settling the tax liability on presentation to the escrow holder of a certificate from the company's statutory auditors that such amounts are immediately due and payable to the taxing authority. Similarly, NTPC shall pay into the tax escrow account any refund received from the taxing authority. The company shall endeavour to minimise its liability for taxes recoverable from SEBs.

7.3.2 The mechanism suggested by NTPC has two major components viz.:

(a) Estimation of tax liability in advance and billing the same as part of tariff;

(b) The management of the escrow account.

The tax liability can not be estimated for the full tariff period in advance but the same could be estimated reasonably a year in advance. Accordingly each utility shall estimate the tax liability two months before the commencement of each year and intimate the beneficiaries with the statutory auditors' certificate. This mechanism ensures that an authenticated estimate of tax liability is made and still any excess payment due to unavoidable wrong estimation continues to earn interest. The refunds if any do not have to be paid back to the beneficiaries but adjusted in the escrow account. Any balance due or returnable would be rolled over to the next year.

Though the system is bound to satisfy the test of smooth tariff profile it is primarily dependent upon the beneficiaries regularly honouring their bills. The redeeming feature is that some flexibility would be available to the beneficiaries within a year to make payments according to their cash flow. According to NTPC, each beneficiary is required to establish an escrow account. The Generating company has access to all escrow accounts subject to the limits as certified by the auditors of the company. In case of delinquent beneficiaries not remitting their dues in the escrow account the liability still would be on the generating company as an assessee. Delinquent beneficiaries would get distinctly exposed. Of course each beneficiary has to open separate escrow accounts with reference to each PSU from which they are getting the supply or service. However once the system get settled it would become a routine.

We find distinct merits in the shape of a smooth tariff profile and certain flexibility to the beneficiaries in making payment. We consider the suggestion of NTPC as an ideal solution to the present problems on this account. As such, we direct that this system of tax escrow account be adopted by all beneficiaries in respect of the central sector utilities. These Escrow Accounts shall be reflected in the books of utilities as their bank account.

7.3.3 NTPC had been insisting on the level playing field along with IPPs in all respects. However, we have not accepted an identical treatment on all matters in tariff determination in pursuit of economy and efficiency but had been selective based on principles. Accordingly, we have maintained parity on return on investment and determination of rate base which incorporate incentives based on reasoning. Tax treatment in respect of IPPs are complicated and as such we have opted for a simplified system. Under the system approved by us utilities need not approach the Commission every year for inclusion of the tax element as part of the fixed charges but have to only make available audited certificate for estimation of the tax liability for the forth coming year. They have to make available certified figures of actual tax paid as evidence for either refund or for additional billing for taxation at the end of each year. No additional billing for taxation shall be resorted to during the course of the year and the same shall be adjusted in the next year. This shall apply to refund of tax if any as well. In case of IPPs the tax liability on incentives earned by them cannot be passed on to the consumer. Similarly any tax benefits like tax holiday or special allowances presumably may be retained by the utility though this is not explicitly clarified. **In case of PSUs however since we have accepted the concept of passing through the actual tax as an expense they also get the benefit of passing through the tax on incentives as well as the tax benefits. However, we have considered this as a totally alternative system to what is adopted in case of IPPs. We have noted that the power sector companies are also liable to minimum alternate tax which is liable to be passed on to the beneficiaries. This may be true of IPP's as well, though clarity is lacking in this regard.**

7.3.4 We understand that presently the tax liability is apportioned to various stations or lines on the basis of capacity. This method of apportionment of the tax liability to stations or regions is not a rational one. As per this method benefits of tax holiday in respect of a new station would not be fully available to the beneficiaries though the high cost of new stations are being fully absorbed by them. In fairness, the beneficiaries of such stations should get the full benefit of the tax holiday. It should be possible to estimate the pretax profit for a year in advance. The stationwise/regionwise profit before tax as estimated shall constitute the basis for distributing the tax liability of all stations/regions. We consider this method equitable and scientific. This would ensure that tax holiday of new stations are fully made available to the respective beneficiaries. Application of this process may pose problems in

case of NHPC and Powergrid which may have carry forward losses of the past for which credit has to be taken. Once the station wise/line wise pre-tax profit is determined, the credit for carry forward losses could also be given in the same proportion which may be equitable for all stations/regions in the absence of more accurate basis. However, specific benefits related to each station/region would ensure to such station and ultimately to the beneficiaries of those stations.

The tax allocated to stations/regions shall be charged to the Beneficiaries on the same lines as annual fixed charges/existing charge.

8. INCENTIVES

8.1 Justification for Incentive:

8.1.1: The concept of incentive is a time tested phenomenon in any industry and power sector is not an exception to this. The Report of the study team appointed by the Government of India and the Asian Development Bank in 1994 (ECC Report) contemplated a package of incentives and disincentives, the objective being to ensure that the generator keeps himself above certain target level of operations and to further incentivise for better performance beyond the target level. The Government notification dated 30th March 1992 envisages incentives beyond a target level of availability, which is provided as a percentage return on equity. The draft notification on Availability Based Tariff (ABT) prepared by the Government of India also contemplated additional payment on account of incentives for availability beyond the target level for generating companies. In our ABT Order we have already taken a view that “generator cannot be rewarded for merely putting up a generating unit. It is necessary for him to make it available for the beneficiaries to a reasonable extent so that the latter could draw upon that capacity. Any short fall in available capacity need to be commercially punished with the denial of fixed cost. Incentive, however, stands on a different footing. In regulated tariffs, it is necessary to keep a provision to reward for better performance in order to promote efficiency and economy through cost reduction. Such a reward linked to efficient performance level should be as challenging as possible”. The Commission has pursued this concept of incentive in regulating tariff of generation as well as transmission utilities. We have also kept in view the interest of beneficiaries so that beyond normative level even after payment of incentive the cost of additional service is less than what is normally being paid. The philosophy behind incentive is referred to in the Consultation Paper in the following words:

“Under a regulated tariff regime, how can a regulator ensure that the norms being used for judging performance and thus allowing incentives or imposing disincentives, are challenging, without being burdensome for the utility? How should incentives be set, so that they induce continuous improvements in the efficiency of supply and demand?"

