ORDER

(Heard on 26th, 27th and 28th July, 1999)

A.R. RAMANATHAN, MEMBER:

1. PRELIMINARY

1.1 The Central Electricity Regulatory Commission (hereinafter called the Commission) was established under the Electricity Regulatory Commissions Act, 1998 (hereinafter called the ERC Act) and has been vested with the jurisdiction inter-alia, to regulate the tariff of generating companies owned or controlled by the Central Government. Even though this Act came into effect from 2nd July, 1998 the Commission got the jurisdiction with regard to tariff as referred to above with effect from 15th May, 1999. Prior to this date, the tariff jurisdiction was exercised by the Central Government by virtue of Section 43A(2) of the Electricity Supply Act, 1948 (hereinafter called the ES Act), which section was deleted with effect from 15th May, 1999 by the Central Government in exercise of its powers under the ERC Act to notify the date of deletion.

1.2 Prior to the deletion of section 43A(2) of the ES Act, it is understood that the Central Government had been examining for over 5 years the reform of the tariff structure of bulk power, with the object of inducing better system operation and grid discipline, through commercial incentives and dis-incentives. For this purpose, the Government had engaged international consultants to comprehensively study the Indian power system and recommend a suitable tariff structure. Their report (ECC Report) was submitted in 1994. It recommended the introduction of what was called the “Availability Based Tariff” (ABT) structure. The Government is reported to have, then, constituted a National Task Force (NTF) as well as Regional Task Forces (RTFs) to debate on various issues in the introduction of Availability Based Tariff (ABT) for bulk power.

Having seen merit in the availability based tariff mechanism, the Government apparently pursued its efforts to put it in position, in exercise of its jurisdiction under section 43A(2) of the ES Act. It is also understood that the government held “due consultations with the Department of Atomic Energy, Ministry of Coal as well as major CPSU’s” till March, 1999. It also framed a draft notification dated 7th April, 1999 which, if it had been notified, would have become operational and binding on all concerned. However, it was not notified and remained in draft form. Consequent to the deletion of section 43A(2) of the ES Act, the jurisdiction in regard to tariff is now vested with the Commission as from 15th May,1999. Consequently, the Government of India could not implement the ABT. Instead, by a letter dated 31st May, 1999, the Ministry of Power, forwarded the following documents to the Commission:

(i) A comprehensive note on the Availability Based Tariff;
(ii) A copy of the ECC Report;
(iii) Copies of minutes of National Task Force headed by Chairman, CEA;
(iv) Draft Notification for ABT

1.3 The Commission after taking into account the objectives behind ABT considered it appropriate to initiate proceedings in this matter in accordance with Regulation 24 of the Conduct of Business Regulations, 1999 (CBR). It designated the Union of India to present the matter in the capacity of a petitioner in the proceedings, which was accepted by the Government. Simultaneously, the Commission also directed that publicity be given to the draft notification of the Government of India, inviting objections/comments. On perusal of the objections/comments the Commission decided to hear the matter in detail. Notice was also issued to the Secretary to the Government of India, Ministry of Power, for these hearings. The Government of India also filed its rejoinder to the written replies filed by various parties. The matter was ultimately heard on 26th to 28th July, 1999 i.e. nearly within 2 months of initiating the proceedings.

2. STATEMENTS FOR RECORD:

Before proceeding further, for the purpose of record, it is necessary to state at this stage that:

(a) Shri R.N. Srivastava, Ex-Officio Member of the Commission did not associate himself with these proceedings on the ground that this issue had been dealt with by him in his capacity as Chairman, National Task Force, which has sent its comments to the Ministry of Power.

(b) In June, 1999, the Commission had been in existence for just ten months. The subject matter of this case is a highly complicated one. To facilitate expeditious disposal of the case, considerable technical inputs were essential. We looked forward to assistance from the Union of India. In this regard we could get some assistance from the CEA. More technical assistance was however essential for the Commission to expeditiously dispose of the matter. In its absence, the Commission took the help of consultants – both Indian and foreign. In this way, the Commission has been able to dispose of the matter at the earliest as stipulated under Regulation 101 of CBR.

(c) In the light of a response received from the Government of J&K in connection with another proceeding before the Commission, the question of jurisdiction of the Commission and applicability of this order with regard to state of J&K came up. This is relevant in view of the provisions of section 1 clause (2) of the ERC Act which state "it extends to the whole of India except the state of J&K."

The Commission decided to make a reference to the Learned Attorney General of India for his opinion in this regard. The opinion received from the Learned Attorney General establishes that in the absence of any law made by the State of J&K, the Commission has jurisdiction to regulate the tariff as also the Inter State Transmission System of which the State is an integral part.

In the light of the opinion of Learned Attorney General that so long as no law has been made by the J&K Government on this subject, there is no question of inconsistency between the Central and the State law and as such, there is no need to resolve any inconsistency in terms of article 254 of the Constitution. The State of J&K being part of the Northern grid of the Inter State Transmission System, we are convinced that the jurisdiction of the Commission shall extend to the State of J&K as well. As such this Order applies to the State of J&K as well.

3. DISTINCTIVE FEATURES OF ABT

3.1 We shall now discuss the distinctive features of the proposed ABT system. In order to understand the need and rationale behind the system, it is necessary to narrate the present problems in grid operation. Some of these as set out by Central Transmission Utility (CTU) in its presentation before the Commission are:

"(i) Low frequency during peak load hours, with frequency going down to 48.0-48.5 Hz for many hours every day.

(ii) High frequency during off peak hours, with frequency going up to 50.5 to 51 Hz for many hours every day.

(iii) Rapid and wide changes in frequency – 1 Hz change in 5 to 10 minutes, for many hours every day.

(iv) Very frequent grid disturbances, causing tripping of generating stations, interruption of supply to large blocks of consumers, and disintegration of the regional grids."

These wide frequency fluctuations tend to cause serious damages both at the generation and load ends, which are not perceived, and have never been quantified or evaluated. Experts consider these fluctuations unacceptable all over the world. In India though the problems have been identified, no progress has been made in bringing them under control. One important reason for this has been the absence of direct incentives or penalties for the individual utilities responsible for the problems. There has also been a general reluctance among all concerned to introduce financial incentives or disincentives.

The CTU has stated that the resolution of these problems requires:

"i) Maximisation of generation during peak load hours and load curtailment equal to the deficit in generation.

ii) Backing down of generation to match the system load reduction during off peak hours, keeping the merit order of generation in view."

These problems and their remedies have to be seen in the light of the present system of tariff. The present bulk tariff system does recognise the total cost as consisting of two elements, namely capacity cost and energy cost. But the mechanism of charging these costs to the beneficiaries is different from the proposed ABT. In the present system, both the fixed cost and the variable cost of a generating station, are charged to the beneficiaries in proportion to the actual energy drawn by them during that period. In the proposed ABT system, the fixed charge for a period is to be pro-rated among the beneficiaries in the ratio of their entitlement for power from that station. The logic is that, the station was created for catering to these beneficiaries. Hence its fixed cost has to be borne by them according to their share in the capacity so created. As regards energy charges, they are proposed to be charged only to the extent of the scheduled drawal by the beneficiary.

By bifurcating the method of charging Capacity Charges (fixed) and Energy Charges (variable), the incentive for trading in power is enhanced. The beneficiaries have a claim on the capacity, which they can trade either within or outside the region. By isolating the variable charge, a beneficiary can again trade such power depending upon its needs, market demand and the economics of power in the home state. All this goes to develop the market for power .

Apart from the two charges, a third charge contemplated in the ABT scheme is for the unscheduled interchange of power (UI charges). The UI charges are payable/receivable depending upon who has deviated from the schedule and also subject to the grid conditions at that point of time. This is the element, which is expected to bring about discipline in the system. This is stated to be effective because, UI charges will be payable/recoverable if:

i) a generator generates more than the schedule, thereby increasing the frequency;
ii) a generator generates less than the schedule, thereby decreasing the frequency.
iii) a beneficiary overdraws power, thereby decreasing the frequency;
iv) a beneficiary underdraws power, thereby increasing the frequency.

These four are clearly identifiable instances of grid indiscipline. The corresponding UI charges will accrue to the benefit of the party who is adversely affected on account of the indiscipline, by any of the acts referred to above. This system of UI charges is absent in the present tariff mechanism. Presently there is over generation/under drawal during off peak time, and under generation/over drawal at peak time. Consequently, grid disturbances and violent frequency fluctuations take place in the system, with consequential inconveniences to all concerned.

3.1 Another distinctive feature of the new system is the method of determining how much of the fixed charges are payable to the generating stations. The generating station obviously cannot be paid all its permissible fixed cost, irrespective of the extent of the capacity utilisation, known as the Plant Load Factor (PLF). As per recommendations of the K.P. Rao Committee which was adopted in modified form by the Government for its tariff notifications (till May 15, 1999), a thermal generation station was entitled to reimbursement of full fixed cost (100%) in case it achieved a PLF of 68.49%. Sometimes, the actual generation might not be to this extent, due to factors beyond the control of the generator. Then a “deemed” generation was also taken into account while determining the capacity utilised, namely, the PLF. Thus the entitlement for fixed cost reimbursement for a generating station depended upon the extent to which its capacity was utilised or was deemed to have been utilised. Though the actual generation could be verified from records, the deemed generation was being certified by the Regional Electricity Board (REB), taking in to account the facts and circumstances of each case. As against this system, the proposed ABT system will entitle the generating station to reimbursement of fixed cost based on the availability or declared capacity of the generating station. The ABT proposal has measures to check and penalise excess/under declaration of availability.

3.2 In order to incentivise generation, there must be rewards for increased generation. The present system has an incentive mechanism, which earns for the generator incentives at the rate of one paisa for every kWh generated beyond the prescribed PLF. For example, in thermal generation, for every kWh generated beyond 68.49% PLF, there is an incentive of one paise per kWh per percentage increase in PLF over and above the normal variable charges. This will be applicable for the deemed generation as well. As against this system, the proposed ABT contemplates incentives reckoned as a percentage return on the equity invested in the project. These incentive rates are also staggered, so that at certain higher levels of availability, the rate of incentive is lower than at the earlier level. This is intended to prevent excessive strain on the generating equipment. For example, under the draft notification, for a thermal station, incentive is payable @ 0.4% on equity for each percentage increase of availability between 70% and 85%, but the incentive rate is reduced to 0.3% for each percentage availability on availability beyond 85%. These distinctive features of the ABT mechanism are tabulated below for a clear understanding of the system:

…..contd……

	Existing System		ABT System
I)	The Annual fixed charges(AFC) include a) Interest on loan b) Depreciation	I)	Fixed charges excluding ROE (i.e.) all other five items of the existing system. ROE treated separately.

	c) O&M expenses d) Return on equity e) Income tax f) Interest on working capital		
II)	AFC at (I) above to be Recovered at 68.49% PLF	II)	FC excluding ROE recovered at 30% availability on prorata basis between 0% & 30% availability. ROE recovered on prorata availability between 30% & 70%.
III)	Above 68.49% PLF, incentive @ 1 paise/kWh for each 1% increase in PLF	III)	Incentive beyond target availability of 70% is proposed as follows: 70% to 85% :0.4% of equity for each 1% increase in availability beyond 70%. 85% to 100% :0.3% of equity for each 1% increase in availability beyond 85%.
IV)	Sharing of fixed cost is based On actual energy drawals. Variable cost is again based on energy drawals.	IV)	Sharing of fixed cost is based on Allocated Capacity. Variable cost is based on scheduled energy.
V)	No additional charges for deviation from schedule.	V)	Additional charges payable for deviations from schedules varying with frequency at the time of deviation.

Note: I) The existing system of recovery of tariff is followed with certain changes by NTPC/NLC. NEEPCo's tariff is not covered by any notification and is a tariff mutually agreed between generators and beneficiaries.

II) Hydro tariff, wherever notified by GOI, is already based on availability.

3.3 The ABT mechanism can be implemented even with the calculation of fixed charges and variable charges as at present. The Commission is finalising tariff principles and norms which it will announce in due course. At that time , the fixed charges and variable charges will be determined as per those norms. Thus, the availability based tariff system can hold good, whether present or changed principles and norms are used for determination of the fixed and variable charges.

4 SUMMARY OF DRAFT NOTIFICATION

Before taking up the issues arising out of this petition for our consideration, it is necessary to set out broadly, the essential features of the system as contained in the draft notification. The preamble describes its applicability as being confined to sale of electricity by generating companies (meaning central generating companies) to electricity boards and other persons, by generating stations having more than one SEB/State/UT as beneficiary. In other words, it does not extend to sale of electricity by any central generating company which exclusively supplies to one SEB/State/UT; nor does it apply to other generating companies. The draft notification essentially contains 10 paras as follows:

1) Programme of implementation
2) The three parts of the Tariff
3) Annual fixed charges (AFC) and rate of energy charges
4) Scheduling
5) Sent out capability
6) Availability
7) Demonstration of declared capability
8) Metering and accounting
9) Billing and payment of capacity charges
10) Dispute redressal

4.1 The programme of implementation was proposed to be staggered, apparently due to the unpreparedness of some of the regions like Northern and Western regions with metering arrangements, etc. This issue will be discussed in detail in the later part of this order.

4.2 The second para sets out the three parts of the tariff, namely Capacity Charge, Energy Charge or Variable Charge, (VC) and charges for Unscheduled Interchange (UI). The AFC is to be related to the availability of the generation station. The formula for calculation of the availability is set out in the Draft. The energy charge is proposed to be worked out on the basis of paise per KWh rate on ex-bus energy scheduled to be sent out from the generating station. The unscheduled interchange for a generating station shall be equal to its actual generation minus its scheduled generation. The UI for the beneficiary shall be equal to its total actual drawal minus its total scheduled drawal. This UI is supposed to be worked out for each 15 minutes time block. The charges shall be based on the average frequency of the relevant time block. The rates set out are as follows:

Average Frequency of time block UI Rate (Paise/ KWh)

50.5 Hz and above	0.0
Below 50.5 Hz and up to 50.48 Hz	4.8
Below 49.4 Hz and 49.02 Hz	355.2
Below 49.02 Hz	360.0
Between 50.5 Hz and 49.02 Hz	linear in 0.02 Hz step

The above rates are to be subject to change through a separate notification from time to time.

4.3 Para 3 deals with Fixed charges and Energy charges. The amount of fixed charges or rate of energy charge with reference to any station was proposed to be governed by notifications issued by the Central Government under Section 43A(2) of the ES Act. This applies to both thermal and hydro stations.

