DISCUSSION PAPER
ON
TERMS & CONDITIONS OF TARIFF

(Tariff Period Commencing 1.4.2004)

June, 2003

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PREFACE

The Central Electricity Regulatory Commission (CERC) was established in July 1998 in terms of the Electricity Regulatory Commissions Act, 1998. With effect from 15 May, 1999, the Central Government notified the deletion of Section 43(A)(2) of the Electricity (Supply) Act, 1948, and as a result the Central Government's powers and responsibilities in regard to tariff regulation were vested in the CERC. The Commission accordingly assumed the jurisdiction for regulation of tariff of generating companies owned or controlled by the Central Government, tariff of other companies with a composite scheme of generation and sale in more than one State, & inter-State transmission of energy including tariff of the transmission utilities. CERC also assumed the responsibility of notifying the Terms and Conditions of Tariff under the provisions of Section 28 of the ERC Act, 1998.

2. The existing Terms and Conditions of Bulk Electricity Tariff were laid down in our Order dated 21 December, 2000. Broadly, the approach was that the norms of tariff up to 31 March, 2001 would be regulated under the Government of India notifications, while the new CERC norms would be applicable for the period from 1.04.2001 to 31.03.2004.

3. The Electricity Act 2003 has now become the law of the land. This new legislation mandates that the tariff norms determined by CERC under the earlier enactments shall continue to apply for a period of one year, or until the Terms and Conditions are specified by the Commission under the new law, whichever is earlier. We have now to initiate action for laying down the Terms and Conditions of Tariff for the period commencing from 01 April, 2004, as required under the Act of 2003. The enclosed Discussion Paper is meant to be a basis for consultation on this issue.

4. The Paper is aimed at generating a debate on the existing tariff norms, and for soliciting the views of all stakeholders, experts and informed citizens, on the way ahead. It will be relevant to point out that this Paper does not, in any way, seek to state the mind of the Commission. However, it distillates certain suggestions based on the views expressed by various stakeholders in the matter, and our regulatory experience of the last few years. The overall objective of the Commission is to promote economy and efficiency in the sector,

generate confidence among the investors, enable investment and competition, and protect the interest of the consumers.

5. We welcome written comments from members of the public, various players in the electricity industry and other stakeholders, on the several issues raised in this paper. This would become a basis for holding formal hearings, with the intention of laying down the principles on which the Commission will approach tariff determination for the next tariff period. This exercise assumes greater importance since the Electricity Act 2003 mandates that, while specifying the norms of tariff in their appropriate jurisdiction, the State Electricity Regulatory Commissions shall be guided by the principles and methodologies specified by the Central Commission for tariff determination for generating companies and transmission licensees.

6. We sincerely look forward to your comments and suggestions.

June, 2003.

(Ashok Basu)
Chairman

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CHAPTER 1

1.0 Introduction

1.1 The Central Electricity Regulatory Commission (CERC) was established in July 1998, in terms of the Electricity Regulatory Commissions Act, 1998 (the ERC Act). The functions of the Commission were spelt out in Section 13 of the ERC Act.

1.2 Section 28 of the ERC Act provided for the guidelines for tariff determination for the Commission.

1.3 Prior to constitution of the Central Electricity Regulatory Commission, the terms, conditions and tariff for sale of electricity by generating company to the State Electricity Board were governed under Section 43(A)(2) of the Electricity (Supply) Act, 1948 which is reproduced below:

> **"***43.A Terms, conditions and tariff for sale of electricity by generating company*
>
> *(1) A generating company may enter into a contract for the sale of electricity generated by it-*
> *(a) with the Board constituted for the State or any of the States in which a generating station owned or operated by the company is located;*
> *(b) with the Board constituted for any other State in which it is carrying on its activities in pursuance of sub-section(3) of section 15A; and*
> *(c) with any other person with consent of the competent government or governments.*
>
> *(2) The tariff for the sale of electricity by a generating company to the Board shall be determined in accordance with the norms regarding operation and the Plant Load Factor as may be laid down by the Authority and in accordance with the rates of depreciation and reasonable return and such other factors as may be determined, from time to time, by the Central Government, by notification in the official gazette:*
>
> *PROVIDED that the terms, conditions and tariff for such sale shall, in respect of a generating company wholly or partly owned by the Central Government be such as may be determined by the Central Government and in respect of a generating company wholly or partly owned by one or more State Governments be such as may be determined, from time to time, by the government or governments concerned".*

1.4 Section 51 of the ERC Act, empowered the Central Government to omit Section 43 (A) (2) of the Electricity (Supply) Act, 1948 from such date as it may notify in the official gazette. The Central Government issued the notification omitting Section 43 (A) (2) with effect from 15.5.1999, and as a result the power to specify the terms and conditions of tariff was passed on to the CERC in respect of companies falling under Section 13(a) and (b) of the ERC Act, 1998. Consequent to the deletion of Section 43 (A)(2), new sets of terms and conditions were required to be notified under the provisions of Section 28 of the ERC Act 1998.

1.5 One of the first activities of the Central Electricity Regulatory Commission on its establishment was to bring about a consultation paper on Bulk Electricity Tariff in September, 1999. This paper was discussed by the Commission with various stakeholders as well as the representatives of industry and commerce, academia etc. in various Regional Electricity Board headquarters at Shillong, Kolkata, Mumbai, Delhi and Bangalore. The feed back obtained in these meetings were also kept in view. The Commission engaged consultants like Crisil Advisory Services for cost of capital, ICRA Advisory Services for depreciation, CEA for thermal operational norms, WAPCOS for hydro operational norms as well as O&M cost norms for hydro power stations, DCL for O&M cost norms for thermal power stations etc. Wherever consultants were not appointed, the Commission generated staff papers for discussions. All these documents were circulated to the stakeholders and all other interested parties and were treated as suo-motu petitions of the Commission. Adequate opportunities were given to all the parties to express their views in the form of written pleadings and subsequently oral arguments were also held. The entire process of finalising the norms complying with the principles of natural justice and transparency took almost one year for the Commission and the final orders on all these issues were passed on 21 December, 2000. Based on this order, the Commission issued four regulations notifying the Terms and Conditions of Tariff along with subsequent amendments, as indicated below:

(1) CERC Notification dated 26 March, 2001 – Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2001;

(2) CERC Notification dated 21 September, 2001: Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (First Amendment) Regulations, 2001; and

(3) CERC Notification dated 08 July, 2002: Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (First Amendment) Regulations 2002.

(4) CERC Notification dated 01 May, 2003: Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (First Amendment) Regulations 2003.

The above notifications contained the Terms and Conditions of Tariff for three year period effective from 1.4.2001 to 31.3.2004. All these Notifications are available on CERC web site **(http://www.cercind.org).**

1.6 The Commission is presently engaged in the process of revision of the Tariff Norms for the next tariff period commencing from 01 April, 2004. In order to enable the Commission to discharge this responsibility, the Commission sought suggestions from various stakeholders vide its letter No.L-7/25(1)/2003-CERC dated 17 January, 2003 on the existing notifications, with a view to assisting the Commission in the preparation of the Discussion Paper.

1.7 The interested parties were advised to furnish their comments by 28 February, 2003, which was extended up to 15 April, 2003. The comments received from various parties have been appropriately used in the development of this Discussion Paper.

1.8 The Electricity Act, 2003

1.8.1 The Central Government have now enacted new legislation, called the Electricity Act, 2003, hereinafter called the Act, which has come into force with effect from 10 June, 2003. Section 72(2) of the Electricity Act, 2003 provides that CERC established under Section 3 of the ERC Act, 1998 and functioning as such immediately before the appointed date shall be deemed to be the Central Commission for the purposes of the Act. Section 79 of the Act provides for the functions of the Central Commission, which is reproduced below:-

"79. (1) The Central Commission shall discharge the following functions, namely: -

(a) to regulate the tariff of generating companies, owned or controlled by the Central Government;

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

(c) to regulate the inter-State transmission of electricity;

(d) to determine tariff for inter-State transmission of electricity;

(e) to issue licenses to persons to function as transmission licensee and electricity trader with respect to their inter-State operation;

(f) to adjudicate upon disputes involving generating companies or transmission licensee in regard to matters connected with clauses (a) to (d) above and to refer any dispute for arbitration;

(g) to levy fees for the purpose of this Act;

(h) to specify Grid Code having regard to Grid Standards;

(i) to specify and enforce the standards with respect to quality, continuity and reliability of service by licensees;

(j) to fix the trading margin in the inter-State trading of electricity, if considered necessary;

(k) to discharge such other functions as may be assigned under this Act.

(2) The Central Commission shall advise the Central Government on all or any of the following matters, namely:-

(i) formulation of National Electricity Policy and tariff policy;

(ii) promotion of competition, efficiency and economy in activities of the electricity industry;

(iii) promotion of investment in electricity industry;

(iv) any other matter referred to the Central Commission by the Government.

(3) The Central Commission shall ensure transparency while exercising its powers and discharging its functions.

(4) In discharge of its functions, the Central Commission shall be guided by the National Electricity policy, National Electricity Plan and tariff policy published under sub-section (2) of the Section 3.

1.8.2 The Act goes a step further in liberalising the framework of electricity industry. Among the important features of this Act are, delicensing of generation, doing away with the requirement of Techno-Economic clearance for thermal generation, freeing captive generation from controls, recognition of electricity trading as a distinct activity, provision of open access in transmission immediately, and open access in distribution in a phased manner to be decided by the State Commissions, specific provisions for supply in the rural areas, stringent provisions for violation of grid discipline and theft of power, setting up of an Appellate Tribunal etc. The provisions of freeing captive generation, open access, determination of tariff through competitive process, provision for more than one licensee in the same area of supply etc., are the provisions which will foster competition in near future, while the evolution of a wholesale power-market will unleash competition in the sector in the long run.

1.8.3 Important provisions governing tariff determination under the Act are quoted below: -

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

(a) the principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;
(b) the generation, transmission, distribution and supply of electricity are conducted on commercial principles;
(c) the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;
(d) safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;
(e) the principles rewarding efficiency in performance;
(f) multiyear tariff principles;
(g) that the tariff progressively reflects the cost of supply of electricity, and also reduces and eliminates cross-subsidies within the period to be specified by the Appropriate Commission.
(h) The promotion of co-generation and generation of electricity from renewable sources of energy;
(i) The National Electricity Policy and tariff policy.

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

"62.(1)The Appropriate Commission shall determine the tariff in accordance with the provisions of the Act for-

(a) supply of electricity by a generating company to a distribution licensee;

Provided that the Appropriate Commission may, in case of shortage of supply of electricity, fix the minimum and maximum ceiling of tariff for sale or purchase of electricity in pursuance of an agreement, *entered into between a generating company and a licensee or between licensees, for a period not exceeding one year to ensure reasonable prices of electricity;*

(b) transmission of electricity;
(c) wheeling of electricity;
(d) retail sale of electricity;

Provided that in case of distribution of electricity in the same area by two or more distribution licensees, the Appropriate Commission may, for promoting competition among distribution licensees, fix only maximum ceiling of tariff for retail sale of electricity.

(2) The Appropriate Commission may require a licensee or a generating company to furnish separate details, as may be specified in respect of generation, transmission and distribution for determination of tariff.

(3) The Appropriate Commission shall not, while determining the tariff under this Act, show undue preference to any consumer of electricity but may differentiate according to the consumer's load factor, power factor, voltage, total consumption of electricity during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required.

(4) No tariff or part of any tariff may ordinarily be amended, more frequently than once in any financial year, except in respect of any changes expressly permitted under the terms of any fuel surcharge formula as may be specified.

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

(6) If any licensee or a generating company recovers a price or charge exceeding the tariff determined under this section, the excess amount shall be recoverable by the person who has paid such price or charge along with interest equivalent to the bank rate without prejudice to any other liability incurred by the licensee".

