Central Electricity Regulatory Commission
New Delhi

Explanatory Memorandum to the Draft Amendments to the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009

1. Amendments for facilitating introduction of Peak and off-Peak Tariffs:

1.1 The Central Electricity Regulatory Commission (CERC) constituted on 24th July, 2009 a one Member Task Force headed by Shri Rakesh Nath, the then Chairperson, Central Electricity Authority (CEA) and ex-officio Member, CERC for examining the issues relating to tariff structure for generating stations set up for meeting the peak demand and to suggest measures that could suitably incentivize as also mitigate the risks to the investors who want to set up power stations for meeting peaking power requirements. The Task Force was also mandated to consider the desirability of permitting differential peak and off-peak tariffs even for base load power plants.

1.2 The Task Force has submitted its report in March 2010 having due regard to the legal and policy framework in this context, relevant reports on power sector reforms, power supply position based on the load generation balance report of CEA, the transactions in the short-term market. A copy of the report of the Task Force is enclosed as Annexure-I.

1.3 In line with the recommendations of the Task Force, it is proposed to amend the CERC Tariff Regulation 2009 with minor changes as discussed below:

(i) With regard to the recommendation of the Task Force in respect of existing base load thermal generating stations to provide for peak and off-peak tariff, it is proposed to give option to such existing thermal generating stations to adopt to an alternate methodology for the recovery of capacity charges during peak and off-peak periods in place of existing methodology.

(ii) In case existing combined cycle gas/liquid fuel based generating stations of NTPC opt for the alternate methodology, then the combined cycle gross station heat rate proposed to be increased by 0.5% instead of 2% recommended by the Task Force. This is with the view that the operation level of these stations is unlikely to deteriorate much from the existing operating level and rather there is scope for improvement in the operation level due to availability of RLNG in future.

(iii) It is also proposed to provide for recovery of energy charges in excess of design energy plus 75% of the energy utilized in pumping in case of pumped storage generating stations at a flat rate of 80 Paise/kWh instead of the average of the energy charge rate of preceding 12 months in respect of the thermal generating stations in the region where the pumped storage station is situated. This is in line with the rate of 80 Paise/kWh for the energy charge payable over and above the design energy in case of conventional hydro generating station.

1.4 Since the task force has also recommended the tariff structure for the gas based open cycle gas turbine peaking station and gas based reciprocating engine peaking station it is necessary to provide for operational norms and O&M norms for such stations.

1.5 With regard to operational norms of Gross Station Heat Rate for the open cycle gas turbines and reciprocating engine based peaking stations are concerned, the same could be on the same lines as specified for new thermal generating stations, based on the designed heat rate, providing for operational margins.

1.6 It is proposed to keep the operational margin of 5% over the designed heat rate, in case of units of open cycle gas turbines based peaking stations. However, in case of reciprocating engine based peaking stations, it is proposed to provide for operational margin of 2% over the designed heat rate due to relatively consistent quality of gas and the fact that performance of such stations are not sensitive to the site ambient conditions and the deterioration in heat rate is expected to be much less as compared to gas turbines.

1.7 The auxiliary energy consumption norm for the open cycle gas turbines based peaking stations is being kept as 1% as the same is expected to be of the same order irrespective of the fact whether the station is operating as base load station or the peak load station. On the other hand the auxiliary energy consumption norm for the reciprocating engine based peaking stations is proposed as 1.5% considering additional energy requirement for the water cooling system and lub oil system.

1.8 As regards O&M expenses norms for the open cycle gas turbine peaking stations are concerned, the task force has recommended the same as 1.5 times the O&M cost norms applicable to combined cycle gas turbine stations. The amendments thus include O&M cost norm for such stations accordingly.

1.9 As regards, O&M expenses norms for the gas based reciprocating engine peaking stations are concerned, no credible data is available with the Commission. But Unlike Gas Turbines, Gas Engines does not lose operating life with number of start and stops or with variation in load. For Gas engines, maintenance cycle comes at intervals, which is independent of such operational characteristics. On this consideration, the repair and maintenance expenses would be much less due to about 2000 hours of operation every year for a peaking station. Further, the man/MW ratio is also expected to be lower than the combined cycle gas turbine stations or the coal based stations. A manufacturer literature indicates Repair and maintenance cost of the order of 0.01-0.02 US$/kWh which translate into Rs. 10-20 Lakh/MW. Taking conservative figure of repair and maintenance for peaking application and considering the cost of consumables namely lub oil about 2gm/kWh and administrative cost of employees etc of the order of about 60% of Repair and maintenance cost, the O&M cost norm for the gas based reciprocating engine peaking stations works out of the order of 16 Lakh/MW. Accordingly, following O&M cost norms are provided for the tariff period 2009-14 considering annual escalation of 5.72%:

(Rs. in lakh/MW)

Year	O&M Cost Norm
(1)	(2)
2009-10	16.00
2010-11	16.92
2011-12	17.88
2012-13	18.91
2013-14	19.99

2. Pumped Storage schemes of Hydro generating station

2.1 The Task Force has recommended setting up of Pumped storage schemes and has also provided a tariff structure for such stations. The Pumped storage schemes are type of hydroelectric projects which utilizes stored energy in the form of water, pumped from a lower elevation reservoir to a higher elevation for load balancing and peaking support. It is therefore, proposed to incorporate amendments to facilitate setting up of pumped storage schemes by providing tariff structure as per the recommendations of the Task Force. Approximately 70% to 85% of the electrical energy used to pump the water into the elevated reservoir can only be regained due to evaporation losses from the exposed water surface and conversion losses. The actual data for 2007-08 and 2008-09 of the Purullia Pump Storage Project (4x225 MW) in this regard is as follows:

	2007-08	2008-09
Total energy received (MU)	499.87	859.61
Total energy Send (MU)	384.63	669.825
Overall efficiency (%)	76.95	77.92

2.2 Considering this it has been proposed that the quantum of electricity required for pumping water from down-stream reservoir to up-stream reservoir shall be arranged by the beneficiaries duly taking into account the transmission and distribution losses etc. up to the bus bar of the generating station. In return beneficiaries will be entitled to equivalent energy of 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir from the generating station during peak hours and the generating station shall be under obligation to supply such quantum of electricity during peak hours. The O&M expenses shall be on the same lines as that for the conventional Hydro generation

3. Apart from above, it is also proposed to amendment certain other provisions which have become necessary as discussed in subsequent paragraphs:

4. Amendments of Regulation 15 due to frequent changes in the rate of MAT

4.1 Regulation 15 of the 2009 Regulations provides as under:

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

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

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

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

(3) The rate of return on equity shall be computed by grossing up the base rate with the normal tax rate for the year 2008-09 applicable to

the concerned generating company or the transmission licensee, as the case may be:

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

4.2 After the notification of the 2009 regulation on 20.1.2009, the MAT rate which was 10% for the financial year 2008-09 has been increased to 15% for the Financial Year 2009-10 and 18% for the Financial Year 2010-11. The Powerlink Transmission Ltd. had filed a Petition No. 17/2010 before the Commission submitting that truing up of Return on Equity with actual MAT tax rate with the tariff petition filed for the next tariff period would result in substantial difference of tariff on year to year basis for the tariff block 2009-14 which would result in cash flow mismatch.

4.3 Commission vide order dated 3.8.2010 in above Petition No 17/2010 decided as follows:

"5. After the notification of the 2009 regulation on 20.1.2009, the MAT rate which was 10% for the financial year 2008-09 has been increased to 15% for the Financial Year 2009-10 and 18% for the Financial Year 2010-11. This substantial change in the MAT rate has serious impact on the funds position of the generating company / the transmission licensee and the beneficiaries. The generating companies/transmission licensees are required to pay income tax in the relevant financial year. If requisite fund is not made available to them for meeting this statutory obligation, they will face problem in cash flow as they will be able to get the under-recovered amount (along with simple interest at the rate equal to the short-term Prime Lending Rate of State Bank of India as on 1st April of the respective year) from the beneficiaries in just six installments after the truing up exercise at the end of the tariff period. On the other hand, the beneficiaries and long term transmission customers will have to pay a huge amount of tax arrears in just six installments and may result in tariff shock to the consumers. This situation needs to be addressed.

6. We are of the view that this issue of 'grossing up the base rate with the normal tax rate for the year 2008-09' is generic in nature and therefore, it will be appropriate to make suitable provisions in the 2009 regulations to cater to any future changes in the tax rate. Accordingly, we direct the staff of the Commission to prepare and submit draft amendment to the 2009 regulations for allowing grossing up of base rate of return with the applicable tax rate as per the Finance Act for the relevant year and direct settlement of tax liability between the generating company/transmission licensee and the beneficiaries/long term transmission customers on year to year basis. Any under/over recovery on account of direct settlement of tax liability shall be subject to the final adjustment at the time of true up exercise."

4.4 Regulation 15 is proposed to be amended accordingly.

5. Amendments of Regulation 5, 6 and 18 due to doing away of PLR system in Banks by the RBI replacing it with base rate system,

5.1 As per the recent directives given by Reserve Bank of India, the lending rates of the banks are now required to be linked to the Base Rate instead of Prime Lending Rate of the respective bank, with effect from 1.7.2010. In view of this it is necessary to amend various provisions of the Tariff Regulation accordingly.

5.2 The State Bank of India announced linking fixed lending rate for the home loan to the base rate of 7.50% as on 1.7.2010 plus 350 basis point. On this consideration it is proposed to provide interest rates linked to Base Rate of SBI plus 350 basis point for the purpose of tariff.

6. Amendment in Regulation 32 regarding sharing of transmission charges and losses as per the CERC (Sharing of inter-state transmission charges and losses) Regulation 2010 from the date of its coming into effect

6.1 CERC has notified Central Electricity Regulatory Commission (Sharing of Inter-state transmission charges and losses) Regulation 2010 on 15th June, 2010, which shall comes into effect from 1.1.2011. After implementation of this regulation, the present methodology of sharing of transmission charges as per regulation 32 would be replaced with the provisions as per above new regulation. Regulation 32 is being amended to provide for this change in methodology from the date of CERC (Sharing of inter-state transmission charges and losses) Regulation 2010 coming into effect.

7. Providing for truing up of capital cost as on 1.4.2009 upfront with regard to un-discharged liability, if any, in the last proviso of Regulation 7, in view of the judgment of the Appellate Tribunal for Electricity.

7.1 The Commission has approved the tariff for the period 2004-09 in terms of Regulations 2004-2009 based on the actually incurred expenditure after deducting undischarged liabilities for the gross block. The Interpretation of Actually incurred expenditure became subject matter of litigation before APTEL in appeal no. 151 and 152 of 2007. The Appellate Tribunal in its judgment dated 10.12.2008 decided the issue as under:

> **Quote**
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> "25. Accordingly, we allow both the appeals in part. We direct that the appellant be allowed to recover capital cost incurred including the portion of such cost which has been retained or has not yet been paid for. ………………
>
> 26. The Commission is directed to give effect to the directions given herein in the truing up exercise and consequent subsequent tariff orders."
>
> **Unquote**

7.2 This requires that the closing capital cost as on 31.3.2009 as approved by the Commission shall undergo change due to the true up exercise to be taken up in already decided cases. This may delay the determination of tariff during 2009-14. Regulation 7 of 2009 Tariff Regulations provides that 'in case of the existing projects, the capital cost admitted by the Commission prior to 1.4.2009 and the additional capital expenditure projected to be incurred for the respective year of the tariff period 2009-14, as may be admitted by the Commission, shall form the basis for determination of tariff.'

7.3 Therefore, there is a need for upfront truing up (in line with ATE judgment) with regard to un-discharged liability based on information furnished by the Generators or the transmission utility. Accordingly, the last proviso of regulation 7 has been proposed to be amended.

8. Amendment in Regulation 9 (2) to providing for additional capitalization after about 15 years on the renovation of gas turbines.

8.1 The NTPC has claimed the Actual/Projected capital expenditure of around 400 Cr during 2009-14 for CEA approved R&M works under Regulation 9 [2] [ii] as change in law in a tariff petition for Gandhar TPS. Similarly, R&M of gas turbine after 15 years is also an issue in case of Anta Auraiya and Dadri TPS.

8.2 The petitioner has argued that the useful life of the combined cycle gas turbine plants has been increased to 25 years as per 2009 tariff regulations from 15 years as adopted prior to 1.4.2009. The Petitioner, in its Affidavit dated 26.04.2010 has further submitted that for safe & reliable operation of gas plant on sustained basis and also to arrest performance deterioration due to ageing, such replacement of components of gas turbine is essential after a definite interval i.e. Equivalent Operating Hours (EOH), which may vary, based on the type of machine, fuel used & operating conditions etc. Most of the gas turbine manufacturers recommend extensive replacement of Hot Gas Path (HGP) components after 1 lakh hours, of operation.

8.3 The 2009 tariff regulations do not provide for allowing any Additional Capital Expenditure after the cut-off date in the normal course for the combined cycle gas turbine plants during the useful life except for change of law under provision 9(2)(ii).

8.4 However, following facts are necessary to be considered in case of combine cycle gas based stations as discussed in subsequent paragraphs:

8.5 The draft Tariff Regulation for tariff period 2009-14 as well as Tariff Regulation 2009 of CERC do not provide any compensation allowance for the gas based stations. The explanatory memorandum issued along with the draft tariff regulation of CERC clearly states in para 5.19 as follows:

> "In case of gas/liquid fuel base stations of NTPC, NEEPCO and transmission systems not much of expenditure has been found to be incurred under these heads. In case of hydro generating stations, it is provided that similar allowance may be allowed on merit on case to case basis where certain parts have to be replaced due to erosion caused by high silt content in water."

8.6 The Draft tariff regulation provided for in regulation 11, an option to be excercised by the thermal generating stations to avail "special allowance" for meeting R&M expenditure after their useful life. The draft Regulation 11 provided as follows:

> "Provided that in case of thermal generating station, the generating company, may, in its discretion, avail of a 'special allowance' as per the norms provided in clause (4) of this regulation, as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof, and in such an event revision of the capital cost shall not be considered."

8.7 However, this dispensation was restricted to be applied to the coal/lignite thermal generating stations and not to the gas based stations in the CERC tariff Regulation 2009. The Commission observed as follows in the para 11.6 of Statement of Reasons of the CERC Tariff Regulation 2009:

> "In case of gas/lignite based stations, such an alternative is not being considered in the absence of sufficient data in this regard. In any case generating companies have the first alternative available with them to come up with a detailed R&M proposal as and when required."

8.8 The explanatory memorandum in para 6.3 read as follows:

> "6.3 The expected or rated 'useful' life of power plants has historically been considered as 25 years for Thermal, 35 years for Hydro and **15 years for Diesel generators and Gas turbines**. ----------------."

8.9 The draft Regulation 17 (4) dealing with depreciation provided for useful life of thermal generating stations as 25 years and did not make any distinction in case of coal/lignite and Diesel/gas based stations.

8.10 The Commission in the 2009 Tariff Regulations provided for useful life of gas based generating stations as 25 years and observed as follows in para 5.3 of the Statement of Reasons":

> **"5.3 Useful life**
>
> 5.3.1 The gas/liquid fuel based stations comprise of two main components. One set of components are the gas turbine and its auxiliaries which are subjected to high temperatures; and the other set of components namely waste heat recovery boiler, steam turbine, generator and their auxiliaries etc are not subjected to very high temperatures.
>
> 5.3.2 So far, the useful life for the gas turbine is being considered as 15 years and that of waste heat recovery boilers, steam turbine etc as 25 years. Historically, the gas turbines were used in aero planes and ships where reliability aspect was very important from the view point of safety and security of life of passengers and crew members. Considering the reliability of the gas turbines, life of gas turbines was considered as 15 years. When gas turbines were used in generation of

electricity, the same period was taken as the useful life. However, experience has shown that many of the first generation gas turbines installed in India have already completed 20 years of operation and continue to operate with major overhauls undertaken at regular intervals of 50000 EOH. The major overhaul of gas turbine involves complete renovation of hot gas path which is subjected to very high temperature.

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

8.11 Accordingly, the CERC tariff Regulation 2009 in Regulation 42 provided as follows:

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

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

8.12 In the light of above, it may be seen that the life of gas turbine referred as 25 years in the Statement of Reasons on CERC Tariff Regulations 2009 was to mean the life of gas based generating stations and not the gas turbine as such. Further, in the absence of R&M data in respect of gas based generating stations and that there was no additional capitalisation witnessed in gas based generating stations up to the 2007-08 neither the option of special allowance was provided not any compensation allowances was a specified for gas based generating station. Despite this no provision was made in the regulation to deal with any additional capitalisation on account of R&M of gas turbines after 15 years but during the useful life of gas based generating stations of 25 years as provided for Hydro Electric generating stations and transmission system in Regulation 9 (2) (iv) and (v) respectively which read as follows:

> "(iv) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) including due to geological reasons after adjusting for proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation; and
>
> (v) In case of transmission system any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement of switchyard equipment due to increase of fault level, emergency restoration system, insulators cleaning infrastructure, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system:

8.13 In the light of above, it is felt that there is a need to provide a similar dispensation for the gas based stations for allowing for R&M after 15 years and for obsolescence of technology.

8.14 However, such additional capital expenditure could be allowed only after de-capitalising the original gross value of assets replaced. Since the R&M on gas turbines would be in the nature of major overhaul, it requires suitable adjustment of capital spares included in the normative operation and maintenance expenses. Accordingly a new clause is proposed to be added as Regulation 9 (2) (iv).