4.4 Para 4 describes in detail the methodology of scheduling. The basic idea behind scheduling is to match the supply and demand on a daily basis at least one day in advance. This para provides that:

i) Each day of 24 hours starting from 00.00 hours be divided into 96 time blocks of 15 minutes each.

ii) Each generating station is to make advance declaration of its capacity for generation in terms of MWh delivery ex-bus for each time block of the next day. In addition, the total ex-bus MWh which can actually be delivered during the day will also be declared in case of hydro stations. These shall constitute the basis of generation scheduling.

iii) While declaring the capability, the generator should ensure that the capability during peak hours is not less than that during other hours.

iv) The Scheduling as referred to above should be in accordance with the operating procedures in force.

v) Based on the above declaration, the regional load despatch centre shall communicate to the various beneficiaries their respective shares of the available capability.

vi) After the beneficiaries give their requisition for power based on the generation schedules, the RLDC shall prepare the generation schedules and drawal schedules for each time block after taking into account technical limitations and transmission constraints.

vii) The schedule of actual generation shall be quantified on ex-bus basis, whereas for beneficiaries, scheduled drawals shall be quantified at their respective receiving points.

viii) For calculating the drawal schedule for beneficiaries, the transmission losses shall be apportioned in proportion to their drawals.

ix) In case of any forced outage of a unit, or in case of any transmission bottleneck, RLDC will revise the schedules. The revised schedules will become effective from the 4th time block, counting the time block in which the revision is advised by the generator, to be the 1st one.

x) It is also permissible for the generators and the beneficiaries to revise their schedules during a day, but any such revisions shall be effective only from the 6th time block reckoned in the manner as already stated.

xi) RLDC is also entitled to revise (if need be), the schedules during the day in the interest of better system operation. These revised schedules shall become effective from the 4th time block counting the time of issue of revised schedule as the 1st time block.

xii) In the event of any grid disturbance, the schedules of both generation and drawal shall be deemed to have been revised to be equal to their actual generation/drawal. The grid disturbance and its duration shall be certified by RLDC.

xiii) The schedules issued/revised by RLDC shall be effective from designated time block, irrespective of communication success or failure.

4.5 Para 5 describes in detail the capability of a generating station to deliver ex-bus MWh (sent out capacity) based on which availability will be worked out. This para deals with the methodology of working out the capability for thermal stations including nuclear stations, and for hydro stations separately. These are technical matters specific to the respective nature of operation.

4.6 Para 6 describes methodology of working out the availability in terms of percentage ratio for each time block and for aggregating the percentage ratios. This is dealt with separately for thermal stations including nuclear stations and hydro stations. The net result of the exercise for determining the availability is the expression in percentage ratio of average capability for all the time blocks during any given period and the rated sent out capacity. Thus for any point of time, namely a day or a month, or year, availability of the station for determining the entitlement for capacity charges and incentives could be worked out.

4.7 Para 7 deals with the test to demonstrate the declared capability. In this connection, the Member Secretary of the concerned REB is empowered to require any station to demonstrate the declared capability. In the event of the generator failing to demonstrate the capability, the fixed charges shall be reduced as a measure of penalty. The procedure for testing is to be decided by the CEA from time to time. It is also stated that, in case the declaration is found to be generally on the lower side, and the actual generation is more than the declaration, then the UI charges due to that generator on account of such extra generation shall be reduced to zero, and the amount shall be credited towards UI account of beneficiaries in the ratio of their capacity share in the station.

4.8 Para 8 deals with metering and accounting arrangements. It is stated that these shall be provided by the RLDC. The processed data of the meters shall be supplied by RLDC to REBs for issuing the regional accounts.

4.9 Para 9 details the billing and payment for capacity charges. Billing for energy charges involves a simple process of applying the determined energy charges per KWh on the scheduled drawal of energy for a month. As regards capacity charges and incentives, on account of the system of monthly billing, it is necessary to spell out the methodology in this regard. Even though the chargeable capacity charges of a station have to be apportioned to the beneficiaries in the ratio of their entitlement, provision has to be made for the unallocated central share of power. As and when it is allocated, it needs to be added to the share of the State to which allocation is made. In case no allocation is made in a month, the entire capacity cost will devolve on the beneficiary states in their respective ratios of allocation. A provision has also been made for re-working the share in case a beneficiary proposes to surrender part of its allocated share to others within/outside the region. In such cases, depending upon the feasibility of power transfer as well as specific agreements reached by the generating company with other states, the shares of beneficiaries may be reallocated by CEA for a specific period. If so, such reallocated shares will constitute the basis for charging the capacity cost. The beneficiaries have also the freedom to negotiate any transaction for utilisation of their share of the capacity. There is also provision for any capacity un-requisitioned during day-to-day operation to be advised by RLDC to all beneficiaries, as well as to other RLDCs so that such capacity could be requisitioned.

Though the system of charging the capacity cost and determining and charging incentive is to be done on an annual basis, there is provision for adjustment of capacity availability on a cumulative basis from month to month. Thus, if there is a higher availability in one month, for that month the capacity charges and incentives shall be payable on the basis of that higher availability. If in the subsequent month there is a lower availability, there is provision for accumulating the previous month's availability with the subsequent month's availability. Similarly, the apportionment to all the beneficiaries is also proposed to be done on a cumulative basis, depending upon their respective share from month to month. In this process of cumulative billing, the year is taken as the financial year, so that one year's figures are not cumulated with the subsequent year's figures.

4.10 Para 10 contemplates that any dispute with regard to the implementation and operation based on this Draft notification, relating to scheduling, grid operation and accounting shall be referred to the Member Secretary of the respective REB for settlement. Un-resolved issues are to be referred to the CEA whose decision is to be final and binding on all.

4.11 The Annexure to the draft notification sets out the method of reckoning the percentage of capacity charge with reference to the availability of a station. Annexure-I (A) deals with coal based and gas/naptha based thermal stations of NTPC and NEEPCO. For these stations the annual capacity charges are payable as follows:

Availability	**Capacity charge**
0-30%	Prorata fixed charge excluding ROE, between 0 and 30 %.
30-70%	Annual fixed charges (excluding ROE) plus pro-rata ROE between 30 and 70 %.
70%	Full annual fixed charges including ROE
70-85%	Full annual fixed charges + 0.4% return on equity for each 1 % increase in Availability beyond 70 %.
85-100%	Full annual fixed charges + incentive up to 85% at 0.4% + incentive at 0.3% for each 1% increase in availability beyond 85 %.

4.12 The annexure also provides for additional payment of capacity charge in respect of prolonged outage of any unit of a station above 90 days of outage. This fixed cost (excluding ROE) is to be provided on a pro-rata basis for the concerned number of days with reference to the capacity of the units under outage as compared to the installed capacity of the station. Here again the full fixed cost (excluding ROE) is not covered, in case of outages beyond 180 days and beyond 360 days after the first 90 days. In the first 180 days, 100% fixed charges (excluding ROE) is allowed, whereas in the next 180 days 75% is allowed, and thereafter 50% is allowed.

4.13 The annexure also contains the method for reckoning capacity charges to be paid for different availabilities for hydro stations, as follows:

Availability	Capacity charge
0-85%	A pro-rata annual capacity charge based on actual availability between 0 and 85 %.

85-92%	Full capacity charges + 0.6% on equity for each 1% increase in availability beyond 85 % as incentive.
92-100%	Full capacity charges + incentive up to 92% at 0.6% of equity + 0.45% of equity for each 1% increase in availability beyond 92%.

4.14 After a study of the contents of the draft notification as well as submissions made by various respondents, the following issues arise for our consideration:

1. Why ABT?
2. Applicability to Nuclear Stations
3. Do the Norms need Revision?
4. Return and Incentives
5. Capacity Charges and Target Availability
6. Capacity Charges at Lower Levels of Availability
7. Treatment of Unallocated Shares
8. Gaming Possibilities
9. Unscheduled Inter Changes
10. Billing & Payment
11. Metering Arrangement
12. Applicability of ABT to Hydro Stations

We propose to address the above issues in the light of the submissions (both written and oral) made by various respondents and the partial rejoinder submitted on the above by the Union of India.

ISSUES

5.1. ISSUE 1 : WHY ABT?

5.1.1 The electricity industry in India is mired in a complex network of problems. They range from inadequate capacities in generation, transmission, and distribution, outdated technologies especially in T&D, poor maintenance, cross-subsidization and consequent financial unviability of a large part of the sector, over staffing, lack of a commercial culture, poor management and accounting practices, etc. A framework of solutions appears to have been attempted for implementation all over the country. The ABT is one among them.

5.1.2 The Commission is mandated to regulate only bulk electric power tariffs viz., the Tariff of generation and transmission, and the inter state transmission of power. It has to exercise this mandate while promoting competition, efficiency and economy, encouraging investment in the industry and safeguarding the consumer interest. The Commission looks forward to the day when it does not have to determine the tariffs of each generating station and can leave it to market forces. However, the present situation does not permit this. In addition of course there are supply constraints due to lack of capacity in transmission as well as in generation. The Commission also has limited mandate in bringing about a competitive market-based system. It has to use the regulatory powers available to it to promote efficiency, and simulate some of the possible effects of a market.

5.1.3 It is argued that Central generating stations (CGS) were set up to supply power to specific SEB's. Hence they must be responsible for the proportionate overheads (fixed charges), of the CGS to the extent that they have agreed to buy the CGS's capacity and it is available. Any running (variable) costs would be paid in relation to energy drawn which can even be traded. This argument entrenches the tie between generator viz. CGS and buyer by ensuring part payment of the fixed charge for the portion of the capacity that is allocated to the customer. Even if he does not need the supply, he has to bear the fixed charges. He can however, sell the capacity entitlement to others, and may pass on to the next buyer such part of the fixed charges that the new buyer is able to pay, depending on the needs of other suppliers and customers. In these circumstances, the regulator has to determine the tariff for each generating station separately, since the fixed charges will vary with each. The regulator has to get into the details of all costs claimed by the generator.

The ABT is not an ideal mechanism for two reasons viz., it recognises the system of allocations of power and it requires the detailed determination of tariffs for each generating station. However, the two part tariff facilitates trading in capacity and actual power. For that reason, ABT is a good first step. Under the ABT proposal a state is free to dispose of the whole or part of the allocated share to anyone else. In this process, the impact of fixed charge can be abated or one can even earn a surplus from it. Similarly, it is possible to trade in power on a non-firm basis. But the liability to pay the generator for the fixed charges or energy charges is of the allottee beneficiary only. ABT also facilitates Merit Order despatch, which is in the interests of economy and efficiency. Of course more steps in system operations are required to be taken to really bring about Merit Order Despatch. The scope for Merit order despatch is presently limited under option ‘C’[1] for scheduling and despatch; however, this potential can be further explored leading gradually to Option ‘A’ [2].

5.1.4 There is an even more imminent reason to welcome the ABT. That is the large variation in frequency over the system. The ABT enables despatch of power in relation to a schedule which can be given by every beneficiary based on the availability of allocated shares of CGS stations and other power that might be available. It enables penal tariffs to be charged when power is drawn beyond the schedules. This feature of ABT can help to bring about a great deal of grid discipline combined with self-discipline on the part of all utilities. This is lacking at present. The redeeming feature however, of the present system is the mechanism of incentives and disincentives which of course needs to be examined very closely.

5.1.5 As the transmission capacity improves, and there is an improvement in generated power, opportunities for trading will increase. At that time, the Commission may decide to move away from the regulatory burden of determining tariffs in such detail, and go for market determination. Preconditions for this to happen include the elimination of allocations of power between CGS and customers, and suitable changes in legislation which permit easy trading without the need for permissions from state governments. It requires that SEBs operate under commercial discipline and that they will buy or back down their generation or shed load, depending on the tariff.

5.1.6 The commercial mechanism of the ABT contemplates the disciplining of all three entities in the grid viz., the generator, transmitter and the beneficiaries. It accords a uniform treatment to all participants in the grid. The commercial mechanism is a self regulated discipline *and* binding on all concerned, as opposed to a regulator-imposed discipline. The UI charges in the ABT mechanism combined with payment of capacity cost on availability basis, facilitates the marketing of both capacity and energy on a continuous basis, and enforcement of grid discipline.

5.1.7 The commercial mechanism appears to be acceptable to all concerned. The two

[1] Decentralised scheduling and dispatch of Central Sector generation and decentralised inter-State and inter-regional trading.
[2] Centralised scheduling and dispatch of all generation, including SEB internal resources, centralised scheduling of all internal trading within the Region, and exclusive authority to negotiate inter-regional trading.

differing interests, generators and beneficiaries in past years have accepted the commercial mechanism of ABT at the RTF and NTF meetings. These meetings led to the draft notification by the Government of India.

5.1.8 The description “Availability Based Tariff” is appropriate, as it reflects all elements of the tariff viz., capacity charges, energy charges and UI charges while *t*he term ‘availability tariff’ may indicate capacity charges only. ‘Frequency linked availability tariff’ may again also be an inappropriate description as it limits its scope

5.1.9 The distinct merits of ABT are, as stated earlier:

(a) facilitating grid discipline;

(b) facilitating trading in capacity and energy; and

(c) facilitating merit order despatch as and when made effective

In addition, a new system of more relevant incentives and disincentives would make for better performance. We therefore consider it proper to introduce the ABT system*.* While doing this we have reserved certain questions to be resolved at a later stage after detailed studies, which are already in progress. Still the ABT system shall be implemented as laid out in this order, with further refinement to be notified later by the Commission. We must also note that considerable time of nearly five years has been spent in discussing the principles of the proposed system. Much valuable time has been lost in bringing about grid discipline and merit order despatch. In the NTF discussions, conclusions of the RTFs were debated and decided. It is unnecessary for us therefore to reopen issues on which consensus has been already reached. The following are the issues on which broad consensus was arrived at the 7th meeting of the NTF held on 8th November, 1996. They are reproduced from the Minutes:

“18. After taking all aspects into consideration, the following decisions were taken:

- Availability based generation tariff will be adopted and will be applied to all including future IPPs
- CEA will formulate the parameters for computing the norms for availability and also the station-wise availability which will be valid for a period of two years and would be reviewed after every two years.
- In view of the views of most of SEBs, the NTF endorsed adoption of option ‘C’. It also decided that, while fixing the merit order operation of generating

plants in a region, due weightage to the transmission losses and other grid conditions would be given.

- In respect of central stations, Fixed charges would be apportioned on the basis of entitlement of the SEBs. If allocated power is not required by any utility, they will have the option of marketing the surplus power.
- Unscheduled inter-change rates will be based on peak and off peak hours and timings will be decided on regional basis."