"63. Notwithstanding anything contained in section 62, the Appropriate Commission shall adopt the tariff if such tariff has been determined through transparent process of bidding in accordance with guidelines issued by the Central Government".

1.8.4 The Commission is mandated to lay down regulations governing terms and conditions of tariff within one year of the appointed date according to proviso to Section 61 of the Act. The current tariff period of three years is due to expire on 31 March, 2004. It is, therefore, considered appropriate that the new set of regulations governing terms and conditions of tariff are in place well before the onset of next tariff period. This discussion paper is aimed at soliciting the views of stakeholders, experts and citizens, as an integral part of this exercise.

CHAPTER 2

2.0 Competition, Trading & Market Development

2.1 Competition: Until the decade of the 80's, electricity supply business was largely considered to be a natural monopoly. It was thought that economy of scale and necessity of effective coordination can permit only a single business firm to provide all services in a vertically integrated manner in the most economical fashion. Technological development such as discovery of CCGT and the use of IT- enabled services in the electricity supply industry in the 80's significantly brought down the size of minimum economic unit, particularly in generation. These developments led to restructuring of electricity supply business globally with a view to separating potentially competitive activities from monopolistic segments.

2.1.1 In the Indian context, Government of India made it compulsory to procure generation assets (IPPs) through international competitive bidding route, abandoning the earlier method of setting up IPP projects through the MOU route. At the state level, starting with Orissa, a number of states undertook comprehensive reforms involving unbundling of vertically integrated State Electricity Boards, setting up of independent Regulatory Commissions with a mandate to promote efficiency, economy, competition etc. So far, the SEBs of Orissa, Andhra Pradesh, Haryana, Karnataka, U.P., Uttaranchal, Rajasthan, M.P. and Delhi have been unbundled and distribution privatised in Orissa and Delhi.

2.1.2 The Central Electricity Regulatory Commission has initiated a number of steps in furtherance of its mandate to promote competition. Some such steps are as follows:

1. Benchmarking of operating parameters
2. Competitive bidding procedures for IPTC route in Transmission
3. Merit order dispatch under ABT
4. Initiation of power trading
5. Interaction with IPPs

2.1.3 The enactment of the Electricity Act, 2003 paves the way for evolution of a genuinely competitive power sector. The provisions contained regarding unbundling of State Electricity Boards (Section 131), allowing non-discriminatory open access to transmission and distribution lines for use by generating companies, trading/distribution licensees from the very beginning and by consumers in a phased manner (Sections 38,39, 40, 42), provision of multiple licensees in same area of supply (Sec. 14), market determined tariff with maximum/minimum thresholds (Sec. 62) and determination of tariff through competitive bidding (Sec. 63) will go a long way in promoting competition in the sector.

2.2 Trading: Power trading by definition is an activity where power is purchased for resale thereof and is carried through the transmission/ distribution network of an existing licensee. Power traders are therefore not required to own generating /transmission/distribution assets. The electricity demand fluctuates in a daily and seasonal pattern. India being a large country with wide seasonal variations from one part to other, there are pockets of surpluses and deficits. As electricity is not a commodity which can be economically stored, power produced at a point in time is not a good substitute for power requirement at another point in time. The electricity traders play a key role as intermediaries in facilitating power transactions in such a situation.

2.2.1 The earlier legislations governing the power sector did not provide for trading in power as a separate activity. With the passing of the new Act, the trading in power is a distinct licensed activity. Besides, generating companies and distribution licensees are also permitted to engage in trading, and there is no requirement of a separate license for the purpose. The Act also prohibits National Load Dispatch Centre, Regional Load Dispatch Centres, State Load Dispatch Centres, Central Transmission Utility, State Transmission Utility and Transmission Licensees from trading, with a view to maintaining the neutrality of transmission as a carrier of electricity. The CERC in the case of inter-state trading and SERCs in the case of intra-state trading are required to prescribe technical requirement, capital adequacy and credit worthiness for obtaining a trading license. The Regulatory Commissions are also required to specify the duties of the Trading Licensee. The CERC will float a separate consultation paper on power trading in near future.

2.2.2 It would be pertinent to mention that even as of today, there is a limited power available for trading. Under the ABT regime, the generation schedule of central generating stations and drawal schedules of beneficiaries are drawn by the RLDC on a day ahead basis, and the same are available on the respective RLDC web sites. On most occasions, there is some unrequisitioned capacity of the central generating stations which is available for purchase. The liability of fixed charge for this capacity remains with the beneficiary, even if it remains unrequisitioned. Similarly, in real time operation, there is some power available for spot trading depending on mismatch between actual generation vs drawal. Some bilateral trading of allocated capacity of central generating stations is already taking place between various states either directly or through PTC. Further, PTC is also endeavoring to enter into various types of long term power trading agreements in which they will be purchasing power from one entity and selling it either to a particular entity or other entities willing to buy power from time to time. There is a need to evolve conducive infrastructure and ground rules for the power market to develop further.

2.3 Market Development: In the legal framework before enactment of the new Act, the development of market in power was highly constrained as the industry structure was horizontally and vertically integrated. The electricity supply to a customer is through a chain of monopolies earlier regulated by the Government and now by the Regulatory commission. Fig. I and II depict the present market structure.

2.3.1 With the new Act, a liberalised market structure is sought to be provided. A customer has a number of choices to get his power. The generators can also compete among themselves for distribution companies/individual customers. There is a provision for surcharge to meet current level of cross subsidy, if a consumer opts to get electricity directly from a generator or any source other than his own distribution licensee and has been allowed open access by the Regulator. However, there is no surcharge when a distribution company buys power from a generator directly. There is also a provision for bilateral contract for supply of power through a competitive process between a generator and distributor. With the provision of non-discriminatory open access to transmission, the competition for bulk supply to distribution companies could become a reality in the near future. The market structure will, perhaps, require to be transformed as shown in Fig. III.

2.3.2 The Commission is committed to the development of a fully competitive power sector. However, given the current realities of the sector (shortages, cross subsidies, long term PPAs, capacity allocation from CGS to state etc.), the market development has to go through a number of intermediate phases. It may be noted that the retail competition has yielded perceptible benefits to consumers in the countries having surplus generation.

2.3.3 There are a number of complex issues such as transition risks, settlement of imbalances in power injected and drawals, effective metering, efficient pricing of transmission, management of congestion etc., on which the Commission would float a separate discussion paper in due course. However, some of the relevant issues in Transmission and Wheeling of electricity needing immediate attention are posed for discussion in the following paragraphs:

2.3.3.1 **Transmission and Wheeling:** With the introduction of mandatory open access, there will be demand by third parties for wheeling of power through the existing transmission networks in addition to wheeling being undertaken at present for various beneficiaries importing power from outside the region. In this context, CERC has jurisdiction for regulation of

Existing Market Structure
Unbundled

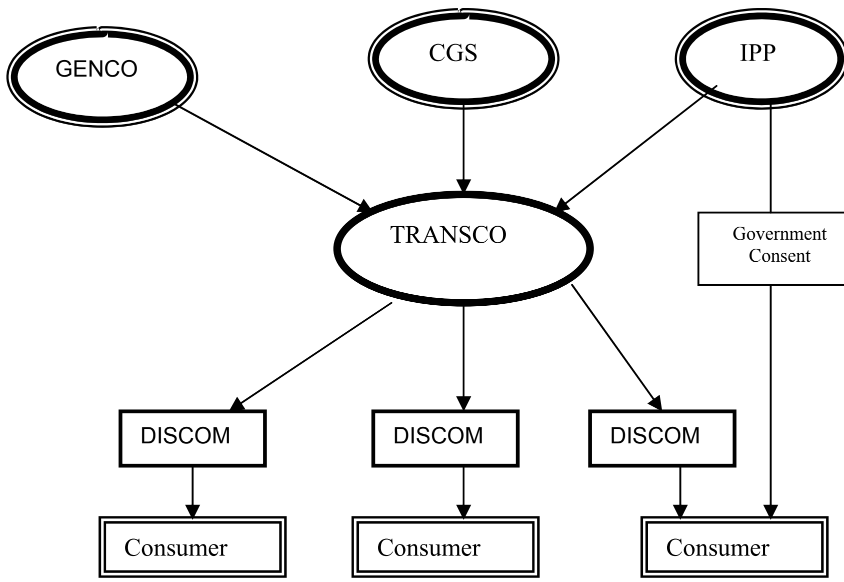

Figure I

Existing Market Structure
Bundled

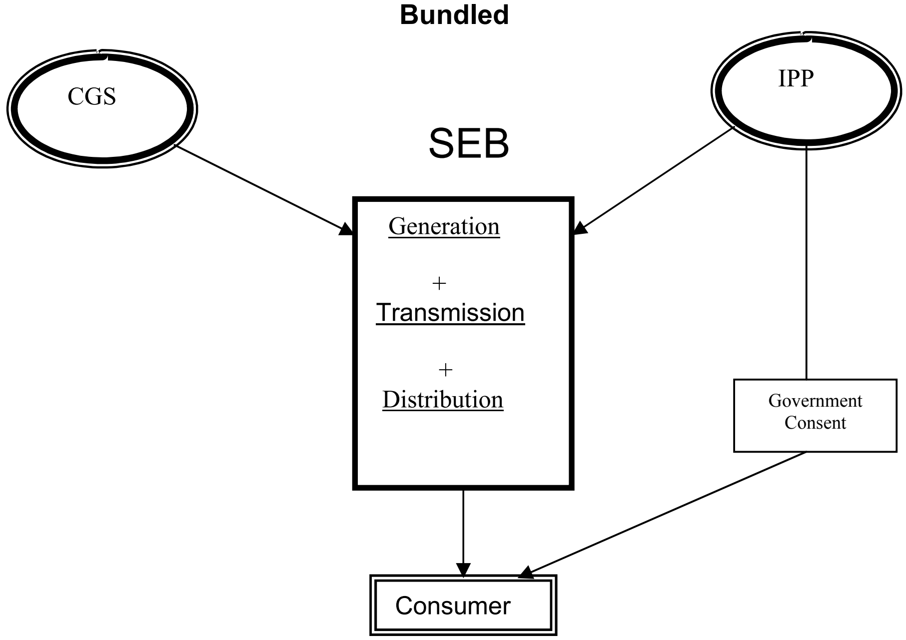

Figure II

Emerging Market Structure

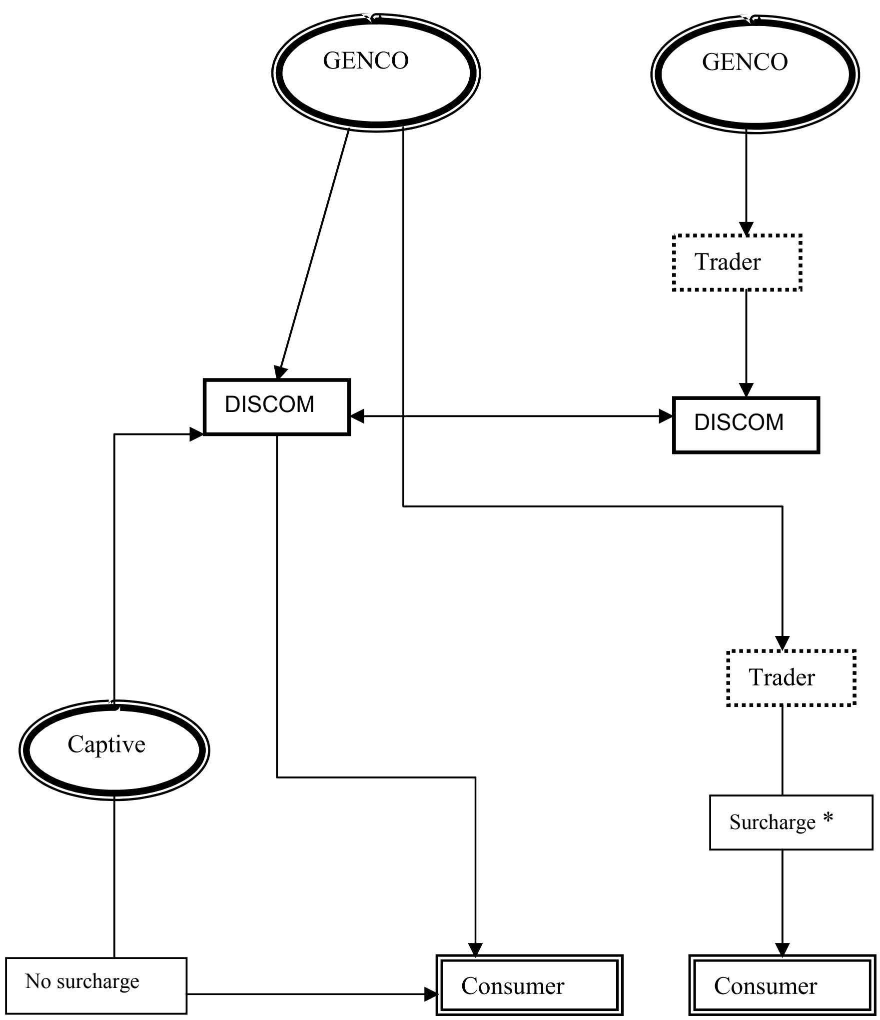

Figure III

* Surcharge to be phased out alongwith cross subsidies.