We propose to address the issues on incentives for all sectors under our jurisdiction in this spirit. The utilities have to view incentives not as an additional return on investment. They must demonstrate efficient operation and consequent cost saving so that they earn the reward they deserve for efforts put in. The beneficiaries have to view the incentives under the following two scenarios:

(a) If the beneficiary does not have its own capacity to meet the additional demand for power, it may have to establish new stations and the cost of power produced from such stations would be much higher than the cost at which this additional energy could be procured from the Central Stations.

(b) Even if the beneficiary has the additional capacity to meet this demand, it may not in some cases make economic sense to produce by itself and it would be economical for it to buy this additional capacity from central stations for operational reasons especially when the full fixed cost has already been paid.

The major issues involved in Incentives relate to:

(a) The basis for reckoning the Incentive; and

(b) The Incentive Rates.

All these issues are common for generation and transmission sector.

Since we have dealt with incentives for hydro sector vide our order dated 8th December, 2000 in Petition No. 85 we deal here with only thermal generation and transmission.

8.2 <u>Present Practice on Incentives</u>:

8.2.1 The generating companies and the transmission companies in Central sector have been receiving incentives for performance beyond normative levels. These incentives are over and above the normative return on equity allowed from time to time. Presently the incentive schemes are different for different companies and these are briefly described below:

(i) **NTPC:**

Incentive for NTPC is available beyond a PLF of 68.49% and is at the rate of 1 paise/kwh for each 1% increase in the PLF above 68.49%. For the purpose of incentives, backing down, as certified by the Regional Electricity Boards, shall be reckoned as generation.

(ii) **NLC:**

By way of an agreement between NLC and the beneficiaries, the utility receives the full fixed cost as incentive beyond the PLF of 70.2%.

(iii) **NEEPCO:**

NEEPCO is presently operating on a single part tariff. This implies that their incentive rate would be same as the fixed cost but in real practice, they do not get any incentive as the PLF achieved by them is much less than 68.49%.

(iv) **PGCIL:**

Incentives for PGCIL commences beyond the system availability of 95% and the incentive rate is 1% return on equity for each one per cent increase in the availability.

8.3 **Basis for Reckoning Incentive**:

8.3.1 The basis for incentive has two elements viz the measure for performance and threshold level to qualify for incentive. What should be the performance measure for incentive? For instance in thermal generation, should it be PLF or Availability? In Transmission, can we have any measure other than availability as a performance measure? . The issue relating to thermal sector became contentious before us with the filing of a review petition by NTPC against the Commission's Order dated 4.1.2000 on ABT. This was perhaps so since in the draft notification prepared by the Government, "availability" was considered as the basis for incentives. "Availability" is the basis for incentives in case of IPPs also. **We have already concluded in our ABT order that incentives should be related to actual generation and not mere availability in the thermal sector. These conclusions are based on detailed considerations for which reference could be made to our order dated 4.1.2000 on ABT and our order dated 15th December, 2000 on**

the Review Petition on the ABT Order. It may be interesting to note that in the past, central thermal stations were getting incentives only on the "PLF" basis and not on availability though "deemed generation" was an aberration which was considered as generation of power. We have already dealt with this issue in detail in our earlier order. As such we confirm that "PLF" shall be the basis for Availability in thermal generation. As regards transmission sector, the Commission visualises enormous scope for cost reduction through introduction of two part tariff, charges based on actual usage, congestion pricing etc. apart from convergence benefits. All these have to be explored in detail. We have already envisaged these reforms in our consultation paper. Till these are explored, with the present 'postage stamp' system of pricing there is no other performance measure than "Availability" for incentivising better performance. As such, for this sector, availability has been taken as the basis for incentives. There has not been any serious objection to this from any of the parties.

8.3.2 Regarding the threshold level for thermal power stations, elaborate arguments were submitted at the time of the ABT Review Petition that the level should be maintained at 68.49% or at worst at 70%, so that incentives should be available beyond that level. In our order dated 4.1.2000 on ABT, we have provided enough justification as to why the cut off level should be raised beyond 68.49%. We do not propose to repeat the same arguments in this order. **We have already confirmed vide our order dated 15th December, 2000 in the ABT Review Petition that the level for recovery of full fixed charges in the case of thermal stations shall be 80%. This operating level for incentive however shall be on PLF and not on availability. Since the availability is the availability of station as declared by the generator and the PLF is dependent on drawal by the beneficiary, there will always be a difference between the availability and the PLF. Hence correction for the backing down of the units based on system requirement may have to be provided for while deciding the threshold level of PLF above which incentives would become payable. For determining the**

equivalent PLF, normal idle time of power plants due to system conditions referred to as "deemed generation" has to excluded. For this purpose, the deemed generation certification for the country as a whole was ascertained from the petitions filed by the NTPC for incentives. This however, shows a very high level of deemed generation viz., 5.4% which needs to be normalised. For the year 1999-2000, the backing down was mainly due to the power position in the Eastern Region. With the introduction of ABT, the PLF of NTPC stations are expected to go up. Further there would be some fuel savings on account of operating at higher PLFs. Taking all these into consideration and the need for sharing of the benefits between the generator and the SEB, the PLF for incentives could be set at 2.7% lower to the target availability . For the sake of convenience the reduction of 2.7% is rounded off to 3% consequent to which the base PLF for calculation of incentives in the case of NTPC shall be 77% which would correspond to the target availability of 80% for recovery of full fixed charges. The target PLF for incentives shall however, be reviewed during the next tariff period based on the actual experience during this period regarding actual PLF, backing down etc.

8.3.3 From the material available on record, we are convinced that a separate dispensation is required in respect of NLC in view of the fact that the PLF is also a function of their captive mine output. NLC is presently charging full fixed charges as incentive beyond 70.2% PLF. In Southern Region, the backing down is hardly significant. The target availability for NLC has been laid down by the Commission separately in its order dated 21st December, 2000 in Petition No. 2/99. The maximum PLF that can be achieved even with 100% capacity utilisation of associated lignite mines was found to be 73.06% PLF. From the data furnished by NLC for the last 5 years, the maximum PLF achieved by them was found to be 77.31%. Keeping these facts in mind with a view to incentivise better operation of the power plants of NLC, a target PLF for the purpose of incentives is reckoned as 72%. This is based on the fact

that currently NLC supplies power to beneficiaries based on an agreement which is valid till 31st March 2001.