In view of the above, we shall hereafter be specifically dealing with only the unresolved issues, or issues which were not taken up nor decided at the NTF in pursuit of introduction of ABT or issues otherwise relevant to the subject.

5.2. ISSUE 2: APPLICABILITY OF ABT TO NUCLEAR STATIONS:

5.2.1 A question has arisen regarding the applicability of ABT to nuclear stations though owned by the Central Government. The basis for this query is the provision contained in section 49 of the ERC Act which makes the provisions of this Act ineffective in so far as they are inconsistent with the Atomic Energy Act, 1962. Thus, though the Commission has jurisdiction to regulate the tariff of centrally owned generating companies, since the Atomic Energy Act, 1962 in section 22(b) states that the Central Government shall have the authority to fix rates for and regulate supply of electricity from atomic power stations the Commission faces a constraint. This constraint did not exist when it *was* the Central Government that was seized of the matter.

5.2.2 During the NTF proceedings the general consensus was to include the nuclear stations under the regime of ABT. However, in view of the special constraints involved in operation of nuclear stations, it was considered necessary to discuss the issue with NPC before taking a final decision. Subsequently after discussion with NPC it was decided to include nuclear stations under the regime of availability based tariff.

5.2.3 In the proceedings before us, both on *the* grid code and on the ABT, NPC took an active part and filed replies to the proposals. The jurisdiction of the Commission has not been challenged in these proceedings. We have also made special provisions for nuclear stations in our order on the Grid Code. Under the ABT regime, NPC has expressed willingness to submit its stations to the regime subject to certain special considerations in view of the peculiar nature of their operations. We are also of the view that in the interest of better grid discipline and merit order despatch nuclear stations should also be included in the system. In fact, even other entities like DVC and BBMB which do not fall within our jurisdiction though they are engaged in inter state transmission, would like to be covered by the ABT system. The practical solution for this problem lies in making use of the alternative under section 22(b) of the Atomic Energy Act, 1962 which contemplates the Central Government authorising any authority established by the Government to do `rate fixation and regulation of supply of atomic stations'. As such, it is only required of the Central Government through the Department of Atomic Energy to authorise the Commission in this regard. We have already suggested to the Nuclear Power Corporation to initiate appropriate steps for the Government to authorise the Commission.

5.2.4 We have also pointed out this inadequacy in the present legislation to GOI, under Section 60 of the ERC Act of 1998 vide letter No.L-7/7(1)/99-CERC dated September 21, 1999 which is pending with the Government. In view of the above, the provisions of this order shall apply to atomic stations subject to the Government's response to these references.

5.3. ISSUE 3 : DO THE NORMS NEED REVISION?

5.3.1 A number of replies from the utilities indicate that the norms for determination of the fixed charges, variable charges and incentives need modification and cannot be accepted on the basis of existing norms. On the one hand, NTPC has claimed additional payment for every startup and partial loading, as also an additional compensation for gas stations for making available the liquid fuel. Some of the beneficiaries like KEB, AP TRANSCO, TNEB, DVC and RSEB have sought revision of the operational norms as well as in respect of ROE, debt equity ratio, incentives etc.

5.3.2 We are in agreement that the norms in respect of tariffs which were fixed as early as in 1992, need to be re-examined and revised. We have already initiated the process through a Consultation Paper on bulk electricity tariffs which addresses these issues, among others. We have also initiated certain studies by experts to help us in determining a rational basis for the revision of the norms. This process is bound to take a few more months. In the meanwhile, in the interest of grid discipline and merit order despatch, we are convinced that the ABT merits implementation. We are conscious of the implications of its introduction without revising the norms. However, the time gap between the introduction of ABT and the evaluation of new norms may not be long.

5.3.3 We understand that during the discussion in the task force meetings, it was advocated that the introduction of ABT should not adversely affect the revenues of the generating companies. It was canvassed before us also that this so-called **"**revenue neutrality**"** should be maintained. In fact, on behalf of the Union of India, it was submitted before us that the guiding principle of **"**revenue neutrality**"** was kept in view while detailing on the tariff parameters of ABT for existing stations. Accordingly, parameters such as return on equity, rate of depreciation, operation and maintenance charges, norms for fuel consumption and norms for auxiliary consumption etc., have been taken to be the same as in the existing tariff.'

On a perusal of the Minutes of the National Task Force, it is found that at its 9th meeting held on 25th March, 1998, there were some discussions to the effect that the intention behind the draft Notification is not to put the generating companies to loss in the process of implementing availability tariff. This discussion was in the background of a 12 % rate of return for NTPC at that point of time. On behalf of the State Electricity Boards, protection was sought so that they should not be required to pay more. As already stated by us, keeping in view the objective of the Commission to promote economy and efficiency, it may not be appropriate to proceed with a pre-determined conclusion that the existing revenues should be protected in the interests of "revenue neutrality. We have to take cognizance of the improvement in operations during the seven years since the norms were introduced in 1992. At the same time, incentives for still further improvement in performance have to be thought of. A balance has to be kept between adequate return for the generator towards encouraging investment, and the possible exploitation of dominant position in generation. As such, in reviewing the norms, we shall not proceed with *apriori* assumptions, but approach the task in an unbiased fashion.

5.3.4 The Commission is anxious to introduce the ABT system on account of its merits, without further loss of time. As an immediate step, and in a broad sense, the

present norms, etc. will continue to be used in the ABT system. Within the short time available, the Commission however, has considered some of the parameters which are dealt within this order. The following are the topics that we shall leave untouched until our studies mentioned above are completed in some months:

- **i) Financial structure**
- **ii) Return on Equity and Income Tax Liability**
- **iv) Depreciation**
- **iii) Method of Reckoning Incentives**
- **v) Operation & Maintenance expenditures**
- **vi) Station heat rate**
- **vii) Auxiliary power consumption**
- **viii) Specific fuel oil consumption**
- **ix) Admissibility of start up charges for thermal plants.**

The remaining topics listed below are dealt with in this Order:

- **i) Target availability**
- **ii) Criteria for Incentives**
- **iii) Procedure for prevention of gaming**
- **iv) Prolonged outages**
- **v) UI charges and frequency variation in different regions**
- **vi) Settlement of UI account**
- **vii) Treatment of unallocated capacities**

5.4 ISSUE 4: RATE OF RETURN AND INCENTIVES

5.4.1 A number of beneficiary states have repeatedly questioned the increase in the ROE from 12 % to 16 % for existing stations. No convincing justification has been advanced by generating companies in this regard excepting to state that public sector companies should be placed on par with the IPPs. From the perusal of correspondence in the files made available to us, CEA appears to have taken a firm stand that the ROE and incentives should be considered as a total package and cannot be isolated and dealt with separately. In fact, the correspondence shows that CEA was not in favour of increasing the rate of return from 12 % to 16 % as it would add a burden of over Rs.400 crores to the states. When the task force was debating on the scheme of incentives as a percentage of return on equity beyond target availability, the ROE under consideration was 12 %. However, without changing the scheme for incentives, the Government of India raised the ROE from 12 to 16 % which the beneficiary states considered as exorbitant and is a heavy burden on them. We have come across in the NTF files a communication from the Ministry of Power to CEA justifying this increase. It is stated therein that it was viewed by the Ministry that the above increase in revenue by NTPC is justifiable in order to enable it to generate adequate necessary resources for its capacity expansion programme during the 9th and 10th Plans. In another communication on record from the Government of India, Ministry of Power to TNEB it is stated: `this point has been reiterated along with a reference to the observations of the disinvestment commission to the effect that the tariff of NTPC is low due to poor rate of return.' Adjusting the Rate of Return in order to finance further expansion plans is a debatable issue. Further, even admitting the same, the extent to which this can be factored-in is also debatable.

5.4.2 The system of incentives based on actual PLF + certification of backing down (called as `Deemed PLF') came into vogue based on the recommendations of the KP Rao Committee. This criterion of giving incentives to the generator, linked to PLF had a remarkable effect in improving the PLF of generating stations. This remedy was essential at that time to augment the actual generation of existing capacities. Over a period of time, however, it has been found that this system has become counter productive and costly in as much as incentive was payable even for backing down. This is the cry from the Eastern Region and before more cries come from other quarters, it is better to remedy this situation.

5.4.3 It is true that the ECC has discussed about both the disincentive and the incentive for better performance. The disincentive is in the form of target availability for full reimbursement of fixed charges. Any availability below the target availability would result in reduced fixed charges. The ECC did contemplate a basic incentive credit which is defined as "that amount which replaces the BAC (Basic Availability Credit) in the capacity payment calculations after the target availability is attained. The BIC is a smaller value than the BAC since it only provides for incremental cost of operation plus an incentive payment to the generators for operation beyond normal availability." (para 5.2.3 of the Report). It is evident from this concept that the ECC meant payment of incentives for operations beyond normal availability after the target availability is attained for which a cost of operation is also involved. Thus it appears that the ECC did not contemplate an incentive payment on mere availability. However, the draft notification gives incentive on mere availability.

A generator cannot be rewarded for merely putting up a generating unit. It is necessary for him to make it available for the beneficiaries to a reasonable extent so that the latter could draw upon that capacity. Any shortfall in available capacity needs to be commercially punished with the denial of fixed cost. Incentive however, stands on a different footing. In regulated tariffs, it is necessary to keep a provision to reward better performance in order to promote efficiency and economy through cost reduction. Such a reward linked to a demonstrably efficient performance level, should be as challenging as possible. Mere availability does not reflect efficiency. At the same time, in order to keep the machine available without break down, the disincentive of denial of fixed charges is adequate enough. What is also required is that the available capacity should also be efficiently used. For this purpose, the entrepreneur generator should demonstrate that his product is competitive enough both in terms of cost and reliability of service so that additional demand would get generated and he will be able to improve his plant load factor. Any improvement in the plant load factor (up to sustainable level) indicates efficient performance, for which reward in the form of incentive is appropriate. Mere availability of the plant without demand cannot justify incentive payment. This conclusion is inevitable from studying the situation in the eastern region. There, though the generator is available, due to lack of demand, he has to back down. In this process, the generator could claim incentive based on mere availability, which is patently unfair to the consumers who are already meeting the full fixed cost. The Commission considers that with the separation of fixed cost from the variable cost, the beneficiaries are bound to view the cost advantage while making their scheduling. Combined with a little more aggressive marketing effort by the generators, it should be possible to create demand for evacuation of power from surplus areas, which is otherwise bottled up. With this situation, the output and consequently the PLF of generating units is bound to go up. Any incentive which is linked to PLF therefore would be an appropriate reward for cost control through better management of resources and better marketing efforts. There could be other and more effective ways which the Commission will be considering. But, for the present, and in view of the foregoing argument, the Commission considers it appropriate that any scheme of incentive should be linked to actual performance, i.e., plant load factor instead of mere availability, though the recovery of fixed charges could be still linked to availability.

5.4.4 The draft notification contemplates reckoning of incentives as a percentage of equity linked to declared availability above the target availability. The incentive rate is also regressive, probably to avoid the temptation of extra earnings at the cost of proper maintenance of equipments. In fact the notification never uses the term "incentive". The extra payment above target availability is included as part of capacity charges. This in other words means that the incentive will be chargeable as part of capacity charge on a monthly basis instead of being claimed at the year end separately. Many respondents have commented upon the adverse consequences of incentives merely based on availability. This has been very forcefully put across from the eastern region particularly because there is surplus power which is not in demand by the beneficiaries. The two distinctive features of the incentive scheme as per the draft notification are:

(a) The basis of determining the incentive; and

(b) The threshold eligibility limit for the incentive

5.4.5 Though we are clear about the criteria for incentives, as already discussed, the method of reckoning the incentive viz., as a percentage of the equity, is a matter which has to be deferred by the Commission since it has already initiated a study on cost of capital including whether the return should be on equity or on total investment. Further the impact on tariff between two comparable plants - one old and another new – with contrasting investment including debt/equity content has to be studied. Obviously, the newer plants would earn much higher incentive for no special performance.

The Commission also finds considerable merit in the argument advanced by the CEA as evident from the files, that the ROE and incentives should be considered together, as a reward to the entrepreneur, though reckoned separately for tariff purposes. As already stated, the Commission is convinced that this incentive should be linked to PLF so that it would really act as a catalyst for improved performance and cost reduction. Once our study on the cost of capital is completed, it would be possible to reach a firm conclusion regarding the justifiable ROE and incentives.

5.4.6 **In fairness to all parties concerned, therefore, when both the issues regarding Return on Equity and method of reckoning incentives are yet to be looked into in detail, it is appropriate to maintain the status quo on both these issues till a final decision on the overall adequate return is arrived at. The Commission may also have to take a view on the effective date as and when the new norm regarding return is finalised. As such the present ROE of 16 % as well as the incentive scheme based on PLF should continue. However, the present incentive scheme provides for incentive**

at 1 paise per kWh for each percentage increase in PLF over 68.49 % which is being revised. This is detailed in the next paragraph.

5.4.7 In view of the discussion as above, the Commission would prefer to continue with the present incentive of 1 paise per kWh. This incentive should be linked to the actual generation achieved over and above the target level of generation. For this purpose, it is necessary to work out the targeted generation for each station* based on the target availability and installed capacity. For

*We have to work out for each station, applying the same principle, since the capacities of the stations may not be the same.

instance, in a station with 400 MW capacity, the target generation at say, 80 % availability would be : $400 \times 8760 \times 0.80 \times 10^{-3}$ = 2803 million kWh[Δ]. Any generation above the target generation in units will be entitled to the incentive @ 1 paise per kWh. Thus the Commission prefers the status quo on ROE as well as on incentive to be maintained with the only exception that the incentive shall be reckoned on actual generation. The incentive shall be payable on a monthly basis as at present and to be finally adjusted at the end of the year. In view of this, there would be no question of "deemed generation" or "backing down certification" which are part of the existing system.

The incentive shall be payable by the beneficiaries in the same proportion in which fixed cost is borne. In a deficit region, the incentive would result in higher generation at reduced cost thereby benefiting both the generator and the beneficiary. In a surplus region, it is hoped that efforts will be made to exploit the idle capacity by negotiating trading opportunities jointly by the generator and the beneficiaries.

[Δ] 8760 is the total number of hours in a year;

However, the incentive shall be borne by the beneficiaries in the ratio in which capacity costs are borne. The Commission is hopeful that in the new system generators **would be amply rewarded for their efficiency along with a fair deal to the beneficiaries. The Commission looks forward to a time when all** anticipated **idle capacities** could be **traded by mutual negotiations between the beneficiaries and the generator.**

5.4.8 In any region, where ABT remains to be implemented, until the implementation, with effect from April 1, 2000, the existing method of charging tariffs shall continue. However, for reckoning the incentive, the relevant PLF percentage shall be 80% for thermal, 77% for lignite and 85% for hydro stations, which shall be the actual PLF without including the deemed generation certification as in the case of other regions in which ABT is in force.