transmission and wheeling charges for all inter-state and inter-regional power flows. As per the existing notification, the wheeling charges are payable at the same rate as the transmission charges for a particular region.

2.3.3.2 **Pan Caking:** According to the existing notification, an importing utility is required to pay wheeling charges in the exporting region plus transmission charges for inter-regional line(s) plus wheeling charges for the intervening SEB(s) plus transmission charges in the importing region. For example, take the case of import by TNEB from the ER via WR through Raipur-Rourkela line connecting ER-WR and Chandrapur-Ramagundam line connecting WR-SR. In this case, TNEB will have to pay a) wheeling charges for ER, b) wheeling charges for Raipur-Rourkela line, c) transmission charges for Chandrapur-Ramagundam line and d) transmission charges for SR. PTC in their comments have mentioned that such pan caking results in very high charges payable by the importing utility, which discourages inter-state exchanges.

2.3.3.3 **Suggestion to Reduce Wheeling Charges:** In its order dated 11.05.02 in petition No 3/2002 filed by PTC, the Commission had rejected the contention of the petitioner that no additional transmission/wheeling charges should be payable in the normal course of trading unless any new system is required to be added for the purpose of trading. However, it is felt that the transmission/wheeling services should not be provided free. It may be argued that the existing transmission owner made the investment without the expectation of use by third parties, and the opportunity for the exchange has arisen only because of the spare capacity. From this viewpoint, the importing utility should not be expected to pay for the sunk investment but may be subjected to payment of incremental O&M charges and some premium (opportunity cost). Similarly, in case of wheeling through SEB system, the importing utility may be asked to pay the incremental O&M charges plus some premium. The amount of premium may have to be graded for type (Firm or Non-Firm) and duration of wheeling service. In the limiting case of a long-term agreement, the wheeling charges may be equal to the transmission charges, as in this case, wheeling service provides an alternative to construction of a new transmission line. At present, only the importing utility/ beneficiary is required to pay the transmission/ wheeling charges. It is for discussion whether part of these charges could be borne by the exporting utility/generator, as is the practice in some of the countries like USA, Sweden, Finland, Norway etc.

2.3.3.4 **Methodology for Sharing of Transmission Charges:** Although the principles for sharing of transmission charges/wheeling charges have been enumerated in detail in the present notification, there appears to be need to bring further clarity in the matter. The following methodology for sharing of transmission and wheeling/congestion charges is proposed for discussion:

- Transmission charges for the inter-regional lines may be shared by the two contiguous regions on 50:50 basis and further shared among the beneficiaries within the respective region.
- Transmission charges for the inter-regional lines may not be pooled with those for the other transmission assets in the respective regions.
- Transmission charges (after deducting the wheeling/congestion charges realised from others) for the regional assets (other than the inter-regional assets) may be shared by the "regional beneficiaries" (Regional beneficiaries means beneficiaries located in the region concerned)
- If an inter-regional asset is used for wheeling by a third party, the balance transmission charges after accounting for the payable wheeling/congestion charges, may be shared by the beneficiaries of the contiguous region on 50:50 basis.

CHAPTER 3

3.0 Tariff Setting

3.1 Basic Approach

3.1.1 As stated in the foregoing chapter, a competitive market in power will evolve gradually. During the intervening period, the regulation of generation tariff will have to be continued on cost of service approach. Even under this approach the objectives of achieving economic efficiency on the one hand and encouraging investment on the other hand would remain. Transmission being a natural monopoly, its tariff will also need to be regulated under a similar principle.

3.1.2 In the cost plus approach, the Regulator has to go into the various components constituting tariff. In thermal generation, cost of fuel is a variable component and all other components such as cost of servicing the capital (equity and loan), depreciation and O&M are fixed components. In hydro generation and transmission sector, there is no fuel cost involved. In performance based regulation, incentive is another component of tariff. The tax liabilities of utility are also to be accounted for in the tariff structure. Presently, the fixed charges comprise the following elements:

(i) Interest on loan;
(ii) Depreciation and advance against depreciation;
(iii) O&M expenses;
(iv) Return on equity;
(v) Interest on working capital; and
(vi) Income tax, as an expense, at acutals.

3.1.3 Tariffs of the utilities regulated by CERC were earlier computed on a single part per kWh basis up to 1991. This was not found to be conducive for proper grid operation. World over, two part tariffs, comprising capacity charge and energy charge were being used with clear advantages in grid operation. Consequent to the recommendations of K.P.Rao Committee, two part tariff was introduced for thermal generating stations of NTPC by the Government of India in 1992. Two part tariff for hydro generation was introduced by the Government of India in 1995. Transmission tariff is a single transmission charge on an annual basis.

3.1.4 For improving the grid operation, the Commission has introduced Availability Based Tariff (ABT), which is at present being implemented in all the regions except North Eastern Region. Under ABT, besides the fixed and variable charges, Unscheduled Interchange (UI) charges are also levied for deviation from schedules issued by RLDCs. Considerable improvement in the grid frequency has been noticed in these regions as a result of the introduction of ABT. The Commission is closely monitoring the ABT in various regions.

3.1.5 The components of the cost plus tariff are being discussed in the subsequent paragraphs.

3.2 Rate of Return

3.2.1 The most common and pervasive system of rate making is the cost of service model. Under this, the Regulator seeks to determine the regulated utilities' costs, including the cost of raising capital, as a prelude to determining the revenues needed to cover its costs. From this revenue calculation, the Commission figures the price that can be charged by the utility for its product or service including an opportunity to recover a reasonable return on investment. Accordingly, the predominant exercise of a Regulator is to determine the nature of return and the rate base. This is often referred to as Rate of Return Regulation.

3.2.2 The Commission's order dated 21.12.2000 clearly brought out the inevitable choices in the rate of return regime –

(a) Return on Capital Employed (ROCE), that is, Return on Total Investment; or

(b) Return on Equity (ROE), that is, Return on Total Investment less the borrowings or Return on normative equity. In this approach, the interest on loan is provided for separately, on actual basis, with quantum of debt on normative or actual basis along with FERV.

3.2.3 The Commission had requisitioned the services of M/s Crisil Advisory Services (CAS) to study the cost of capital, before the orders were issued in December 2000. The recommendation of the CAS at that time was that CERC might adopt Cost of Equity Approach. Cost of Capital Approach may be considered at the next review after examining various issues relating to bench marking Cost of Debt and Debt - Equity Mix. When the Report was subjected to hearing by the Commission, many views were expressed by different organisations. NLC, NHPC and PGCIL were in favour of the Cost of Equity Approach, whereas the NTPC supported the Return on Investment Approach as it allows incentive for optimising the return by financial engineering, refinancing etc. After considering the views of all the parties, the Commission came to the conclusion that the Cost of Capital Approach is the preferable approach. The view of the Commission was:

"We considered 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 change over to ROCE could be brought about after the interest rates are stabilised and bench marking of debt/equity is perfected."

3.2.4 The different suggestions now received in response to the Commission's letter No. L-7/25(1)/2003 dated 17.01.2003 are as follows:

(a) ROE should be reduced to 12% of paid up and subscribed capital based on current interest rates;
(b) ROE of 16% should be allowed only where debt-equity ratio is 4:1;
(c) ROE should be reduced to match with falling interest rates, and could have a relationship with Primary Lending Rates (PLR) or RBI rate;
(d) The concept of ROCE could be adopted for all future projects, and the existing Government of India notifications could be continued for all existing projects.

3.2.5 PGCIL has expressed the opinion that the ROE should not be lower than 16%. The main argument of the State Electricity Boards for reduction of the ROE is based on the fact that we are in an era of falling interest rates and with improved security measures after implementation of the scheme of one time settlement of SEB dues, the business risk in the power sector has considerably reduced. In fact, one of the State Electricity Boards has even suggested that the ROE could be brought down to 8% of the paid up and subscribed capital, because the rate of return in a Government of India Bond is only 6.75%, to which a risk premium of 1.25% could be added to bring it up to 8%.

3.2.6 In view of the fact that the interest rates have come down and are stabilising and also the financial condition of State Electricity Boards has improved as a result of the scheme of one time settlement of SEB dues, which has led to a reduction in payment risk, it can be considered if this could be an appropriate time to switch over from ROE to ROCE. In determining a rate of return, four primary concerns will require to be attended to:

(i) Fairness to investors;
(ii) Fairness to consumers;
(iii) The need to attract capital; and
(iv) Administrative simplicity.

3.2.7 Simplicity involves avoidance of complexity. One of the major features of the power tariff in India is the "pass through" mechanism. Interest on loans, foreign exchange variations, Income-tax and fuel charges are the major elements which constitute the "pass through" in the tariff. One approach could be to have a rate of return on investment, which will be composite enough for the purpose and do away with the need for "pass through" at least in determining fixed charges. Fuel charges (variable charges) fall in a different category, and there is a well tried adjustment mechanism which takes care of the requirements. Accordingly, the attempt should be to evolve a rate of return on the capital employed through a simple mechanism. The question, which needs to be addressed in this context, is to bench mark a debt-equity ratio for the purpose of determining the rate. Broadly, a debt-equity ratio of 80:20 is generally preferable. However, in order to ensure a smooth change over, perhaps it would be advisable to adopt a normative debt-equity of 70:30. As regards return on equity element, the Commission had already expressed its views in para 2.6 of the order dated 21.12.2000 as under:

> "*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.*"

3.2.8 In view of the assurance given by the Commission and also to avoid Regulatory uncertainty on this count, it is for consideration whether it would be advisable to disturb the existing return on equity.

3.2.9 There is need, however, to lay down a clear basis for determining the interest on debt portion. A simple method would be to adopt the Prime Lending Rate (PLR) for this purpose. ROCE can then be evolved taking into account the return on equity at 16% and the return on debt portion equivalent to PLR at say 11%. On a base of 100, the return on equity would work out to 4.8 and the interest on debt would be 7.7. Both added together (4.8+7.7) would give an ROCE of 12.5%. It is also necessary to make a provision, which would take care of the income-tax element, if any. In a typical ROCE model, these elements cannot be allowed to be a pass through and, therefore, a miscellaneous provision of 0.5% could take care of these and other requirements. We can have a miscellaneous provisions of 0.5% which could give an ROCE of 13%. In the ROCE model, the need to provide for Foreign Exchange Rate Variation (FERV) may not arise.