8.3.4 NEEPCO is presently operating on a single part tariff which implies that if they perform beyond the target PLF, incentives would be available at the rate of full fixed charge/kwh. But in reality the PLFs achieved by them are much lower and the recovery of full fixed charge itself is in question. **The Commission proposes to address these issues in detail while passing orders on ABT Petition for North-eastern region filed by NEEPCO. The details with regard to the ABT Petition are still to be confirmed by NEEPCO and we direct that this should be done immediately to enable the Commission to pass appropriate orders before the implementation of ABT in the North-eastern region.**

8.3.5 The Commission is conscious of the fact that in the past PLF based incentive had resulted in excess generation beyond schedule/requirement. As such we direct that in reckoning the PLF for incentive purposes, only the scheduled generation will be taken into account. Deviation from the schedules are dealt with through the UI accounting system separately under the ABT.

8.3.6 As regards transmission sector, we have already dealt with in detail The threshold level for the purpose of incentive vide our order dated 8th December, 2000 in Petition No. 86/2000. We have already come to the conclusion after detailed consideration that the cut off level shall be 98% availability. The procedure for reckoning the availability has also been already settled by us through our order dated 26th September, 2000 in Petitions No. 12/99, 13/99, 14/99 and 16/99.

8.4 <u>Incentive Rates:</u>

8.4.1 Having settled the basis for incentive, we should address the question of incentive rates. As per the tariff notification dated 30.3.1992 and in the draft notification on ABT, incentive as a percentage of equity for every percentage increase in availability was proposed. This issue was discussed in detail before us during hearings. In our ABT Order we have already expressed a view that incentives linked to equity would result in higher incentive for no special performance. Further this would be an unfair burden on beneficiaries of new projects who are already burdened with higher fixed charges due to increased cost of such projects. **The value of additional power beyond target level needs to be evaluated more rationally for all the consumers. In fact, the endeavour should be, that if possible the older units be encouraged to perform better whereas the newer units with latest technology in any case are bound to perform at higher level. Further it would be more appropriate to keep in view the "avoided cost" which accrues to the State level beneficiaries while determining the rate for the incentive. In fact in case of NLC as per the present agreement, the per kWh fixed cost itself constitutes the incentive, without a share to the beneficiaries. The Commission therefore, is of the considered view that incentives should be based on actual performance at a rate keeping in view the avoided cost rather than as a percentage of equity. A percentage on equity without due linkage to actual performance signifies as if the incentive is an addition to the return on investment which however should not be the principle. In our ABT order we indicated our inclination to consider this as an addition to the return on investment. We are convinced that the additional power has to be evaluated better on avoided cost principle rather than as return where the value link is missing. In view of this, it is proper that the incentive is worked out as a percentage of the fixed cost per kwh keeping in mind the share of the avoided cost going to the utility and the beneficiary in thermal sector.**

8.4.2 **The power stations of NTPC were set up at different points of time and the fixed cost/kwh was found to be varying in the range of 26 paise/kwh to as high as 155.70 paise/kwh. It would be unfair once again to the beneficiaries of newer stations if a share of actual avoided fixed cost is determined as**

incentive. Currently some of the stations of NTPC are operating at PLF of around 90%. At 90% based on the existing formula, the incentive works out to 21.5 paise/kwh. It may be fair to the utilities to sustain this incentive level so that there is not much of a tariff jolt. As regards beneficiaries, as already discussed, in case the additional power is to be procured from a new plant, the fixed cost to the beneficiary would work out to be much higher. In this light, the Commission feels it appropriate to allow recovery of 50% of the fixed cost/kwh as incentive for generation beyond 77% PLF with a cap rate of 21.5 paise/kwh. This would ensure that the fixed cost is shared between the utility and the beneficiary. Such an arrangement would be equitable for both the generators and the beneficiaries. In this process the incentive for older stations would be protected if not enhanced but the newer stations' beneficiaries would not be heavily burdened.

8.4.3 While claiming the incentives it has also to be kept in mind that the equipments are not flogged to maximise the revenue. This has been the principle in the previous regime of tariff as well. Accordingly, the incentive rate has to come down beyond a certain level of operation. Considering the past performance of various units and considering the threshold level of 77% in case of NTPC the above incentive rates shall apply upto a PLF of 90%. Any operation beyond this level by NTPC shall be eligible for only 50% of the incentive. In case of NLC however, the range for incentive earning is limited viz., 72% to 77%. The utility however has scope for reaching levels beyond 77% if appropriate initiatives are taken in mining lignite. In the circumstances, the apprehension of flogging the machine does not exist. Hence the need for readjusting the incentives at higher level of operation does not arise.

8.4.4 As regards the transmission sector, at present it is not possible to consider any other alternative except to determine incentive as a return on equity. Perhaps this can be explored in detail if a two part tariff is devised, but as at present there are no outputs to measure and evaluate in this sector.

However, the same principles regarding structuring of the incentive have been adopted. As already stated inevitably the availability of the system has to be the basis for incentives for the present. Accordingly, the following shall apply for transmission sector:

The availability level at which the full fixed charge is recoverable shall be 98%. Incentives shall be available to the utility for achieving availability beyond 98%. In keeping with the present practice the incentives are cumulated so that every stage increase in availability would entitle the utility to the incentive as indicated in the cumulative incentive column in the following table:

Availability %	Incentive As a percent of equity	Cumulative Incentive As a percent of equity
98% and below	0.00	0.00
98.01% -98.50%	1.00	1.00
98.51% - 99.00%	1.00	2.00
99.01% - 99.50%	1.00	3.00
99.51 –99.75%	1.00	4.00

Incentive is capped at 99.75% with a view to provide for essential maintenance requirements of the system.

8.4.5 The incentive to generating stations shall be shared by the beneficiaries in the ratio of energy scheduled beyond target PLF. As such our direction in the ABT Order that incentive shall be shared in the ratio of fixed cost is superseded. Incentive to transmission utility shall however be shared as per the existing practice.