5.5. ISSUE 5 : CAPACITY CHARGES AND TARGET AVAILABILITY

5. 5.1 The Central generating stations which are mostly pit head thermal stations were established in different regions in order to cater to the power requirements of various states in the regions. The investment has been made by the Central Government and the devolution of share of power to each state in the region has been determined on the lines of the Gadgil formula for devolution of central assistance to the states. This had happened in the 1970s. Over time, the tariffs for power from these stations have been based on commercial considerations. It is argued that the beneficiary states must bear the capacity charges of the stations in the region. As per the draft notification, the capacity charges consisting of fixed charges including rate of return is to be borne by the beneficiary states in proportion to their percentage share in the capacity of the station. The notification also contains an annexure which stipulates payment of an extra percentage on equity, which is included in the definition of capacity charges and which is generally perceived in the industry as an incentive payment. The notification does not identify this as an incentive payment. This incentive payment portion of the capacity charges has been dealt with already by us in para 5.4. Hence presently we deal with the capacity charges other than incentive. These are the fixed charges and return on equity.

5.5.2 One of the essential features of the ABT is that the level for full reimbursement of fixed charges and ROE is the target availability of the generator to despatch energy. This target availability is defined by ECC as “the equivalent availability factor (EAF) the unit is expected to attain on the average considering the unit’s historical experience and the industry’s experience with similar equipment. Operation of the unit with good utility practice should be assumed”. (Para 5.2.3 of the Report).

There is considerable logic behind allowing capacity charges to be made payable in full, based on a target availability which is the average level a unit is expected to attain, so that below average performance is not rewarded with full fixed charges. The availability level for payment of full fixed charges is a departure from the existing criterion of payment at a PLF of 68.49%. Keeping in view the background that central generating stations were specifically designed to cater to a cluster of states, prescribing payment of fixed charges on availability subject to achieving a target is understandable and the substitution of PLF by availability is also more rational. Even though PLF along with deemed generation may be verifiable (as they are record based), the proposed system is also fool proof since there is a system of checking of availability, as contained in the ABT. Testing of availability with consequent penal provisions for misdeclaration, further reinforces the system. In view of this, the disincentive in the form of commercial penalty for shorter availability can be considered as more appropriate and equally effective as the existing system for recovery of fixed charges.

5.5.3 We also find from the minutes of the 7th meeting of the NTF held on 8th November, 1996 that there was concurrence of all concerned, both central generators as well as the beneficiary states on the adoption of availability based generation tariff which incorporates this criteria for recovery of fixed charges. As such, the Commission is convinced that it is acceptable to all concerned. In view of this the objections of KEB, APTRANSCO and TNEB against capacity charges based on declared capacity instead of actual energy drawal, cannot be considered.

5.5.4 Having accepted declared availability as basis for full recovery of fixed charges we have to consider the determination of target availability which is the minimum level to be declared for full recovery of fixed charges. The target availability as contained in the draft notification envisages a level of 70% in case of coal based and gas/naphtha based thermal power generating stations of NTPC and NEEPCO. As regards hydro-stations of NHPC and NEEPCO, a target availability of 85% has been contemplated.

These levels of target availability for thermal plants have not been justified. They cannot also be justified based on the recommendations of ECC or the discussions at the NTF meeting. The ECC contemplated fixation of target availability for each generating station based on past operating experience, which is required to be examined every 2 years. In this connection it has observed that "each generating unit shall have a target availability defined which shall be based on past operating experience unless new plant improvement projects indicate higher achievable values. This value should be re-examined every 2 years in order to reflect changes in generator operation and plant improvement projects. The study team expects that availability targets should generally be 85% or higher". (Executive summary 2.0.) It should be kept in mind that this level was recommended by the study team in February 1994. Some of the beneficiary states like Tamil Nadu and Rajasthan have strongly urged that the target availability should be based on the past performance of the station. For instance TNEB has stated that in case of Ramagundam STPS the target availability should be at least 80%. RSEB has suggested that the target availability should be 85% instead of 70% as proposed in the draft notification. The Administrative Staff College of India in its reply has stated that the availability factor of 70% to recover full fixed charges is low and suggested that the availability should be based on past performance of the plant or similar plant and for a thermal plant 80 to 85% would be reasonable. Similar comments have also been received from certain other beneficiary states. Though we granted a special opportunity to NTPC (which is also one of the respondents) to file a counter affidavit, these contentions have not been refuted.

A perusal of the Annual Report of the Central Electricity Authority for the year 1998-99 shows that the average plant load factor of NTPC stations is 75.6% though All India average PLF is 64.6%. This average of 75.6% when combined with the experience of deemed generation, would lead to an average availability of around 80 to 85%.

5.5.5 Minutes of the 7th meeting of the NTF are also worth considering. "The general consensus in RTF was that the norms for equivalent availability factor should be based on historical data of performance and industry experience with good utility practice for the past 4 years for existing plants". The norms for determining equivalent availability factor should be reasonable and realistic so as to encourage better performance. "Performance of NTPC stations should not be compared with that of SEBs old station while determining target availability for NTPC units".

5.5.6 In the background of the above, the Commission called for data from NTPC, NLC and NHPC to understand the average availability of thermal and hydro plants for the past 5 years, which is as follows:-

Y e a r

	1994-95	1995-96	1996-97	1997-98	1998-99
NTPC*	69.28% to 90.17%	70.82% to 95.35%	74.45% to 91.01%	74.36% to 93.39%	78.30% to 95.28%
NLC:- Availability					
Stage I (630 MW)	71.98%	71.13%	80.02%	86.23%	85.05%
Stage II (840 MW)	72.54%	86.74%	85.25%	86.30%	83.99%
NHPC				79.06% to 99.64%	82.09% to 96.21%

* The above availability factors do not include the following availability figures:

	1994-95	1995-96	1996-97	1997-98	1998-99
NTPC	Kawas GPP: 48.91% Feroz Gandhi Unchahar TPP: 59.35%	Kawas 45.13% Jhanor-Chandar GPP: 63.34%	Kawas GPP: 50.84% Talcher Super TPP: 59.32%	Kahalgaon STPP: 58.38% Talcher STPS: 66.50%	
NHPC	-	-	-	Chamera HEP: 56.20% Salal HEP: 69.83%	Baira Siul HEP: 74.53% Salal HEP: 74.42%

5.5.7 These studies lead us to the conclusion that in case of thermal plants a target availability of 70% as provided in the draft notification cannot be justified. We could not find any justification in this regard from the records, excepting the only possible justification of revenue neutrality. In our view, to compromise on the target availability to justify revenue neutrality is unfair to the beneficiary states. We also considered the possibility of introducing station-wise target availability. We could not accept this proposition since it may involve accepting existing inefficiencies of each unit and the target cannot therefore be an ideal in all cases. As such we differ from the recommendation of ECC quoted earlier, that target availability for each station should be determined separately. We are of the view that the target availability should operate as an ideal which should be normally achievable.

5.5.8 We are conscious of the fact that there are some smaller units of thermal stations which were performing even below 80% and some of the hydro-stations also which are performing below 80%. It is necessary to pull these stations up to the proposed Target Availability. The draft notification had created a comfortable feeling over the last two years that recovery of fixed charges was possible at 70% which the generators must overcome. The power sector has not been exposed to regulatory experience so far. For this reason we consider it appropriate to allow a reasonable period. In the circumstances though we are convinced that the target availability should be 85% for full capacity charges recovery for thermal stations, the same shall come into force after one year from the date of first implementation of ABT i.e. Ist April, 2000 as prescribed herein. Till then, taking into account the sustained level achieved by thermal stations, it is appropriate to insist on a target availability of 80%. It is fair and proper to afford a reasonable opportunity to low performing stations to improve. It is felt that the time span of one year is adequate to enable all the thermal units to reach 85% availability. Lignite stations are dealt with separately in the next paragraph.

5.5.9 Experience of operating lignite based power plants in India is limited only to Neyveli Lignite Corporation. This fuel has a higher moisture content and in view of its spontaneous combustion, it is preferred to be used near the mine itself. Transportation of this fuel over long distances is, therefore, avoided. The lignite as obtained at Neyveli also contains marcasite, which leads to slagging on the furnace. This slagging formation sometimes leads to shut down of the boiler for its removal. This process is stated to be taking around 5 to 6 days which includes cooling time, manual breaking of the slag and its removal and bringing up the unit to its rated capacity. The quantum of marcasite also varies from seam to seam of lignite. An effective method for separating marcasite in a cost effective manner is yet to be found out by NLC. Another method of improving efficiency could be use of fluidised bed combustion. However, the present boilers are not of a type to enable this. The details furnished by NLC for their Stage-I and Stage-II projects has shown an availability factor ranging from 71.13 to 86.23 for Power Station-II, Stage-I (3x210 MW) and 72.54 to 86.74 for Power Station-II Stage-II (4x210 MW). The single part tariff agreed to between NLC and beneficiaries has provided for payment of full fixed charge beyond 6150 hours (70.21% PLF) per annum of operation, which charge is also found to be high. Taking into account the special features required to be provided for using lignite as fuel, we are of the opinion that conventional lignite fired power plants should have an availability of about 82% as compared to 85%, for conventional coal fired power plants. NLC should be able to maintain the target availability level of 82% with proper handling of lignite to get rid of its impurities which cause slagging.

5.5.10 While going through the existing arrangements for charging the tariff in respect of NLC we found that the tariff is a single part-one without distinctly separating the fixed charges and variable charges. This is the outcome of an agreement signed between the

NLC and the beneficiary States. In order to uniformly implement the ABT system in all stations, it is necessary to bifurcate and quantify the charges separately for capacity and energy. This exercise was carried out based on the present tariff with data available in the agreement in respect of total charges and energy charges. The difference between the total charges and the energy charges as per the agreement reflects the figure of fixed charges which could be quantified for the power station at 68.49% PLF by the Commission staff with the assistance of NLC. This has also been linked up with the data of fixed charges of Power Station as submitted by NLC in absolute figures. Based on this data, the Capacity Charges per annum and variable charges per kWh for Stage-I and Stage-II of NLC shall be reckoned accordingly.

5.5.11 As such, with effect from 1st April, 2000 the initial target availability shall be 80% in case of all thermal stations, 77% in case of lignite based stations and 85% in case of all hydro stations. After one year, i.e. from April 1, 2001, the target availability will be 85% for thermal stations and 82% for lignite based stations. The target availability for hydro stations for recovery of capacity charges was reduced in 1999 from 90% to 85%, and shall remain unchanged for the year 2000-2001. The target availability of hydro station for the further period would be announced by the Commission in due course. The Commission is hopeful that within this period, the generators will improve the performance of low performing units to reach the higher levels indicated earlier. The immediate target is also an ideal for at least some stations who are below this level. We are hopeful that in the background of actual performance of thermal stations it should be possible for these stations to reach the average target availability of 85% over this one year period.

The following is the summary of the targets now ordered:

<u>TARGET AVAILABILITY FOR VARIOUS TYPES OF PLANTS (IN Percentages)</u>

	THERMAL COAL/GAS	LIGNITE	HYDRO
1st April 2000 to 31.3.2001	80	77	85
1st April 2001 onwards	85	82	To be notified by the Commission

5.6:ISSUE 6:CAPACITY CHARGES AT LOWER LEVELS OF AVAILABILITY

5.6.1 Another incidental question, which has to be answered is with regard to the method of charging the capacity charges including ROE below the target availability levels. Presently, there are different practices for different companies. For instance, in case of NTPC at zero availability 50 % of the capacity charges and ROE on pro rata basis are payable. At levels from zero to 68.49 % balance capacity charges including ROE are payable. In case of NLC, as per agreement, charges are payable on pro rata basis from zero availability up to target level, which means that at zero availability there is no capacity charge payable. In case of NHPC, the same practice as in NLC is adopted excepting in the case of two stations where an agreed rate prevails. As regards NEEPCO the existing Tariff is a single part tariff for the energy delivered. As per the draft notification, a distinction is made between fixed charges and ROE. Full fixed charges are reimbursed at availability of 30 % and no fixed charges shall be payable at zero % availability. Between zero and 30 % pro rata fixed charges are payable taking 30 % as equal to 100 %. Above 30 % availability up to target availability (which is 70 % as per the notification), pro rata ROE depending upon the actual declaration of availability is payable. Many beneficiaries like KEB, AP TRANSCO, TNEB and DVC have stated that the availability of 30 % is very low for reimbursement of full capacity charges. Similarly, ASCI has stated that the availability factor of 70 % to recover full fixed charges is low. ASEB has suggested pro rata payment of capacity charges below stipulated availability level. In fact MPEB has suggested going back to the PLF basis for reimbursement of fixed charges as well. NLC has suggested that in an integrated power and mine complex, fixed charges should cover even the cost of mining operations.

5.6.2 As regards NLCs plea that the fixed charges of mining operations should also be considered, we have to state that mining operations do not fall within the regulatory jurisdiction of the Commission. In fact mining activities are being regulated by the Ministry of Coal. The Commission cannot step in to regulate this activity. Hence it would only be possible to admit a transfer price for lignite for the purpose of tariff of power. We have carefully considered all the other suggestions with regard to the levels for recovery of fixed charges and the ROE. There has been practically no objection to zero fixed charges recovery for zero availability excepting that NTPC protested on the ground that this might deny a facility which was available to them so far. We are convinced that the varying practices for charging capacity charges should end and there should be uniformity.

5.6.3 The payment of fixed charges at 0 through 30 % availability has become a contentious issue. Generating companies desired that this proposal should continue on the ground that they will be deprived of capacity charges in any such contingency, though none of them could submit facts and figures to show that any of their units were operating at these levels at any time. The data on operations so far submitted do not indicate anything to this effect. Even Nuclear Power Corporation, who raised the issue, could not provide any data indicating that their units were in this situation at any point of time. In the circumstances, it is our conclusion that it is only a safety net which some of the generators would like to keep in a contingency. The decision regarding capacity charges at the two ends viz., zero level and at target level appears to be inevitable viz., that it shall be zero and 100 % respectively. The question remains as to what happens in the in-between stages. The draft notification contemplates denial of ROE up to 30 % availability and pro rata ROE from 30 % till the target level of availability. We do not find any reason why the generator should be denied a return when he has made an investment. The return on equity should be seen as part of the capacity charges as it has been done all along and also as considered by the ECC. This has been made specifically clear in para 5.2.2 of the Report while recounting the fixed cost – one of the elements included therein is `allowable return on equity'. This has also been the concept under the earlier KP Rao formula. The ECC report also contemplates a pro rata payment of fixed cost by dividing the same by the total megawatts available i.e. a pro rata payment in relation to the level of availability. We therefore, do not find any merit in deviating from the past practice of allowing fixed charges including therein the return on a pro rata basis uniformly for all levels between zero and target level of availability.