3.2.10 A question, which needs to be addressed, is whether the ROCE should be a fixed number for the tariff period or it should be a dynamic number, to be fixed every year after taking into account the change in the PLR. If the tariff period is short, then it could be a fixed number, say for a period of 2-3 years. However, if the tariff period is 5 years, this could be considered to be too long to keep a static rate for that length of time. If the dynamic approach is to be adopted, the question which needs to be addressed is whether the rate would require to be adjusted at the beginning of each year or we can provide one time change in the mid period say after 2 years at the beginning of the third year for the balance period. The latter has a distinct advantage in the sense that too many adjustments may not be necessary and the tariff will be predictable for the entire tariff period.

3.2.11 There is another aspect, which needs attention. This relates to abnormal variation in the PLR in any particular year with a sharp increase or fall in the interest rates. Freezing the PLR number for certain number of years obviously carries risk. There would also be a need to clearly define the term, "abnormal variation". For example, if the PLR varies $\pm$ 5%, the tariff could be reset in that particular year. This would require consideration.

3.2.12 There is also a clear need to lay down the base date for determining the PLR. For this purpose, one suggestion is to consider the PLR as on 01 January of a calendar year as the base PLR to determine the tariff from 01 April of the same calendar year, corresponding to the beginning of the financial year. It could also be that the PLR as on 01 March could be the base because by that time the budget would have been presented to the Parliament and at least the direction would be clear. The disadvantages of this are:

(a) The budget would have been just introduced and not yet passed by the Parliament ; and
(b) One month may not be sufficient for the Commission to reset and notify the tariff in time as the new tariff will have to take effect from the 01 April.

It would, therefore, be necessary to consider the base date which would be crucial for adopting the PLR for determining the rate of return on the investment.

3.3 Rate Base

3.3.1 Determination of rate base is a critical step in calculation of the returns to a utility. The rate of return is applied to a rate base. ROE is calculated on the equity base while the interest cost on outstanding debt is a pass through. If it is decided to switch over to the ROCE, the rate base will be the total capital base, which represents prudent investments made by the utility on which the return is calculated and provided in the tariff. The present practice is to determine the base as on the date of COD, where the Auditors can certify the expenditure.

3.3.2 When the issue was examined by the Consultant, M/s Crisil Advisory Services Limited, they recommended that the determination of rate base at the commencement of a project, should be decided by referring to the balance sheet of the Company. It was recommended that the regulated assets should be identified along with borrowing, and unregulated assets should be deducted from the total assets, to reckon the resultant capital base. In this connection, they also referred to two methods, namely, 'Aggregated Rate Base' and 'Dis-aggregated Rate Base'. In the Aggregated Rate Base method, the total fixed assets as per the balance sheet, will be the base. From this aggregated rate, net fixed asset not related to regulated business such as capital works in progress (not regulated), non statutory investments and current assets in excess of norms are to be deducted. This could be further split as per the normative debt-equity ratio. In the Dis-aggregated 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 a net worth which would form the base. The basic difference is that, in the first method, the normative debt-equity is applied whereas in the second method, the net worth is arrived at after taking the actual long-term loan.

3.3.3 The recommendation of the Crisil Advisory Services (CAS) was considered by the Commission earlier and it was decided that the balance sheet method presented practical difficulties. For example, there is bound to be a time lag between the availability of audited balance sheet and the commencement of the year, whereas the tariff is required to be determined before the commencement of a year. The conclusion arrived at by the Commission was that the methodology for obtaining the rate base has to be different, that is , independent of the balance sheet.

The rate base, as Capital Expenditure, can be further classified as:

a) Initial Capital Expenditure
b) Additional Capital Expenditure

3.3.4 **Initial Capital Expenditure**: Initial Capital Expenditure could be arrived at by the following criteria:

a) In the case of a Generating Station/Transmission System for which tariff orders were issued by CERC, the capital cost as admitted in those cases will be the initial capital expenditure.

b) In cases where tariff petitions are filed for the first time before the Commission and no other tariff notification/order exists, the actual capital expenditure as on COD based on audited accounts of the company may be considered subject to prudence check by the Commission.

3.3.5 While on the issue of Initial Capital Expenditure, it is necessary to discuss the treatment of Initial Spares. At present, initial spares are covered under clause 2.5 (Thermal), 3.3 (Hydro) and 4.3 (Transmission) of CERC Tariff Notification dated 26.3.2001. It is mentioned in clause 2.5 and 3.3 that project cost shall include reasonable amount of capitalised initial spares. Clause 4.3(b), applicable to transmission system, states that the capital cost shall include capitalised initial spares for the first 5 years of operation. There is no ceiling limit specified for the amount to be capitalised under spares. This can result in over capitalisation. In view of this, the question of applying ceiling norms on the capitalised initial spares as a percentage of the approved project cost or actual capital expenditure, which ever is lower, need to be debated.

3.3.6 **Additional Capital Expenditure:** CERC tariff notification dt. 26.03.2001 under clause 1.10 provides:

> *"Tariff revisions during the tariff period on account of capital expenditure within the approved project cost incurred during the tariff period may be entertained by the Commission only if such expenditure exceeds 20% of the approved cost. In all cases, where such expenditure is less than 20%, tariff revision shall be considered in the next tariff period."*

3.3.6.1 NTPC's contention is that tariff for the new station is determined based on the actual capital expenditure incurred on COD of the station. In most of the cases, only essential systems and services, immediately required for operation of the stations are completed and capitalised up to COD. There are many services/systems like administrative office, township, ash dyke, offsite services etc., which are completed after the COD of the station. In thermal plants, such expenditure after the COD may be substantial but unlikely to exceed 20% of the cost. Thus not allowing revision of tariff on account of capitalisation of such expenditure till the next tariff revision will amount to penalising the utilities. It has further been contended that this would have adverse effect in the COD of the station, which may get extended and will not be in the interest of beneficiaries.

3.3.6.2 The other important issue is the criteria to be adopted for admitting additional capital expenditure. NTPC and NHPC have suggested that tariff regulations should include principles/procedures based on which additional capital expenditure after COD of station will be admitted by the Commission. Broadly speaking, the claim of additional capitalisation could be classified into following categories:

(a) Deferred expenditure on works & services in the original scope of work: This includes Works/services under taken after COD and Balance payments of works/services undertaken before COD.

(b) Expenditure on new works/services not in the original scope of work: This includes, (i) Expenditure on miscellaneous works/services undertaken after COD, (ii) Expenditure on replacement of obsolete/old equipments which have completed their useful life, (iii) Expenditure on Renovation & Modernisation and Life Extension of plant, (iv) Expenditure involving replacement of asset/works arising out of contingency/accident e.g. floods, fire etc. and (v) Expenditure arising out of statutory provisions/change of law, such as on new environmental regulations.

3.3.6.3 However, it may be mentioned that the expenditure on new works after COD relating to replacement of obsolete/old assets and R&M works including life extension could be admitted on merit, provided the original value of old asset is written off from the gross block. NTPC is currently following this practice.

3.3.6.4 It is a question for consideration whether the additional capital expenditure on miscellaneous works/services left out or conceived subsequently such as office equipment, IT & communication equipment, welfare facilities, testing kits, lab. equipment, workshop equipment, additional residential quarters, soil conservation, de-watering pumps etc. should be admitted.

3.3.6.5 In case FERV becomes payable, the following options have been suggested:.

i) Payment of FERV, arising on account of interest payments and payments of instalments of loan, at actuals, on quarterly or yearly basis.
ii) Payment of FERV in accordance with Accounting Standard-11 (AS-11) of Institute of Chartered Accountants of India.
iii) Payment of FERV in accordance with AS-11 of Institute of Chartered Accountants of India after dividing the FERV component into normative Debt and Equity.

These issues require detailed consideration.

3.3.7 There is an important question whether the asset side approach as recommended by the CAS should be adopted or the liability side approach. Broadly, in the asset side approach, the value of the core assets on the ground are taken for arriving at a base, whereas 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. As a corollary, in the liability side approach, the depreciation is independent of the rate base determination. The liability side approach provides scope for double counting of the equity in case the depreciation amount instead of being used for replacement of the capacity is otherwise used for addition to the capacity. In the asset side approach, this situation is avoided.

3.3.8 The Commission had studied the whole matter in depth along with the policies of the Government of India in the past. It was noticed that there was a conscious decision to offer incentives to investors so that they could continue to sustain their plants and operate the services. It was decided by the Commission to continue with the liability side approach. The order dated 21 December, 2000 states:

> "*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.*"

3.3.9 It is for consideration whether it would be advisable to continue with the liability side approach or adopt the Net Fixed Asset (NPA) Model where the NFA shall be arrived at by deducting the accumulated depreciation from the Gross Capital Cost admitted for tariff purposes.

3.3.10 It is relevant to discuss different practices, which are prevailing in the tariff setting process of the CPSUs. In the case of NTPC, the capital expenditure on the date of COD is taken as the capital cost which is divided into debt and equity on a normative 50:50 basis. Return on equity is being allowed on the 50% of the capital cost on a perpetual basis over the entire life of the assets. The interest on loan is being computed duly taking into account the actual repayment schedule and necessary adjustment for the repayments are made to correspond with the normative debt equity ratio. This methodology results in gross fixed assets getting reduced year after year by the repayment. In the case of all new projects of NTPC, the debt equity ratio, repayment etc. are based on the actual financial package. From this, it could be seen that the GFA concept is being followed in the case of NTPC.

3.3.11 In the case of NHPC, the two part tariff was set after 1995, based on actual financing deals. The single part tariff in the case of Loktak and Bairasiul Hydro Electric Project have been converted into two part tariff in 2002 by the CERC. From this it could be seen that the rate base for the NHPC is also based on GFA concept.

3.3.12 In the case of POWERGRID, the tariff up to 31.3.1997 was being done in a particular way, namely, the capital expenditure on commercial operation of an asset was considered as capital cost, which was divided notionally into debt and equity. The depreciation was considered as loan repayment up to 31.3.1997, thereby implying that the NFA concept was being used. Based on a notification of 16 December, 1997 by Government, w.e.f. 1.4.1997 the NFA was divided into debt and equity in the normative ratio of 50:50, and the equity is being serviced for the balance life of the assets at the prescribed rate of ROE. The normative debt is being serviced as per annual interest rates and repayment schedule. The change in procedure w.e.f. 1.4.1997 in case of POWERGRID has changed the rate base from the NFA concept to GFA concept.

3.3.13 In the case of NEEPCO, the rate base is linked to the GFA in accordance with the Notifications of the Government of India in this regard.

3.3.14 In the case of NLC, the tariff was agreed between the parties by mutual consent through a contract. It is understood that the contracts entered into earlier are based on the NFAs.

3.3.15 Since the tariff setting of various utilities is based on different methodologies, the Commission would like to get the views of the utilities as well as the stakeholders with regard to the appropriate choice of the rate base.

3.3.16 Once the Rate Base is finalised, the treatment of working capital will also have to be decided. In the event of selecting NFA concept for the rate base, the working capital will have to be appropriately added to the NFA. On this NFA, ROCE can be allowed if that method is resorted to. If ROE and interest on debt are to be allowed separately, the NFA has to be divided into debt and equity by an appropriate method. Thereafter, return on equity will have to be allowed on the equity, and interest on loan will have to be appropriately allowed on the debt portion. Interest on working capital will have to be allowed separately.