9. DEVELOPMENT SURCHARGE

9.1 Plea for sustaining cash flow

9.1.1 The tariff of central generating companies in the recent past appears to have been influenced by the cash flow requirements for capacity expansion by these utilities. This is evident from the increases in the rates of return and acceleration of depreciation for central generating companies after 1994. We also specifically noted in our ABT order that an increase of 4 % in the ROE was provided in order to make additional cash flow for expansion purposes. The acceleration of depreciation since 1994 facilitated additional cash flow in the hands of central sector utilities. These efforts however could not fetch the desired results due to receivables becoming extremely sticky. Additional financial cost on account of such receivables, operational inefficiencies in some cases including expenditure incurred beyond norms, lack of alternate sources of funding probably resulted in the desired return not forthcoming. These conclusions in general though obvious in nature could not be analysed, isolated and quantified, due to lack of adequate information from the central sector utilities.

9.1.2 Each of the Central sector utilities was making its own case for either protecting the existing cash flow or for augmenting the cash flow further for the purpose of capacity expansion. NTPC in the submission, filed in May, 2000 stated that profits are being deployed for establishing new generating stations which is in public interest. There are ambitious expansion programmes in the 9^{th} and 10^{th} plans for which funds have to be made available. As such NTPC pleaded that the existing norms governing performance should not undergo any change.

In the subsequent submission in September, 2000 NTPC criticised the recommendation of CAS on return on equity since it had not taken note of the need for resource mobilisation while recommending the ROE. According to NTPC, resource mobilisation for expansion is a basic issue which has to be addressed while determining the desired return. On the direction of the Commission, NTPC also submitted detailed workings justifying the demand for increased rates of return to take care of the developmental requirements in the next two Five year plans. NLC has also furnished some limited details regarding expansion programmes, in a different context.

9.1.3 PGCIL though did not submit details of expansion programmes, filed their written submissions justifying a much higher rate of return in order to meet the expansion needs of the inter regional transmission sector. It has made out a case to the effect that a return of 27% ROE is warranted if return is allowed during construction period also and alternatively a return of 34 % in case return during construction period is disallowed.

9.1.4 A special case was made out by NHPC through a separate petition (Petition No.34/2000) praying for levy of a surcharge of 10 paise per unit on the energy available to beneficiaries at bus bar of their generating stations. NHPC has stated that the major constraint faced by the Company is the limited budgetary support available and the limited amount of internal resources that can be raised. The purpose of levying a surcharge as sought by NHPC is to create a hydro power development fund so that adequate resources for plant and development of hydro electric power are available with the company. In the petition, it is also stated that the Government of India in the policy for hydropower development issued in 1998 had noted that survey and investigation of hydro projects in the states had been discontinued due to paucity of funds. As a result, there are not enough projects that could be taken up in the next 2-3 years and get completed in the 10^{th} plan or early 11^{th} plan. It also contended that projects could be developed up to pre construction stage in order to attract IPPs to invest in these projects. For this purpose, it was proposed to levy a power development cess of 10 paise per kWh of electricity consumed in the country. This levy was recommended by the sub-committee of the NDC Committee on power, which gave its report in January 1994. According to the petition, no action has been taken by the Government in this direction till date. In the meanwhile, the Ministry of Power on 23.2.2000 vide a letter addressed to NHPC felt that Commission may be approached for the levy of surcharge of 10 paise per unit to create a hydro power development fund. Accordingly, NHPC has filed this petition. Since we were to take into account the fund requirement for expansion of all utilities under our jurisdiction, we directed that this petition may also be considered as part of the total proposal regarding requirements for expansion programme.

9.1.5 All the above pleadings for additional return were circulated to the beneficiary states for their reaction. Very limited reaction was received from the beneficiaries. TNEB stated in its reply that increase in ROE for mobilising additional funds for investing in the power sector cannot be accepted as the SEBs themselves if in a position to pay can invest this money in power projects of their own, rather than pay higher tariff for existing stations and full tariff for the new stations for which part of the equity would be from the SEBs. Karnataka Power Transmission Corporation has stated that increasing the ROE beyond 16% would be burdensome and as such the Commission may consider restoring the returns to 12 % in the interest of the SEBs and the consumers.

9.1.6 We have noted right from the discussions in the national task force on availability based tariff that there has been a constant plea for maintaining revenue neutrality. In other words the utilities would like to protect their cash flows so that their expansion programmes are not jeopardised. We have already expressed our disagreement about this preconceived determination while regulating tariff. As a quasi-judicial body in the discharge of its functions, the Commission has to keep a balance between the two sides. There was no plea for additional cash flow for capacity expansion excepting for the hydro levy, till the Commission raised the issue at the hearings. The Commission however, can not lose sight of the need for further investment in the sector. Of course the Commission has to primarily regulate the tariff with reference to the cost attributable legitimately to the activity for which tariff is being fixed. We have noted that in order to promote investment into the sector certain incentives like enhanced rate of return at 16 % and sustaining the equity base irrespective of the pay back due to depreciation have been already extended which are sustained. Incentives for exemplary performance has also been recognised and augmented in order to encourage better performance. Tax advantages on incentives, which are presently available under the alternative system applicable to central generating stations, have also been sustained by us for these utilities. Still, the Commission should not lose sight of the cash flow requirements for expansion activities.

The combined effect of our tariff proposals may be to readjust the tariff revenue of the utilities particularly on account of our proposals to bring down the depreciation rates to pre 1992 levels which of course are well founded. No doubt utilities would get the benefit of advance against depreciation for the specific purpose of loan repayment in deserving cases. All the same there is possibility of a minor short fall in cash flow immediately consequent to this readjustment of depreciation. This however is inevitable. The proposals on incentives and O&M cumulatively may not result in any adverse impact on the cash flow. Yet the Commission is anxious to ensure that cash requirements for capacity additions should not be hampered due to our tariff proposals. In the process the beneficiaries should not also end up paying increased tariffs only to finance the capital expenditure requirement of utilities. An appropriate balance has to be struck.