9. Amendment to Regulation 18 (1) (b) (ii) to provide for liquid fuel stock duly taking into account the mode of operation of the generating station on gas fuel and liquid fuel.

9.1 The Regulation 18 (1) (b) (i) and (ii) reads as follows:

(i) Fuel cost for one month corresponding to the normative annual plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel;

(ii) Liquid fuel stock for ½ month corresponding to the normative annual plant availability factor, and in case of use of more than one liquid fuel, cost of main liquid fuel.

9.2 The fuel cost of 1 month is determined duly taking into account mode of operation of the generating station on gas fuel and liquid fuel but the same is not mentioned in respect of liquid fuel stock whereas the liquid fuel stock is also determined duly taking into account mode of operation of the generating station on gas fuel and liquid fuel in various tariff orders of the Commission. Thus to make it clear, it proposed to substitute the existing provision with following:

"(ii) Liquid fuel stock for ½ month corresponding to the normative annual plant availability factor, duly taking into account the mode of operation of the generating stations of gas fuel and liquid fuel and in case of use of more than one liquid fuel, cost of main liquid fuel."

REPORT OF THE

TASK FORCE ON

PEAK AND OFF PEAK TARIFFS

FOR

GENERATING STATIONS

MARCH, 2010

EXECUTIVE SUMMARY

The Central Electricity Regulatory Commission (CERC) constituted on 24th July, 2009 a one Member Task Force headed by Shri Rakesh Nath, Chairperson, Central Electricity Authority (CEA) and ex-officio Member, CERC for examining the issues relating to tariff structure for generating stations set up for meeting the peak demand and to suggest measures that could suitably incentivize as also mitigate the risks to the investors who want to set up power stations for meeting peaking power requirements. The Task Force was also mandated to consider the desirability of permitting differential peak and off-peak tariffs even for base load power plants. The Task Force was assisted by Shri S.C. Shrivastava, Jt. Chief (Engg.), Shri Sushanta K. Chatterjee, Dy. Chief (Regulatory Affairs) and Shri S.N. Kalita, Dy. Chief (Fin) of CERC.

The Task Force has examined the legal and policy framework in this context and also the relevant reports on power sector reforms. The Task Force has also analysed power supply position based on the load generation balance report of CEA and studied the transactions in the short-term market. Based on the analysis, the Task Force has concluded that the power supply position in the country indicates continued energy and peaking shortages. While the energy shortage makes it imperative to set up base load stations, the peak shortage underscores the need for separate dispensation to meet demands during peak periods. The load duration curve of the country further reveals that the duration of peak demands being shorter, it may not be economically viable to depend on purely base load stations to meet such peak demands. It makes more sense to set up some power plants for operating only during peak period. However, such plants would require a different tariff structure to recover their costs.

For examining the need for separate treatment for peaking power plant, the Task Force has studied the existing tariff structure for generating stations. It has been felt that while the philosophy of tariff structure is based on sound principles of recovery of fixed cost as well as incentive linked to availability, it does not fully address the need for differential tariff based on time of day and demands of the system. The Task Force has felt that there is a need for special commercial signal (other than UI which is primarily aimed at managing the real time imbalances and cannot be relied upon for investment decisions) for setting up of peaking power plants and has suggested differential tariff structure for peak and off peak periods for the existing generating plants as well as for the new peaking power plants.

The pit head coal based stations will continue to be used for meeting base load demands and as such the tariff design suggested for such stations does not substantially alter the existing dispensation. The non-pit head power plants and coastal plants based on imported coal with higher variable charges may have to alter the load during the day depending on the load demand. However, during the off-peak hours also, such coal based plants may continue to operate, though at reduced load. As far as possible, the suggested tariff design would ensure revenue neutrality for the existing coal based stations. However, the existing combined cycle gas based stations can be used to meet intermediate and peak demands as well since adequate gas is not available for their base load operation and as such the tariff design suggested for gas based stations is based on the premise that the availability of such power plants during peak hours will be higher than their corresponding availability during off-peak hours.

Salient features of the recommendations are as follows:

Duration of peak and off-peak hours

- For daily recovery of peak hour capacity charges, the peak hours in a day may be considered as 6 hours in case of thermal generating stations and 3 hours in case of hydro generating stations to be declared by the National Load Dispatched Centre from time to time.

Basis for differentiation of peak and off-peak tariff

- The tariff structure has been proposed to make the fixed cost component of the tariff for peak hours 25% higher than the tariff for off-peak hours for existing coal and combined cycle gas power plants. In future, higher weightage for tariff for peak hours may be considered keeping in view the need for greater commercial signal for optimum utilization of resources based on system demands.

Recovery of fixed cost and incentive/disincentive

- It has been suggested that recovery of the fixed cost for generating stations (except hydro stations) may be linked to achievement of Normative Plant Availability Factor (NPAF) for peak and off-peak periods respectively.
- For a coal based (existing and new) generating station, it has been suggested that the incentive/disincentive for over achievement/under achievement vis-a-vis respective NPAF (for peak and off-peak hours) should be recovered as a defined function of 'average' capacity charge rate (average of peak and off-peak capacity charge rate).
- For a gas based (existing and new combined cycle) generating station, it has been suggested that recovery of the fixed cost should be linked to achievement of NPAF for peak hours (i.e. 90%) and off-peak hours (i.e. 63%) respectively. However, incentive may be linked to achievement of NPAF beyond 85%. Given the availability/allocation of gas for

power sector, with 90% plant availability during peak hours and 63% plant availability during off-peak hours based on gas as the only fuel, it is assumed that the overall availability during the day will be 70%. This will mean that there will be a dead band between 70% and 85% availability in so far as incentive is concerned as incentive will be available only for achievement over and above 85% plant availability (based on gas and/or alternate fuel) @ average capacity charge rate (average of peak and off-peak capacity charge rate).

- For a hydro generating station (existing and new), the dispensation as in the Tariff Regulations, 2009 may continue, except that
  - Incentive for over-achievement vis-a-vis normative annual plant availability factor during peak hours may be allowed @ 75% of AFC instead of the existing provision of allowing incentive @ 50% of AFC. This incentive structure is based on the premise that the hydro generating stations are meant primarily to meet peak demand and should be incentivized to achieve this objective. It is also in national interest to harness hydro generation to its maximum extent. In the event of extra generation from hydro stations during peak hours, the distribution companies would also be benefited in that their dependence on short-term purchases will reduce and they would also have corresponding relief from the vagaries of price fluctuation in the short-term market.
- For a new open cycle gas based peaking generating station, the incentive/disincentive for over-achievement/under-achievement by every one percentage vis a vis NPAF during peak hours has been suggested as 10% of the peak capacity charge rate.
  - However, for any generation beyond 100% capacity the generating station may not be allowed any UI payment. In such an event the generating station may be allowed overload charge @ 5% of the peak capacity charge rate in addition to the energy charge rate.

    - For operating during the off-peak hours such generating station may be allowed an incentive @ 1/10th of the peak capacity charge rate in addition to the energy charge.

Normative Plant Availability Factor (NPAF) and O&M expense

- The NPAF for coal based (existing as well as new) stations may remain the same as the normative annual plant availability factor as in the Tariff Regulations, 2009.
- For gas based (existing and new combined cycle) generating stations, NPAF for peak hours has been recommended as 90%. The average NPAF for the day may be treated as 70%.
    - The O&M expenses shall be as per the prevailing norms as per CERC regulations as any additional expenses towards repair & maintenance required due to one start /stop of one gas turbine gets offset by reduced O&M due to lower running hours of GTs.
- For hydro stations (existing and new) the same principles of normative annual plant availability factor as in Tariff Regulations, 2009 may be followed.
- For new open cycle gas based peaking stations NPAF has been recommended as 95% for peak hours.
    - Also an additional allowance of 50% towards O&M expenses over and above that is allowed in 2009 regulations have been recommended to take care of additional O&M expenses due to frequent start/stop of the machine.

Separate tariff philosophy for pumped storage hydro generating stations

- A separate tariff fixation for pumped storage hydro generating stations has been suggested.

Supply of gas at varying quantity for peak and off-peak periods

- For combined cycle gas based stations the Task Force has recognized that the existing gas supply contracts do not provide for variation in supply of gas.
    - The proposed operation of combined cycle gas based stations would require them to minimize generation during off-peak night hours by closing down gas turbines (GTs) after the evening peak hours and restarting before the morning peak hours. Thus in a module of 2 GTs and 1 steam turbine (ST), one GT could be closed down during the night off-peak hours so that ST remains in service at partial load with 1 GT (with nearly 50% loading).
    - The CCGT power plant with single shaft GT and ST configuration could back down generation during off-peak hours to about 70%. It may result in higher heat rate by about 4% which may have to be allowed. It is expected that with increase in gas pipeline capacity such variation could be possible at most of the power stations connected to the national gas grid.
    - For other CCGT stations connected to isolated or smaller gas grids the existing tariff structure may continue.
- The Task Force has therefore recommended that supply of gas of varying quantity during off peak and peak periods by the GAIL and other gas supply companies would need to be taken up at appropriate level in the Government.
- The implementation of the recommendation for the gas based stations is dependent on supply of gas in varying quantity during peak and off-peak periods.
- The existing CCGT stations which do cyclic duty may also have to be given additional margin of 2% in heat rate norms to allow for start and stop of GTs.

Norms for gas engine based generating stations

- The fixed cost recovery could be linked to the peak hour availability as in case of open cycle gas base peaking stations. The Commission may specify norms of operation and O&M cost norm for gas engine based generating stations to be used as peaking stations in consultation with CEA.

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CONTENTS

Chapter – I

CONSTITUTION OF THE TASK FORCE

1.1 The Central Electricity Regulatory Commission (CERC) in its meeting held on 20.7.2009 considered the issue of differential fixed charges for peak and off peak hours for the generating stations under cost plus regime as envisaged in the Tariff Policy and decided to constitute a one member task force headed by Shri Rakesh Nath, Chairperson, CEA and Ex-Officio Member, CERC for the purpose.

1.2 The terms of reference of the Task Force included :

- To examine the issues relating to tariff structure for generating stations set up for meeting the peak demand, such as gas based and storage type hydro stations.
- To suggest measures that could suitably incentivize as also mitigate the risks (e.g. risks associated with low plant utilization factor) to the investors who want to set up power station for meeting peak requirements.
- To consider the desirability of permitting differential peak and off peak tariffs even for base load power plants as it would make the sale of costlier peaking power from peaking stations easier.

1.3 The Task Force was assisted by Shri S.C. Srivastava, Joint Chief (Engg.), Shri S.K. Chatterjee, Dy. Chief (Regulatory Affairs) and Shri S.N. Kalita, Dy. Chief (Fin.) of CERC.

Chapter – II

INTRODUCTION AND HISTORICAL PERSPECTIVE

2.1 Legal and Policy framework

2.1.1 The Electricity Act, 2003 provides in section 61 the guiding principles for the appropriate commission which are required to be taken into consideration while specifying the terms and conditions of tariff. The guiding principles include inter alia the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments.

2.1.2 The National Electricity Policy and the Tariff Policy also underscore the need for differential tariff structure for peak and off peak periods to induce energy efficiency, demand side management. The relevant provisions of the Tariff Policy are quoted below:

> Para 6.2(1):
>
> *"A two-part tariff structure should be adopted for all long term contracts to facilitate Merit Order dispatch. According to National Electricity Policy, the Availability Based Tariff (ABT) is to be introduced at State level by April 2006. This framework would be extended to generating stations (including grid connected captive plants of capacities as determined by the SERC).* ***The Appropriate Commission may also introduce differential rates of fixed charges for peak and off peak hours for better management of load****."*
>
> Para 6.3:
>
> *Captive generation is an important means to making competitive power available. Appropriate Commission should create an enabling environment that encourages captive power plants to be connected to the grid.*
>
> *Such captive plants could inject surplus power into the grid subject to the same regulation as applicable to generating companies. Firm*

supplies may be bought from captive plants by distribution licensees using the guidelines issued by the Central Government under section 63 of the Act.
The prices should be differentiated for peak and off-peak supply and the tariff should include variable cost of generation at actual levels and reasonable compensation for capacity charges.
Alternatively, a frequency based real time mechanism can be used and the captive generators can be allowed to inject into the grid under the ABT mechanism.
Wheeling charges and other terms and conditions for implementation should be determined in advance by the respective State Commission, duly ensuring that the charges are reasonable and fair.
Grid connected captive plants could also supply power to non-captive users connected to the grid through available transmission facilities based on negotiated tariffs. Such sale of electricity would be subject to relevant regulations for open access."

2.2 Historical Perspective

2.2.1 The need for separate tariff for peak and off peak periods has been emphasized in several deliberations and reports on power sector reforms.

2.2.2 Way back in 1990, the Committee constituted under the Chairmanship of Shri K.P. Rao on Fixation of Tariffs for Central Sector Power Stations (K.P. Rao Committee) recognized the need for separate treatment for peak and off-peak power. Relevant extract from the Report is reproduced below:-

"In the above situation, sharing of fixed expenses of on the basis of capacity allocation as at 38(ii) above, independent of the receipt of corresponding quantum of energy or the share of power during peak and off peak times places an unfair financial burden on such States. To overcome this, the following could be considered:

(i) The share of fixed costs should initially be computed on the basis of energy drawls as per global energy accounting and billed for accordingly by the Central Generating Company.

(ii) These will be further moderated as explained below.

(a) Where a Board does not receive its share of power in terms of energy but has been drawn by some other State ignoring the needs of the beneficiary States, the same may, with mutual consent, either be rectified by regulating future drawls, or a financial penalty attached. The financial disincentive/surcharge levied on such over-drawls would go to the credit of the States which have foregone that power. This would be in addition to the fixed charges recoverable per unit, which could be transferred, under arrangements between the Boards, to the State which has drawn power.

(b) It would be necessary that a distinction should be made between drawl of power in the peak and off-peak time. Over-drawls in peak time should be over a stiffer surcharge compared to over drawls in off-peak time – (say 10% to 50% of fixed charges), as may be decided in the REB.

(iii) ……………………

Need to ensure absorption of zero cost energy.

43 In the case of hydro generating stations, the incremental cost of generating power is zero. It, therefore, follows that all attempts should be made to absorb hydropower on a 100% basis, by backing down other forms of generation of power. This is particularly so when waters have to be released because of inadequate storage capacities or because of irrigation requirements or heavy rains. Whenever this happens, hydropower generation should take place to the maximum extent possible and thermal generation backed down and such power should invariably be absorbed by the system. Where waters can be stored and power generation can be regulated to meet the future demands of the system as and when necessary, the generation may conform to the requirements of the system, peaking or otherwise.

44 To enable the above being done, it is necessary that tariff for Central hydro generating stations distinguishes between the power that is generated under conditions of surplus water or releases made to suit irrigation purposes, as distinct from power system requirements. The tariff for such power should be fixed at a level lower than the fuel cost of the thermal generating stations of the region. This would motivate all *the Boards to back down their thermal generation and absorb the lower cost hydropower. It is also necessary that such concessional tariffs are notified well in advance to enable proper planning of power generation and shut-down/maintenance of thermal units.*

45 As regards firm power i.e power that can be generated according to the requirements of the system demand, the tariff should be so calculated as to ensure that on the overall, i.e. taking into account revenues arising from the uniform (seasonal) power also, the generating company recovers the full fixed charges plus the prescribed return. The underlying idea is that in a surplus situation, the Boards would be motivated to buy zero cost hydro power by providing an attractive tariff which does not run counter with the Boards' commercial interest whereas in a shortage condition, the Boards would themselves be willing to pay slightly higher tariff to draw power from the hydro stations, including peaking requirements thus motivating the Boards at all times to absorb the hydro power to the fullest extent.

46 The Committee unanimously recommends that a rate of 5 paise per kwh may be adopted for such seasonal power. Credit for this income should be taken while determining the tariff for firm power, as indicated in para 42. Modalities for segregating firm and seasonal power and adjustment of tariffs will be determined by CEA in consultation with the REB.

NEED TO DISTINGUISH BETWEEN PEAK/OFF PEAK POWER AND NEED FOR TOD METERING

47 The above arrangements would call for the "Time-of-the Day" metering systems. It is, therefore, imperative that TOD meters are installed on an urgent basis on all inter-connecting points on the system between States, as well as generating stations the Central generating Companies. The Committee recommends that this should be done on a top priority basis so that accounting and billing of power can be done duly differentiating its nature viz surplus power, peaking power, over-drawls and under-drawls in peaking/off peak times, and so on, and necessary monetary penalties/incentives and disincentives could be attached to such drawls."

2.2.3 In 1994, the report of a study team led by ECC, Inc., Fairfax, Virginia in collaboration with NERA, Washington, D.C. also examined the alternative tariff structures for bulk power transactions and for power transmission. The study was commissioned by ADB for Government of India. The relevant provisions of the report are quoted below:

"4.3 Basic Tariff Pricing Considerations and Definitions

There are basic tariff pricing considerations which are applicable to the different types of tariffs discussed in the following sections. These pricing considerations include:

1. *Product definition*

   The basic interchange products are capacity and energy. It is helpful to describe electricity as a manufactured product in order to promote an increased commercial environment for the production and sale of bulk power.