3.4 Interest on Working Capital

3.4.1 Working capital is an important component in any industry. The need for provision of working capital in power supply industry was examined earlier by the K.P. Rao Committee. On the one hand, it was argued that the tariff payable includes returns and depreciation which are not cash expenses, and the additional recoveries would provide enough funds to meet the working capital requirements for operation. The contrary view was that the resources from return and depreciation are used as the internal resources for capacity addition programmes and hence, are not available for meeting the working capital requirements. Accordingly, the conclusion arrived at by the K.P. Rao Committee and subsequently by the Government through various notifications was that, though margin money in working capital may be included in the project cost, the short-term funding has to be obtained from banking institutions for which the interest liability has to be borne by the project authority, that is the regulated Central utility. This is the basis on which the inclusion of interest on working capital based on the cash credit rates was justified.

3.4.2 The items of working capital have been clearly laid down by the Government of India notification, which was adopted by the Commission. These are mentioned below separately for Thermal Power Stations, Hydro Power Stations and Transmission Systems.

3.4.3 Elements of Working Capital for Thermal Power Stations include:

i) Fuel cost for one month and reasonable fuel stocks as actually maintained but limited to fifteen days for pit head stations and thirty days for non pit-head stations, corresponding to the "Target Availability";
ii) Sixty days stock of secondary fuel oil, corresponding to the "Target Availability";
iii) Operation and Maintenance expenses (cash) for one month;
iv) Maintenance spares at actual subject to a maximum of one per cent of the capital cost but not exceeding one year's requirements less value of one fifth of initial spares already capitalized for first five years; and
v) Receivables equivalent to two months' average billing for sale of electricity calculated on "Target Availability".

3.4.4 Elements of working capital for Hydro Power Stations include:

i) Operation and maintenance expenses for one month;
ii) Maintenance spares at actual but not exceeding one year's requirements less value of one fifth of initial spares already capitalized for the first five years; and
iii) Receivables equivalent to two months of average billing for sale of electricity.

3.4.5 Elements of working capital for Inter-State Transmission Systems include:

i) Operation and maintenance expenses (cash) for one month;
ii) Maintenance spares at a normative rate of 1% of the capital cost less $1/5^{th}$ of the initial capitalized spares. Cost of maintenance spares for each subsequent year shall be revised at the rate applicable for revisions of expenditure on O&M of transmission system; and
iii) Receivables equivalent to two months' average billing calculated on normative availability level.

3.4.6 We have received comments from various agencies on this subject. One State Electricity Board has mentioned that the cash credit rate should be adjusted through each period at the prevailing rates and the benefits passed on to the consumers. Working capital requirements should be met out of the bank finance and claiming ROE on the margin money used as working capital should be discouraged. It has also been suggested that the interest could be linked to the PLR of a nationalised bank for the respective State Electricity Board's credit ratings.

3.4.7 Comments have also been received on the elements of the working capital. Some of the State Electricity Boards have made the point that working capital should not include one month's O&M expenses as two months' receivables already include two months' O&M expenses. Accordingly, the provision of one month's O&M is an unrealistic extra burden on the State Electricity Boards. It has also been contended that the O&M expenses are paid after incurring such expenditure. For example, salaries are paid at the end of the month and spares are generally provided for one year. Minor spares may not constitute a major share and may not exceed 0.5% of the O&M expenses. Accordingly, the provision of O&M expenses in the working capital should be excluded. There has also been a suggestion that the interest on working capital needs to be deleted in view of the above arguments and also in view of the improved liquidity position as a result of the scheme for one time settlement of SEB dues.

3.4.8 The need for providing an element towards interest on working capital has to be viewed with reference to the cash flows for meeting various commitments by the regulated entity. If interest on working capital cannot be given as a separate entity, the matter requires to be debated as to whether the ROCE needs to be increased suitably to take care of the additional cash flows which may be necessary for the actual operation of the project. In the earlier discussions on the Rate of Return Regulation, a miscellaneous provision of 0.5% to take care of the income-tax was suggested. It needs to be seen whether this miscellaneous provision requires a slight upward adjustment so that the ROCE can take care of the working capital requirements as well. This will impart sufficient simplicity and also avoid controversies on the elements of working capital etc. This will also provide the much needed leverage for project authorities in day-to-day financial management of the project.

3.5 Operation & Maintenance Cost

3.5.1 The Operation & Maintenance Cost covers a vast spectrum of expenditure incurred on the employees, repair and maintenance of the generating stations/transmission system, administrative overheads etc. The existing norms for fixing O&M is in reality a continuation of the two step formula as contained in the K.P. Rao Committee Report and the Government notifications. The first step is towards computation of the base. The second step is to escalate the same using a suitable escalation factor based on the Consumer Price Index and refined index of the Wholesale Price Index after imparting suitable weights.

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

3.5.3 As regards the O&M for Hydro Power Stations, the approach was the same except for the fact that in the case of new stations which were not existing for a period of 5 years, the base O&M will be fixed with reference to 1.5% of capital cost, as against 2.5% in respect of thermal stations. However, in the Commission's order dated 21 December, 2000 in respect of O&M of Hydro Stations, it was specifically mentioned that the data of actual O&M expenditure should exclude all abnormal expenses on account of :

(a) Security expenses on account of law and order problems;
(b) Problems due to abnormal siltation as noticed in Salal and Bairasul HE Projects; and
(c) Impact of over staffing, as it was noticed that in certain stations, owing to a section of redeployment of staff from completed projects, the number of employees in some cases was larger than the actual requirement.

3.5.4 As regards the O&M expenses of the transmission sector, the Commission arrived at a different approach to take care of future expansions in the regional transmission systems. If the O&M expenses of sub-stations and lines were separately available for each region, it was decided that these should be normalised by dividing them by line length and number of bays in each region respectively. The average of such normalised O&M expenses per Km. of line length and per bay for the last five years would then be used to derive the base O&M for lines and sub-stations. Where the data was not available, the Commission also suggested a proxy method of apportioning the O&M expenses in the region to the sub-stations and lines on the basis of 30:70 ratio. In the transmission sector also, it was clearly mentioned that the regulated entity should present their tariff petition with full details of year wise actual O&M cost after excluding abnormal expenditure such as on account of security related issues. The escalation factor up to 1999-2000 was 10% and 6% beyond that period. The Commission's Order also provided for the deviation of the escalation factor on the same lines as was done for the thermal and hydro sectors.

3.5.5 The Commission's intention while issuing the notification of the current norms was to obtain the full details of actual O&M expenses and apply the test of prudence to arrive at permissible items of expenditure which should form the O&M cost. However, in many cases, the actual experience of the Commission was that the information was not forthcoming and where the details were given, they were not sufficient to conduct a clear test of prudence. This was partly on account of the fact that the O&M expenditure, by itself, is kaleidoscopic in nature, which defied a detailed examination within a reasonable span of time. During the hearing also, the respondents pleaded that the electricity expenses for power consumed by residential colony, construction power etc. should be excluded from the O&M charges for tariff purposes. Some of them contended that if further details are given, they could come up with their arguments for further 'exclusions' from O&M charges.

3.5.6 The suggestions in this regard received from the State Electricity Boards, Generating Companies etc. are as follows:

(i) According to a generating company, the escalation rate for O&M charges should be 10% per annum and not 6% as notified for the current tariff period.

(ii) It was mentioned by another entity that CERC should lay down procedure for taking up capital expenditure during the O&M period, which should be considered for determining the tariff. It was also mentioned that the escalation factor should be based on the formula introduced by the Commission with reference to Wholesale and Consumer Price Index and not flat 6% per annum as notified.

(iii) A State Electricity Board gave the suggestion that the base O&M expenses for the year 2003-04 should be escalated at 4% only for future years as inflation rates are low at present.

(iv) Another State Electricity Board has given the suggestion that the duties, cesses, taxes levied by the local bodies or authorities should be reckoned as part of O&M charges. When the actual O&M charges exceed the limits, the utilities could be allowed to approach the Commission through separate petition. It was mentioned that the regulated entities presently recover these as additionalities over the O&M charges.

(v) An expert has given the suggestion that the O&M charges should be restricted to 2.5% of the capital cost to be escalated as per the formula for WPI and CPI arrived at by the Commission.

3.5.7 In this connection, it may also be mentioned that when the hearings were held before the finalisation of the existing norms, NTPC suggested that 3.5% of the capital cost should be allowed as O&M expenses for coal based generating stations. For the gas based generating stations, the suggestion was that the normative base for O&M should be 5% of the capital cost. On the other hand, NLC had suggested that 3.0 to 3.25% of the capital cost should be allowed as O&M expenses. Suggestions on the kind of percentages to be adopted for determination of the O&M may be proposed for consideration of the Commission, if the switch over to the normative method of computation is to be introduced. One suggested framework is to lay down the normative O&M percentage in the beginning of the tariff period, which should include the normal water charges at prevailing rates. During the tariff period, if water rates are revised upward by more than 30% of the rate as existing at the beginning of the tariff period, the regulated entity could file a separate petition to the Commission. A similar approach could be adopted for liabilities on account of security/insurgency etc. This model framework requires consideration.

3.5.8 It is also seen from the various petitions received for the tariff period 2001-02 to 2003-04 that in respect of one hydro generating station, the O&M expenses have risen steeply, from Rs. 10.92 crores in 1995-96 to Rs. 25.15 crores(projected) in 2003-04. In another hydro station, the O&M expenses in 1996-97 were Rs. 8.17 crores which have gone up to Rs. 24.10 crores(projected) in 2003-04. Similarly, fluctuations of different magnitude are also noticeable in respect of the transmission sector. Thermal sector is comparatively stable but the tendency towards increase in actual O&M expenses is noticeable. A suggestion has been made that, in order to achieve economies and also a certain definiteness in tariff, it will be preferable to move away from the actual O&M to a normative O&M. It could be reckoned as a percentage of the capital cost. It may be recalled that 2.5% of the capital cost for the new thermal stations, 1.5% of the capital cost for hydro stations and 1.5% and 2% of the actual expenditure at the time of commissioning in the plain area and hilly area respectively for transmission systems were provided as O&M expenses under the Government notifications.

The issue which needs to be debated is whether it would be advisable to move away from "Actual" to "Normative" system.

3.5.9 Normative O&M expenses could be arrived at by any of the following options :

(A) As percentage of Capital cost or
(B) As a benchmark cost per MW/Bay/Km for a typical installation.

3.5.10 Option (A) above will require ascertaining the base capital cost for the purpose of computing normative O&M charges. The O&M charges would have to be revised based on the additional capitalisation from time to time. If capital base is more due to any reason such as time & cost over-run, the normative O&M charges will be more. The Commission had foreseen the difficulty of linking the normative O&M expenses to the capital cost in its order dated 21 December, 2000 on tariff norms as follows:

"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."

"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."

3.5.11 Option (B) requires benchmarking of O&M expenses in Rupee terms on per unit basis with reference to a base year. For Thermal & Hydro plants, it would be in terms of Rupees per MW. In case of Transmission system, it would be in terms of Rupees per bay for substations and Rupees per circuit kilo metre for transmission lines. A similar approach is presently in use for O&M charges in respect of interstate transmission systems.

3.5.12 Option (B) appears to have the following advantages over option (A):

i) In view of the complexities in the measurement of the capital cost, linking the base level O&M expenses to the capital cost may not be appropriate.
ii) In order to discourage over-capitalisation, O&M charges and incentive to the project may not be linked to the capital cost.
iii) In case of old power stations, it may difficult to work out the O&M charges on the basis of capital cost of the project.

iv) O&M charges based on capital cost could result in anomalies in hydro projects where there is wide variation in the project capital cost due to abnormal time and cost over run, geological surprises etc. It is rational to assume that for a similar power station, O&M charges are of the same magnitude irrespective of its exact capital cost.

v) This option could be conveniently followed by the states.