9.2 **Plea for surcharge**

9.2.1 During the arguments on NHPC's petition for levy of a surcharge for development purposes, it was submitted that the Commission has jurisdiction to add a surcharge to the tariff since it is a mere super added charge, a charge over and above the usual or current dues. In this connection, the decision of the Supreme Court in Bisra Stone Lime Co. Ltd. and another Vs. Orissa State Electricity Board and another (1976-I-SCR 307) was cited. In that case the Orissa State Electricity Board had imposed a uniform surcharge of 10 % on the tariff. It was found in that case that the levy of surcharge had become necessary for improving the board's overall financial return. The Court in the ultimate analysis came to the conclusion that the State Electricity Board had the jurisdiction to collect an additional chargé over and above the usual or current dues. The above decision was cited before us in order to establish that the surcharge is not in the form of a cess. A cess is a tax or a fee, which falls within the authority of the Government by virtue of the provisions of law. It is imposed under a statutory power without taxpayers consent and payment enforced by law. This has also been recognised by the Supreme Court in a number of cases. Any surcharge in the form of a levy without any specific purpose particularly in a cost based tariff mechanism may amount to a cess. Thus, it was argued that the Commission is well within its jurisdiction to order a surcharge on tariff for development purposes but not a cess.

9.2.2 It is necessary to examine the context in Bisra Stone Lime Company's case to understand its relevance now. In that case the Supreme Court upheld the power of SEB to levy a surcharge in order to improve the board's overall financial return. In this connection the Court had also noted that section 49 of the Electricity Supply Act empowers the board to fix uniform rates of tariff which can be fettered only in case there is a special agreement to the contrary. In other words, the power of the SEB to fix tariff under section 49 (1) and (2) are unfettered powers. It is necessary to note here that section 49(1) and (2) contemplate "framing" or "fixing" uniform tariffs. In contrast the Commission has the power to "regulate" the tariff. "Regulation" has much broader connotation than "framing" or "fixing" the tariff. The Supreme Court in K. Ramanathan vs. State of TN and another (1985-II-SCC-116) held the word "regulate" is difficult to define as having any precise meaning. It is a word of broad import having broad meaning and is very comprehensive in scope. It has specifically held that "the power to regulate carries with it full power over the thing subject to regulation and in the absence of restrictive words the power must be read as plenary power over the entire subject." Read in this background, the Commission's power to regulate the tariff carries with it the power to use the tariff mechanism for promoting investment. The authority of the State Electricity Board to levy a surcharge was recognised in Bisra Stone Lime Company's case, and the utilisation of the surcharge was not an issue. The surcharge was only to improve the general finances of the Board. Under the Act, the Board has the powers and duties related to generation transmission and distribution of electricity in the state but there was no specific mandate to promote investment in the sector. In contrast the Commission is specifically entrusted with the function of facilitating mobilisation of adequate resources for the power sector. This is specifically stated under section 13(e) of the ERC Act, which has to be fully explored in national interest. Again section 28 also envisages, encouragement of optimum investments through tariff terms and conditions.

Relevant portions of sections 13 and 28 of the ERC Act are reproduced below:

1. Section 13: "The Central Commission shall discharge all or any of the following functions, namely:-

(a)…………..
(b)…………..
(c)…………..
(d)…………
(e) to aid and advise the Central Government in the formulation of tariff policy which shall be-
   (i) fair to the consumers; and
   (ii) facilitate mobilisation of adequate resources for the power sector."

2. Section 28: "The Central Commission shall determine by regulations the terms and conditions for fixation of tariff under clauses (a), (b) and (c) of section 13, and in doing so, shall be guided by the following, namely:-

(a)……………..

(b) the factors which would encourage efficiency, economical use of the resources, good performance, optimum investments and other matters which the Central Commission considers appropriate;

(c) national power plans formulated by the Central Government; and

(d)………"

The above provisions relating to mobilisation of resources and encouragement of optimum investments which are contemplated as part of the functions of the Commission do not find specific mention in the functions of State Electricity Boards under the Electricity Supply Act, 1948. Thus the Commission has an unfettered power to use the tariff mechanism for the discharge of its functions of facilitating mobilisation of resources for the power sector and encouraging optimum investment as may be considered appropriate. As such we are convinced that the Commission has jurisdiction to consider the levy of a surcharge, for the specific purpose of promoting investment.

9.3 <u>**Options before the Commission**</u>

9.3.1 The options open to the Commission in respect of this additional charge are:

(a) recommend to the Government to levy a cess for development purposes or

(b) include a surcharge in tariff for capacity expansion.

As regards levy by the Central Government of a cess on electricity consumption the proposal has been before the Government since 1994. It appears that the Government has not been able to implement this proposal. "Electricity" being a concurrent subject, the imposition of a levy by the Central Government through billing by State Electricity Boards may have to have the concurrence of the states including for the utilisation of such fund. It may be noted that this recommendation regarding cess was made by a sub committee of the NDC Committee on Power. Still, not much progress could be made. It should also be noted that NHPC approached the Commission only on the initiative of the Government of India, Ministry of Power vide its letter D.O.No.37/10-98-DH(I) dated February 23, 2000 which is sufficient indication that the Government has not been able to make any progress on the suggestion for levy of cess. In the circumstances, the Commission may not rest content with making a mere suggestion or advice to the Central Government to impose a levy or cess for developmental purposes. Since the tariff jurisdiction under section 43A(2) of ERC Act is no longer with the Central Government, it cannot use this instrument to mobilise resources for capacity expansion, in respect of central generating companies.