   The charge for capacity includes fixed costs. The charge for energy includes the variable production costs. Capacity and energy are separable products and should generally be purchased separately, each being a part of the two part tariff concept. It is obvious that these two products are interrelated, e.g. system capacity which is related to low variable cost energy may be more valuable than low cost capacity which is associated with high variable cost energy. Therefore, capacity pricing is very much a function of the associated energy cost.

   There are many other products which may be defined, e.g. reactive supply and scheduling services, and which may be priced separately. However, it is the Study Team's experience that bundling of capacity and energy pricing into a single one part tariff, creates problems and perverse economic incentives.

2. *Time and season differentiation*

   The cost and value of interchange is likely to vary as a function of time and season, e.g. during the monsoons energy from hydro based systems is worth less than during dry periods. Therefore, it is accepted that interchange should typically vary in price at least for on-peak and for off-peak periods, either daily or seasonally.

3. *Duration*

The value of a transaction to either the buyer or to the seller may vary as a function of the duration of the transaction. The pricing should reflect this value. Because of the shortage of generating capacity in India, it could be expected that sellers may only want to commit to relatively short transactions. However, if a buyer were willing to pay a sufficient premium, the seller might be willing to negotiate a longer duration transaction.

4. *Size*

It is possible that a single 100 MW transaction may be worth a great deal more to a seller than ten transactions each of which is ten MW. In the latter case, the seller's administrative costs are likely to be higher than for the single larger transaction. The tariff price should reflect these value and cost effects.

5. *Degree of firmness*

Transactions are negotiated on the assumption that they can be delivered. However, it is not unusual for unexpected outages of generation or transmission to require the transaction to be totally or partially terminated. If a seller has negotiated multiple transactions and some, but not all must be terminated, one possible criterion is to cut the buyer which paid the lowest amount. The interchange tariff may vary the price as a function of the degree of firmness of the transaction.

6. *Frequency*

India has a significant problem with widely varying frequencies. Just as a frequency linked tariff has been proposed for consideration for generation, so could frequency also be a factor in pricing interchange. If metering were available to support such a tariff, it might be possible to relate pool transactions to the frequency, with increasing penalties as a function of the amount of frequency deviation from the nominal 50 Hz. However, this type of tariff only appears to be applicable to pool transactions.

In setting any tariff, the selling utility must know its internal cost of producing the product and **the value** *of selling its product. The buying utility must know its alternative cost and* **the value** *of the purchase. The six tariff pricing considerations listed above may or may not be significant in any specific transaction. However, at a minimum, each should be considered. But, in all instances, the approach should be in* *view of the capacity, reflecting fixed costs, and energy reflecting variable costs. These capacity and energy costs may then be varied as a function of the above list of factors.*

5.2.3 Availability Tariff

A generation tariff based on availability is standard in the industry. It provides the proper signals and incentives to the generators so that they provide their service in support of overall system requirements. One of the major advantages of an AT over the MRT approach is that the AT provides better incentives for achieving good grid control discipline.

An outline of one approach to implement an availability tariff is given below.

1. *Each generator has a target availability defined, which will be based on past operating experience and industry published data. This value will be reexamined every two years in order to reflect changes in generator operation.*
2. *For each generating unit a Basic Availability Credit (BAC) is calculated based on the fixed costs for the unit and its target availability. The BAC is given as Rupees/MW for each hour the MW is available. The value of the BAC will be such that when the target availability is reached the fixed costs of the unit will be covered.*
   *For example, suppose the BAC is set at X rupees/MW actually available. A unit with an actual capability of 100 MW for one hour would receive X*100 rupee for that hour, even if the unit was not dispatched at the full 100 MW.*
3. *For operation beyond the target availability, a smaller incentive credit defined as the Basic Incentive Credit (BIC) will be utilized to determine the availability payment to the generator. The reason for the reduction to the BAC is that the unit's fixed costs, such as depreciation, interest on loans, O&M, etc., are recovered once the target value is reached. Further income for these items is not needed. The new BIC would only cover an incentive payment plus any incremental costs not covered in the initial fixed cost calculation.*
4. ***The BAC and BIC can be modified on a seasonal, time-of-day, or week-end/weekday basis. This provides a means <u>to send accurate signals to the generators that reflect the differing needs of the system</u>.***

5.3 Hydro Generation Tariffs

Hydro generation differs from thermal generation in one very important aspect and that is the supply of "fuel". Where a thermal plant assures an adequate but not excessive supply of fuel by a purchasing procedure based on forecasted needs, a hydro plant's availability of fuel (water) is not determined by purchase but by many factors, many of which are not under its control. These factors include, but are not limited to, precipitating to supply the water, widely variable inflows into the plant, amount of storage and, for multiple use installations, the requirements of other applications (i.e. irrigation, flood control, etc.).

Expected hydro generation is based on the concept of "dependable energy". Dependable energy is defined as the expected level of hydro generation in 90% of the years. Dependable energy varies throughout the year and is higher in the wet seasons as compared to dry seasons. The estimated amounts of dependable energy are based on computer simulations which use historic or reconstructed stream flow records. Typically, actual energy will exceed dependable energy in nine out of ten years. Conversely, actual energy will be less than the dependable energy in one out of ten years.

All of the above factors dictate different types of use of the plant, such as run of river, peaking, and continuous operation*. Each is dependent on the characteristics of water availability. This wide variation of applicability of hydro complicates the formation of a tariff for hydro generation.*

The alternative hydro tariffs discussed include:

- *Incremental Energy Cost Tariff*
- *Fixed Cost Tariff*
- *Hybrid Cost Allocation Tariff*

5.3.1 Incremental Energy Cost Tariff

An Incremental Energy Cost Tariff was one of the options considered for a hydro generation tariff. This type of tariff would be a one-part tariff based on each unit's fixed and operational costs and its dependable energy generation (less the 12% "free" portion allocated to the home State). The main characteristics of this type of tariff include:

1. *Fixed costs are determined for each unit in the same manner as done for thermal stations. The exception is that the rates of depreciation would be different, as provided in the Electricity (Supply) Act.*

2. *O&M expenses may initially be taken at 0.5% of capital costs. Likewise, auxiliary consumption may be taken at 0.5% (Normative). These values may be reviewed and modified every two years.*
3. *Different tariffs for energy pricing would be applied as follows:*

a. *Seasonal hydro energy generated in excess of design energy shall be priced at 5% of average hydro energy rate. The average energy rate is the total annual expenses divided by total dependable energy less auxiliary consumption.*
b. ***Off-peak energy may be priced at a fixed rate which is lower than the lowest variable cost in the Region.***
c. ***The tariff for peak energy is computed by dividing annual fixed expenses less revenue from a) and b) above by the sale of peak energy.***

Since the energy pricing presented under 3 above is based on estimated or design values, it will be necessary to adjust the tariffs at the end of the year to reflect actual energy generated. All adjustments needed to allow the proper income (fixed cost and profits) to the Hydro generator, whether they are plus or minus, should be reflected in a retroactive adjustment of the peak energy tariff.

5.3.3 Hybrid Cost Allocation Tariff

The major concepts of the Hybrid Cost Allocation tariff are:

1. *Annual fixed costs for the plants are divided between availability payments and incremental energy costs.*
2. ***<u>For each plant, off-peak and on-peak energy rates will be developed. The off-peak rate will be less than the incremental cost for pit head coal fired units. The net design energy generation (design energy generation less the "free" energy located to the home State) will be divided into on-peak and off-peak portions.</u>*** *Each of these portions will be multiplied by the appropriate rate and the sum of the two energy calculations will represent the portion of the annual fixed costs allocated to incremental energy costs.*
3. *The remainder of the annual fixed costs will be paid by an availability payment. A target mechanical availability will be set and a BAC will be developed similar to the availability tariff developed for thermal plants. The BAC will be based on the target mechanical availability, net capability (total capability less the "free" allocation to the home State) and will be expressed in Rupees/MW for each hour available. Availability; will be calculated for mechanical availability of plant, neglecting restrictions that might occur due to lack of water. Once the*

target availability is reached, the availability portion of the fixed charges will be covered.

4. *For mechanical availability beyond the target, a lower BIC in Rupees/MW for each hour, covering an incentive and the incremental O&M costs only, will be utilized. The BIC will be lower than the BAC.*
5. *Actual energy output will be billed at the rates developed in Item 2 above.*
6. *If the water inflow cannot be stored in order to utilize as much water as possible the plant will be designated "must run" and the energy priced at an off peak rate. Should the RLDC direct the plant to reduce output during a "must run" condition, due to system constraints, the lost revenue will be returned to the plant through an increase in the BAC or BIC during the reduced output period. The increase will be applied only to those units that were backed down and will be such that if these units are available during the entire reduced output period the plant's lost revenue will be recovered.*

A variation of the hybrid tariff is required to cover the area of Pumped Storage Hydro generation. *This type of installation differs from normal hydro installations in that it uses relatively inexpensive off peak energy to pump water up hill into the upper reservoir. This water is then used to generate electricity during peak periods and replaces high cost energy that would normally be utilized. Therefore,* **the energy produced by a pumped storage unit has an incremental energy cost associated with it to cover the pumping costs***.*

The Study Team recommends a tariff for pumped storage units that closely resembles the Hybrid Tariff as described in the following points:

1. *Annual fixed costs are recovered through availability payments and incremental energy costs.*
2. *For each week of operation the cost of pumping water, priced at the lowest incremental cost energy available to the RLDC for pumping operation, plus any costs associated with natural flow into the upper reservoir are divided by the total kwh of generation provided by the two sources of water, to determine an incremental cost of generated energy. Since it is stored in a reservoir along with input from other weeks a method of accounting is needed to determine the incremental cost of generation at any given time. The Study Team recommends that a "First In, First Out" concept be used.*
3. *During high water flow periods (monsoon season) the natural flow into the upper reservoir may exceed the amount of available storage. In order to make use of this excess flow, the pumped storage units at these sites must be dispatched on a "must run" basis with an off peak rate*

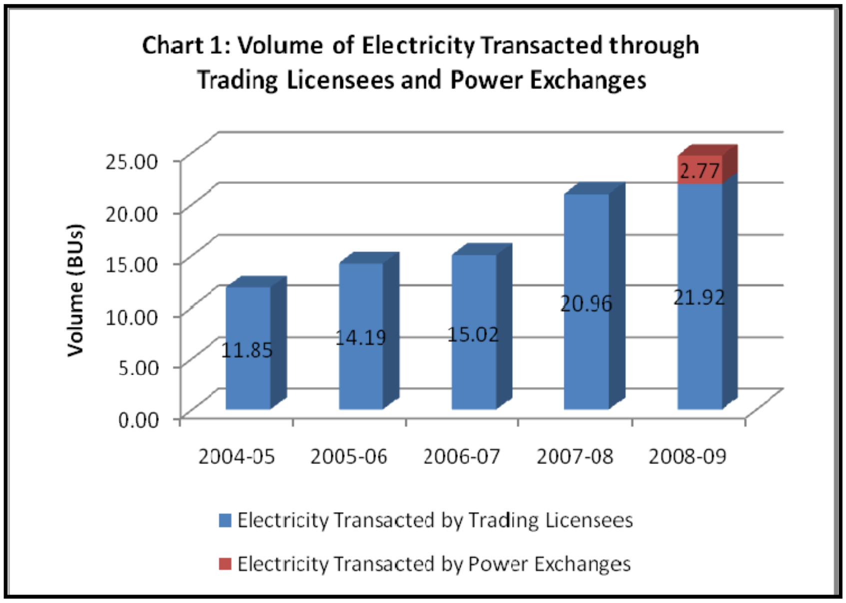
assigned for the incremental energy cost. This will ensure water is not spilled unnecessarily.

4. *The amount of "must run" energy must be estimated on an annual basis utilizing historical data. Each year, this estimated MWh value times the off peak incremental cost used in #3 will be used to determine the portion of the annual fixed costs which will be recovered through energy sales. For example, this value may be equal to 5% of the unit's annual fixed costs.*
5. *The remainder of the annual fixed costs will be paid by an availability payment the same as proposed for standard hydro installations.*
6. *"Must run" energy above or below the estimated must run amount represents additional profit or loss for the plant, respectively. This amount of money is calculated by using the off peak incremental rate times the MWh above or below the average. Should the RLDC direct the plant to reduce output for some period of time during a "must run" situation due to system constraints, the amount of income lost by the plant will be returned to the plant through an increase in the BAC or BIC during the period of reduced output. The amount of increase in the BAC or BIC will be such that if the units remain available during the constrained operating period, the plant will be fully compensated for the lost "must run" energy income.*
7. *Since the economy of pumped storage operation is extremely dependent on system conditions, the RLDC will issue instructions for the operation of the plant in both the generation and pumping modes. Failure of the plant to follow RLDC instructions will be penalized by a reduction in availability payments.*

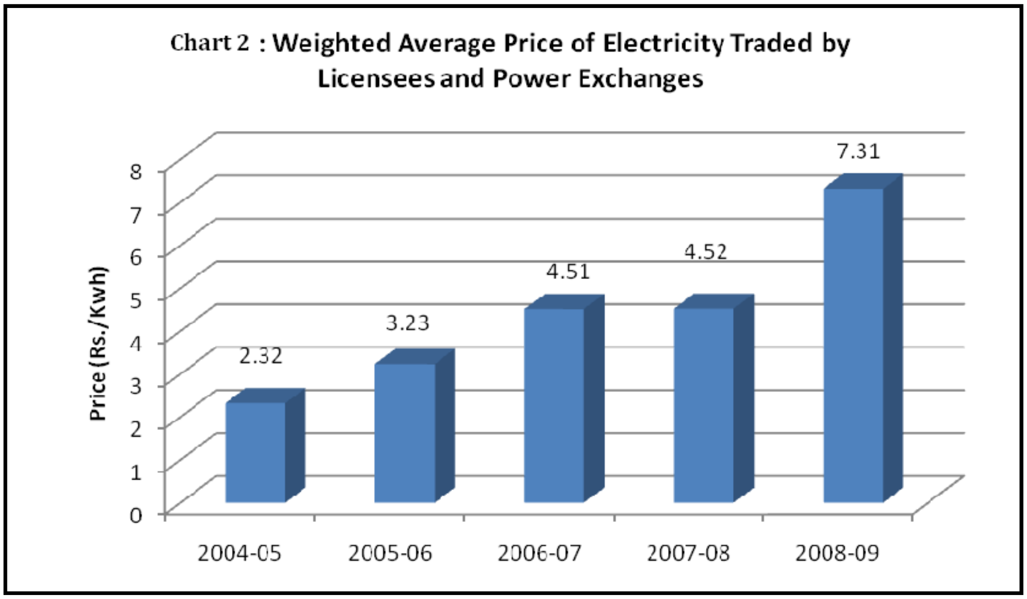
Chapter – III

ANALYSIS OF TRANSACTION IN SHORT-TERM MARKET

3.1 Over the period the volume of transaction in the short-term market has been increasing. The short-term market constitutes primarily the transactions involving traders and power exchanges. The following figure shows the increasing volume of electricity transacted in the short-term market for the period from 2004-05 to 2008-09.



3.2 Along with the increasing volume, the prices of electricity transacted in the short-term market have also been persistently increasing over the years. As per the Report of Market Monitoring Cell (MMC) of CERC from August, 2008 to June, 2009 the weighted average price of electricity transacted through trading licensees has increased three times during the period - from Rs.2.32/kWh in 2004-05 to Rs.7.31/kWh in 2008-09.



3.3 This increasing trend of price is again a manifestation of the mismatch between demand and supply. This mismatch further accentuates the price level in the short-term market depending on time of day or seasons in a year. The following figure shows the average price of short-term transaction of electricity, month-wise from August, 2008 to December, 2009.

Table-1: PRICE OF SHORT-TERM TRANSACTIONS OF ELECTRICITY (Rs/Kwh)

Period	Bilateral through Traders				Power Exchange		UI	
	RTC*	Peak#	Off-peak@	Total	IEX	PXIL	NEW Grid	SR Grid
Aug-08	6.51	7.43	7.29	6.78	7.61		5.17	7.64
Sep-08	7.27	6.60	6.90	7.17	7.95		6.50	7.87
Oct-08	6.99	8.90	8.51	7.78	8.32	7.57	6.32	8.97
Nov-08	7.56	8.82	8.35	7.98	7.47	7.22	5.33	8.55
Dec-08	7.77	8.37	8.04	7.89	6.64	6.58	4.89	7.66
Jan-09	7.43	8.55	6.78	7.23	6.16	6.86	4.99	7.61
Feb-09	6.89	8.16	6.19	6.58	6.85	7.42	4.89	7.68
Mar-09	7.35	8.08	7.53	7.43	8.33	8.54	4.85	8.20
Apr-09	6.83	9.05	8.47	7.21	10.10	10.18	5.36	6.04
May-09	6.60	8.18	8.03	6.82	6.84	8.74	4.17	3.99
Jun-09	5.04	6.44	5.07	5.05	7.39	9.60	4.94	5.10
Jul-09	4.72	5.92	4.98	4.75	4.81	4.85	4.12	4.67
Aug-09	4.46	6.32	5.77	4.64	7.40	6.15	6.29	5.85
Sep-09	4.60	6.02	5.48	4.73	4.00	4.32	5.02	4.20
Oct-09	4.86	6.48	5.80	5.07	4.73	5.18	4.24	5.83
Nov-09	5.05	5.76	5.91	5.33	3.16	3.39	2.72	3.79
Dec-09	4.96	5.12	5.06	4.99	3.22	3.07	3.26	3.92

**** RTC: Round the Clock***
 # Peak : Peak hour transactions of the month
@ Off-peak : Off-peak hour transactions of the month

3.4 Clearly the price of electricity transacted during peak periods was high when compared with the price of electricity transacted during Round the Clock (RTC) and off-peak periods in the transactions through traders.