The claim of NTPC that it was provided the facility of 50 % fixed cost on zero availability and hence that should continue, cannot be sustained. It is their contention that in the draft notification, an alternate arrangement was provided in the form of a specific provision for prolonged outage. It has also been found from data submitted that there were no such prolonged outages in the past adversely affecting the availability of a station. In multi unit stations, which is the general feature, the station availability could still be maintained by operating other units. Any prolonged outage is clearly an abnormal event. As a rule impacts of abnormal events can not be built into the normal cost and tariff, as a matter of pricing principle. Otherwise, for example, the entire consequences of a cyclone may have to be borne by the consumers.

In the circumstances, we are not inclined to either consider payment of 50% fixed charges at zero availability or to make provision in the tariff for prolonged outages. Thus, the full capacity charges including returns that may be due, will become payable at the target availability level, while at lower levels the capacity charge recovery, shall be pro rata. At zero availability, no capacity charges shall be payable.

5.7 ISSUE 7:TREATMENT OF UNALLOCATED SHARE

5.7.1 Another vexed question which has implications on sharing of capacity charges and which remains to be answered is the issue relating to allocation of central share to various parties or to any particular beneficiary state. In this connection, the draft notification specifies that the total capacity share for any beneficiary would be its capacity share plus allocation out of the unallocated portion. In the absence of specific distribution of unallocated power, the same shall be added to the allocated shares in the same proportion as the allocated shares. It is further contemplated that the beneficiaries may propose selling part of their allocated share to other states within/outside the region. The beneficiaries may propose surrendering their shares or generating companies may enter into agreements with other states. In such cases, depending upon the technical feasibility of power transfer and specific agreements entered into by the generating company with other states within/outside the region for such transfers, the shares of beneficiaries may be reallocated for a specific period. When such reallocations are done the capacity charges may be payable on the reallocated basis. The beneficiary states will also have freedom for negotiating any transaction for utilisation of their shares in which case though the liability for the beneficiary states will not change, they may get an opportunity to trade. Such bi-lateral arrangements can be facilitated also by the RLDC informing the beneficiaries about unutilised capacities.

5.7.2 The draft notification while providing flexibility for shifting the burden of the capacity charges also fastens the liability for capacity charges to the beneficiary states, who have the allocation. With the expansion now taking place in the power sector, the liability for these capacity charges is being resisted by the beneficiary states. It was also stated by some beneficiaries that allocation of 15 % is being done out of the installed capacity without taking the available capacity into account. It was suggested by some of the beneficiary states that unallocated share should be allowed to be traded either through the RLDC or through the PTC. The Commission, however, has to keep in view the historical fact that central thermal generating stations were established mostly at pit heads to facilitate catering to the states in each region. It cannot at present ignore the specific commitments entered into between the CGS and the states constituting each region. However, the possibility of entrusting the unallocated share to the Power Trading Corporation thereby reducing the burden on the states as suggested by some of the beneficiaries could be considered by the Government, with a clear guideline that if the allocation is not made the same could be traded. In fact from the rejoinder filed by Union of India, it appears that the Government is even willing to review the philosophy of capacity allocation. In the view of the Commission the concept of capacity allocation will have to ultimately go as

- more capacities are added in all the regions
- the national grid facilitating inter regional flow is evolved
- the Power Trading Corporation starts playing an active role

This may take some more time. In the meanwhile, the facility of trading the allocated power would provide some flexibility subject to transmission facilities being available. **Taking these factors into account the Commission considers the arrangement of fixed charges recovery in respect of unallocated power to be satisfactory and workable as obtaining today.**

5.7.3 From the replies submitted on this subject by GRIDCO, DVC and TNEB, it transpires that the beneficiary states would not like to bear the capacity charges relating to the unallocated share. It is contended that this cannot be charged to them without their prior consent or request. The objection from the beneficiaries is that even though trading for the capacity entitlement is contemplated, the timing of the decision of the Government of India makes all the difference as the opportunity for trading would be lost if the decision is delayed. **We find considerable weight in the argument and as such we recommend that the Government may decide at least a month in advance with regard to the allocation of the unallocated share based on availability so that trading of such capacity is facilitated and the burden on the SEBs is reduced. Any decision on the allocation to the existing beneficiaries so long as it is taken in advance should be acceptable to them.** It is open to them thereafter to trade such capacity either within or outside the region. The Government may consider issuing a notification to the effect that if no allocation of unallocated power is done by the end of the previous month the same may be taken as available for trading. Thereafter, the generator should be free to trade that power subject to frequency constraints, in case the Government does not choose to entrust the unallocated share to Power Trading Corporation as already suggested.

5.7.3 While on the subject of trading, the Commission anticipates an emerging situation of a surplus on account of the gap between the availability and scheduled generation. This power could go unutilised as the capacity for this generation is blocked because the capacity charges are borne by the beneficiary' states. In order to economise operations, it would be appropriate to make use of this power on firm or non-firm basis with a suitable understanding between the beneficiary states and the generator. It is therefore suggested that the generating company may initiate a dialogue with the beneficiary states for making use of this power for which the terms could be negotiated by themselves. Though, strictly speaking, this tariff also falls within the jurisdiction of the Commission, due to the short term nature of this transaction the **tariff could be freed to be negotiated for which a general exemption could be taken from the Commission. This would provide substantial additional revenue to the generator if he goes about aggressively marketing this surplus power.**

5.8:ISSUE 8:GAMING POSSIBILITIES

5.8.1 With declared availability as the key factor for reimbursement of fixed charges and rate of return, the obvious question is about the over declaration of available capacity. There is also the possibility of under declaration which may facilitate earning undeserved UI charges. In either case, this would amount to deliberate `gaming', which must be curbed. This means the availability as declared should be subject to verification for its veracity. This aspect has been dealt with by the ECC in para 5.2.7of their report where it is said `monitoring and enforcement of generation availability may be accomplished through auditing plant records and conducting unannounced tests. If a unit fails to reach the level of availability which was declared by the plant operator, the capacity charges should be reduced to cover the actual availability for that day. The capacity charges should then stay reduced until a higher availability can be demonstrated. If a unit fails in an availability test, severe penalty should be imposed, possibly retro-active for some period.'

5.8.2 The draft notification has dealt with this situation in para 7 under the head `Demonstration of Declared Capacity.' This clause contemplates that a generator may be required to demonstrate the declared capability when asked to by the Member Secretary, REB of the region. In case of failure to demonstrate, the capacity charges due to the generator shall be reduced as a measure of penalty. Similarly, if the declaration is observed to be on the lower side and the actual generation is more than the declared capacity then the UI charges due to the generator shall be credited to the UI account of beneficiaries in the ratio of their share in the capacity.

5.8.3 Apprehensions were expressed regarding this clause by various beneficiaries. UPSEB has stated that the beneficiary should have a right to demand demonstration of declared capacity and also suggested periodical and surprise checks for declared capability. Similar view was expressed by WBSEB. DVC along with WBSEB suggested that in case of misdeclaration, capacity charges may be reduced for the preceding 30 days or from the date the availability was last demonstrated. TNEB suggested a penalty of twice the capacity charge for misdeclaration apart from reserving the right to demand demonstration by any beneficiary. GRIDCO has stated that the procedure for testing and the quantum of penalty may be fixed once for all and should not be revised from time to time. Similar view has been expressed by generators like NLC and NHPC. Views have been expressed by NTPC and NHPC to provide for factors beyond the control of the generator in demonstrating the declared capacity.

5.8.4 The need for demonstration and imposition of penalties has been accepted by all concerned in principle. We have also looked at the relevant clauses of PPAs concluded with IPPs recently to see if there are any lessons from them. The important issues on which we are required to rule relate to -

(a) Who can call for demonstration?
(b) Procedure for testing declared capacity;
(c) Exceptions if any for non-demonstration; and
(d) Consequences of non-demonstration.

5.8.5 The plea of some of the beneficiaries for their individually and directly demanding demonstration is in our view, unworkable. However, any beneficiary can, through the RLDC, call for demonstration in which case the RLDC shall immediately on such request, plan load generation balance and after organising consequential arrangements, call upon the generator to demonstrate. It should be ensured that demonstration is done within the shortest period commensurate with the ramping requirements of the machine. RLDC may also reject repeated demands for such demonstrations, if in its opinion, repetition is not necessary and that it would only disturb normal grid operations.

5.8.6 Regarding the procedure for testing declared capacity, the same has to be operated through the RLDC. We understand that it should be possible to issue instructions for demonstration from the control room of RLDC within a short time. In addition, RLDCs shall prepare a standing procedure including a schedule for conducting tests in consultation with the REB concerned. This shall be coordinated by the CTU. The schedule of tests shall be such that stations, which have a potential for gaming will get tested at a periodicity to be determined by RLDC on a random basis. RLDC shall maintain a record of all the tests carried out from time to time with full particulars. In drawing up the schedule, RLDC shall ensure that transmission net work and other technical parameters are conducive for conducting the test. Any corrective parameters in arriving at a final result of the test shall also be included in the standing procedure.

5.8.7 The plea of some of the generators regarding allowance for factors not under the control of the generator has also been considered by us. This, of course,

depends upon the circumstances of each case. The CTU, a statutory body, as the supervisor and Controller of ISTS, can arrive at a final decision in this matter after the RLDC reports the findings of the test. If any party is aggrieved by the decision of the CTU, an appeal can be made to the Commission within 30 days. An additional responsibility on RLDC is to keep a close watch on any frequent revision of availability, which can be an act of gaming. Such instances shall also be brought to the knowledge of CTU forthwith.

5.8.8 The cost of testing shall be normally recoverable by RLDC as part of RLDC charges from all beneficiaries. When mis-declaration is established, the full cost of the test will be borne by the generator. CTU shall submit to the Commission within two months of this Order the standing procedure including for determination of testing costs.

5.8.9 We are in agreement that there should be deterrent penalties for non-demonstration of capacity. In fact, ECC has recommended retro active penalties. This has also been suggested by DVC and WBSEB. The Union of India in its rejoinder, has concurred with the views of beneficiaries on the procedure, demonstration and the need for penalty. Keeping in view the financial implication of misdeclaration and as a deterrent for wrong declarations commensurate penalties have to be imposed. We are also of the view that the severity of the penalty should be increased for subsequent wrong declarations. The penalty has to have a relationship with the fixed charges for a day. In case of misdeclaration the fixed charges have to be sacrificed. As a measure of penalty, as suggested by TNEB, for misdeclaration for any number of blocks in a day, two days' fixed charges shall be denied to the generator. This can constitute the basic penalty for misdeclaration. If this is repeated for the second time, the penalty shall be double the basic penalty and shall be multiplied in the same geometrical progression for subsequent mis-declarations. As regards under declaration, the penalty and the procedure for sharing the penalty as suggested in the draft notification shall be implemented. In all these situations of mis-declaration the generator shall continue the operations as usual and shall not stop operation.

5.8.10 It is also necessary to fix responsibility on specific individuals for wrong declarations. For this purpose as in the case of `occupier' under the Factories Act, the `Officer in Charge' for declaration of capacity has to be identified and informed in writing in advance to the RLDC which shall incorporate the details in the records maintained by them. In case of consistent misdeclaration beyond five times in a year, apart from the penalties contemplated as above, action for non-compliance under section 45 of ERC Act could be contemplated. A suitable clause in the relevant portion on standing procedures shall be inserted to this effect by the CTU.

5.9 ISSUE 9 : UNSCHEDULED INTERCHANGES

5.9.1 The ECC Study team has elaborately dealt with the need for UI charges in order to stabilise the frequency in the regional grids and to minimise extreme deviations in the frequency. A special task force constituted by the study team has observed that "while inadvertent UI could be accepted and tolerated as a necessary feature of pooled operation, the deliberate UI should be discouraged. Therefore, there appears to be a need to apply a mandatory pricing scheme to scheduled inter changes in India". (Para 4.6.2). The study team has stated that it is unaware of experience with pricing UI in the Western countries. The study team believed that a comprehensive UI tariff which is based on both deviations from schedules and deviations from frequency is required to improve the Indian grid discipline and quality of supply. Accordingly, the study team recommended that tariff for unscheduled inter change should be based on the principles of the grid control-linked UI Tariff with addition of a frequency sensitive component.

5.9.2 The consensus of the task force constituted by the ECC study team was that the price of UI during power shortage conditions should be high enough to provide an economic signal to those pool members who are causing the problem. Other members of the pool who may be deprived of power should be suitably compensated for any financial losses. This commercial mechanism should be reinforced by the enforcement of the provisions contained in the grid code, violation of which, will lead to penal consequences. It has been observed that in India though the declared frequency is 50 Hz, there are instances of wide variations in the frequency in different regions with frequency going down as low as 48 Hz as well as going up as high as 53 Hz which are not in the interest of any participant in the pool, the permissible variation being $\pm$ 3% which means 48.50 Hz to 51.50 Hz. This variation is within the provisions of Indian Electricity Rules, 1956. However, in order to ensure integrated grid operation of all the 5 Regional Grids, it is essential that the frequency hovers around 50 Hz. This, in due course could lead to an All India grid facilitating transfer of bulk power between the states and the regions. This would in turn lead to a balanced power supply position in the entire country and to an integrated national grid.

5.9.3 The draft notification contemplates planning the generation and drawal through a process of scheduling. After considering the declaration by generators of their availability and requisitions from the beneficiaries, RLDC is required to prepare the generation and drawal schedules in advance after taking into account the transmission losses. This schedule is to be finalised each day for the following day starting from 00 hours separately for 96 time blocks of 15 minutes each. It is expected that the schedule of generation and drawal shall be observed by the respective parties with flexibility granted to modify the schedules with advance notice and with exemption in appropriate cases like grid disturbance, transmission constraint, grid safety etc. Any variation of the actual generation or drawal from the schedule shall be liable to a special UI charge payable/receivable by parties concerned. This charge is reckoned with reference to the frequency of the grid at which the deviation takes place. It is possible that a deviation sometimes is favourable or unfavourable to grid operation. Depending upon whether a utility is helping or adversely affecting the grid, UI charges will be receivable or payable. A proper metering arrangement needs to be provided so that deviation in each time block is clearly reflected and shall be billed accordingly.