3.5.13 The adoption of option (B) for thermal stations would require specifying benchmark value for the following categories of stations:

(i) Coal/lignite based stations
(ii) Gas/liquid fuel based combined cycle stations

The benchmark values could be based on actual O&M expenses for the best operating stations. . A reasonable weightage on the O&M benchmark value may have to be assigned for the unit size.

3.5.14 Similarly, in case of Hydro stations, benchmark values may have to be specified separately for the following categories of stations:

(i) Purely Run of the River stations.
(ii) Run of the River with pondage type stations.
(iii) Storage type stations.

A reasonable weightage on the O&M benchmark may have to be assigned for generating unit size, length of water conductor system and storage capacity of the reservoir.

3.5.15 In case of Transmission system, instead of allowing region wise normative O&M charges based on actuals, adoption of either average normative O&M charges of all the regions or normative O&M charges of the most efficient region may serve as norm on all India basis. The option of using average O&M charges will not induce any efficiency in the transmission utility. So, O&M charges of most efficient region may be a better option to benchmark O&M value.

3.5.16 Option (B) however, does not capture the requirement of additional O&M in certain special cases. Hence, some allowance may need to be provided in special cases such as hilly/difficult terrain, abnormal siltation, abnormal water charges, security charges etc. The above issues need to be debated.

3.6 Depreciation

3.6.1 Depreciation can be defined in both accounting and regulatory terms. Depreciation in accounting terms, is a measure of the weeding out, consumption or other loss of value of a depreciable asset arising from use, effluxion 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 amortization of assets whose useful life is predetermined.

3.6.2 For the treatment of deprecation, three views are generally expressed: the first is that it represents a cash flow for repayment of loan; the second is that it represents a return of capital subscribed; and the third is that it represents a replacement of capital or a charge for the replacement of the assets consumed.

3.6.3 The philosophy of depreciation as adopted by the Commission in the existing norms was the result of detailed study by a Consultant earlier whose report was subject to hearing by the parties. There were broadly two methods of depreciation which were considered:

(a) The Straight Line method by application of a fixed rate over the fair life of the asset;
(b) Optimized Depreciated Replacement Cost (ODRC) based method under which the depreciation could be a method for replacement of the asset.

3.6.4 The final orders of the Commission on the subject sum up the philosophy -

> "W*e 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 installments"*

3.6.5 The salient features as approved by the Commission are as follows :

(a) Depreciation should be calculated annually by the Straight Line Method as per rates prevailing prior to 1992 in the schedule as notified under the Electricity (Supply) Act;
(b) These rates shall, however, be changed for revision in useful life in respect of these assets. When the useful life is revised, fresh schedule shall be drawn out accordingly;
(c) Whenever any loan repayment as original schedule requires additional cash flow over and above the depreciation allowable,

to that extent and subject to original limit of $1/12^{th}$ 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 should not exceed 90% of the original cost;

(d) On repayment of the entire loan, the remaining depreciable value shall be considered over the balance useful life of the assets;

(e) Depreciation is chargeable from the first year of operation as against the earlier practice of a depreciation holiday in the first year; and

(f) The value base for depreciation should be the historical cost and not the replacement cost or any other value. In this context, the historical cost, which is the original cost, will also include additional capitalisation.

3.6.6 Suggestions have been received from the regulated entities as well as the State Electricity Boards. According to a regulated entity, the rate of depreciation allowed should fully cover the repayment of debt. Depreciation plus advance against depreciation (limited $1/12^{th}$ of the loan amount) may be allowed to be recovered even after repayment of the loan till the total depreciation, that is, 90% of the actual approved cost, is recovered. Another generating company has insisted that the rate of depreciation should be 7.84% instead of 3.6% for thermal stations. The argument in favour of this revision is that the life span of the plants in India is shorter than in many other countries for various reasons. Yet another regulated entity has suggested that depreciation should be as per the old Government of India notification. One Electricity Board has said that the loan repayment should match the depreciation. This is because, according to the Electricity Board, in some cases loan repayment may start later, due to moratorium period . Another State Electricity Board has advised the deletion of the advance against depreciation, alternatively, the advance against depreciation should be provided only when the cumulative depreciation allowable as per schedule is less than the original scheduled loan payments on cumulative basis subject to 90% of the cost of the asset. An expert has suggested that on repayment of the entire loan, advance against depreciation should be reckoned first. For this purpose, cumulative advance permissible should be separately accounted and adjusted. According to him if this is done, the tariff will work out to be less than under the present method. Most utilities have expressed the view that if depreciation is raised to the level Government of India notification of 1994, the Advance Against Depreciation & Development Surcharge need not be provided. Many Electricity Boards have raised the issue of reduction of equity corresponding to recovery of depreciation, once the loan is fully repaid, as recommended in the K.P. Rao Committee Report. A view has been expressed that depreciation as defined under the Companies Act may be adopted for the purpose of tariff also.

3.6.7 There is also a view according to which depreciation as compared to other elements of cost is not the cash outgo incurred during the 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 constitutes a cash inflow for utilities. The question which has been raised is when the depreciation does not constitute an expenditure, should it form a necessary component of a cost based tariff? The proponents of this view hold that the depreciation could be treated as an accounting entity for the legal purposes under the provisions of the Companies Act or to satisfy accounting standards laid down by the Institute of Chartered Accountants. But this need not necessarily form part of the tariff, when the liability side approach is adopted. This requires examination.

3.6.8 The question then arises as to how exactly the required cash flows of the Company for repayment of loans could be taken care of. In this context, the suggestion is that the repayment of the loans should be provided as a separate item in the tariff exercise. The suggested framework in this regard is repayment of loan could be provided on an annual basis as part of the tariff depending upon the financial package. If the financial package is approved by an independent neutral agency like CEA, this financial package may be adopted for the purpose along with the repayment schedule, which would be a part of the approved financial package. In other cases, where the financial package has not been approved by an independent agency, the CERC could itself draw a tentative a schedule of repayment of loan; and such a schedule for repayment of loans could form the basis of financial outflows as part of the tariff. It has also been suggested that the financial package so adopted should be only for tariff purposes, with enough scope for the utilities to handle their financial operations as they deem fit. If the actual repayment schedule is differently handled by the utilities from the one approved by the Commission, this should not be objected to. This would also be in line with the general approach of the Commission, which is not to micro manage or interfere with the day-to-day working of the regulated entity.

3.6.9 In dealing with the depreciation, the order of the Commission dated 21 December, 2000 also lays down that in order to ensure compliance with the environmental regulations, it would be necessary to identify those assets relating to environmental protection separately. When the tariff is being set, the Commission could examine whether in the past, environmental standards such as pollution level etc. as prescribed have been complied with during the previous tariff period. In the case of non-compliance, the Commission could disallow the depreciation of such assets.

3.6.10 There is also a progressive view that depreciation should not be handled in a restricted manner. This advocates that the amount charged towards depreciation during the useful life of the asset is really meant for replacement of the asset at a future date. The question then arises is: whether the concept of depreciation should relate to the economic value of the asset, which would mean 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. This would mean moving away from the historical cost and also broadening the scope of the concept of depreciation to provide for substantial amounts which could help in capacity addition in the form of new plants or new lines/bays etc. On the other hand, if this approach is adopted, the tariff would certainly increase from the present levels. If such an approach is adopted, perhaps a detailed accounting system would also required to be laid down under which the amounts collected from depreciation are credited to a separate Depreciation Fund which should be frozen for purposes other than the capacity addition. If such funds were to be used for any other purpose under extraordinary circumstances, it could be laid down that this should be done only with the prior approval of the Commission. Since the country has fallen short of the target of required capacities and the expansion of private sector has not been up to the mark, a view will require to be taken whether a 'liberal' depreciation would need to be deliberately provided to the central generating stations, but with necessary safeguards. The advisability of this approach would require detailed examination.

3.7 Operational Norms

3.7.1 Operating Norms for Thermal Generation

3.7.1.1 It may be recalled that during the exercise to decide the norms for tariff period 2001-2004, it was noticed by the Commission that there was considerable divergence of opinion on the draft norms of the CEA and the norms asked for by Central Generating Companies. To resolve this matter, an Expert Group was set up by the Commission. Ultimately, it turned out that there was no consensus among the Members of the Expert Group. The Report of the Expert Group was only the opinion of the Chairman of the Expert Group who came from CEA. Other Members of the Group, who were mainly from the regulated entities, chose to differ and submitted a separate report. Commission noticed that the two reports - one by Shri V.S. Verma and other by the rest of the Members of the Expert Group - took extreme positions on all major issues concerning the operational norms.

3.7.1.2 The Commission then decided that the existing norms as contained in the Government of India notification dated 30 March, 1992 should be continued. However, in case of existing projects, where projects specific notifications of GoI existed or if there was a PPA entered between the parties, the norms specified therein were applied. Insofar as the operational norms in respect of PLF and Target Availability are concerned, these were separately laid down by the Commission. The Commission also directed NTPC, NLC and NEEPCO to maintain accurate and verifiable data relating to the operational norms and furnish the same to the Commission on a quarterly basis. It may be mentioned at this stage that the Commission has received information from these entities though they are not complete in all respects. In some cases, it is vague indicating only the range of variation and not exact details. It may be pertinent to point out that some of the plants of NTPC like Kahalgaon STPS and Gas based projects like Gandhar, Kawas, Dadri, Anta & Auraiya are having relaxed norms as compared to other projects. This was due to lower dispatches for lack of demand/restricted availability of gas. This could be reviewed in the light of current situation and recent performance levels.

3.7.1.3 In this context, it is also relevant to point out that the Commission has subsequently notified the operational norms for smaller gas turbines power plants, which have gas turbines of less than 50 MW capacity.

3.7.1.4 It is also relevant to point out that the various regulated entities as well as the State Electricity Boards/Utilities submitted their suggestions on various aspects relating to the operational norms. In order to facilitate a discussion, the following key issues are identified for consideration:

3.7.1.5 Station Heat Rate

3.7.1.5.1 Heat rate is an important element which determines the computation of variable charges, along with price and gross calorific value (GCV) of the fuel. The heat rate is invariably mentioned by the suppliers of the power plants. However, the manufacturers' recommendations in this context have to be corrected by application of the margins for actual operating conditions. The existing norms for coal based thermal power stations specify that the heat rate should be 2500 kilo calories/kwh . During the stabilisation period, however, the station heat rate for coal based station has been specified as 2600 kilo calories/kwh in the Government of India notification of 30 March, 1992. In respect of the gas based stations, the norms are 2900 kilo calories/kwh and 2000 kilo calories/kwh for open cycle and combined cycle operation respectively. It may be mentioned that on the earlier occasion when the Expert Group studied the matter, the Chairman of the Expert Group recommended the margin of about 4% whereas the NTPC had asked for margin of over 10% on guaranteed heat rate by the manufacturers. This was specially true of the gas/liquid fuel based stations. But similar divergence of opinion exists in the case of coal fired power plants also.

3.7.1.5.2 The suggestions from a State Electricity Board and the regulated entities have been received on the subject. The State Electricity Board has suggested that the gross station heat rate should be related to manufacturers' guaranteed heat rate. On the other hand, the regulated entities have recommended the retention of the existing heat rate norms without any change. NLC has, however, added that the gross station heat rate should further be arrived at after providing a factor for moisture content.

3.7.1.5.3 The question that needs to be addressed is whether the heat rates would require to be revised. This will be especially necessary if only the norms are to be adopted and the actuals ignored. It is suggested that the State Electricity Boards/State GENCOS may study the heat rate requirements with reference to their own plants functioning in their jurisdiction and come up with suitable suggestions in this regard. It may be mentioned that heat rate is an important element which has a high sensitivity on the tariff. Accordingly, it would be necessary to take adequate care in the matter so that the interest of the generator as well as the consumer is fully protected while finalising the norm for the future.