3.5 The above trends both in terms of volume and price of electricity in the short-term market further reiterate the need for setting up of adequate generation capacity in general and peaking power plants in particular to enable the distribution companies to make long-term planning for meeting their requirements for power for base-load as well as peak-load.

Chapter – IV

POWER SUPPLY POSITION

4.1 Load Generation Balance Report is brought out by the CEA at the beginning of the year to present a review of the actual power supply position during the previous year in the country and an assessment of the power requirement during the year in the various States.

4.2 The anticipated power supply position of the Country for the year 2009-10, region-wise, emerges as presented in the Table below:

Table: 2 Anticipated Power Supply position for the year 2009-10

Region	Energy				Peak			
	Require-ment	Availabi-lity	Surplus(+)/ Deficit (-)		Demand	Met	Surplus(+)/ Deficit (-)	
	(MU)	(MU)	(MU)	(%)	(MW)	(MW)	(MW)	(%)
Northern	241461	222875	-18586	-7.7	35460	29970	-5490	-15.5
Western	276827	234819	-42008	-15.2	37330	34276	-3054	-8.2
Southern	220126	201222	-18904	-8.6	31384	27216	-4168	-13.3
Eastern	91386	93613	2227	2.4	15110	14165	-945	-6.3
North-Eastern	10744	9586	-1158	-10.8	1804	1537	-267	-14.8
All India	840544	762115	-78429	-9.3	118794	103816	-14978	-12.6

Source : CEA

4.3 CEA has also worked out the anticipated power supply situation at the end of the 11th Plan in 2011-12 based on the demand projections as per the 17th EPS and expected capacity additions of 62374 MW with higher degree of certainty during the Plan. The power supply position is expected to be as follows at the end of the 11th Plan:

Table: 3

Region	Energy				Peak			
	Require-ment	Availabi-lity	Surplus(+)/ Deficit (-)		Demand	Met	Surplus(+)/ Deficit (-)	
	(MU)	(MU)	(MU)	(%)	(MW)	(MW)	(MW)	(%)
Northern	294841	293501	-1340	-0.5	48137	43790	-4347	-9.0
Western	294860	294456	-404	-0.1	47108	43475	-3633	-7.7
Southern	253443	222558	-30885	-12.2	40367	34033	-6334	-15.7
Eastern	111802	126510	14708	13.2	19088	19015	-73	-0.4
North-Eastern	13329	11598	-1731	-13.0	2537	2395	-142	-5.6
All India	968659	948836	-19823	-2.0	152746	142765	-9981	-6.5

Source : CEA

Chapter – V

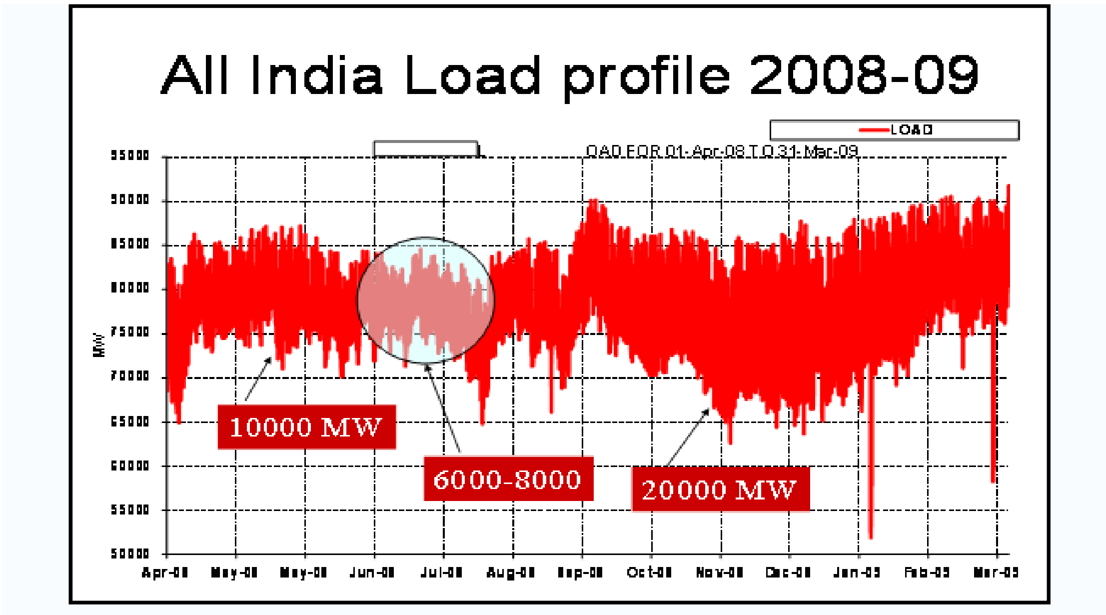
ANALYSIS OF THE NEED FOR PEAK PEAKING PLANTS

5.1 It may be seen that the anticipated energy and peaking shortage in the country in the current year 2009-10 are expected to be of the order of 9.3% and 12.6% respectively and by the end of the year 2011-12 are expected to be of the order of 2% and 6.5 % respectively based on the present position of commissioning of new generating capacity during the 11th Plan. Thus the energy availability in the country by the end of 2011-12 is expected to improve substantially reducing the energy shortages to marginal level of about 2% but the peak shortages may continue to prevail.

5.2 During the year 2008-09, though the total ex-bus energy availability increased by 3.76% over the previous year and the peak met increased by 6.6%, the shortage conditions prevailed in the country both in terms of energy and peaking availability. All the Regions in the country namely Northern, Western, Southern, Eastern and North-Eastern Regions continued to experience energy as well as peak power shortage of varying magnitude on an overall basis, although there were short –term surpluses depending on the season or time of day. The surplus power was sold to deficit states or consumers either through bilateral contracts, Power Exchanges or traders.

5.3 Let us look at the all India load profile of the year 2008-09:

Figure: 1



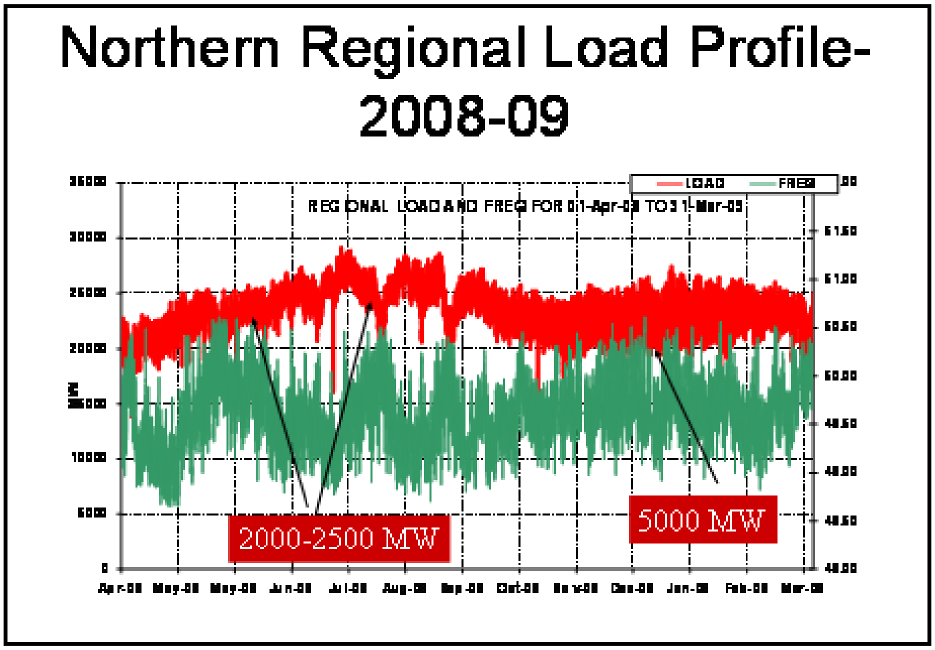
Source: NLDC

5.4 It can be seen that the difference in maximum demand and minimum demand during winter months is of the order of 20000 MW as against the difference of about 10000 MW during summer months.

5.5 The minimum demand is of the order of 70000 to 75000 MW throughout the year irrespective of the peak period of the days. These are required to be met throughout the year calling for a base load capacity to sustain the demand of this magnitude. The demand over and above 75000 MW (maximum of the order of 85000-90000 MW as per the curve) could be met through peaking power plants or the power plants which are relatively low on merit order thus not getting dispatched fully throughout the day.

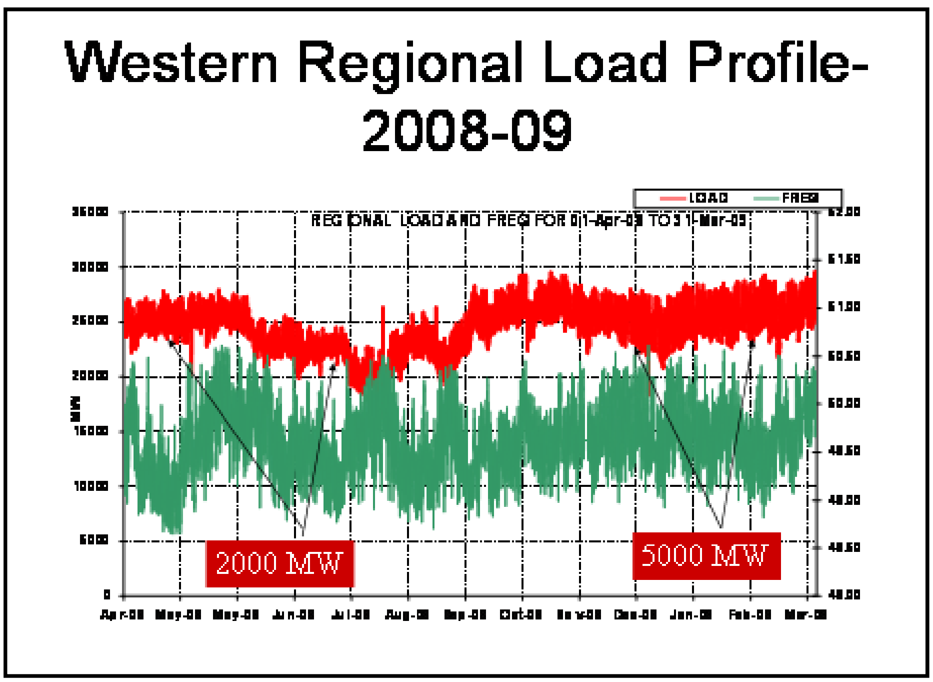
5.6 The following figures also further highlight the huge variation in demand between the peak and off-peak periods across regions in the country and hence underscore the need for peaking plants:

Figure: 2



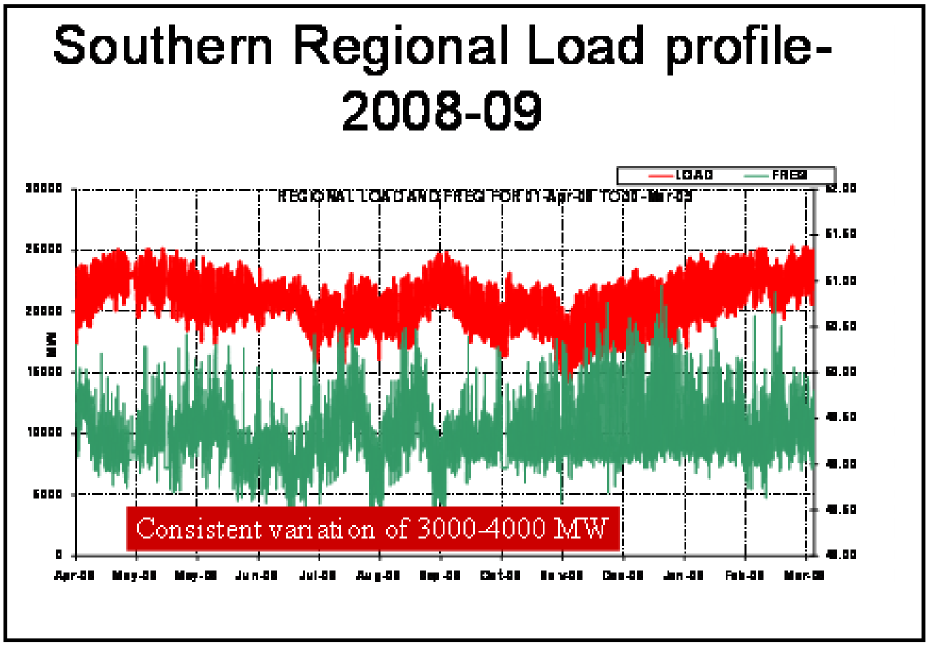
Source: NLDC

Figure: 3



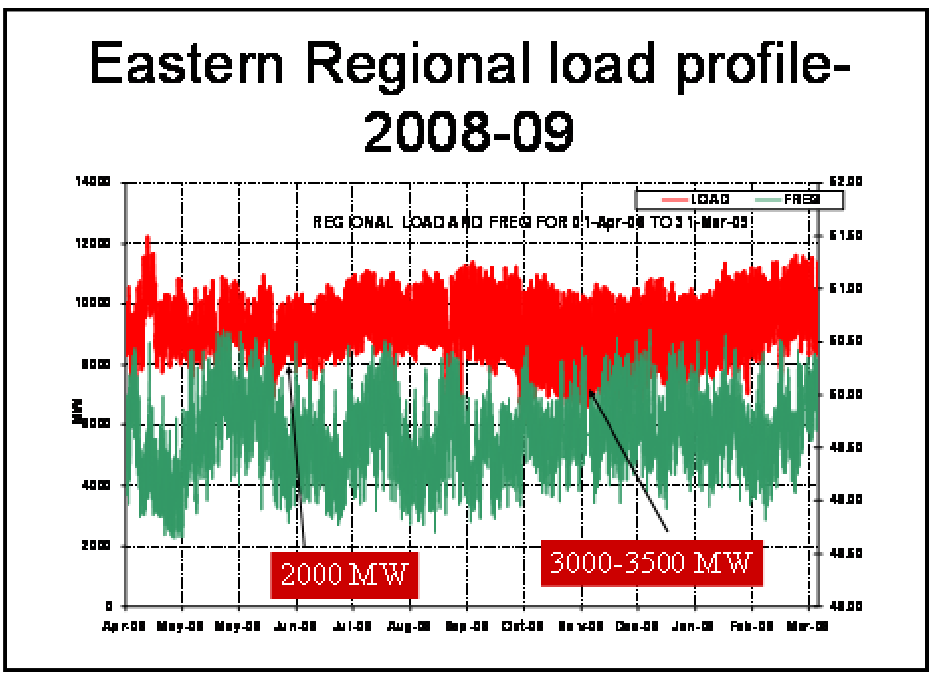
Source: NLDC

Figure: 4



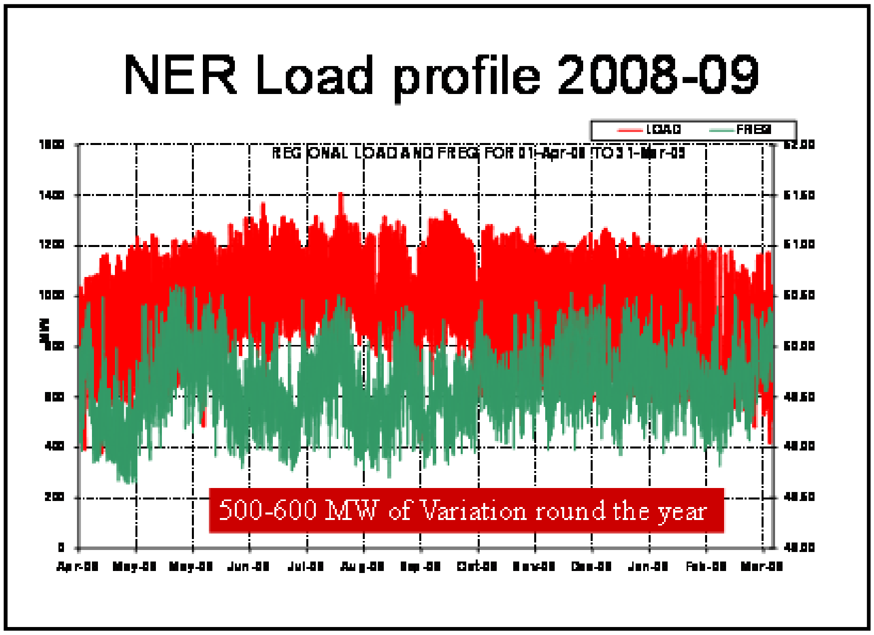
Source: NLDC

Figure: 5



Source: NLDC

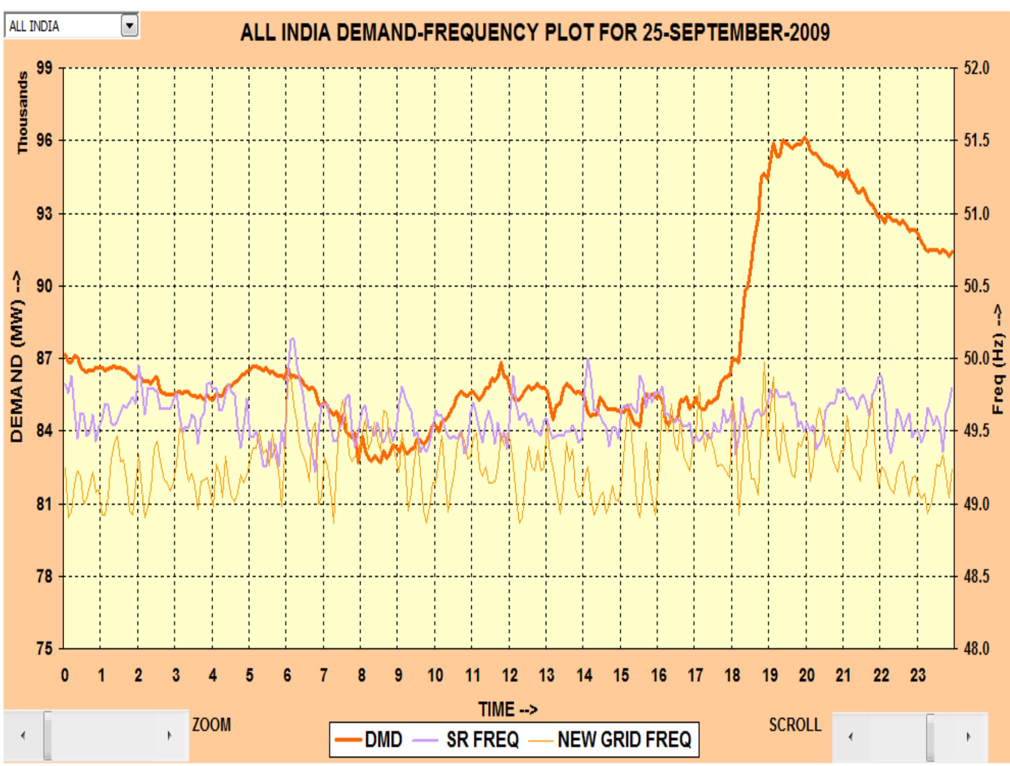
Figure: 6



Source: NLDC

5.7 The following figure represents the recorded load pattern of a particular day (restricted load) in a year:

Figure: 7



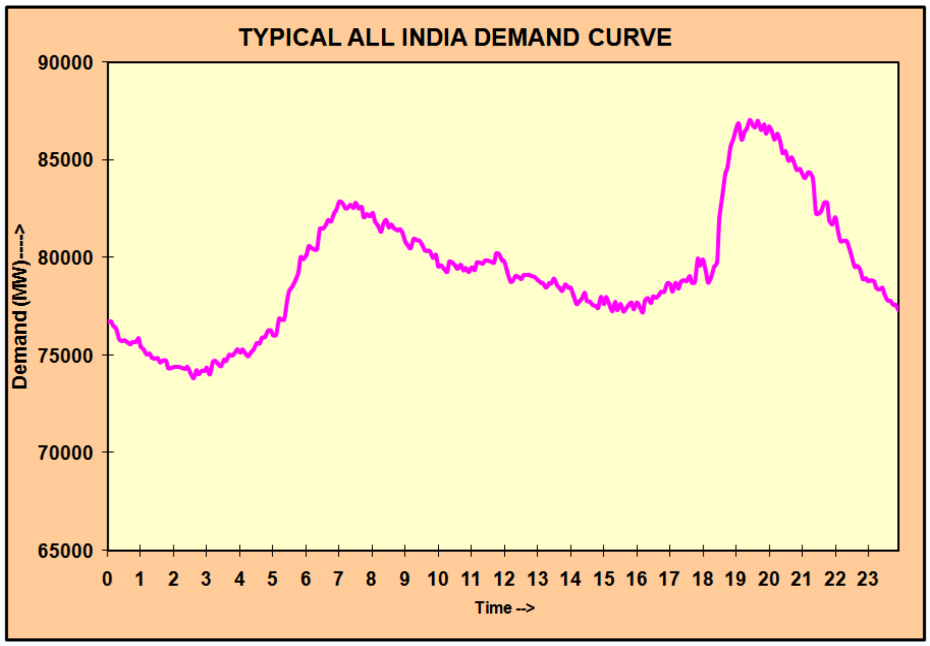
Source: NLDC

5.8 It can be seen that rise in demand during the evening peak was very steep at about 150 MW/minute. This establishes the need for peaking support with very high ramping rate. Peaking power can ideally be provided by pondage / reservoir based hydro plants. However, hydro capacity alone may not be able to meet the peaking demand. Fast response during peak hours could be provided by the gas engine based generation because of their excellent peaking support capability as discussed below:

- Plant Heat Rate at Part Load-No change in efficiency, e.g. Plant size of 96 MW with 11x8.73 MW can actually operate at 9% loading at the same plant efficiency.
- Plant Auxiliary consumption-Approx.1.5% of Plant capacity. Low gas pressure requirement [5bar(a)] eliminates requirement of gas compression.
- Additional O&M charge- No change due to variable load profile.
- Part load charge-No part load charge as the efficiency does not suffer with part loading on Plant due to multiple units.
- Additional fuel consumption due to per Stop/Start- Marginal, as gas consumption does not suffer due to fast ramp up rate and zero idling.
- Water Consumption- Negligible due to air cooled option. Consumes approx 1.5m3 per day of treated water for 100 MW operation for 24 hours.
- Ramp-up time- 30% loading per minute & about 1/2 minute from start time to synchronisation. This leads to practically "zero" idling.
- Transmission loss minimal as it is load centre based solution.

5.9 It would also be important to assess, in this context the time period during which peak demand persists. A typical all India demand curve is as follows:

Figure: 8

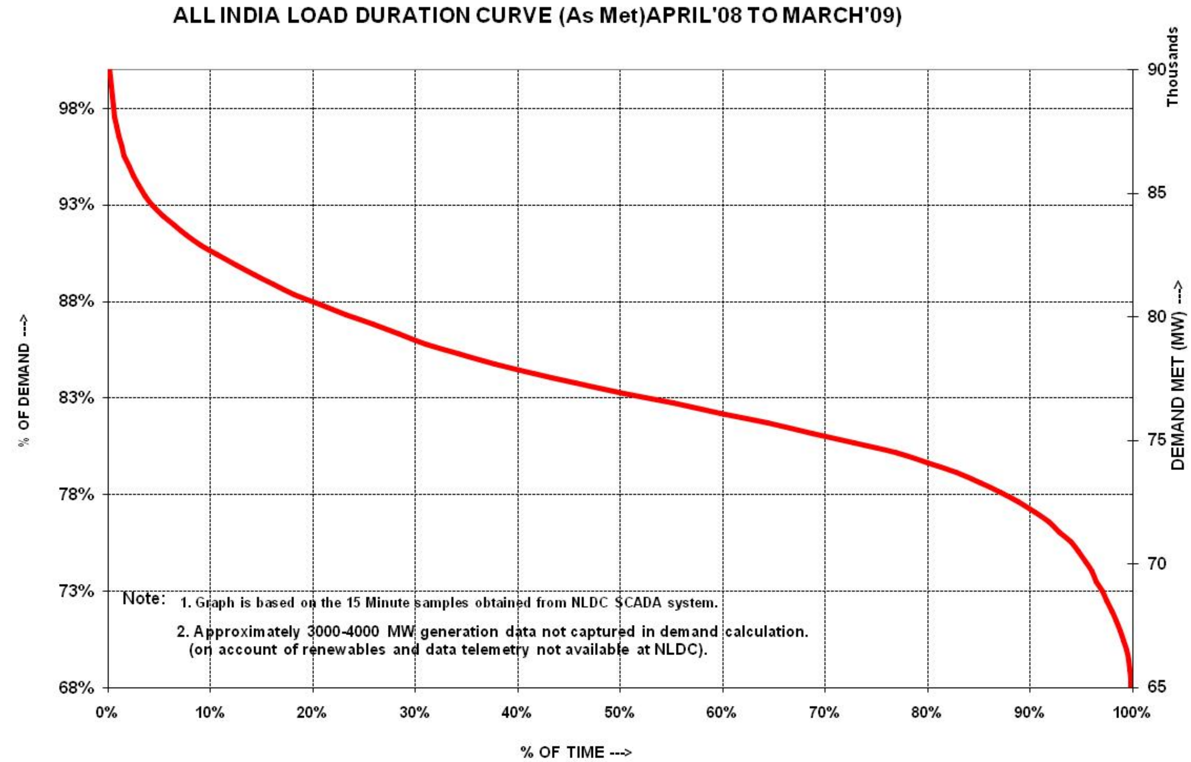


Source: NLDC

5.10 It can be seen that there are typically two periods of the day when the demand is at its peak; one in the morning of about 2 hours duration and another in the evening of about 4 hour duration.

5.11 The following figures show respectively the all India load duration curve (as met) for 2008-09 and projected for 2016-17:

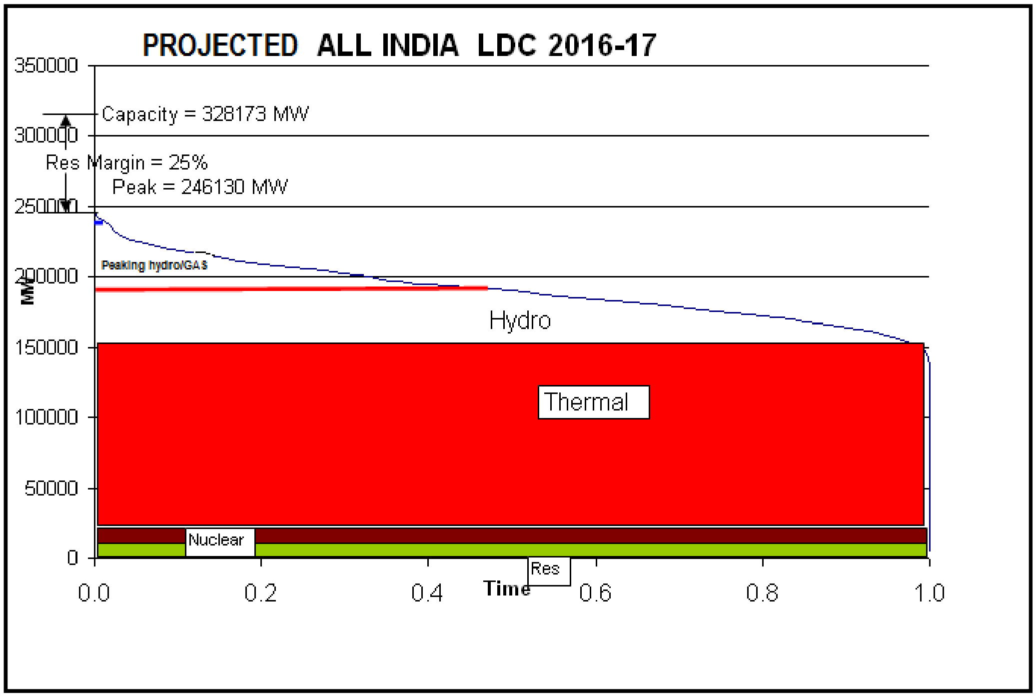
Figure: 9



Source: NLDC

Figure: 10

Figure: 10



Source: CEA

5.12 The optimum base load capacity is the one which can supply energy under the Load Duration Curve (LDC) running at nearly full load both technically as well as commercially (with reference to its cost of operation and efficiency). On the merit order the demand is first met from nuclear or renewable energy sources or run of the river hydro stations and hydro plants with storage which have to release water to meet irrigation requirements which are must run, followed by generation from pit head coal based station, followed by load centre and coastal coal based stations, and combined cycle gas based station. Balance demand could be supplemented further by peaking power plants, namely, storage type hydro generating station including pumped storage schemes, open cycle gas turbine station, and gas based reciprocating engines.

5.13 Given the continuing peaking shortages on all India level and the region specific or State specific shortages there is a need for peaking power plants. At the same time, given the fact that energy shortages also persist we would continue to need investment in the base load / intermediate load stations.

5.14 Peaking plants are generally gas turbines that burn natural gas. A few plants burn petroleum-derived liquids, such as diesel oil and jet fuel, but they are usually more expensive than natural gas, so their use is limited. However, many peaking plants are able to use petroleum as a backup fuel. The thermodynamic efficiency of open cycle gas turbine power plants ranges between 30 to 42% for a new plant. Reciprocating gas engines are also good options for the peaking plants near the load centers and can provide higher efficiency of about 44%.

5.15 The hydro generating stations, other than run of the river type, can be operated, as and when required. In these stations water can be stored during off-peak hours so as to generate more power during peak hours. As such these hydro generating stations are normally used as peaking power stations. The pumped storage hydro generating station is also a good option for meeting peak demand.

5.16 The present installed capacity of the country is 156908 MW. About 108000 MW thermal, hydro and nuclear capacity is under construction in the country which is expected to be operational by the end of 2014-15. The break-up of the present capacity and that expected at the end of 2011-12 and 2014-15 is as under:

Table: 4 **All figures in MW**

		Installed capacity as on 31.01.2010	**Installed capacity expected by 31.3.2012 (with higher degree of certainty)**	**Installed capacity expected by 31.3.2015**
Hydro		36885 (23.5%)	42891(20.6%)	49008 (17.7%)
Thermal	**Coal**	82221	115261	165441
	Gas	17056	20309	21295
	Diesel	1200	1200	1200
Sub-total		100477(64%)	136770(65.5%)	187936(68%)
Nuclear		4120(2.6%)	7280(3.5%)	8680(3.1%)
Renewable		15427(10%)	21761(10.4%)	30760(11.2%)
		156909	208702	276384

5.17 The major capacity addition is expected in hydro, coal and renewable. Hydro capacity addition though small is also mainly in run of the river type or with small pondage. No peaking stations are under execution except 1000MW pumped storage scheme at Tehri, order for which is yet to be placed. Thus there is an urgent need to plan for peaking capacity. It would also be desirable to operate the combined cycle gas based capacity to meet mainly the peaking and intermediate load demand.

5.18 Most of the combined cycle plants have modules with 2 GTs and 1 steam turbine. It is proposed to close down 1 GT in each module after the evening peak hours and restart at the commencement of the morning peak hours. Thus, during night hours such plants may operate at about 50% capacity. Some modern combined cycle gas based plants have single shaft configuration with 1 GT and 1 ST. Such unit may have to be closed down completely during night hours after evening peak hours or may have to be operated at partial load during off-peak night hours.

5.19 Allocation of gas to the CCGT plants connected to gas grid from domestic sources corresponds to operation of these plants at a PLF of 70 to 75%. Cyclic operation of CCGTs in the manner indicated above will be optimal use of available gas. Presently, GAIL does not allow wide variation in withdrawal of gas by power plants. However, with increase in pipeline capacity such variations may be possible in near future. Matter will have to be taken with GAIL in this regard.

5.20 Similarly we may also have to plan some open cycle GTs / Reciprocating Gas Engines to meet the peaking requirements. These plants will be expected to be operated for about 6 hours a day. It is recommended that such open cycle plants may be constructed near the metro cities in the vicinity of existing or proposed gas grid. Besides meeting the peaking demand these plants could also be operated during the system contingencies such as low voltage, transmission constraints, etc., thus adding to reliability of power supply of the metro city.

5.21 Operation of CCGTs in peaking mode as suggested above and OCGT for peaking may result in higher heat rate and O&M costs (on account of higher repair and maintenance cost) for which the power plant will have to be compensated. An analysis has been made about additional costs for peaking operation for CCGT and OCGT plants and is enclosed at Appendix - I. The results are summarized below:

Table: 5

Description	Units	Base Case GTs operating in CC mode	Case-1 GTs operating only for peaking purposes	Case-2 2GTS+1ST module with one GT trip in the night	Case-3 Single Shaft Machine-Module at 70% load in the night
Impact on Repair and Maintenance Cost	Factor	1.00	1.56 to 2.53	0.83	1.00
Impact on heat rate	Factor	1.00	1.00	1.02	1.04

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CHAPTER VI

EXISTING TARIFF STRUCTURE

6.1 We analysed in the previous chapter that given the load pattern across different regions in the country and the trends of transactions in the short-term market, there is a need for peaking plants. Now the question is whether the existing tariff structure has adequate incentive for peaking plants and whether there is a need for separate treatment in terms of tariff for peak and off-peak hours of the day. Let us analyse the existing tariff structure first.

6.2 ABT Tariff Mechanism

6.2.1 Presently we have Availability Based Tariff (ABT) structure for the generating stations regulated by CERC. The ABT is in vogue since 2001. The power plants have fixed and variable costs. The fixed cost elements are interest on loan, return on equity, depreciation, O&M expenses and interest on working capital. The variable cost comprises of the fuel cost, i.e., coal, gas and oil in case of thermal plants. In the Availability Tariff mechanism, the fixed and variable cost components are treated separately.

6.2.2 The payment of fixed cost to the generating company is linked to availability of the plant, that is, its capability to deliver MWs on a day-to-day basis. The total amount payable to the generating company over a year towards the fixed cost depends on the average availability (MW delivering capability) of the plant over the year. In case the average actually achieved over the year is higher than the specified norm for plant availability, the generating company gets a higher payment. In case the average availability achieved is lower, the payment is also lower. This is the first component of Availability Tariff, and is termed 'capacity charge'.