5.9.4 Even though in the National Task Force, all parties have agreed in principle to the system of UI charges, apprehensions of generators were expressed before us both by generators and beneficiaries on this system. The apprehensions of the generators are on the following lines:

(i) NTPC has suggested a specified ramp rate to be considered for special changes in generation schedule during various time blocks. It has also suggested that to achieve the objective of economy and efficiency, in the utilisation of resources, regional merit order for all generators in the grid has to be ensured. This of course has been already dealt with by NTF decisively. It further suggested that revision of schedules in case of forced outages should be allowed without any provision for communication time gap.

(ii) NLC has suggested that revision of schedule should be allowed and accepted even if not communicated to RLDC due to inability, but if passed on through SEB, it should be accepted. There was also a suggestion that exemption from the discipline of schedule which is permissible on grid disturbance should be available on certification by REB. NLC has further suggested that the time gap for revision by generators or beneficiaries should be reduced from six time blocks to four time blocks. It is also stated that RLDC should not revise the schedule without consultation.

A number of objections were also received from beneficiaries which are summarised below:

(i) The time block of 15 minutes should be revised to one hour (MPEB) and three hours (UPSEB).
(ii) Operating procedure for generation schedule should be as per the decision of REB (WBSEB).
(iii) Technical limitations contemplated in the UI Scheme to be decided by REB (WBSEB).
(iv) Any revision in the event of forced outage of the unit should not be allowed and the generating company should compensate SEBs for commitment already made (TNEB).
(v) In the event of transmission constraints, UI charges should be paid by the transmission utility to the generator (TNEB, WBSEB).
(vi) Time for normalisation of grid following grid disturbances should be 15 minutes (TNEB) and grid disturbance should be defined (WBSEB); in the event of grid disturbance, availability should also be revised (UPSEB).
(vii) Revised schedules should become effective only after successful communication from RLDC (NTPC, NPC, DVC, Gridco and WBSEB).

(viii) Any defaulter generator, whose failure calls for post facto revision should pay for UI charges (WBSEB).

5.9.5 Another major objection is that payments have to be made for scheduled energy, apart from paying UI charges, though actual energy drawn may be less. This in our opinion is a baseless apprehension. If there is self discipline and advance planning, such a fear of huge payment on account of scheduled drawal is unfounded. Adequate opportunity is available for revising schedule within 1 1/2 hours notice; the daily planning should also be done with more foresight. This system of discipline should settle down over a period of time. It should also be noted that in case of high frequency the beneficiary can get free power. Thus the scheme is evenly balanced. We have carefully considered all the above objections. These are being dealt with hereunder.

5.9.6 The provisions regarding scheduling as contained in para 4 of the draft Notification contemplate three situations for revision of schedules –

(i) A forced outage of a unit of the generator in which case revision of schedule will be allowed effective from the 4^{th} time block from the time of advice of outage.

(ii) Request for revision of declared capability by generator and revision of drawal schedule by beneficiaries in which case the revisions will be effective from the 6^{th} time block from the request for revision.

(iii) Revision due to factors other than those attributable to the generators or beneficiaries viz.

(a) Bottlenecks in evacuation of power due to constraints or limitations etc., in the transmission system in which case RLDC will revise the schedule to be effective from the 4^{th} time block in which the bottleneck occurs. In this case for the earlier three time blocks also the schedules will be deemed to have been revised to actuals. Bottleneck shall have to be certified by RLDC.

(b) In case of any grid disturbance the schedule of generation and drawals shall be deemed to have been revised for all the time blocks affected by grid disturbance. Certification of grid disturbance and its duration shall be done by RLDC.

(c) If at any point of time RLDC observes need for revision of schedule for better system operation, it may do so and it shall be effective from the 4^{th} time block.

It can be seen from the above that in case of situation (iii) above, the factors are beyond the control of generator or beneficiary and as such responsibility is cast upon RLDC to certify. However, RLDC shall adopt certain norms for the certification/revision which we shall deal with later. In these three cases, it should be noted that though the schedules are revised, the declared capability is not revised, thereby preserving it as regards capacity charges as these are beyond the control of generators.

In case of forced outage of a unit at the request of the generator the declared capability also gets revised and the recovery of capacity charges also are accordingly revised.

In the second case, any revision of declared capability not only affects the schedule of generation but also impairs the recovery of capacity charges.

It can be seen from the above that wherever a generator revises the schedule on his own, his declared capability also gets affected, resulting in impairment of recovery of capacity charges. For reasons beyond control of the generator, if revision takes place, it is unfair to deny the declared capability to him. As such, the claims of some of the beneficiaries for revision in this regard are unfair. The time limits for communication for revision in the different situations is also fair keeping in view the circumstances for revision including any revision on account of emergency reasons and the same is applicable irrespective of communication success. In fact it should be possible with more familiarisation of the system to reduce the time gap for corrective action. **This appears to be the international experience. Any unforeseen difficulties in the operation of the system have to be sorted out as and when such situations may arise, but the**

proposition otherwise appears to be fair to all parties concerned. Further, the detailed scheduling as per the Grid Code shall be adopted in operating the UI system.

5.9.7 Para 2(iii) of the Draft Notification deals with the rates for UI charges based on the average frequency of each time block. The proposed rates at the two ends viz., 50.5 Hz and above on the one hand and at 49 Hz on the other have been stated as .0 paise/kWh and 360 paise/kWh respectively. Between 50.5 Hz and 49.00 Hz adjustment of 4.8 paise/kWh for each 0.02 Hz change is proposed. It is noted from the documents given to us that the rate was initially pegged at Rs.6/kWh at 48 Hz which was subsequently revised in the draft sent by CEA to MOP as Rs.4.5/ kWh based on the 9th NTF meeting. This however, was reduced to Rs.3.6 in the draft notification. The basis for arriving at the UI rate was however, not found in the documents. Since UI rate is proposed for over drawals/under generation during low frequency period and under drawal/over generation during high frequency period, the rate has to be linked to the costliest form of generation which is usually diesel generation. The draft notification has also envisaged that UI rates should be separately notified from time to time which means that any revision in diesel prices could be incorporated and UI charges revised accordingly.

We however, do not consider it necessary to provide a special ramp rate as claimed by NTPC since the time schedules provide for sufficient flexibility for the purpose.

Subsequent to the notification, there has been an increase of about 33 % in the diesel prices. Consequently a revision in the UI charges is warranted. The original proposal of 360 paise/kWh has been considered as the total cost of generation of power through diesel which incorporates in itself on our reckoning two elements viz., capacity charge of Rs.1.60/kWh and variable charge of Rs.2/kWh. **Applying the recent revision of diesel price, the variable charge goes up to Rs.2.67 per kwh resulting in a total value of Rs.4.27/ kWh, which may be rounded off to Rs.4.20/kWh at 49.00 Hz. As such the charges are approved. The Commission may review the charges as well as the corresponding frequency levels as and when necessary.**

5.9.8 Another point for consideration is whether charges for over drawal should be the same at 49 Hz and even below 49 Hz. It should be noted that the declared frequency in India is 50 Hz. An integrated power system should operate with a grid frequency hovering around 50 Hz. In practice however, the frequency range in India has been 48.5 Hz to 50.00

Hz. This is not desirable for achieving interconnected/integrated operation of the grid. With the additions to generation capacities it is hoped that there may not be a drop below 49 Hz. Further the disincentive at 49.00 Hz is in itself a deterrent; and there is no need to make any provision for still lower levels of frequency at higher rates. **In the circumstances, we consider that the charges as proposed in the draft notification subject to the revision on account of diesel prices is considered appropriate. We are hopeful that with more self discipline contemplated by the scheme, frequency would be kept within permissible range. In fact the attempt should be to further narrow down the range with more generating capacities coming up and redundancy created.**

5.9.9 We also considered the possibility of prescribing separate frequency limits for different regions. This may involve deviating from statutory frequency limits. This would also involve discriminating between regions. By maintaining the uniform frequency range, capacity additions could be expedited and demand side management would be given more importance. Besides, inter regional flow could be facilitated. **Hence we are not inclined to prescribe differential frequency limits.**

5.9.10 The operation of the UI mechanism is proposed to remain suspended during the period of transmission bottleneck, grid disturbance etc., till the revised schedule becomes operative. Apart from this, certain exemptions have been contemplated under para 5 of the Notification. A special dispensation has been given for gas turbine/combined cycle stations and for nuclear stations to provide correction in the schedule generation by a certain percentage where the frequency is below 49.02 Hz. This special dispensation appears to have been considered based on the special nature of their operations. Against this exemption, NPC has sought a total revision of scheduled generation so as to be equal to actual generation even if the frequency variation is more than 2 %. **The reason given by NPC viz "to protect NPC from the liability of payment of UI" is not convincing and as such no further exemption is warranted.**

The Notification under para 5(b) also contemplates exemption from UI for hydro stations. We do not find any justification for this exemption or denial of UI to hydro stations. **As such, the special exemption from UI for hydro stations needs to be deleted. It is the Commission's considered view that all the generators should conform to the UI discipline unless exceptional circumstances warrant special treatment for which a case could be made before the Commission separately.**

5.9.11 Some reservations have been expressed by beneficiaries on upsetting of schedules on the plea of grid disturbance which has not been precisely defined. This will have its implications on capacity charges and incentives. Sometimes, instances of grid disturbance may be internal to the beneficiary which cannot be the reason for suspending the UI. A reference to grid disturbance should be attributable to the disturbance of the regional grid. Even here some of the instances which have come to the notice of the Commission are :

(a) when the regional grid splits into two big islands;
(b) when generation at central generating stations gets affected due to tripping of a number of transmission lines without substantially affecting integration of the grid;
(c) Isolation of small parts from the grid or events within the control of beneficiaries affecting only the drawal pattern of the beneficiaries.

There may be several instances of grid disturbances. Similarly transmission bottleneck is also a very wide area wherein it is possible to fix responsibilities on the party concerned at fault. All this casts a great responsibility on RLDC while doing the certification. Certification therefore should not be granted in case RLDC considers that the situation has arisen out of any party's fault. **The same should be reported to the CTU so that the latter can deal with the same appropriately. This should take care of any gaming possibilities at the beneficiaries' end with the objective of earning undue UI charges. RLDC shall be vigilant against such practices. In case any matter needs to be settled before the Commission, subject to CBR, it shall be the responsibility of CTU to bring it up with notice to the other side. It is also necessary for the CTU to announce in due course a detailed procedure to be followed for suspension of UI scheme on account of any grid disturbance or bottlenecks in transmission. This procedure shall also cover recovery from grid disturbance in line with the grid code. As and when the recovery takes place, RLDC shall notify all the constituents as well as outside the region, sufficiently in advance (at least 4 time blocks in advance) in order to resume the UI. The role of REB was questioned by some parties. Since the questions are not in conformity with the legal provisions, they cannot be accepted. Regarding the claim for payment of UI charges by transmission utility, specific instances of dereliction on the part of transmission utilities can always be brought up. The default on the part of**

a generator resulting in revision of schedule would have its own consequences on the generator.

5.9.12 We have also considered the views of some of the beneficiaries to change the time block of 15 minutes. We are convinced that a short time block of 15 minutes can be expected to ensure alertness on the part of the dispatcher to take quick corrective action for maintaining desirable system parameters. If the interval is larger, there may be a tendency to defer the action with possibilities of steep frequency excursions thereby inviting damages to the system.

5.9.13 We draw the attention of the CTU the following responsibilities viz.:

(1) to ensure proper recording of two way communication regarding revision of schedule;

(2) to minimise the time taken by RLDC for revision of schedule so that the impact of UI charges could be kept to the minimum;

(3) to formulate a procedure for meeting contingencies both in the long run and in the short run (daily scheduling);

(4) to announce the procedures for temporary suspension and resumption of UI scheme.

The Commission directs CTU to devise procedures in the above **regard and inform all concerned within two months of this Order.**

5.10:ISSUE 10 : BILLING, PAYMENT AND OPERATION OF POOL ACCOUNTS

5.10.1 Para 9 of the draft notification deals with billing and payment of capacity charges. This is proposed to be done on a monthly basis whereby each beneficiary shall pay capacity charges in proportion to the allocation. This para also deals with the unalllocated portion, which we have covered already. It also deals with the method of charging and recovering on a cumulative basis the capacity charges, though basically it is a monthly charge. The recovery from the beneficiaries is proposed on a monthly basis taking into account the weighted average percentage of allocated share of the beneficiary on a cumulative basis. The year is taken to be the financial year so that no carry forward is taken to the next year. This proposal appears to be fair and acceptable to all.

5.10.2 Certain suggestions have been received during the proceedings on the subject, which are summarised below:

i) Monthly capacity charges for hydro stations should be recovered proportionately to the design energy of that particular month (NHPC)
ii) In determining the saleable energy for hydro power, the free power to home state should be borne by that state (TNEB); should be borne by the generating company (DVC).
iii) Either specific allocation of unallocated power should be withdrawn or the party getting the allocation should pay capacity charges (TNEB, DVC, & Gridco)
iv) Reallocation of shares should be with the consent of generating company (NLC).
v) Surrendering of shares may be permitted only on long term basis (NTPC).

We have considered these objections. As regards capacity charges for hydro stations, we consider that the present arrangement should be continued in the interest of simplicity of the system of charging. Regarding free hydro power to the home state the existing arrangements based on agreement can not be wished away and the free element becomes part of the cost to be taken into account for tariff. Regarding unallocated power, the arrangement proposed in the draft notification is satisfactory. As regards the surrendering of shares we are in aggrement with the suggestion of NTPC. However, this matter relates to the government for its decision for reallocation of shares. We have already covered these issues, regarding unallocated shares in this order.

As regards energy charges, the same shall be billed directly by the generator based on the scheduled energy drawal for which the necessary information shall be provided by the RLDC to REB for accounting purposes.

5.10.3 The third element viz. the UI charge, is proposed to be settled through a regional pool account to be operated by the Member Secretary of REB. Detailed procedure in this regard was proposed to be laid down by the Central Electricity Authority from time to time. From the correspondence on files, it is found that CEA has proposed a broad outline of procedure for operation of the regional pool account by which:

a) the billing for UI payable shall be done by REB to various parties;
b) the parties shall pay the UI charges within 15 days of billing;
c) any delay in payment shall attract interest @ 2% per month;
d) Any money received on account of UI to be distributed to the claimants pro-rata to their claim; and
e) Any undue delay in payment will attract the extreme step of regulating the supply.