9.4 **Legal and Economic Justification**

9.4.1 Inevitably in pursuit of the second alternative the Commission has to find both legal and economic justification for inclusion of a surcharge in tariff. As already stated, the ERC Act under section 13(e) envisages facilitating mobilisation of resources as one of its functions. Section 28 also enjoins the Commission to set out its terms and conditions for tariff with a view to promote optimum investment consistent with the national electricity plans. The Act also contemplates power to the Commission to make regulations consistent with the Act to carry out the purposes of the Act. Apart from these, the Commission is also to be guided by the financial principles as contained in schedule VI of the ES Act, 1948 in formulating the terms and conditions for tariff. Clause 2(c) of the schedule contemplates inclusion of certain specific special appropriations to cover contributions to contingency reserve and development reserve as part of the allowable expenses to be charged as tariff. The appropriations to contingency reserve and development reserve are in the nature of provisions which are specifically intended to meet non revenue outgo like replacement of plant or works or for investment in business of electricity supply of the undertaking. **Thus in pursuit of this provision under section 28(d) of the ERC Act, the Commission has statutory jurisdiction and obligation to build in its tariff an element towards financial requirement for capacity additions. Schedule VI as such applies to licensees only, but section 28 of the ERC Act mandates that the Commission shall take cognizance of the financial principles contained therein, in determining the terms and conditions of tariff.**

9.4.2 We also examined the question of economic justification for a development charge. The need for creation of additional capacity both in generation and in transmission at the national level based on the desirable rate of economic growth has been already set out by the Government. These targets have also been approved at the level of conferences of Chief Ministers of all the States with the Ministry of Power, Government of India. These investments could take place in the central as well as state sector supplemented by the investments from the private sector. The experience so far has been that investments are not taking place as per plans due primarily to private sector participation not taking place resulting in lowering the investment targets. It has also been seen that projects taken up by central sector utilities have proved to be not only very economical. Ultimately, the benefit of al these investments would accrue to the states as a whole. Hence any funds available for investment, given the alternative of a state and central sector utility may preferably be used through central sector. There may however be some exceptions but this is the broad conclusion from a sample study of comparative thermal projects made in connection with the tariff of one of the mega projects considered by the Commission. A question may however arise as to why a beneficiary should contribute as part of the tariff for investments on which a return will be earned by the central sector utility. This is a valid question. **So long as this question is adequately taken care of, the proposal for development surcharge would have a sound economic justification in the overall interest of the sector. As such, subject to the above question we find valid economic**

justification for a development surcharge. In fact, once this concept is successfully tested, it would be worth pursuing further on a larger scale.

9.5 **Estimation of requirements**

Having established the need and the jurisdiction of the Commission to include a surcharge in tariff it is necessary to quantify the surcharge on a realistic basis. For this purpose we required the utilities to submit details of financial requirement for expansion purposes. NTPC responded with detailed submissions on the fund requirements for capacity additions upto year 2012. It has also included in the requirement R&M activity as well as investments in joint ventures. The basis for the assumptions by NTPC is as follows:

(a) Capacity addition of 27050 MWs as per corporate plan
(b) Further capacity addition of 16200 MWs which is not incorporated in the corporate plan.

The company anticipates that the entire equity inputs for these capacity additions shall be generated from internal resources i.e. through the tariff to be fixed. No equity input from the Government has been assumed probably on the plea that the Government would be content with a 8% dividend on equity as on 31.3.2000 or alternatively a dividend outgo at 30 % of current years profits.

NTPC has also made a large number of assumptions with regard to operational parameters, debt equity ratio etc. It has also assumed that incentives will be available for PLF levels above 70 % at 0.4 % ROE. It has further assumed conservative returns on joint ventures so that a comprehensive view of the fund requirement by taking all activities could be taken. An assumption has also been made that surplus funds would earn 10 % per annum pre tax. Detailed assumptions on receivables, outstanding as on 31.3.2000 as well as future receivables have also been considered.

On the above assumptions, NTPC has estimated a return on equity of around 22 % in order to finance their capacity expansion as per corporate plans. The requirement would be still higher in case further capacity additions of 16200 MWs are also to be taken up. The various assumptions in the working for arriving at this expected rate of return may be challengable. All the same, the total equity requirement till the 11^{th} Plan period is about Rs.64,000 crores i.e. about Rs.5000 crores per annum on an average. This has to come out of ploughed back profits.

PGCIL could not submit any details of their expansion programmes or fund requirement. It has only submitted a statement to the effect that the required return is 27% in case ROE during construction period is allowed and a return of 34 % incase it is disallowed. This working does not give any indication of the quantum of equity requirements divided into that expected from plough back and fresh equity inputs. However, from published documents of CEA regarding demand forecast the transmission investment could be estimated.

NHPC has already aimed a contribution of about Rs. 100 crores per annum based on 10 paise per unit of generation towards a corpus fund for initial project development for facilitating private investment in hydro sector. This is besides the investment required for the projects. NLC has also submitted limited details of expansion plan in some other proceedings.

9.5.2 It is not the intention of the Commission to provide for all the funds for capacity expansion through tariff. The utilities are being provided a reasonable return as well as incentives with tax advantage which in any case should be able to generate resources for ploughing back into the business for capacity additions. Further, the Government as the sole owner of these utilities should also be in a position to subscribe to the equity of these companies within its budgetary constraints. The utilities have made out a case for additional rates of return going much beyond 16 % ROE to meet the

capital expenditure requirements. No precise break up of further equity infusion plough back and additional requirements could be worked out due to insufficient data. The utilities have all along been only pleading that the existing cash flows should not be eroded. They have made out a case for additional return to meet capacity additions only at our behest. The utilities apparently were confident of meeting the expansion requirements if the existing cash flow is protected. The principles contained in schedule VI to add a small percentage to tariff on account of contingency reserve and development reserve, can however be extended to these generating companies also. Such an additional payment is already in the tariff of licensees. Keeping this in view there is justification for a surcharge, which can provide additional cash flow to a certain extent.

In view of the above we consider it appropriate to fix a surcharge on every bill for fixed charges (for NHPC both on capacity and energy charges) raised by the utilities in respect of generation/transmission at regional levels. Operations exclusively within a state shall not be liable for this surcharge. Accordingly, there shall be a surcharge on the following rates:

NTPC – 5 %; NLC – 5 %; NHPC – 5 %; Powergrid – 10 %

Rates for other utilities if any falling under the jurisdiction of the Commission shall be decided in due course.

9.5.3 We are conscious of possible apprehensions of state level beneficiaries regarding the utilisation of the surcharge. We are also concerned that the surcharge should not have the effect of a further increase in present tariff which itself is not being collected easily. We are convinced that even after including the surcharge the burden would be affordable and reasonable. As regards utilisation of the surcharge we have considered the matter in detail. The above surcharge is intended to specifically meet a portion of the capital expenditure to be incurred by the utility for the purpose of capacity addition. This is not available for capital expenditure relating to R&M or for replacement of existing capacity. This shall be available only for investment in the business of the electricity supply undertaking for addition of capacity.