6.2.3 The second component of Availability Tariff is the ‘energy charge’, which comprises of the variable cost (i.e., fuel cost) of the power plant for generating energy as per the given schedule for the day. It may specifically be noted that energy charge (at the specified plant-specific rate) is not based on actual generation and plant output, but on scheduled generation. In case there are deviations from the schedule (e.g., if a power plant delivers 600 MW while it was scheduled to supply only 500 MW), the energy charge payment would still be for the scheduled generation (500 MW), and the excess generation (100 MW) would get paid for at a rate dependent on the system conditions prevailing at the time. If the grid has surplus power at the time and frequency is above 50Hz, the rate would be lower. If the excess generation takes place at the time of generation shortage in the system (in which condition the frequency would be below 50.Hz), the payment for extra generation would be at a higher rate. This payment for deviations from schedule is governed by what is known as Unscheduled Interchange (UI) mechanism.

6.2.4 The ABT provides for payment of fixed costs linked to a normative availability of generating units which is under control of the generating company . On the other hand, the energy charges are payable by the beneficiaries of the station depending upon the level of the dispatch sought by them based on the merit order of the generating stations. The merit order means the generating station which has the lowest energy cost shall be asked to dispatch first and the station with next higher energy cost shall be dispatched second and so on and so forth. Similarly, in case of load reduction, the station with highest energy cost shall be asked to back down first. This is with a view of cost optimization in running of the power stations. Therefore, the dispatches from a generating station are controlled by beneficiaries who pay for level of dispatches as energy charges. The normative level of availability in case of thermal generating stations of CPSUs is set at sufficiently high level of performance i.e. of the order of 80-85% over a year keeping in mind the base load operation of such stations. However, in case of storage type hydro generating stations normative level of availability of minimum 3 hour duration in a day is considered sufficient for the full recovery of capacity charges which is 50% of AFC keeping in mind the peak load operation of such stations. Other 50% of fixed charges are recovered as energy charges and is linked to scheduled generation.

6.3 Tariff Regulations 2009

6.3.1 The Tariff Regulations 2009 stipulate recovery of Annual Fixed Charges (AFC) at Normative Plant Availability Factor (NAPAF). The Commission has specified NAPAF for thermal and hydro stations. If a generating station operates above NAPAF, it is entitled to earn additional revenue linked to the AFC of the station. Conversely, if the actual plant availability is below the NAPAF, the generating station loses on pro-rata basis linked to its AFC.

6.3.2 Tariff structure for thermal generating station

- For thermal generating stations, which are in operation for 10 years or more, the additional revenue for over achieving the NAPAF is prorated to 100% of AFC.
- Further, if the thermal generating station is operating for a period of less than 10 years, the additional revenue earned by the station over and above NAPAF is proportionate to 50% of the AFC.
- The relevant provisions in the Regulation are quoted below:-

  "24 (1) The fixed cost of a thermal generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share / allocation in the capacity of the generating station.

(2) The capacity charge (inclusive of incentive) payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae :

(a) Generating stations in commercial operation for less than ten (10) years on 1st April of the financial year :

$$AFC \times (NDM / NDY) \times (0.5 + 0.5 \times PAFM / NAPAF) \text{ (in Rupees);}$$

Provided that in case the plant availability factor achieved during a financial year (PAFY) is less than 70%, the total capacity charge for the year shall be restricted to

$$AFC \times (0.5 + 35 / NAPAF) \times (PAFY / 70) \text{ (in Rupees).}$$

(b) For generating stations in commercial operation for ten (10) years or more on 1st April of the year:

$$AFC \times (NDM / NDY) \times (PAFM / NAPAF) \text{ (in Rupees).}$$

Where,

AFC = Annual fixed cost specified for the year, in Rupees.
NAPAF = Normative annual plant availability factor in percentage
NDM = Number of days in the month
NDY = Number of days in the year
PAFM = Plant availability factor achieved during the month, in percent:
PAFY = Plant availability factor achieved during the year, in percent

(3) The PAFM and PAFY shall be computed in accordance with the following formula:

$$PAFM \text{ or } PAFY = 10000 \times \sum_{i=1}^{N} DCi / \{ N \times IC \times (100 - AUX) \} \%$$

Where,

AUX = Normative auxiliary energy consumption in percentage.

DCi = Average declared capacity (in ex-bus MW), subject to clause (4) below, for the ith day of the period i.e. the month or the year as the case may be, as certified by the concerned load dispatch centre after the day is over.

IC = Installed Capacity (in MW) of the generating station
N = Number of days during the period i.e. the month or the year as the case may be.

Note : DCi and IC shall exclude the capacity of generating units not declared under commercial operation. In case of a change in IC during the concerned period, its average value shall be taken.

(4) In case of fuel shortage in a thermal generating station, the generating company may propose to deliver a higher MW during peak-load hours by saving fuel during off-peak hours. The concerned Load Despatch Centre may then specify a pragmatic day-ahead schedule for the generating station to optimally utilize its MW and energy capability, in consultation with the beneficiaries. DCi in such an event shall be taken to be equal to the maximum peak-hour ex-power plant MW schedule specified by the concerned Load Despatch Centre for that day"

6.3.3 Tariff structure for hydro generating station

- In case of hydro generating station, the AFC is notionally bifurcated into capacity charge and energy charge.
- The recovery of capacity charge is linked to NAPAF.
  - NAPAF is set by the Commission with due regard to the operating conditions of each station like variation in FRL, MDDL and silt level. In case of new stations also the factors like MDDL and rated head have been considered. Apart from above, a generator can earn extra revenue as capacity charge for declaring availability more than the NAPAF.
- The recovery of energy charge is linked to scheduled energy and the energy charge rate (ECR). The Energy Charge Rate (ECR) is calculated based on the design energy of the generating station.

- In case the Energy Charge Rate (ECR) for hydro generating station exceeds 80 paisa per unit and the actual saleable energy exceeds the saleable Design Energy (DE), the energy charge for the energy generated in excess of the saleable designed energy is restricted to 80 paisa per unit.
- The relevant provisions of the tariff regulations, 2009 are quoted below:

"22. Computation and Payment of Capacity charge and Energy Charge for Hydro Generating Stations.

(1)…………..

(2) The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month shall be
AFC x 0.5 x NDM / NDY x (PAFM / NAPAF) (in Rupees)
Where,
AFC = Annual fixed cost specified for the year, in Rupees.
NAPAF = Normative plant availability factor in percentage
NDM = Number of days in the month
NDY = Number of days in the year
PAFM = Plant availability factor achieved during the month, in Percentage
(3)…………..
(4) The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary, excluding free energy, if any, during the calendar month, on ex powerplant basis, at the computed energy charge rate. Total Energy charge payable to the generating
company for a month shall be :

(Energy charge rate in Rs. / kWh) x {Scheduled energy (ex-bus) for the month in kWh} x(100 – FEHS) / 100.

(5) Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis, for a hydro generating station, shall be determined up to three decimal places based on the following formula, subject to the provisions of clause (7) :

ECR = AFC x 0.5 x 10 / { DE x (100 – AUX) x (100 – FEHS)}
Where,
DE = Annual design energy specified for the hydro generating station,

In MWh, subject to the provision in clause (6) below. FEHS = Free energy for home State, in per cent…

(6)………..

(7) In case the energy charge rate (ECR) for a hydro generating station, as computed in clause (5) above, exceeds eighty paise per kWh, and the actual saleable energy in a year exceeds
{ DE x (100 – AUX) x (100 – FEHS) / 10000 } MWh, the Energy charge for the energy in excess of the above shall be billed at eighty paise per kWh only:

Provided that in a year following a year in which total energy generated was less than the design energy for reasons beyond the control of the generating company, the energy charge rate shall be reduced to eighty paise per kWh after the energy charge shortfall of the previous year has been made up."

- To take care of the situation when the hydro generating station generates less than the Design Energy on account of hydrological failure, special provisions have been made in the Regulation.
- In case, the energy shortfall occurs within 10 years from the date of commercial operation of a generating station, the ECR for the year following the year of energy shortfall is computed by considering the Design Energy for the year equal to the actual energy generated during the year of shortfall, till the energy charge shortfall of the previous year is made up. This is explained by following example (Reference Statement of Objects and Reasons of the CERC Tariff Regulations 2009) :-

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

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

ECR for 2009-10 = 265x105 x0.5/ {1135 x (100-1.2)x (100-12)}
= Rs. 1.343 /kWh

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

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

AFC during 2010-11= Rs. 250 crore (assumed)
Design energy to be considered for 2010-11= 1000 MU
ECR for 2010-11 = 250x105 x0.5/ {1000 x (100-1.2)x (100-12)}
= Rs. 1.438 /kWh

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

- In case the energy shortfall occurs after 10 years than the following shall apply:

"Suppose the specified annual design energy for the station is DE MWh, and the actual energy generated during the concerned (first) and the following (second) financial years is A1 and A2 MWh respectively, A1 being less than DE. Then, the design energy to be considered in the formula in clause (5) of this Regulation for calculating the ECR for the third financial year shall be moderated as (A1 + A2 – DE) MWh, subject to a maximum of DE MWh and a minimum of A1 MWh. Actual energy generated (e.g. A1, A2) shall be arrived at by multiplying the net metered energy sent out from the station by 100 / (100-AUX).
Consider the case of Chamera-I HE station of NHPC:
Annual design energy = 1665 MU
Suppose the actual generation (A1) during 2009-10 is 1500 MU & actual generation
(A2) in 2010-11 is 1700 MU
Thus, design energy to be considered in the formula in clause (5) of the Regulation for calculating ECR for the FY 2011-12 shall be moderated as (1500+ 1700-1665)= 1535 MU, to compensate for energy charge shortfall corresponding to less generation of 165 MU in the year 2009-10."

6.4 It can be interpreted from the above that the existing tariff structure has an incentive linked to declaration of availability irrespective of the time period of such declaration. It is only in case of shortage of fuel, the option is with the beneficiary to demand the generation to be available during the peak hour (refer to regulation 21(4) as quoted above). For hydro generation, 3 hours operation period is regulated by the load dispatch centres based on the demand by the beneficiaries. While the philosophy of the existing tariff structure is based on sound principles of recovery of fixed cost as well as incentive linked to availability, it does not fully address the critical dimensions like – (a) differentiation of tariff/recovery of fixed cost based on 'value' of the electricity during a particular time of day, say during peak and off-peak periods and (b) separate tariff structure for peaking plants, that is separate tariffs for the plants that need operate only during peak periods to meet the peak demand and (c) operation of CCGTs in cyclic mode mainly to meet the intermediate and peak load requirements..

6.5 The Task Force is conscious of the fact that Unscheduled Interchange (UI) mechanism provides for charges linked to frequency reflecting system demands at a particular point of time. But the objective of this mechanism being grid discipline and management of real time imbalance, it is neither desirable nor advisable to depend on UI mechanism for meeting the kind of peak demands that exist in the country. At the same time one can not think of taking investment decisions of setting up of peaking plants based on UI charges.

Chapter – VII

RECOMMENDATIONS

7.1 The Task Force feels that the tariff should reflect both the cost and the value of the product. The existing tariff structure reflects the cost but not necessarily the value based on time and season of generation. The Task Force takes note of the observation of the ECC report and reiterates that "*in setting any tariff, the selling utility must know its internal cost of producing the product and <u>the value</u> of selling its product. The buying utility must know its alternative cost and <u>the value</u> of the purchase.*"

7.2 The Task Force feels that differential tariff for peak and off-peak period will also encourage the State Commissions to go for time of day tariff for end consumers. Time of day tariff at the distribution end does not make complete sense without the corresponding differentiation of supply side tariff. All this will also induce demand side management at the consumer end and help the distribution companies to manage their load better.

7.3 The Task Force, therefore, recommends the following tariff structure (i) for peak and off-peak periods for the plants which meet the base load and intermediate load and peak loads and (ii) for new stations meant to meet only the peak demand.

7.4 <u>RECOMMENDATION ON GENERIC ISSUES</u>

7.4.1 It is assumed that the peak hours in a day will be 6 hours - 2 hours in the morning and 4 hours in the evening. A differential tariff for peak hours and off-peak hours for the generating station has been proposed. In case of hydro generating station,

this differential tariff may not be applied to the run-of-the river type hydro station. The concerned RLDC may be required to declare in advance the peak hours in the morning and in the evening at least two days before in the concerned region.

7.4.2 For recovery of daily peak hour capacity charges, the peak hours in a day may be considered as 6 hrs in case of thermal generating stations and 3 hrs in case of hydro generating stations. The three hour peaking in case of hydro generating station is in line with the concept in Tariff Regulations, 2009, of allowing recovery of capacity charge for hydro stations based on their availability of at least three hours.

7.4.3 Considering the acute shortage of power during the peak hour, the differential tariff may be worked out in such a way that the value of power generated during peak hours becomes 25% more than the value of power generated during off-peak hours. Reference is invited to the weightage factor as discussed in Appendix-II.

7.4.4 For the existing coal/lignite based generating stations, the differential tariff has been suggested in such a way as to ensure as far as possible, revenue neutrality to the generating station as well as the beneficiaries.

7.4.5 However, the existing gas based stations may be encouraged to meet peak demands. As such, the tariff design suggested for gas based stations is based on the premise that the availability of such power plants during peak hours will be higher than their corresponding availability during off-peak hours.

7.4.6 The fixed cost for generating stations (except for hydro generating stations) may be computed on annual basis and recovered on daily basis under capacity charge. Recovery of the fixed cost of the generating stations – existing as well as new - may be linked to achievement of the Normative Plant Availability Factor (NPAF) on daily basis for peak and off-peak periods respectively. For hydro generating stations the existing dispensation of recovery of capacity charge based on normative annual plant availability factor as in Tariff Regulations, 2009 may continue except that incentive for over-achievement vis-à-vis normative annual plant availability factor may be allowed @ 75% of AFC instead of the existing provision of 50% of AFC as incentive. This incentive structure is based on the premise that the hydro generating stations are meant primarily to meet peak demand and should be incentivized to achieve this objective. It is also in national interest to harness hydro generation to its maximum extent. In the event of extra generation from hydro stations during peak hours, the distribution companies would also be benefited in that their dependence on short-term purchases will reduce and they would also have corresponding relief from the vagaries of price fluctuation in the short-term market. Disincentive for under achievement may, however, continue @50% of AFC.

7.4.7 For a gas based (existing and new combined cycle) generating station, it has been suggested that recovery of the fixed cost should

be linked to achievement of NPAF for peak hours (i.e. 90%) and off-peak hours (i.e. 63%) respectively. However, incentive may be linked to achievement of NPAF beyond 85%. With 90% availability during peak hours and 63% availability during off-peak hours, it is assumed that the overall availability during the day will be 70%. This will mean that there will be a dead band between 70% and 85% availability in so far as incentive is concerned as incentive will be available only for achievement over and above 85% availability @ average capacity charge rate (average of peak and off-peak capacity charge rate).

- **For combined cycle gas based stations the Task Force has recognized that the existing gas supply contracts do not provide for variation in supply of gas.**
- The proposed operation of combined cycle gas based stations would require them to minimize generation during off-peak night hours by closing down GTs after the evening peak hours and restarting before the morning peak hours. Thus in a module of 2 GTs and 1 ST one GT could be closed down during the night off-peak hours so that ST remains in service at partial load with 1 GT (with nearly 50% loading). For such cyclic operation, an additional margin of 2% in heat rate may be given.
- The CCGT power plant with single shaft GT and ST configuration could back down generation during off-peak hours to about 70%. It may result in higher heat rate by about 4% which may have to be allowed. It is expected that with increase in gas pipeline capacity such variation could be possible at most of the power stations connected to the national gas grid.
- For other CCGT stations connected to isolated or smaller gas grids the existing tariff structure may continue.

- The Task Force has therefore recommended that supply of gas of varying quantity during off peak and peak periods by the GAIL and other gas supply companies would need to be taken up at appropriate level in the Government.

- The implementation of the recommendation for the gas based stations is dependent on supply of gas in varying quantity during peak and off-peak periods.

7.4.8 The Task Force recommends setting up of some open cycle GTs/gas reciprocating engines to meet the peaking demand. Such plants may be located near the metro cities in the vicinity of the existing or proposed national gas grid. Besides meeting the peak demand these plants could be operated during system contingencies thus adding to the reliability of supply to the metro cities which require a higher level of security of supply.

7.4.9 The fixed cost recovery in case of gas based reciprocating engine stations should be linked to the peak hour availability.The Commission may specify norms of operation and O&M cost norm for gas engine based generating stations in consultation with CEA.

7.4.10 In case of pumped storage hydro generating station, a general Tariff Design has been proposed.

7.5 RECOMMENDATION ON SPECIFIC ISSUES – EXISTING STATIONS

7.5.1 Existing Coal based stations

- Capacity Charge and incentive / disincentive.
  - The fixed cost may be computed on annual basis based on the norms as in the Tariff Regulations, 2009 and recovered on daily basis under capacity charge.
  - Recovery of capacity charge for peak and off-peak periods may be allowed based on the principle that peak hour capacity charge is 25% more than the off-peak hour capacity charge.
  - For a generating station which is in commercial operation for less than 10 years, the incentive/disincentive for over achievement/under achievement vis-a-vis NPAF may be allowed @ 50% of the average capacity charge rate (average of peak and off-peak capacity charge rate).
  - For a generating station which is in commercial operation for 10 years or more, the incentive/disincentive for over achievement/under achievement vis-a-vis NPAF during peak and off-peak periods may be allowed @ the average capacity charge rate (average of peak and off-peak capacity charge rate).
- Normative Plant Availability Factor (NPAF) may be on lines of the normative annual plant availability factor as in the Tariff Regulations, 2009.