5.10.4 The above proposed system of operation of pool account does not appear to be satisfactory. The UI charge is not in the nature of penalty but is part of the tariff as contemplated in the notification. As tariff, it constitutes the income/expenditure of the utilities concerned. As such it will have to be included in the revenue accounts of the utilities in pursuance of the accrual system of accounting which is a statutory requirement and can not be kept unaccounted outside its books. With the possibility of all the utilities ultimately becoming corporate bodies, this is a necessary accounting requirement. Any outstanding UI charges at the end of each year has to be reflected in the balance sheet of the utilities concerned as asset or liability, as the case may be.

The pool mechanism was contemplated perhaps on account of the difficulty in relating the receipt and payment on one to one basis, between the receiver and the giver of the UI. Though the solution suggested appears to be simplistic it goes against the principles of accrual accounting particularly when it is recognised as part of the tariff to be received or paid. Further a one-to-one identification cannot be totally avoided. As more and more utilities join the pool, the accounting task would be stupendous. On a sample basis the UI calculated for Eastern Region for a typical day in March, 1999 worked out to Rs.99.44 lakhs. Thus the amount involved is substantial, unlike a penalty element alone which may be small.

Any party, who is to receive a tariff has to raise a bill for the tariff. If the bill for UI is raised by the REB the question is whether it would constitute the income of REB? Similarly do any outstanding charges have to be shown as the assets of REB? This however, is not the correct position. REB is only carrying out the function of a clearing house. In that case it would not appear as asset or liability of anyone. REB should not take up the financial responsibility for managing the funds of the utilities unless it is specifically agreed to by all parties concerned. In this connection, NTPC has suggested that since it would be the net receiver of UI it may be adjusted in the energy bills of NTPC instead of merging the same in the pool account. Thus the proposed arrangement does not have the concurrence of NTPC.

By resorting to the system of pool account, the task of identifying the UI charges on a one-to-one basis is only postponed but not finally resolved. **Under the proposed arrangement any portion of UI as and when received is to be distributed pro rata to the outstanding of all parties. Alternatively from the records, it should be possible to link up over drawals and under drawals on a regular basis. This can be adjusted on every 48 hour basis from Control Room Readings. In this way a composite scheme can be evolved by which at the end of the month the balance portion for distribution of the UI could be finalised by the REB. The arrangement has to be organised by the RLDC in consultation with REB. The net UI charges after these regular adjustments should be distributed, billed and paid at the end of each month. This accounting system should be worked out by CTU in consultation with all the beneficiaries and could be put in position in the next three months time so that when the ABT is implemented the method of distribution is also finalised. Based on the distribution of UI at the end of each month as advised by REB bills can be raised by the utilities including the generators against each party so that any outstanding can be pursued by the respective parties as a commercial debt rather than left to the REB to sort out. The utility concerned can also initiate steps for recovering the dues as considered appropriate. This would also enable reflection of a true and fair view of the income/expenditure and assets and liabilities of the various utilities. This will also enable the generators to justify their sales based on bills duly raised. This system may also obviate any difficulty on account of sales tax or other levies which may be payable on tariffs of generating companies. The setting out of a fool proof system was assigned by us to the CTU in the Grid Code order. Accordingly, the CTU should in consultation with all concerned lay down the procedure for distributing the UI charges.**

5.11:ISSUE 11 :
METERING ARRANGEMENTS AND PROGRAMME OF IMPLEMENTATION

5.11.1 A number of parties who deposed before us have stated that the ABT should be enforced only after proper metering, telemetering and associated hardware and software is commissioned. It is stated by MPEB that, in the western region, the ABT cannot be implemented unless the special energy meters are installed. It is also suggested that after the installation of the meters there should be some time allowed to conduct mock exercises. It is also felt in some quarters that the joint meter reading would be a mammoth exercise which goes against the practicability of implementing ABT with 15 minute interval for UI charges. We however understand that the metering system does not involve elaborate manual reading.

5.11.2 We understand that the metering arrangements are primarily confined to the special energy meters which measure both energy flows and frequency over 15 minute time block to enable working of the UI charge. It is understood from Powergrid that these meters have been procured and installed in consultation with all concerned. According to the Union of India, meters are already in place in the Southern Region, Eastern Region and North-Eastern Region. Meters in Northern and Western Regions are yet to be installed. According to the Union of India in its rejoinder, mock exercises may not serve much purpose. "However, it would be necessary to ensure that all the meters are in place and the procedure for collection, reading, decoding of data and software for accuracy are made operational. Trial run for these should take place to trouble-shoot these procedures before actual implementation".

During the hearing NLC has expressed certain apprehensions about the metering arrangements. However, it will not be possible for the Commission to check the adequacy and reliability of the metering arrangements. This will be the responsibility of the CTU.

5.11.3 On a consideration of the above facts and submissions we find that the Southern and Eastern Region are in readiness for implementation of the ABT. PGCIL has clarified that the meters for Northern Region are already ordered and the specifications for the meters for the Western Region are in the process of finalisation. As regards North-Eastern Region, though the meters are stated to be in position, according to the ASEB, it is not possible to implement ABT due to the presence of certain agreement for single part tariff. Keeping all the above we consider that the CTU/Powergrid should take on hand the complete responsibility of installation, testing and trial run of the metering arrangements. As regards North-Eastern Region it may not be possible in view of the special situation to implement the ABT in the present form. However, it is not clear as to how exactly the region would like to proceed in this matter. **Therefore, it is appropriate that NEEPCO should come forward with a petition, with all concerned parties as respondents, on the programme for implementation of ABT. This shall be done within a month from the date of receipt of a copy of this Order.**

5.11.4 In view of the special request of Powergrid/CTU to stagger the implementation of ABT so that they will be able to make satisfactory arrangements before implementation, the following schedule for implementation of ABT shall be followed:-

Southern Region	**-**	**1-4-2000**
Eastern Region	**-**	**1-6-2000**
Northern Region	**-**	**1-8-2000**
Western Region	**-**	**1-10-2000**

We understand from Powergrid/CTU that this schedule is practicable.

As already, stated as an interim arrangement after 1st April,2000 till the introduction of ABT the PLF excluding deemed generation for calculation of incentives shall be 80 % instead of the present PLF of 68.49% including deemed generation in East, North and Western Regions for thermal stations, 77% for lignite and 85% for hydro stations.

5.12:Issue 12:APPLICABILITY OF ABT TO HYDRO STATIONS

5.12.1 None of the utilities represented before us have contested the applicability of the ABT to the Hydro sector. However, questions have been raised regarding the manner of application to Hydro Stations taking into account the special features of hydro operations as compared to other systems of generation. For instance, ASEB has stated that there is duplication of elements considered for energy charge and capacity charges. DVC has stated that hydro units should also pay UI charges if actual generation is less than schedule generation in case of frequency below 49.5 Hz, though the draft Notification exempts them from UI charges. ASEB has objected to the payments for deemed scheduled generation on account of spillage of water. RSEB has suggested a review of the formula for determining availability by eschewing any capacity not available for peaking.

5.12.2 A number of suggestions have been received with regard to the valuation of secondary energy. NHPC has questioned the capping of secondary energy charges at 72 paise per kWh which, it stated, is against the hydro policy of the Government of India. UPSEB has questioned the valuation of secondary energy. RSEB has suggested that the secondary energy rates for hydro stations should be less than the lowest variable cost on thermal power stations and proposed a rate of 15 to 20 paise per kWh. DVC has suggested that the energy charges for hydro stations should be limited to 30 paise per kWh which is equal to the UI rate at 50.2 Hz as per the UI scheme suggested by it. NHPC has also suggested modifications in the reckoning of sent out capacity for hydro stations for working out the availability. According to it though total actual generation may be limited to Design Energy, any loss of generation due to reasons not attributable to the generator should also be included for determining availability.

5.12.3 We have gathered from the minutes of the National Task Force that till their last meeting they could not come to any definite conclusions on the treatment to be given to hydro stations in the ABT system. AT the instance of NTF, CEA constituted a committee on "Time of day metering and peak load Pricing", which was later reconstituted as `Committee on Hydro Tariff'. The Committee finalised its report but the same could not be taken up by the NTF. This committee had considered the recommendations of ECC in regard to tariff for hydro stations, apart from the proposals of NHPC. The following are the major recommendations of this committee, which we consider as relevant for our purposes:

(i) The hybrid tariff structure comprising of capacity charges and energy charges should be continued, however, the method of bifurcating energy charges shall be on notional variable cost of thermal station.

(ii) The following two alternative computations for bifurcating energy charges were recommended:

a) Rate for primary energy for all hydro stations except for pumped storage stations to be taken as 90 % of the lowest variable charges of the thermal power station of the concerned region. Total energy charges may be computed on the basis of this rate and saleable energy of the project. This is intended to facilitate merit order despatch; or

b) The rate for primary energy during peak and off-peak to be taken as 90 % of the highest variable charges and 90 % of the lowest variable charges of thermal stations of the region respectively. After determining the quantum of peak energy, balance saleable energy should be taken as off-peak energy. Total energy charges shall be computed on the basis of the aforesaid rates and corresponding saleable energy figures.

(iii) In case the energy charges exceed the total annual charges, 50 % of the annual charges may be recovered as energy charges and in case of second alternative the rate for peak and off-peak energy may be reduced proportionately.

(iv) The rate for primary energy may be computed for each project on the above lines and may be reviewed every year.

(v) The balance amount after deducting energy charges as referred to above may be recovered as capacity charges. In case the actual availability happens to be lower than the target availability the capacity charges may get reduced on pro-rata basis. The capacity charges may be recovered from the beneficiaries in proportion to their entitlement.

(vi) In case of actual availability being higher than the target availability incentive will be payable.

(vii) The parameters for target availability and rate of incentive for higher availability to be finalised separately.

5.12.4 We have considered the special treatment granted in the draft notification under para 3(b), 5(b) and 6(b) with regard to Hydro Stations**. We have also considered the replies from various utilities as well as the recommendations as summarised already of the Committee on Hydro Tariff constituted by the CEA. We consider the committee's recommendation to bifurcate the energy charges into peak and off-peak based on the highest and lowest variable cost of thermal power station of the concerned region respectively as sensible keeping in view the need for promotion of hydel generation as well as avoidance of backing down of hydro stations when they are really required. However, this has to wait till our detailed consideration of peak and off peak pricing of power. A study on this subject is in progress. We do not advocate the arbitrary splitting of the total cost into capacity charges and energy charges. However, since a two part tariff is essential for ABT the procedure for bifurcation as suggested by the committee under alternative `a' as already referred to in para 5.12.3(ii) should be implemented. This would facilitate merit order despatch for hydro stations. The balance of total charges in any case would be recovered as capacity charges.**

5.12.5 As regards determination of sent out capacity and availability which are covered in para 5(b) and 6(b), the following are our findings:

(i) **Since the hydro stations are willing to submit to the discipline of UI there is no need for a special treatment at extreme low or high frequencies. Hence hydro stations should also be subject to UI mechanism at all levels of frequency. However, in order to prevent undue earning of UI charges, the hydro stations shall be obliged to revise their scheduled generation in case of higher inflow of water. In other words, in monsoon season on any sudden increase in inflow of water the scheduled generation shall be deemed to have been revised and the hydro stations shall inform RLDC accordingly.**

(ii) It shall be ensured that by declaring capacity above designed energy and actually generating above designed energy a situation of more than 100 % availability is not brought about which of course is presently covered by the notification. It shall also be ensured that the Declared Capacity does not exceed the Installed Capacity of the Plant.

(iii) **Regarding the pricing of secondary energy we are in agreement with the contentions of NHPC that the same should be priced as primary energy.**

(iv) **We are convinced that the proposal as contained in the Draft Notification read with this order shall ensure (a) full recovery of all costs and (b) provide scope for incentive on better performance as well as on secondary energy.**

(v) **The method of reckoning the incentive shall be based on the actual PLF and not on availability i.e. the same procedure as for thermal stations shall be adopted.**

(vi) **Apart from the above which are specific deviations from the draft notification, the rest of the features of the notification with regard to hydro stations stand approved.**

5.12.6 There is no separate provision necessary for tariff of pumped storaged Stations because the underlying idea behind hydro tariff proposals is that the full cost would get recovered either in the form of energy charges or fixed charges. With the bifurcation of variable charges by adopting the lowest available cost of thermal station in the region, it is only necessary to add thereto the cost of pumping as part of the variable charges. Hence a separate Tariff treatment is considered unnecessary.

5.12.7 The objection of ASEB with regard to the bifurcation of total cost into fixed and variable has been already taken into account. Regarding the other objection of ASEB on compensation for water spillage, it has been adequately dealt with in the notification as the underlying principle is that compensation has to be made upto the design energy. However, the reasons for this spillage have been restricted to low system demand or constraints in transmission system or any other reason not attributable to the generator which means the spillage is virtually a capacity charge. As regards the objection of DVC on exemption of hydro units from UI charges, the same has been taken note of by us and hydro stations shall also be liable to pay UI charges. We understand that it should be possible to schedule the generation even by run of the river stations with the facility to revise the schedule within six time blocks. Regarding the objection of capping the secondary energy, the same has been already taken care of in this order.

SCHEDULE 1

Tariff for Thermal Stations of NTPC

1. The Availability Based Tariff Order will be applicable to the following stations of NTPC :-

Northern Region

1. NCTPP Dadri (4 X 210 MW)
2. Feroz Gandhi Unchahar TPS (2 X 210 MW)
3. Dadri Gas Power Station (829.78 MW)
4. Anta Gas Power Station (419.33 MW)
5. Auraiya Gas Power Station (663.36 MW)
6. Singrauli STPS (2000 MW)
7. Rihand STPS (1000 MW)

Western Region

8. Korba STPS (2100 MW)
9. Vindhyachal STPS (1260 MW)
10. Kawas Gas Power Station (656.2 MW)
11. Jhanor Gandhar Gas Power Station (657.39 MW).

Southern Region

12. Ramagundam STPS (2100 MW).

Eastern Region

13. Farakka STPS (1600 MW)
14. Kahalgaon STPS (840 MW)
15. Talchar STPS (1000 MW).

Applicability of ABT for stations with multiple beneficiaries, other than the above, will be covered by suitable Notification to that effect.

2. The capacity charge for all the above stations shall be the Annual Fixed Charges (AFC) as notified by Government of India from time to time till the Commission notifies the operational and financial norms. Till such time the capacity charge and the rates of variable charge as well as fuel price adjustment shall be governed as

per Notifications issued by the Government of India. The procedure for payment of components of tariff, namely Capacity Charge, Energy Charge and Unscheduled Interchange Charge Incentive Payments, are given below.