3.7.1.6 Specific Secondary Fuel Oil Consumption

3.7.1.6.1 The existing norm for the Secondary Fuel Oil Consumption is 3.5 ml/kwh. Earlier, the draft norms of CEA specified that it should be 1.0 ml/kwh for coal and 3.0 ml/kwh for lignite based power stations. During the hearing on the last occasion, NTPC had argued that reduction of the norms from the existing 3.5 ml/kwh would result in a situation leading to furnace pressurisation and even endangering the human lives. Also, with the introduction of ABT, it was argued that it will lead to higher partial load cycling on the machine. This would lead to instability in operation and machines would require to be shut down considering merit order operation and restart depending upon the requirement of the Grid. This would lead to increased secondary fuel oil consumption.

3.7.1.6.2 One State Electricity Board has suggested that the secondary fuel oil consumption should be related to actuals, and has indicated that the actuals in respect of their own thermal stations was less than 3.5 ml/kwh. Another State Electricity Board has suggested that the norms for secondary fuel oil consumption should be 2.0 ml/kwh during stabilisation and 1.0 ml/kwh for post stabilisation period. The central generating utilities have not suggested any change in the existing norms for secondary fuel oil consumption.

3.7.1.6.3 In view of the contention of the State Electricity Boards, the question that needs to be addressed is whether there is scope for improvement of the existing norms. After taking into account the views of the State Electricity Boards, it may require to be examined whether these norms could be reduced to 2 ml/kwh from the existing 3.5 ml/kwh, without impairing the efficient functioning of the machines.

3.7.1.7 Auxiliary Energy Consumption

3.7.1.7.1 The existing norms for the auxiliary consumption are as follows:

Auxiliary Consumption	**With Cooling Tower**	**Without Cooling Tower**
(a) Coal based stations		
- 200 MW series	9.5%	9.0%
-500 MW series (Steam driven pumps)	8.0%	7.5%
- Electricity Driven Pumps	9.5%	9.0%
(b) Gas Based Stations		
- Combined Cycle	3.0%	
- Open Cycle	1.0%	

(During the stabilisation period, normative auxiliary consumption shall be reckoned at 0.5% over and above the figures specified above).

3.7.1.7.2 The suggestions given by the Chairman of the Expert Group constituted earlier was that it should be in the range of 6-8% for various stations. NTPC had argued that the existing norms for auxiliary energy consumption should not be disturbed. NLC has suggested that for 200 MW series, auxiliary consumption should be 10.5% without cooling tower as against 9% as indicated above. NLC had also contended that the norms and not the actual should be the basis. On the other hand, one Electricity Board has suggested that the actual auxiliary energy consumption should be basis. It has also been pointed that it would be much less if colony power consumption and construction power consumption are excluded. Another Electricity Board has suggested that it should be 9.0% for 200 MW series with cooling tower and 8.0% without cooling tower. In respect of 500 MW series for steam driven pumps, it should be 7.0% with cooling tower and 6.5% without cooling tower. For electrical driven pumps, it should be 7.5% with cooling tower and 7.0% without cooling tower. The basic questions which need to be considered are whether the norms require improvement as suggested by the State Electricity Boards and also whether, while adopting the normative percentage, it would be better to remove the condition of "normative or actual, whichever is less". According to the generating utilities, the actual should not be insisted upon and that the norms should be laid down which will not only regulate but also provide enough encouragement to generating stations to improve their performance and achieve savings. Such savings, it is averred, should form the earnings of the generating company.

3.7.2 Operating Norms for Hydro Generation

3.7.2.1 In case of Hydro Generation, Operational norms such as auxiliary consumption, transformation losses, normative Capacity Index and also rate of primary energy, method of computation of capacity charge, primary and secondary charge etc. had been revised by the Commission for the present tariff period 1.4.2001 to 31.03.2004.

3.7.2.2 The Commission had introduced the new concept of Capacity Index in place of Availability, which was earlier in use based on GOI notification. While Availability of a plant is expressed in terms of mechanical availability of the generating units of the stations, the Capacity Index of a Hydro station is related to the availability of its generating units and availability of water for generation. The Commission in its order dated 08 December, 2000 has stated in respect of operational norms for hydro power stations that :

"The basic criteria for Capacity Index are:

a) Water spillage must be minimized;
b) As far as possible, the peak capacity of each plant must be available when it is most required by the system "

No major suggestion for further improvement has been received from the stakeholders.

3.7.2.3 For Primary & Secondary Energy rates in Hydro Generation, comments have been received that division of the annual fixed charge into capacity charge and primary energy charge is not based on sound technique and logic. Hydro stations are preferred only because of their negligible variable costs. In view of this, it is argued that the artificial division of the fixed charge into capacity charge and primary energy charge and also the fixation of tariff for primary energy at 90% of the lowest variable cost of thermal station in the region is not a proper approach. It has also been observed that, in certain region, there is no coal based power station and consequently, the lowest variable charge has to be derived from the adjoining region. The existing CERC Notification also equates the secondary energy rate to the primary energy rate. Another issue for discussion appears to be pricing of secondary energy, which at present is equal to the price of primary energy.

3.8 Incentive

3.8.1 Incentive for Thermal Generation

3.8.1.1 The Target Availability (TA) has been specified by the Commission based on the performance that can be achieved by the utility which will determine the level of fixed charge recovery. The Commission's present orders lay down 80% availability level for full fixed cost recovery. In case of performance below this availability level, pro-rata reduction in recovery of fixed charges is provided. As regards the incentive, the provision is that it will be @ 50% of fixed charges in paise/kwh on actual generation beyond 77% PLF upto 90% PLF subject to a ceiling of 21.5% paise/kwh. Beyond 90%, the incentive rate is reduced to half. It may be recalled that the Commission originally wanted to have 80% Target Availability with a provision to revise it to 85% subsequently. However, based on a review of the ABT Order, the Commission decided to introduce 80% TA and keep on hold the 85% norm for availability.

3.8.1.2 The State Electricity Boards, who have given their suggestions in the matter, have uniformly advocated the TA of 85% as against 80% for thermal stations. This is mainly on the ground that the TA of 86.2% is on average possible for most of the NTPC power stations. As regards the PLF for calculating the incentive, one Electricity Board has suggested that it should be 80% for thermal stations while two other State Electricity Boards have suggested that it should be 85%. The Electricity Boards have also suggested that for NLC, TA should be 82% as against 72% at present, and the PLF should also be 82% as against 72% as at present. Yet another Electricity Board has suggested that for NLC, the TA and PLF should be 77% as against 72% at present. A private entrepreneur has made a suggestion that the TA and PLF should be governed by the signed Power Purchase Agreements or other agreements existing on the date of notification. An expert has suggested that the net capacity of a generating station could be arrived at by taking into account the rated capacity of the plants in question. Another view has been expressed regarding linking of incentives to availability rather than PLF.

3.8.1.3 NLC has submitted that the TA for NLC Stations should be 67%, and PLF for incentive purposes should also be 67% as against 72% in both cases. NTPC has suggested that the TA for recovery of full capacity charges should be 70% for all thermal stations and the PLF should also be 70%. However, during stabilisation period, NTPC have contended that the norms for TA should be 75% of the norms specified above. The basis for NTPC's submission is that the national average PLF for the year 2001-02 was about 69.9%. Norms fixed should be achievable by the better performing utilities on consistent basis and should provide reasonable achievable bench mark for low performing utilities to improve their performance. In view of this, NTPC has contended that the TA level should be fixed at 70%. It has also been pointed out by NTPC that as compared to Coal stations, loss in capacity/availability for gas stations is higher and, therefore, even achieving 70% TA on sustained basis for gas based stations could be difficult.

3.8.1.4 The question, which needs to be considered, is whether there is a case for increasing the TA levels as well as the PLF norms for incentive purposes or keeping them constant on the existing basis. The contention of the generating utilities for reduction of the TA/PLF norms should also be seen i.e. whether there is a case for reduction on realistic basis. It will be useful for the State Electricity Boards to assess the performance of their own thermal stations and indicate their position. They may also give recommendations on realistic TA/PLF norms, which need to be adopted for the thermal stations.

3.8.1.5 In the context of incentive rate, one State Electricity Board has suggested that the deemed generation should be outside the computed PLF for incentive purposes. Also, the utilisation of energy for township and construction should be outside the purview for purposes of calculating the PLF. Both NTPC and NLC have argued that the ceiling of 21.5 paise/kwh and 50% of the above beyond 90% TA is unrealistic. According to NLC, the rate of incentive should be 100% of fixed cost/kwh beyond schedule PLF without any ceiling. NTPC has contended that the rate of incentive for generation above normative PLF level should be shared equally between generator and purchaser, that is, @ 50% of fixed charges without any cap on the rate of incentive. It has also been suggested that disincentive for not achieving the target availability should be limited to 50% of fixed charges to ensure equitable treatment for incentive and disincentive.

3.8.1.6 At present, the incentive rate is linked to the fixed cost of the project, which is derived from the project cost. The project cost of coal and gas based thermal plants varies widely depending upon their year of installation and project specific features even for same type and similar capacities. Therefore, the incentive works out to be different for different plants having the same performance level and the same installed capacity. Since the fixed cost of old plants is less than that of new plants, the incentive for older plant works out much lower than for new plants. Linking incentive to the project cost in a way encourages over capitalisation in a cost-plus regime. At present, the incentive in thermal generation is linked to fixed cost, but the same has been capped at the ceiling rate of 21.5 paisa/kwh. An alternative approach could be to delink incentive totally from the fixed cost and provide incentive for generation above target PLF at a flat rate (Paisa/kwh), which is attractive to the generators and fair to beneficiaries.

3.8.2 Incentive for Hydro Generation

3.8.2.1 As per CERC tariff notification of 26 March, 2001, in addition to secondary energy charge, the generator is paid incentive when the Capacity Index (CI) exceeds the normative capacity index of 85%. When the annual Capacity Index achieved is less than 85%, there will be disincentive to the generator on pro-rata basis.

3.8.2.2 The incentive for a hydro station is governed by the following formula:

Incentive = (Annual Fixed Cost – Primary Energy Charge) x (CI_A – CI_N)/100

Where,
CI_A = Capacity Index achieved
CI_N = normative Capacity Index

3.8.2.3 On perusal of various petitions filed with the Commission and subsequent studies made, it has been observed that as the hydro station grows older and loans are paid off, the Annual Fixed Cost goes on decreasing. Thus for the same level of performance, the incentive payable to the generator goes on decreasing year by year. At some stage, the Primary Energy Charge worked out on the basis of 90% of the lowest variable cost of the central sector thermal plant of the region could even exceed the Annual Fixed Cost. Thus there would be no incentive for the company to run its old hydro plant efficiently. GRIDCO has commented that with the above incentive formula, incentive is more for the same capacity index achieved, when the primary energy charge is less.

3.8.2.4 To summarise, it has been argued that the existing incentive formula for the tariff period 1.4.2001 to 31.3.2004 has the following disadvantages:

i) Incentive tends to decrease every year for the same level of performance due to reduction in value of AFC.
ii) It does not differentiate between peak time and off peak time generation.
iii) Costlier projects get more incentive for the same level of performance.
iv) Incentive tends to increase, if actual generation is less than primary energy.

3.8.2.5 NHPC has suggested that there should be incentive to the hydro generator for generation during peak hours in addition to the incentive on account of higher capacity index and secondary energy.