- Energy Charge
  - The recovery of energy charge may be allowed as in the Tariff Regulations, 2009.
- Other norms may be as in the Tariff Regulations, 2009.

7.5.2 Existing Gas based stations and new combined cycle stations

- For CCGT stations connected to isolated or smaller gas grids, the existing tariff structure may continue.
- For CCGT stations with 2 GTs and 1 ST configuration and single shaft GT and ST configuration, the following tariff structure may be considered.
- Capacity Charge and incentive / disincentive

  The fixed cost may be computed on annual basis based on the norms as in the Tariff Regulations, 2009.

  - Recovery of capacity charge for peak and off-peak periods may be allowed based (i) on the principle that peak hour capacity charge is 25% more than the off-peak hour capacity charge and (ii) on achievement of NPAF for peak and off-peak period respectively.
  - For a generating station which is in commercial operation for less than 10 years, the incentive for achievement of daily NPAF above 85% based on gas and/or alternate fuel, may be allowed @ 50% of the average capacity charge rate (average of peak and off-peak capacity charge rate) during peak as well as off-peak hours.
  - For a generating station which is in commercial operation for 10 years or more, the incentive for achievement of daily NPAF above 85% based on gas and/or alternate fuel, may be allowed @ the average capacity charge rate (average of peak and off-peak capacity charge rate) during peak as well as off-peak hours.
- **NPAF :** The NPAF based on gas as the only fuel may be 90% for peak hours and 63% for off-peak hours for the recovery of full fixed charges respectively for peak and off-peak periods. However, the incentive should be admissible only if the average availability based

on gas and/or alternate fuel for the day exceeds 85%. The average NPAF for the day may be treated as 70% based on gas as the only fuel.

- Energy Charge
    - The recovery of energy charge may be allowed as in the Tariff Regulations, 2009. However, heat rate for CCGT with 2 GTs and 1 ST configuration may increase due to cyclic operation of such plants by 2%, and that for CCGT with single shaft GT and ST configuration may increase by 4%.
- Other norms may be as in the Tariff Regulations, 2009.

7.5.3 Existing Hydro Generating stations

- Capacity Charge and incentive / disincentive
    - The existing dispensation of recovery of capacity charge based on normative annual plant availability factor as in Tariff Regulations, 2009 may continue except that incentive for over-achievement vis-à-vis normative annual plant availability factor may be allowed @ 75% of AFC instead of the existing provision of 50% of AFC as incentive. Disincentive for under-achievement may, however, continue to be @ 50% of AFC.

- **NPAF :** The same principles of normative annual plant availability factor as in Tariff Regulations, 2009 may be followed.

- Energy Charge
  - The recovery of energy charge may be allowed as in the Tariff Regulations, 2009.

- Other norms may be as in the Tariff Regulations, 2009.

7.6 RECOMMENDATION ON SPECIFIC ISSUES – NEW STATIONS

7.6.1 New Coal based stations

- Same as for existing Coal based stations.

7.6.2 New Gas based (open cycle peaking) stations

- Gas based power stations based on open cycle mode have been envisaged to operate primarily during peak hours.

- Capacity Charge
  - The fixed cost may be computed on annual basis based on the norms as in the Tariff Regulations, 2009 except the following, and recovered on daily basis under capacity charge:
    - An additional allowance of 50% towards O&M expenses may be allowed.

  Note: In case of new peak gas based thermal generating station, peak load operation shall be of open cycle type. These stations will operate during the morning and evening peak load periods. Accordingly, there will be two start / stop of the station. This frequent start / stop of the machine will lead to much more repair and maintenance (R&M) expenses which may be as high as 1.56 to 2.53 times (on an average about 2 times) the expenses when the gas turbines are running continuously depending upon the nature of overhaul. Since the repair and maintenance expenses are on account of gas turbines, weightage of 80% of R&M expenses is being considered for the gas turbines. However, there would be reduction in the employee cost due to two shift operation. Accordingly, O&M norm for the open cycle operation may be 1.5 times the O&M norms for the Combined cycle gas/liquid fuel based stations provided in the 2009 Tariff Regulations. An additional fuel requirement on account of two start / stop per day may also be considered.

  - Recovery of capacity charge for peak periods may be allowed on the principle that full capacity charge is recovered based on operation during peak hours.
  - The incentive/disincentive for over achievement/under achievement vis-a-vis NPAF during peak hour may be allowed @ 10% of the peak capacity charge rate. However, for any generation beyond 100% capacity, the generation station may not be allowed any UI payment. In such an event the generating station may be allowed overload charge @5% of the peak capacity charge rate in addition to the energy charge.
  - For operating during the off-peak hour, the new gas based generating station (open cycle) may be allowed an incentive of $1/10^{th}$ of the peak capacity charge rate in addition to the energy charge.

- **NPAF :** NPAF for peak hours may be 95%.
- Energy Charge
  - The recovery of energy charge may be allowed on lines of the principles for gas based generating stations under the Tariff Regulations, 2009.
- Other norms may be as in the Tariff Regulations, 2009.

7.6.3 New Hydro based stations

- Same as for existing hydro based stations.

7.6.4 Pumped storage hydro generating station

- The pumped storage type of hydro station has an additional cost on account of pumping water from the down-stream to the up-stream reservoir. The following tariff principles are being suggested to take care of the special nature of operation of such station:
- The quantum of energy that can be generated during high water flow period on account of natural flow into the up-stream reservoirs need to be assessed. The Central Electricity Authority (CEA) may be requested to determine this quantum of energy, as Design Energy.

  During the period of availability of excess water due to natural flow of water these stations may be dispatched on a 'must run' basis. This is required to ensure that the excess water is not spilled unused. This energy may be allowed to be sold at a flat rate, i.e. single part tariff. The average of the energy charge rate of preceding twelve months in respect of the coal pit head thermal generating stations in the region where the pumped storage station is situated may be considered as the single part tariff for sale of this energy. The revenue earned by the station on account of sale of this energy may be adjusted with annual fixed cost of the station.
- The annual fixed cost of the station may be calculated as per the provision of the Tariff Regulation, 2009 applicable to storage type of hydro generating stations. The revenue to be earned from sale of energy out of natural flow of water, as discussed above, may be deducted from the annual fixed cost to arrive at net annual fixed

cost. This net annual fixed cost may be recovered on daily basis under capacity charge. The total capacity charge payable for a pumped storage generating station may be shared by its beneficiaries as per their respective share/allocation in the capacity of the generating station. Full capacity charge shall be recoverable at 85% normative annual plant availability during the peak hours. Incentive/disincentive for over-achievement and under-achievement may be allowed @ of the net annual fixed cost.

- A major additional component of expenses in case of these hydro stations is the cost of electricity used for pumping water from down-stream reservoir to up-stream reservoir. This may be settled in kind with beneficiaries till we reach a stage where such generators can procure energy from the market during off-peak periods. The energy to be arranged by the beneficiaries may also take into account the losses etc. upto the bus bar of the generating station. In return the beneficiaries will be entitled to equivalent energy from the generating station during peak hours. In the event of the beneficiaries failing to supply the desired level of energy during off-peak hours, there will be pro-rata reduction in their energy entitlement from the station during peak hours. The beneficiaries may, however, sell their share of capacity in the generating station, in part or full, whereupon the owner of the capacity share will be responsible for arranging the equivalent energy to the generating station in off-peak hours, and be entitled to corresponding energy during peak hours in the same way as the original beneficiary was entitled.
- Any generation above or below the level of scheduled generation may be settled at the prevailing UI rate as applicable to thermal power stations at present.

7.7 SAMPLE STUDY

- To assess the impact of the above recommendations, a sample study has been carried out based on certain assumptions, and differential Peak/Off-peak Hour capacity charge rates for both existing and new thermal station have been calculated, as in **Appendix-IV** (read with Appendix II and III).

- Findings of the sample study, which is only illustrative in nature, are as below:-
    - Sample tariff calculation has been carried out for various scenarios at proposed Normative Plant Availability Factor (NPAF).
    - In all the scenarios the Internal Rate of Return (IRR) to the developers remains same.
    - In case of coal based thermal generating station, the average differential capacity charge rate (average of peak and off-peak capacity charge rate) is the same as that of the normative capacity charge rate.
    - In case of the existing gas based combined cycle generating station, the average differential capacity charge rate (average of peak and off-peak capacity charge rate) is higher than the average normative capacity charge rate.
    - In all the cases the per unit capacity charge during peak hour is 25% higher than the per unit capacity charge during off-peak hour.

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CHAPTER – VIII

IMPLEMENTATION IMPERATIVES

8.1 In order to implement the recommendations of the Task Force, coordinated efforts at the level of Central Government and Central Commission would be required.

8.2 The Central Electricity Regulatory Commission (CERC) may have to amend the Tariff Regulations, 2009 to suitably accommodate the recommendations. The Task Force interacted with the experts in the field while evolving the recommendations. The Task Force also had extensive discussion with National Load Despatch Centre to assess the implications of tariff structure on grid operation. It is expected that CERC while amending the provisions of the Tariff Regulations, 2009 would hold further discussion with stakeholders across the board in the country.

8.3 The Task Force is convinced of the need for encouraging setting up of peaking power plants. The committee, however, also recognizes the fact that the tariff of such new peaking power plants would be substantially higher than the normal tariff for the generating stations, more so compared to the tariffs for the base load generating stations. In order to alleviate the impact of such high tariffs, a regulatory charge may be considered by treating the requirement for peaking plants as ancillary service. The scheme on lines of Generating Based Incentive (GBI) may be evolved and the developers of the Peaking Power Plants may be given the support towards capacity charge linked to the normative plant availability factors suggested for such power plants. This will also reduce the burden of the beneficiaries buying power from the peaking plants.

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APPENDIX - I

Impact of Various modes of operation of GTs on R&M costs

Description	Units	Base Case GTs operating in CC mode	Case-I GTs operating only for peaking purposes	Case-2 2GTs+1ST module with one GT trip in the night	Case-3 Single Shaft Machine-Module at 70% load in the night
Hrs of operation per year	Hrs	7500	2010	6200	7500
Starts per year	Nos	20	660	185	20
Typical recommended Overhaul schedule by GT Manufacturer (Inspection/Overhaul becomes due depending on the operating hours or start ups whichever occurs first)					
Combustion inspection/OH	Hrs	8000	8000	8,000	8000
	Starts	450	450	450	450
Hot gas path inpsection/OH	Hrs	24000	24000	24,000	24000
	Starts	1200	1200	1,200	1200
Major inspection/OH	Hrs	48000	48000	48,000	48000
	Starts	2400	2400	2,400	2400
Rotor Inspection/OH	Hrs	144000	144000	144,000	144000
		5000	5000	5,000	5000
Service factor for starts	No.	1	1	1	1
Service factor for operation	No.	1	1	1	1
Applicable Overhaul schedule for the GTs based on operation scenario envisaged					
Combustion inspection/OH	Hrs	8,000	1,370	8,000	8,000
	Years	1.07	0.68	1.29	1.07
Hot gas path inpsection/OH	Hrs	24,000	3,655	24,000	24,000
	Years	3.20	1.82	3.87	3.20
Major inspection/OH	Hrs	48,000	7,309	48,000	48,000
	Years	6.40	3.64	7.74	6.40
Rotor Inspection/OH	Hrs	144,000	15,227	144,000	144,000
	Years	19.20	7.58	23.23	19.20
Impact on R&M charges per year basis					
Impact on Comb OH	Factor	1.000	1.564	0.827	1.000
Impact on HGP OH	Factor	1.000	1.760	0.827	1.000
Impact on Major OH	Factor	1.000	1.760	0.827	1.000
Impact on Rotor OH	Factor	1.000	2.534	0.827	1.000
Average Impact on Heat rate	Factor	1.000	1.000	**1.015**	**1.035**
Conclusions					
In case-1, the start up criteria determines the overhaul schedules and leads to higher R&M costs					
Case-2 leads to lower O&M costs due to lower running hours of GTs. However the heat rate is higher due to lower					
efficiency of steam turbine generator at part load operation with one GT					

Case-3 leads to higher heat rate due to part load operation in the night.					
*The impact on heat rate indicated is overall heat rate increase for the full operating period.					
Assunptions					
Hours of Operations					
Base case: Operation in OC/CC mode for 7500 hrs per year. 20 Startups per year					
Case-1: Operation GTs in open cycle for 6 hours per day, 2 hrs in morning and 4 hrs in evening peak, 335 days per year					
Case-2: Operation in OC/CC with one GT in each module shut down for 8 hrs per day (in night), 335 days per year					
Case-3: Single shaft machines with Operation in CC and reduced load of 70% for 8 hrs per day (in night), 335 days per year					
All other operating conditions have been assumed to be same that is:-					
Water steam injection and its impact on duty factors					
Unscheduled Trippings etc and their impact					
Fuel mix and its impact					
Off frequency operation					

APPENDIX - II

Weightage Factor (WF)

The purpose of using Weightage Factor (WF) is to arrive at a Differential Capacity charge rate for peak hour and off-peak hour where the Peak Hour Capacity charge rate shall be 25% higher than the Off-Peak Hour Capacity charge rate. WF has been calculated by taking into account the normative energy generated by generating station during peak hours and off-peak hours. This leads to a linkage of WF with that of the Normative Plant Availability Factor and Operating Hour of the generating station during peak hour and off-peak hour. In shortage scenarios, the Generating Station should ensure higher plant availability during the peak hours. The balance fuel / water available after operating the plant at higher Normative Plant Availability Factor ($NPAF_{ph}$) during peak hours has been considered for arriving at the Normative Plant Availability Factor ($NPAF_{oph}$) during off peak hours.

For arriving at the NPAF during peak hours and off-peak hours, in case of thermal generating station, the normative annual availability factor as in Tariff Regulations, 2009 may be considered as the daily NPAF. It is assumed that coal based thermal power station shall be used as base-load station. Accordingly, the NPAF for the coal-based thermal power station is same for both peak hours and off-peak hours. Due to limitation in availability of gas, the gas based thermal power station shall be used as peaking power plant. For the purpose of sample calculation, it is assumed that the gas will be available to operate the plant at an average plant load factor of 70% throughout the day. The existing gas based generating station shall be operated at a Normative Plant Availability Factor ($NPAF_{ph}$) of 90% during peak hours (6 hrs.) and balance gas available shall be used for running the plant during off-peak hours (18 hrs), which results in a Normative Plant Availability Factor ($NPAF_{oph}$) of 63% during off-peak hours.

The formula for calculation of WF is as below:-

WF (%):

$WF_{ph} = AFC_{ph} / (AFC_{ph} + AFC_{oph})$
$WF_{oph} = AFC_{oph} / (AFC_{ph} + AFC_{oph})$

AFC (Rs. Lakh):

$AFC_{ph} = FCPU_{ph} \times NG_{ph} \times 10$
$AFC_{oph} = FCPU_{oph} \times NG_{oph} \times 10$

FC per Unit (Rs./Unit):

$FCPU_{oph} = AFC_n / (1.25 \times NG_{ph} + NG_{oph}) / 10$
$FCPU_{ph} = 1.25 \times FCPU_{oph}$

Net Gen (MU):

$NG_{ph} = IC \times NPAF_{ph} \times (1\text{-}AUX) \times (1\text{-}FEHS) \times 365 \text{ days} \times NHD_{ph}/1000$
$NG_{oph} = IC \times NPAF_{oph} \times (1\text{-}AUX) \times (1\text{-}FEHS) \times 365 \text{ days} \times NHD_{oph}/1000$

As such,

$AFC_{ph} = FCPU_{ph} \times NG_{ph} \times 10$

$= 1.25 \times FCPU_{oph} \times NG_{ph} \times 10$

$= 1.25 \times (AFC_n / (1.25 \times NG_{ph} + NG_{oph}) / 10) \times (IC \times NPAF_{ph} \times (1\text{- }AUX) \times (1\text{-}FEHS) \times 365 \times PH / 1000) \times 10$

$$= \frac{1.25 \times AFC_n \times (IC \times NPAF_{ph} \times (1\text{-}AUX) \times (1\text{-}FEHS) \times 365 \times NHD_{ph}) \times \cancel{10}}{(1.25 \times NG_{ph} + NG_{oph}) \times \cancel{10} \times 1000}$$

$$= \frac{1.25 \times AFC_n \times (IC \times NPAF_{ph} \times (1\text{-}AUX) \times (1\text{-}FEHS) \times 365 \times NHD_{ph}) \times \cancel{1000}}{(1.25 \times IC \times NPAF_{ph} \times (1\text{-}AUX) \times (1\text{-}FEHS) \times 365 \times \underline{NHD_{ph}}) + (IC \times NPAF_{oph} \times (1\text{-}AUX) \times (1\text{-}FEHS) \times 365 \times \underline{NHD_{oph}}) \times \cancel{1000}}$$

$$= \frac{1.25 \times AFC_n \times NPAF_{ph} \times NHD_{ph} \times \cancel{(IC \times (1\text{-}AUX) \times (1\text{-}FEHS) \times 365)}}{\cancel{(IC \times (1\text{-}AUX) \times (1\text{-}FEHS) \times 365)} \times ((1.25 \times NPAF_{ph} \times \underline{NHD_{ph}}) + (NPAF_{oph} \times \underline{NHD_{oph}})}$$

$$= \frac{1.25 \times AFC_n \times NPAF_{ph} \times NHD_{ph}}{(1.25 \times NPAF_{ph} \times \underline{NHD_{ph}}) + (NPAF_{oph} \times \underline{NHD_{oph}})}$$