The state level beneficiaries would like that the surcharge collected by a particular station or relating to a line should not be used to cross subsidise another station or line of another region. There are also apprehensions that these surcharges may be applied in the normal operations of the utility. There are already averments that any contribution towards capacity addition should not earn a return to the utility concerned but should go to reduce the tariff of beneficiaries belonging to the region. All these apprehensions are justified and as such adequate stipulations have to be made with regard to the utilisation of the surcharge. Accordingly, we direct that:

(a) **Surcharge collected by the utilities shall be kept in a separate bank account and may be invested in securities of recognised infrastructure funds like IDFC or IDBI Tax free bonds so that income therefrom shall also be credited to that bank account;**

(b) **The utility shall maintain separate accounts in its books and reflect the balance in the Development Surcharge Reserve Account and the investment represented against the same in their balance sheet;**

(c) **On the purchase of the undertaking or on any such contingency the reserve and the corresponding investments shall be transferred to the successor undertaking to subserve the same objective of fresh capacity addition;**

(d) **The fund can be made use of to the extent of 1/3rd of the equity requirement for any capacity addition in the respective region and the balance 2/3rd being provided by the utility;**

(e) **To the extent to which the fund is used as equity in any new capacity addition, pro rata reduction for the return on equity in the determination of tariff of the new project shall be given;**

(f) **A certificate in the prescribed form regarding the use of these funds shall be filed with the Commission every year duly verified by the statutory Auditors of the company;**

(g) **The use of these funds in any other manner shall be only with the prior approval of the Commission either on petition or suo motto for which the due process as per the CBR shall be followed.**

9.5.3 From the tax angle the development surcharge should be clearly distinguished from the special appropriation as contained in Schedule VI of the Electricity Supply Act, 1948. The special appropriations are in the nature of application of the profits of the company and as such the tax liability on the profits shall accrue. The Hon'ble Supreme Court has in Associated Power Company Ltd. Vs. CIT (1996-7-SCC 221) and in Vellore Electric Corporation Ltd. Vs. CIT (1997-6-SCC 705) has held that these special appropriations are not liable for deduction in arriving at taxable profits of the Electric Supply Company. While dealing with this matter in Associated Power Co. Ltd.'s case the Supreme Court has observed as an <u>obiter dicta</u> that "the application of the doctrine of diversion of income by reason of a overriding title is quite inapposite. The doctrine applies when by reason of a over riding title or obligation income is diverted and never reaches the person in whose hands it is sought to be assessed. (see CIT vs. Sital Das Tirath Das – AIR 1961 SC 728)" The Court distinguished such income from creation of reserves out of clear profit if it exceeds a reasonable return. The Court has held in that case

(CIT vs. Sital Das Tirath Das AIR 1961 SC 728) that "There is a difference between an amount which a person is obliged to apply out of his income and an amount which by the nature of the obligation cannot be said to be a part of the income of the assessee. Where by the obligation income is diverted before it reaches the assessee, it is deductible; but where the income is required to be applied to discharge an obligation after such income reaches the assessee, the same consequence, in law, does not follow."

The development surcharge constitutes a diverted receipt in the hands of the utility in the capacity of a trustee. It is not to be confused with appropriation of profits. This surcharge shall be in the nature of a receipt collected along with tariff by the utility and shall be accounted for separately by it. The utility is expected to apply this receipt only on expansion of capacity and not to take credit for the same in the profit and loss account of the company. The utility will only be a trustee of this money collected with an obligation to make use of it for the purpose of capital addition. In case the capital addition does not take place the utility will be obliged to return the money to the beneficiaries and shall not be entitled to appropriate the same to itself. Such an obligation once again distinguishes this receipt in the taxability. This was recognised by the Supreme Court in Poona Electric Supply Co. Ltd., Bombay Vs. CIT Bombay (AIR 1966 SC 30). The reserve created along with the corresponding investment shall not be taken into account in valuing its business. With the above terms we are convinced that this development surcharge shall not be liable to taxation. **However, in order to avoid any controversy and unintended burden to the beneficiaries on account of taxation, we recommend to the Central Government to issue a suitable clarification to preempt any avoidable dispute on this account.**

10. CONCLUSION

10.1 With this order, apart from pronouncing our decision on the bulk tariff discussion paper, the following petitions also stand disposed of:

(i) Petition No.4/2000 regarding operational norms for thermal generation.
(ii) Petition No.31/2000 relating to financial norms and rate of depreciation;
(iii) Petition No.32/2000 relating to financial norms for cost of capital;
(iv) Petition No.34/2000 relating to surcharge on hydro generation;
(v) Petition No.85/2000 regarding O&M cost norms for hydro power stations;
(vi) Petition No.86/2000 regarding O&M cost norms for inter-state transmission;
(vii) Petition No.88/2000 regarding O&M norms for thermal stations

10.2 This order has to be read along with our orders on petitions 85/2000 and 86/2000 on operational norms for hydro power stations and for inter state transmission respectively. This order along with the order dated 4th January, 2000 on Availability Based Tariff read with our order on review petition No.13/2000 on availability based tariff will constitute the frame work for notifications on terms and conditions of tariff to be regulated under section 13(a)(b) and (c) of the ERC Act. Separate notifications shall be issued by the Commission incorporating these findings in accordance with section 28 of the ERC Act, 1998.

10.3 The central generating companies to which these orders are primarily applicable have been, till recently operating on the principle of reimbursement for services rendered in the power sector. They are now gradually looking up to tariff fixation on commercial principles. The Commission believes that ultimately the tariff would be appropriately decided by the market forces of supply and demand. This, however, is a far cry at present due to lack of adequate supply, lack of complete transmission facilities and constraints in free trading in power. As such till market mechanism is developed, the Commission has endeavoured to evolve a tariff mechanism keeping in view the interest of generating companies, beneficiaries and the development of a vibrant and viable power sector in the country.