3.8.2.6 In view of the above, it is suggested that the formula for computation of incentive may be modified as follows:

Incentive = Actual Peak Time Generation x (Incentive Rate in Rs./Kwh) x (CI_A - CI_N)/100

3.8.2.7 The formula proposed above has the following features:

i) Incentive is not related to capital cost of the station.
ii) It relates to actual peak time generation as well as Capacity Index.
iii) There will be significantly higher incentive for storage/ pondage type hydro stations as compared to purely Run-of-River schemes. As such, it would encourage setting up of peaking type hydro plants for future hydro capacity addition.
iv) Incentive does not decrease for older plants.

The above methodology for incentive is presented for discussion and debate

3.8.3 Incentive for Transmission System

3.8.3.1 In the existing Notification, transmission utility is entitled for incentive beyond the target availability of 98%. The incentive is 1% of the equity for every 0.5% rise in the availability above 98% (except for the target availability in the range of 99.51 to 99.75% for which incentive @1% of equity has been allowed). PGCIL have argued that the TA for the transmission sector should be reduced to 95% from the existing 98% levels. One Electricity Board has suggested that the transmission loss above a particular level, should be declared as disincentive. Another Electricity Board has suggested that there should be no incentive for transmission sector. The question of the incentive scheme in the transmission sector would need to be examined.

3.9 Development Surcharge

3.9.1 The issue of mobilisation of resources and encouragement of optimum investment was examined by the Commission at the time of laying down the existing norms. It was noted that the tariff of Central generating companies was to a large extent, influenced by the cash flow requirements for capacity expansion by these utilities. This was evident from the increased rate of return on equity (from 12% to 16%) notified by the

Government of India and also the acceleration of depreciation since 1994. Keeping this in view, the Commission came to the conclusion that it was appropriate to provide a mechanism through which mobilisation of resources could be ensured for the Central Public Sector Companies.

3.9.2 The Commission had two options in the matter:

(I) Advise the Government to levy a cess for developmental purposes; or
(II) Include a surcharge in tariff for capacity expansion.

The Commission chose the second option and came to the conclusion that there was valid economic justification for a development surcharge.

3.9.3 The development surcharge covers every bill for fixed charges (for NHPC both on capacity and energy charges) raised by the utilities in respect of generation/transmission at original levels. Operations exclusively within a State shall not be liable for this surcharge. The rates of surcharge fixed by the Commission are as follows:

NTPC	5%
NLC	5%
NHPC	5%
PGCIL	10%

3.9.4 Surcharge collected by the utilities has to be kept in a separate bank account and could be invested in securities of recognised infrastructure funds like IDFC or IDBI bonds so that the income thereon could also be credited to the same bank account. There are also certain conditions attached to utilization of funds for capacity expansion in the respective region from where the development surcharge is collected. It has also been laid down that the use of these funds in any other manner shall be only with the prior approval of the Commission.

3.9.5 It is relevant to mention that the Commission made it clear in the order that it was not the intention to provide for all the funds for capacity expansion through tariff. The utilities are being provided a reasonable return as well as incentives which should be able to generate resources for ploughing back into the business for capacity addition. It was also mentioned that the Government was sole owner of these utilities and would be in a position to subscribe to the equity of these companies within its budgetary constraints.

3.9.6 The State Electricity Boards which have given their suggestions are unanimous in recommending the abolition of the development surcharge on the ground that it constitutes an extra burden, and that the beneficiary would not benefit directly. NTPC has suggested the continuation of the development surcharge, with the recommendation that the various conditions laid down by the Commission in regard to the accounting, utilisation of funds in the region etc. should be removed. In short, the development surcharge should be another source of cash inflow for the utilities with full flexibility to be utilised in the manner desired by them. PGCIL has also recommended that the development surcharge should not be related to regional transmission only. Another suggestion is to abolish the development surcharge, if the depreciation is allowed as prescribed by the Government of India.

3.9.7 It may be mentioned that the question of the need for funds for capacity addition has also been raised in the chapter on 'Depreciation'. If liberal depreciation were to be provided to include the requirement of capacity addition, perhaps the development surcharge will not be necessary. If the structure of depreciation is not disturbed as at present, the development surcharge would, perhaps, be required to be continued in future also. In that eventuality, it would also require to be considered whether the existing conditions attached to the accounting and utilisation of the funds collected through development surcharge should remain as they are, or would require modification. It appears that if the funds are specifically collected for development purposes, it would be necessary to ensure that the funds are utilised only for the purpose for which it is collected. To that extent, the minimum safeguards would seem to be necessary.

CHAPTER 4

4.0 Other Important Issues

4.1 Tariff Period

4.1.1 The current tariff notified by the Commission on 26 March, 2001 is valid for three years i.e. for the period from 1.4.2001 to 31.3.2004. The Commission is required to lay down the terms and conditions of tariff by regulations within a period of one year from the enactment of the Electricity Act 2003, and in the interim period the existing notifications are saved. The Commission, therefore, considers it appropriate to lay down the regulations governing terms and conditions of tariff within the stipulated time of one year and well before the expiry of the present terms and conditions.

4.1.2 The Commission also would like to decide on the time period for which these regulations shall be valid. Different time periods were suggested in various comments received by the Commission in this regard. One comment was to keep this period as 4 years, since the overhaul of a gas turbine is done once in 4 years, with a mid-term review after 2 years. The majority view is to keep the tariff period as 5 years. Another view was to keep the terms and conditions constant, and make changes as and when required, similar to the laws remaining in perpetuity with amendments being brought about as and when required. In this context, the tariff period becomes very important, and the Commission solicits the views of the stakeholders on this issue.

4.2 Regional Tariff

4.2.1 A suggestion has been received with regard to setting generation tariff for the region as a whole. For example, if a region comprises four power stations of a particular generating utility, the proposal is for aggregating the fixed charges of all the four stations together and then recovering the same from the beneficiaries. This has to be necessarily followed by a single variable cost for all these four stations. This proposal for regional tariff is comparable to the regional tariff prevailing in transmission. The generators and beneficiaries may offer their suggestions on this proposal.

4.3 Peak & Off-peak Tariff in Bulk Generation

4.3.1 The Commission has been deliberating on concept of peak and off-peak tariff in bulk generation for quite some time. NHPC has also suggested the introduction of peak and off-peak tariff. At present, fixed charges and variable charges are evenly distributed for all the 24 hours in a day. One way to arrive at different peak and off-peak tariff is to distribute fixed charges between peak and off-peak period unevenly. By asymmetric distribution, we could arrive at suitable peak and off-peak fixed charges, keeping total fixed charges of the Day as same (say, peak period = 3 hours in a day of 24 hours, from 6.00 p.m. to 9.00 p.m.)

4.3.2 The distribution of the fixed charges may be represented as:

FC= (3/24) X 'a' X FC + (21/24) X 'b' X FC

Where, FC is Fixed Charges per day;
'a' and 'b' are weights for the peak and off-peak periods, respectively.

At present, fixed charges are uniformly distributed, so a=b=1.
If we take, 'a'= 2 in the above equation, we get 'b'=18/21.

FC=(3/24) X 2 X FC + (21/24) (18/21) FC
or
FC= 0.25 FC + 0.75 FC

FC (Peak) = 0.25 FC
FC (off-peak) = 0.75 FC

In other words, 25% of the Fixed charges shall be allocated to peak period and 75% Fixed charges shall be allocated to off-peak period (Fixed charges per hour during peak period shall be 2.33 times the Fixed charges per hour for off-peak period)

4.3.3 By assigning suitable values to 'a' and 'b', desired weightage for peak and off-peak periods can be obtained. The above concept of peak and off-peak tariff in bulk generation could be applied to any type of plants, be it hydro or thermal. Further, it is possible to apply separate target availability / capacity index criteria during peak and off-peak periods.

4.3.4 This will require separate monitoring and evaluation of peak time and off-peak time Availability/Capacity Index for recovery of fixed charges in case of Thermal/Hydro stations, by the RLDCs/REBs. The basic system of monitoring and metering is already in place. The pros and cons of introducing peak and off-peak tariff in bulk generation and its methodology could be debated.

4.4 Declared Capacity

4.4.1 In the present notification (clause 2.1), the Declared Capacity for thermal generating station is defined as the ex-bus capability in MWh and it is stated that this shall not exceed the Installed Capacity (IC). Hence, maximum declared capacity gets restricted to the sent-out capability arrived at after deducting the normative auxiliary consumption from generation capability at the generator terminals. Since the actual auxiliary consumption varies and it is generally lower at higher PLFs, the plant can deliver more power than the sent-out capability corresponding to IC arrived at after deducting normative auxiliary consumption, particularly under favorable ambient and system conditions. TNEB, PGCIL and NTPC have sought for the deletion of the above restriction. PGCIL has sought to revise the definition of declared capacity as the capability of a generating station to deliver ex-bus in MW terms rather than in MWh. In case of hydro generating stations, declared capacity (clause 3.1) has been stated in MW. Actually, declaration/scheduling is being done on ex-bus MW basis. Thus, this definition needs to be deliberated.

4.5 Definition of Auxiliary Energy Consumption

4.5.1 Auxiliary energy consumption has been defined in clause 2.1 of the CERC notification as

> *"In relation to any period, means the ratio expressed as a percentage of energy in KWH generated at generator terminal minus energy in KWH delivered at the generating station switchyard to gross energy in KWH generated at generator terminals"*.

NTPC has suggested the following definition:

"In relation to any period, means the ratio expressed as a percentage of summation of gross energy in KWH generated at generator terminals of all the units of the station minus the net energy export in KWH ex bus to summation of gross energy in KWH generated at generator terminals of all the units of the station".

However, the general view of the beneficiaries is that any consumption of construction power and consumption in the residential houses shall not be the part of the auxiliary consumption. This could be further deliberated.

Abbreviations	
ABT	Availability Based Tariff
AFC	Annual Fixed Charges
CAS	Crisil Advisory Services
CCGT	Combined Cycle Gas Turbine
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CGS	Central Generating Stations
CI	Capacity Index
CI_A	Capacity Index Achieved
CI_N	Normative Capacity Index
COD	Commercial Operation Date
CPI	Consumer Price Index
DC	Declared Capacity
DCL	Development Consultants Limited
DISCOM	Distribution Company
ER	Eastern Region
ERC Act	Electricity Regulatory Commission Act, 1998
FERV	Foreign Exchange Rate Variation
GCV	Gross Calorific Value
GENCO	Generating Company
GFA	Gross Fixed Asset
GOI	Government of India
IC	Installed Capacity
IPP	Independent Power Producer
IPTC	Independent Private Transmission Company
IT	Information Technology
HE	Hydro-Electric
kWh	Kilo Watt hours
MOU	Memorandum of Understanding
MW	Mega Watt
MWh	Mega Watt hours
NEEPCO	North Eastern Electric Power Corporation Ltd.
NFA	Net Fixed Asset
NHPC	National Hydro-Electric Power Corporation
NLC	Neyvelli Lignite Corporation
NTPC	National Thermal Power Corporation
O&M	Operation & Maintenance
ODRC	Optimised Depreciated Replacement Cost
PEC	Primary Energy Charge
PGCIL	Power Grid Corporation of India Ltd.
PLF	Plant Load Factor
PLR	Prime Lending Rate
PPA	Power Purchase Agreement

PTC	Power Trading Corporation
REB	Regional Electricity Board
RLDC	Regional Load Dispatch Centre
R&M	Renovation & Modernisation
ROCE	Return on Capital Employed
ROE	Return on Equity
SEBs	State Electricity Boards
SERC	State Electricity Regulatory Commission
SR	Southern Region
STPS	Super Thermal Power Station
TA	Target Availability
TNEB	Tamil Nadu Electricity Board
TRANSCO	Transmission Company
UI	Unscheduled Interchange
WAPCOS	Water and Power Consultancy Services
WPI	Wholesale Price Index
WR	Western Region