(i) <u>Capacity Charge:</u>

Capacity Charge will be related to 'Availability' of the generating station. 'Availability', for the purpose of this order, means the readiness of the generating station to deliver ex-bus output expressed as a percentage of its related ex-bus output capability as per rated capacity.

Payment of Capacity Charge at various 'Availability' levels for different categories of multi-beneficiary generating stations in commercial operation shall be regulated as per formulae given in Para-8 & 9 of this Schedule.

(ii) <u>Incentives:</u>

Incentive payments shall be payable to the generator when the actual generation is more than normative generation corresponding to the target availability as explained in Para 5.4.7 of the order. The total incentive payment calculated on an annual basis shall be shared by the various beneficiaries as per their individual allocated capacity. The payments for incentives shall be paid on monthly basis and shall be adjusted on a financial year basis.

(iii) <u>Energy Charge</u>:

Energy Charges shall be worked out on the basis of a paise per Kwh rate on ex-bus energy scheduled to be sent out from the generating station as per the following formula:

Energy Charges= Rate of Energy Charges x Scheduled Generation (Ex-Bus)

(iv) <u>Unscheduled Interchange (UI)</u>

Variation in actual generation/drawal and scheduled generation/drawal shall be accounted for through Unscheduled Interchange (UI). UI for generating station shall be equal to its actual generation minus its scheduled generation. UI for beneficiary shall be equal to its total actual drawal minus its total scheduled drawal. UI shall be worked out for each 15 minute time block. Charges for all UI transactions shall be based on average frequency of the time block and the following rates shall apply:

Average Frequency of time block	UI Rate (Paise per kwh)
50.5 Hz and above	0.0
Below 50.5 Hz and up to 50.48 Hz	5.6
Below 49.04 Hz and up to 49.02 Hz	414.40
Below 49.02 Hz	420.00
Between 50.5 Hz and 49.02 Hz	linear in 0.02 Hz step

The above average frequency range and UI rates are subject to change through a separate notification from time to time.

Settlement of UI:

The settlement of UI shall be done in accordance with the System of settlement evolved by CTU as per Para 5.10.4 of this order.

3. Scheduling: (This shall be read with Chapter 7 of IEGC regarding procedure for scheduling).

Methodology of Scheduling and Calculating Availability shall be as under:

(i) Each day starting from 00.00 hrs. will be divided into 96 time blocks of 15 minutes intervals.

(ii) The generator will make an advance declaration of capability of its generating station. The declaration will be for that capability which can be actually made available.

In case of Thermal Stations, the declaration will be for the capability of the generating station to deliver ex-bus MWH for each time block of the day. The capability as declared by generator, hereinafter referred to as DC, would form the basis of generation scheduling. The declaration in relation to gas turbine/combined cycle stations shall be the capacity which can be made available at 50.00 Hz.

(iii) While making or revising their declaration of capability, the generator shall ensure that their declared capability during peak hours is not less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronisation of units as a result of forced outage of units.

(iv) The generation scheduling shall be done in accordance with the operating procedure, as stipulated in the IEGC.

(v) Based on the declaration of the generator, RLDC shall communicate their shares to the beneficiaries out of which they shall give their requisitions.

(vi) Based on the requisitions given by the beneficiaries and taking into account technical limitations on varying the generation and also taking into account transmission system constraints, if any, RLDC shall prepare the economically optimal generation schedules and drawal schedules and communicate the same to generator and beneficiaries.

RLDC shall also formulate the procedure for meeting contingencies both in the long run and in the short run (Daily scheduling).

(vii) All the scheduled generation and actual generation shall be at the generator's ex-bus. For beneficiaries, the scheduled and actual net drawals shall be at their respective receiving points.

(viii) For calculating the net drawal schedules of beneficiaries, the transmission losses shall be apportioned to their drawals.

(ix) Scheduled generation of the generating station for each time block hereinafter referred to as SG will mean the Scheduled MWH to be Sent Out Ex-bus from the generating station.

(x) Actual generation of the station for each time block, hereinafter referred to as AG will mean actual MWH actually Sent Out Ex-bus from the generating station.

(xi) In case of forced outage of a unit, RLDC will revise the schedules on the basis of revised declared capability. The revised schedules will become effective from the 4^{th} time block, counting the time block in which the revision is advised by the generator to be the first one. The revised declared capability will also become effective from the 4^{th} time bock.

(xii) In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, *associated switchyard and substations owned by CTU* (as certified by RLDC) necessitating reduction in generation, RLDC will revise the schedules which will become effective from the 4^{th} time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. Also, during the first, second and third time blocks of such an event, the scheduled generation of the station will be deemed to have been revised to be equal to actual generation and also the scheduled drawals of the beneficiaries will be deemed to have been revised to be equal to their actual drawals.

(xiii) In case of any Grid Disturbance, Scheduled Generation of all the Generating Stations and Scheduled Drawal of all the Beneficiaries shall be deemed to have been revised to be equal to their Actual Generation/Drawal for all the time blocks affected by the Grid Disturbance. Certification of Grid Disturbance and its duration shall be done by RLDC.

(xiv) Revision of declared capability by generator(s) and requisition by beneficiary(ies) for the remaining period of the day will also be permitted with advance notice. Revised schedules/declared capability in such cases shall become effective from the 6th time block, counting the time block in which the request for revision has been received in RLDC to be the first one.

(xv) If, at any point of time, RLDC observes that there is need for revision of the schedules in the interest of better system operation, it may do so on its own and in such cases, the revised schedules shall become effective from the 4th time block, counting the time block in which the revised schedule is issued by RLDC to be the first one.

(xvi) Generation schedules and drawal schedules issued/revised by RLDC shall become effective from designated time block irrespective of communication success.

(xvii) For any revision of scheduled generation, including post facto deemed revision, there shall be a corresponding revision of scheduled drawals of the beneficiaries.

(xviii) A procedure for recording the communication regarding changes to schedules duly taking into account the time factor shall be evolved by CTU.

4. <u>Sent Out Capability:</u>

Sent out Capability of a generating station, hereinafter referred to as SOC, would mean the capability to deliver Ex-bus MWH based on which ‘availability’ will be worked out.

SOC for Thermal Stations shall be the DC, with all before-the-fact revisions/updating. The declared capacity shall not exceed the installed capacity.

NOTE 1: In case of gas turbine/combined cycle stations, the generator shall give DC for units/modules on gas fuel and DC for units/modules on liquid fuel separately, and the two shall be scheduled separately. Total DC and total SG for the station shall be the sum of the two.

NOTE 2: For the gas turbine/combined cycle stations for any time block, the average frequency is below 49.52 Hz but not below 49.02 Hz and SG is more than 98.5% of DC, SG shall be deemed to have been reduced to 98.5% of DC and if the average frequency of the time block is below 49.02 Hz and SG is more than 96.5% of DC, SG shall be deemed to have been reduced to 96.5% DC.

5. Availability:

Availability of thermal generating station for any period shall be the percentage ratio of average SOC for all the time blocks during that period and rated Sent Out Capability of the generating station as per the following formula:

$$\text{Availability} = \left\{ \sum_{i=1}^{n} \frac{SOCi}{(1-AUX/100)} + CL \right\} \times \frac{100}{h \times I.C.}$$

where,

I.C. = Installed Capacity of the station in MW

SOCi = SOC of the i^{th} time block of the period

n = Number of time blocks during the period

AUX = Normative Auxiliary Consumption as a percentage of gross generation.

h = Number of hours during the period = n/4

CL = Gross MWH of capacity of unit(s) kept closed on account of Generation scheduling order.

6. Demonstration of Declared Capability:

The Generator may be required to demonstrate the declared capability of its generating station as and when asked by the RLDC of the region in which the generating station is situated. In the event of generator failing to demonstrate the declared capability, the capacity charges due to the generator shall be reduced as a measure of penalty. The quantum of penalty for the first mis-declaration for any duration/block in a day shall be the charges corresponding to two days fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in the same geometrical progression as per the order of the Commission.

NOTE: In case it is observed that the declaration of its capability by the generator is on lower side and the actual generation is more than DC, then UI charges due to the generator on account of such extra generation shall be reduced to zero and the amount shall be credited towards UI account of beneficiaries in the ratio of their capacity share in the station.

7. Metering and Accounting:

Metering arrangements, including installation, testing and operation and maintenance of meters and collection, transportation and processing of data required for accounting of energy exchanges and average frequency on 15 minute time block basis shall be provided by the PGCIL/RLDCs. Processed data of the meters along with data relating to declared capability and schedules etc., shall be supplied by RLDCs to REBs and REBs shall issue the Regional Accounts for energy as well as UI charges on monthly basis. The UI account shall also be prepared and released by the REB in accordance with Para 5.10.4 of this order so that invoices can be raised by the recipient of the UI charges.

8. <u>Billing and Payment of Capacity Charges</u>:

Billing and Payment of capacity Charges shall be done on a monthly basis in the following manner:

i) Each beneficiary shall pay the capacity charges in proportion to its percentage share in total saleable capacity of the station. Saleable capacity shall mean total capacity minus free capacity to Home State(s), if any.

NOTE 1: Allocation of total capacity of Central Sector Stations is made by GOI from time to time which also has an unallocated portion. Allocation of the unallocated portion shall be made by the GOI from time to time, for the total unallocated capacity. The total capacity share of any beneficiary would be sum of its capacity share plus allocation out of the unallocated portion. In case of no specific distribution of unallocated power by the GOI, the unallocated power shall be added to the allocated shares in the same proportion as the allocated shares.

NOTE 2: The beneficiaries may propose surrendering part of their allocated share to other States within/outside the region. In such cases, depending upon the technical feasibility of power transfer and specific agreements reached by the generating company with other States within/outside the region for such transfers, the shares of beneficiaries may be re-allocated by the GOI for a specific period. When such re-allocations are made, the beneficiaries who surrender the share will not be liable to pay capacity charges for the surrendered share. The capacity charges for the capacity surrendered and reallocated as above will be paid by the State(s) to whom the surrendered capacity is allocated. Except for the period of reallocation of capacity as above, the beneficiaries of the generating station will continue to pay the full fixed charges as per allocated capacity shares.

(ii) The beneficiaries will have full freedom for negotiating any transaction for utilisation of their capacity shares. In such cases, the beneficiary having allocation in the capacity of the generating station will be liable for full payment of capacity charges and energy charges (including that for sale of power under the transactions negotiated by them) for all its scheduled and unscheduled transactions from its capacity share.

(iii) If there is any capacity which remains un-requisitioned during day-to-day operation, RLDC, shall advise all beneficiaries in the region and the other RLDCs so that such capacity may be requisitioned through bilateral arrangements with the concerned generating company/beneficiary(ies) under intimation to the RLDC.

(iv) The Capacity Charges as in para 2 (i) of this schedule shall be paid by the Beneficiary(ies) including those outside the Region to the generator every month in accordance with the following formula:

Total Capacity Charges payable to the generator for the:

1st month = (1xACC1)/12
2nd month = (2XACC2 - 1XACC1)/12
3rd month = (3xACC3 - 2XACC2)/12
4th month = (4xACC4 - 3xACC3)/12
5th month = (5XACC5 - 4xACC4)/12
6th month = (6XACC5 - 5xACC5)/12
7th month = (7XACC7 - 6xACC6)/12
8th month = (8xACC8 - 7xACC7)/12
9th month = (9xACC9 - 8xACC8)/12
10th month = (10xACC10 – 9xACC9)/12
11th month = (11xACC11 - 10xACC10)/12
12th month = (12xACC12 - 11xACC11)/12

and, Each beneficiary having firm allocation in capacity of the generating station shall pay for the :

1st month = [ACC1 x WB1]/1200
2nd month = [2XACC2 x WB2 - 1XACC1x WB1]/1200
3rd month = (3xACC3 x WB3 - 2XACC2 x WB2]/1200
4th month = (4xACC4 x WB4 - 3xACC3 x WB3]/1200
5th month = (5XACC5 x WB5 - 4xACC4 x WB4]/1200
6th month = (6XACC5 x WB6 - 5xACC5 x WB5]/1200
7th month = (7XACC7 x WB7 - 6xACC6 x WB6]/1200
8th month = (8xACC8 x WB8 - 7xACC7 x WB7]/1200
9th month = (9xACC9 x WB9 - 8xACC8 x WB8]/1200
10th month = (10xACC10 x WB10- 9xACC9 x WB9]/1200
11th month = (11xACC11 x WB11- 10xACC10x WB10]/1200
12th month = (12xACC12 x WB12- 11xACC11x WB 11]/1200

Where,

ACC1, ACC2, ACC3, ACC4, ACC5 ACC6, ACC7, ACC8, ACC9, ACC10, Acc11 and ACC12 are the amount of Annual Capacity Charge corresponding to 'Availability' for the cumulative period up to the end of 1st, 2nd 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th months respectively.

and, WB1, WB2, WB3, WB4, WB5, WB6, WB7, WB8, WB9, WB10, WB11 and WB12 are the weighted average of percentage allocated capacity share of the beneficiary during the cumulative period up to 1st, 2nd 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th 11th and 12th month respectively.

and,

Year will be taken as per financial year.

When the month of changeover to tariff as per this notification is not the first month of a financial year, then ‘Availability’ for the part of the year prior to switchover shall be “deemed PLF” determined on the basis of actual generation plus backing down and weighted average of percentage allocated capacity share of the beneficiary shall be equal to his total drawal from station (as per regional energy accounting) expressed as percentage of total ex-bus generation. Payment of capacity charges for the period prior to switchover shall be regulated as per tariff applicable till the date of switchover and pro-rata incentive, as applicable, shall be paid. Payment of capacity charges for the month after the switchover to tariff as per this order shall be as per the formula given in para 9 of this schedule.

9. Payment of capacity charges for coal based and gas/naphtha based thermal power stations of NTPC covered by this order will be regulated as follows:

CAPACITY CHARGE & INCENTIVE

Period		Annual Capacity Charge (ACC_n)		Incentive	
From	**To**	**Availability**	**Formula for Calculation**	**PLF**	**Rate of Incentive**
Date of implementation of ABT	31.3.2001	0 - 80%	$\frac{\text{AFCxAvailability(\%)}}{80\%}$	Above 80%	1 paise/KWh for each 1% increase in PLF.
1.4. 2001	onwards	0 - 85%	$\frac{\text{AFCxAvailability(\%)}}{85\%}$	Above 85%	

Sd/- Sd/- Sd/- Sd/-

(A.R. Ramanathan) **Member**

(G.S. Rajamani) **Member**

(D.P. Sinha) **Member**

(S.L. Rao) **Chairman**

New Delhi, dated 4th January, 2000

……