10.4 The Commission took up the task of prescribing the terms and conditions soon after assuming the tariff jurisdiction. For this purpose it had to study, understand and appreciate the tariff mechanism in the past for the central generating companies. The Commission as mandated was also required to follow a transparent process which incidentally results in participative decision making. In this experience, the Commission observed certain significant aspects which are worth recording:

- The tariff fixation process in the past had not been pervasive enough involving wide ranging participation of stake holders;

- The Government, in its dual capacity as a regulator and sole investor in generating companies, had sometime compromised in maintaining a balance between the utilities and beneficiaries. In particular, windfallfall payments have been permitted through easily achievable operational norms and PLF. Besides, adoption of unusual mechanism for rate base determination, delinking the useful life of assets in spreading the depreciable value of assets for tariff etc., are some examples of PSUs being unduly facilitated at the expense of the beneficiaries. Decisions in this regard lacked clarity in the absence of the background and justification for these decisions;

- Retrospective billing to beneficiaries on account of capital cost revision, foreign exchange rate variation and corporate taxation resulted in tariff shocks to beneficiaries which could not be instantaneously passed on to the end consumers;

- The State Electricity Boards who were invariably the respondents in tariff petitions were found wanting in many respects like arrangements for receipt and the submission of pleadings, effective representation of their case before the Commission, lack of authority with the representatives to take decisions on behalf of their organisations and sluggishness in compliance.
- The central public sector utilities, though forthright in putting forward their case, had not always been responding in the manner the Commission desired. As wholly owned government undertakings, these utilities ought to be more transparent than they are at present.

The Commission considers that some of the above experiences are due to the power sector being new to the independent regulatory system and is hopeful that with understanding of each other in the system all concerned would play their roles in the light of the objective behind the reform process. All the same we are appreciative of the role played by all stake holders in cooperating with the Commission. At this point the Commission would also like to place on record its appreciation of the Central Electricity Authority on their technical excellence and timely assistance.

10.5 The Commission has set out at the commencement of this order two broad principles in the tariff mechanism which have been kept in view through out. The tariff determined as per these principles shall only act as a cap price within which the utilities and the beneficiaries are at liberty to negotiate. The Commission could not immediately address the following issues:

- Tariff based on the time of use
- Recommendation for cross subsidisation of renewable power through environmental levy.

These issues however, shall be taken up in future.

10.6 The following highlights of the present order need emphasis:

(I) The tariff shall be stationwise/linewise for generation and transmission respectively;

(ii) The normal tariff period shall be a period of five years but shall at this stage be for a period of three years;

(iii) The tariff would remain undisturbed for the entire tariff period excepting for changes in foreign exchange rate variation, corporate taxation and fuel costs. Revision on account of exchange rate variation and corporate taxation shall be on annual basis with advance notice; revision on fuel cost shall be based on actuals. Consequently, there shall be no retrospective adjustment of the tariff. A mechanism for firming up the capital cost at the commencement of operations has been evolved.

(iv) The Commission is in favour of introduction of the concept of return on capital employed which shall be explored in detail before the next tariff period. However, the minimum return on equity of 16 % is assured for the investor;

(v) The Commission does not propose to change the method of reckoning the rate base. It is recognised that the present method is a deliberate incentive for the investor to continue to engage itself in the power sector. In the circumstances, any diversification to non-core sector shall be with the approval of the Commission;

(vi) The Commission is convinced that depreciation has to be on straight line method spreading the depreciable value over the useful life of the asset. However, there is scope for reviewing the useful life of the assets for which studies have to be undertaken. All the same, utilities should be extended the benefit of advance against depreciation to tide over the cash flow requirements for repayment of loans subject to a test of prudence. This advance however shall be adjusted in subsequent years. Depreciation funds are not to be used for capacity expansion resulting in fund shortage in replacement of assets.

(vii) The base for O&M cost shall be the average normal actual O&M expenditure of the station/region instead of the capital cost; escalation formula has been made more realistic to reflect the movement in the wholesale and retail price indices. The past five years trend in the indices is taken to project the O&M cost for the entire tariff period thereby smoothening the tariff impact. However, for new projects capital cost base shall continue to be adopted for the first time.

(viii) Variable cost relating to fuel shall be a pass through at at present; energy charges for hydro shall facilitate merit order despatch. Revision in thermal operational norms as proposed by CEA has been recognised in principle with the practicability of implementation to be examined; operational norms for hydro sector as recommended by the Consultants, are being implemented; operational norms for transmission sector as recommended by the CEA are also being implemented.

(ix) The methodology for accounting and for tariff fixation with regard to foreign exchange rate variation as per the accounting standards of the

Institute of Chartered Accountants of India accepted for uniform application.

(x) Procedure for pass through of corporate taxation sustained in principle with improved mechanism to ensure tariff smoothness and more rational allocation of the tax burden on the stations/regions.

(xi) More meaningful system of incentives which ensures rewards to the generator for exemplary performance beyond the target levels in all sectors, viz. Thermal and hydro generation and transmission.

(xii) Provision for additional development surcharge on the lines of the contribution to contingency reserve and development reserve as in Schedule VI of the ES Act with stipulations regarding the use of the surcharge only for capacity expansion. This surcharge shall not be liable to taxation.

10.7 The Commission would like to reiterate that it is conscious of its powers to enforce its orders. The procedure for regulating power supply for persistent default is being finalised separately. The Commission however, is determined to enforce its orders under section 45 of the ERC Act in case of continued noncompliance in the matter of settlement of bills. This however, shall be resorted to in the eventuality of all other measures not bearing fruit. The objective behind Commission's endeavours is captured in the conclusion on tariff setting principles in the consultation paper:

Ensuring the financial viability of efficient and proactive utilities, will be a prime concern. At the same time, safeguarding the interests of the consumers becomes a major responsibility of the Commission, particularly, when the market structure and system conditions do not support competition. The Commission is to play a balancing role. It intends to discharge this responsibility transparently, through a consultative mode. It expects that participative decision making will lighten the burden of transiting to a more efficient system, for all stakeholders.

The Commission is hopeful that with the balance kept between the interest of the utilities and beneficiaries compliance would follow.

(A.R. Ramanathan)	(G.S. Rajamani)	(D.P. Sinha)	(S.L. Rao)
Member	Member	Member	Chairman

New Delhi
Dated: 21st December, 2000