Similarly,

$$AFC_{\ oph} = \frac{AFC_n \times NPAF_{oph} \times NHD_{oph}}{(1.25 \times NPAF_{ph} \times \underline{NHD_{ph}}) + (NPAF_{oph} \times \underline{NHD_{oph}})}$$

Hence,

$AFC_{ph} + AFC_{oph}$

$$= \frac{(1.25 \times AFC_n \times NPAF_{ph} \times NHD_{ph}\ ) + (AFC_n \times NPAF_{oph} \times NHD_{oph})}{1.25 \times NPAF_{ph} \times \underline{NHD_{ph}} + NPAF_{oph} \times \underline{NHD_{oph}}}$$

$$= \frac{AFC_n \times \cancel{(1.25 \times NPAF_{ph} \times} NHD_{ph} \cancel{+ NPAF_{oph} \times} NHD_{oph}\cancel{)}}{\cancel{1.25 \times NPAF_{ph} \times} \underline{NHD_{ph}} \cancel{+ NPAF_{oph} \times} \underline{NHD_{oph}}}$$

$$= \quad AFC_n$$

Hence,

$$WF_{ph} = AFC_{ph} / (AFC_{ph} + AFC_{oph})$$

$$= \frac{1.25 \times \cancel{AFC_n} \times NPAF_{ph} \times NHD_{ph}}{((1.25 \times NPAF_{ph} \times \underline{NHD_{ph}}) + (NPAF_{oph} \times \underline{NHD_{oph}})) \times \cancel{AFC_n}}$$

$$= \frac{1.25 \times NPAF_{ph} \times NHD_{ph}}{(1.25 \times NPAF_{ph} \times \underline{NHD_{ph}}) + (NPAF_{oph} \times \underline{NHD_{oph}})}$$

Similarly,

$WF_{oph} = AFC_{oph} / (AFC_{ph} + AFC_{oph})$

$$= \frac{\cancel{AFC_n} \quad x \quad \underline{NPAF_{oph}} \quad x \quad \underline{NHD_{oph}}}{(1.25 \text{ x } NPAF_{ph} \text{ x } \underline{NHD_{ph}}) + (NPAF_{oph} \text{ x } \underline{NHD_{oph}}) \text{ x } \cancel{AFC_n}}$$

$$= \frac{NPAF_{oph} \text{ x } NHD_{oph}}{(1.25 \text{ x } NPAF_{ph} \text{ x } \underline{NHD_{ph}}) + (NPAF_{oph} \text{ x } \underline{NHD_{oph}})}$$

2. The daily NPAF in case of existing gas based thermal generating station has been assumed as 70% (assuming a station with normative annual plant availability factor of 70%). The weightage is a function of NPAF and normative hours during peak and off-peak periods. Based on this assumption, the values of some weightage factors for the sample calculation are as below:

	WF_{ph}	WF_{oph}	$NPAF_{ph}$	$NPAF_{oph}$	$NPAF_d$	NHD_{ph}	NHD_{oph}
Existing Power Station:							
Coal	0.29	0.71	85%	85%	85%	6	18
Gas (CCGT with cyclic duty. Other CCGT plants not subjected to cyclic duty	0.37	0.63	90%	63%	70%	6	18
New Power Station:							
Coal	Same values as for existing coal based stations						
Gas (Open cycle peaking)	1.0	0	95%	NA	95%	6	0

APPENDIX - III

- **The capacity charge payable to a generating station (except for a hydro generating station) for a day may be calculated in accordance with the following formulae:**
  - $CC_d = CC_{phd} + CC_{ophd}$

    Where,

    CC_d = Capacity Charge for the Day

    CC_{phd} = Capacity Charge for peak hours of the day

    CC_{ophd} = Capacity Charge for off-peak hours of the day
  - CC_{phd} = Peak Hour Capacity charge rate x AHD_{ph} x IC x $PAFD_{ph}$

    CC_{ophd} = Off-Peak Hour Capacity Charge Rate x AHD_{oph} x IC x $PAFD_{oph}$

    Where,

    AHD_{ph} = Actual nos. of peak hours operation in a day

    AHD_{oph} = Actual nos. of off-peak hours operation in a day

    $PAFD_{ph}$ = Plant Availability Factor achieved during the peak hours of the day

    $PAFD_{oph}$ = Plant Availability Factor achieved during the off-peak hours of the day
  - Peak and Off-peak Hour Capacity charge rate

    Peak Hour Capacity Charge Rate
    = WF_{ph} x AFC / (IC x $NPAF_{ph}$ x NDY x NHD_{ph})

    Off-Peak Hour Capacity Charge Rate
    = WF_{oph} x AFC / (IC x $NPAF_{oph}$ x NDY x NHD_{oph})

Where,

AFC = Annual Fixed Cost

WF_{ph} = Weightage factor for peak hour tariff

WF_{oph} = Weightage factor for off-peak hour tariff

IC = Installed capacity, in MW

$NPAF_{ph}$ = Normative Plant Availability Factor for peak hours of the day

$NPAF_{oph}$ = Normative Plant Availability Factor for off-peak hours of the day

NDY = No. of days in a year

NHD_{ph} = Normative no. of peak hours in a day

NHD_{oph} = Normative no. of off-peak hours in a day

- Weightage Factor for peak hour and off-peak hour tariffs may be calculated based on the following formula:-

$$WF_{ph} = \frac{1.25 \times NPAF_{ph} \times NDH_{ph}}{(1.25 \times NPAF_{ph} \times NDH_{ph}) + (NPAF_{oph} \times NDH_{oph})}$$

$$\text{and } WF_{oph} = \frac{NPAF_{oph} \times NHD_{oph}}{1.25 \times NPAF_{ph} \times NHD_{ph}) + (NPAF_{oph} \times NHD_{oph})}$$

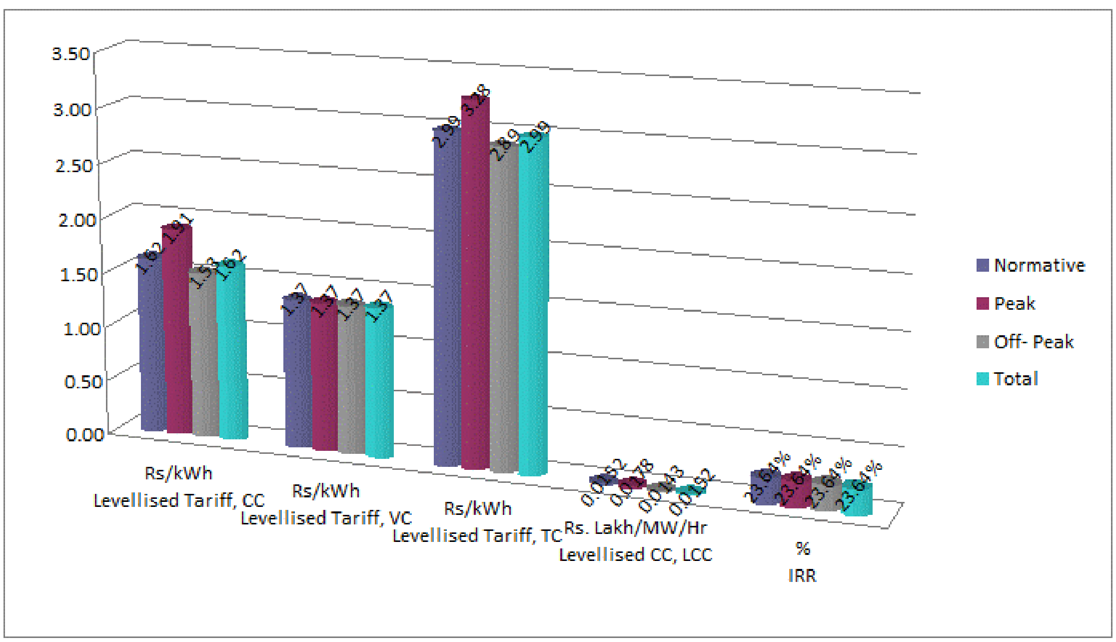
<u>**APPENDIX-IV**</u>

Assumptions (Coal-based thermal power station)							
Particulars		**Unit**	**Normative**	**Peak**	**Off-peak**	**Total**
Capacity	IC	MW	300	300	300	300
PAF	NAPAF	%	85%	85%	85%	85%
	NPAF	%	85%	85%	85%	85%
	Actual PAF	%	85%	85%	85%	85%
Capital cost	Rate	Rs. Lakh/MW	500	500	500	500
	Capital cost	Rs. Lakh	150000	150000	150000	150000
Debt/Equity	Debt	%	70%	70%	70%	70%
	Equity	%	30%	30%	30%	30%
	Total Debt	Rs. Lakh	105000	105000	105000	105000
	Total Equity	Rs. Lakh	45000	45000	45000	45000
RoE	Base Rate of RoE	%	15.5%	15.5%	15.5%	15.5%
	Rate of RoE	%	23.481%	23.481%	23.481%	23.481%
IoL	Interest rate	%	10.75%	10.75%	10.75%	10.75%
	Moratorium period	yrs.	0	0	0	0
	Normative loan period	yrs.	12	12	12	12
	Repayment	%	Depn	Depn	Depn	Depn
Depreciation	Salvage Value	%	10%	10%	10%	10%
	Rate - 12 yrs	%	5.28%	5.28%	5.28%	5.28%
	Rate - after 12 yrs	%	2.05%	2.05%	2.05%	2.05%
O&M Expenses	Normative O&M	Rs. Lakh/Yr/MW	16	16	16	16
	Factor	%	0%	0%	0%	0%
	Peak O&M	Rs. Lakh/Yr/MW	16	16	16	16
IoWC	Interest Rate	%	12.25%	12.25%	12.25%	12.25%
	Fuel cost	Months	1.5	1.5	1.5	1.5
	Secondary Fuel oil	Months	2	2	2	2
	Maintenance spares	%	20%	20%	20%	20%
	O&M	Months	1	1	1	1
	Receivables	Months	2	2	2	2
Escalation rate	O&M	%	5.72%	5.72%	5.72%	5.72%
	Coal Price	%	6.12%	6.12%	6.12%	6.12%
	Naptha price	%	18.80%	18.80%	18.80%	18.80%
	Oil price	%	13.60%	13.60%	13.60%	13.60%
	Discounting Factor	%	10.19%	10.19%	10.19%	10.19%

Operational Data	Normative life	yrs.	25	25	25	25
	Aux	%	6.5%	6.50%	6.50%	6.50%
	Differential SHR	%		0%	0%	
	SHR	Kcal/kwh	2425	2425	2425	2425
	Specific FOC	ml/kwh	1	1	1	1
	Gas	%	100%	100%	100%	100%
	Naptha	%	0%	0%	0%	0%
Fuel Data	GCV - Coal	Kcal/kg	4068.96	4068.96	4068.96	4068.96
	GCV - Oil	Kcal/ltr	10122	10122	10122	10122
	Base Price --Coal	Rs/MT	1286.23	1286.23	1286.23	1286.23
	Base Price - Oil	Rs./KL	16580.05	16580.05	16580.05	16580.05
I. Tax	Rate	%	33.990%	33.990%	33.990%	33.990%
Working Hours	Normative	hrs/day	24	6	18	24
	Start/Stop	Nos.	0	0	0	0
	Start up time	Minute	15	15	15	15
	Starting time	hrs/day	0	0	0	0
	Actual RH	hrs/day	24	6	18	24
	Normative	hrs./yr.	8760	2190	6570	8760
	Actual RH	hrs./yr.	8760	2190	6570	8760
weightage for Fixed Charge allocation	NetGen	MU	2089	522	1566	2234
	Weightage to peak tariff	%		25%		
	FC per Unit	Rs/Unit	1.73	2.03	1.62	0.78
	AFC	Rs. Lakh	36038	10599	25439	17325
	Weightage		1.00	0.29	0.71	1.00

<u>SUMMARY SHEET</u> (Coal-based thermal power station)

Particulars	Unit	Normative	Peak	Off-Peak	Total
Levellised Tariff, CC	Rs/kWh	1.62	1.91	1.53	1.62
Levellised Tariff, VC	Rs/kWh	1.37	1.37	1.37	1.37
Levellised Tariff, TC	Rs/kWh	2.99	3.28	2.89	2.99
Levellised CC, LCC	Rs. Lakh/MW/Hr	0.0152	0.0178	0.0143	0.0152
IRR	%	23.64%	23.64%	23.64%	23.64%

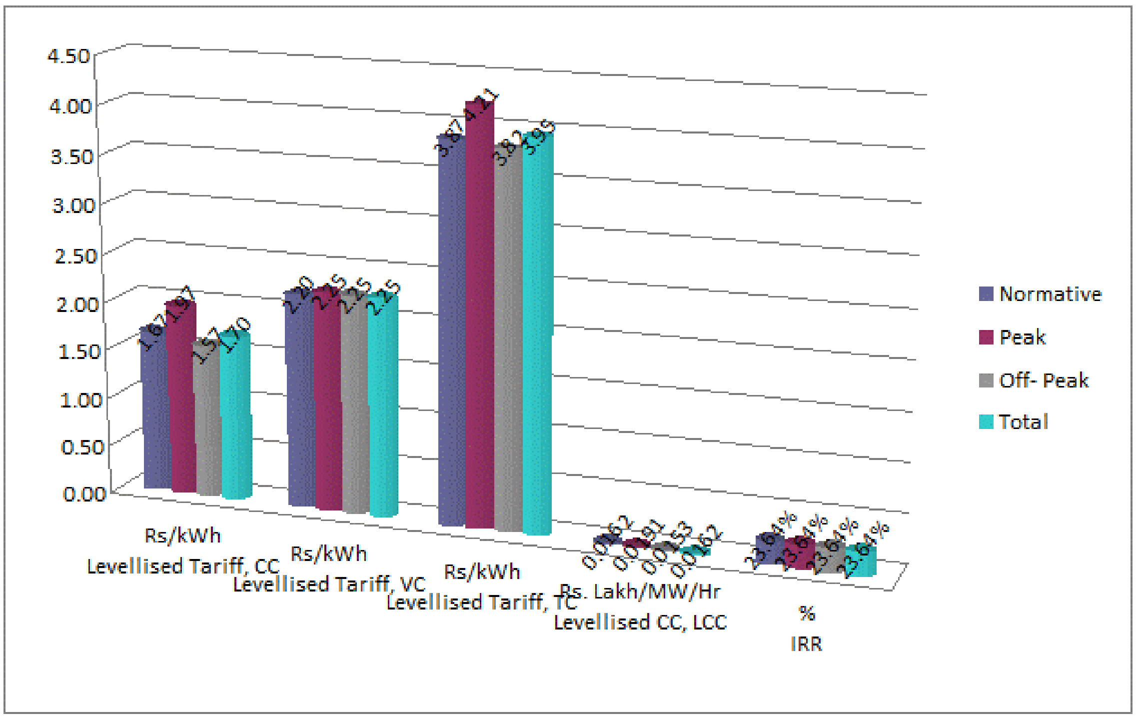


Assumptions (Gas-based thermal power station Combined Cycle)						
Particulars		**Unit**	**Normative**	**Peak**	**Off-peak**	**Total**
capacity	IC	MW	100	100	100	100
PAF	NAPAF	%	85%	85%	85%	85%
	NPAF	%	70%	90%	62%	69%
	Actual PAF	%	70%	90%	62%	69%
Capital cost	Rate	Rs. Lakh/MW	450	450	450	450
	Capital cost	Rs. Lakh	45000	45000	45000	45000
Debt/Equity	Debt	%	70%	70%	70%	70%
	Equity	%	30%	30%	30%	30%
	Total Debt	Rs. Lakh	31500	31500	31500	31500
	Total Equity	Rs. Lakh	13500	13500	13500	13500
RoE	Base Rate of RoE	%	15.5%	15.5%	15.5%	15.5%
	Rate of RoE	%	23.481%	23.481%	23.481%	23.481%
IoL	Interest rate	%	10.75%	10.75%	10.75%	10.75%
	Moratorium period	yrs.	0	0	0	0
	Normative loan period	yrs.	12	12	12	12
	Repayment	%	Depn	Depn	Depn	Depn
Depreciation	Salvage Value	%	10%	10%	10%	10%
	Rate - 12 yrs	%	5.28%	5.28%	5.28%	5.28%
	Rate - after 12 yrs	%	2.05%	2.05%	2.05%	2.05%
O&M Expenses	O&M	Rs. Lakh/Yr/MW	14.8	14.8	14.8	14.8
	Factor	Factor	0%	0%	0%	0%
	Differential O&M	Rs. Lakh/Yr/MW	14.8	14.8	14.8	14.8
IoWC	Interest Rate	%	12.25%	12.25%	12.25%	12.25%
	Fuel cost	Months	1	1	1	1
	maintenance spares	%	30%	30%	30%	30%
	O&M	Months	1	1	1	1
	Receivables	Months	2	2	2	2
Escalation rate	O&M	%	5.72%	5.72%	5.72%	5.72%
	Gas Price	%	1.31%	1.31%	1.31%	1.31%
	Naptha price	%	18.80%	18.80%	18.80%	18.80%
	Discounting Factor	%	10.19%	10.19%	10.19%	10.19%
Operational Data	Normative life	yrs.	25	25	25	25
	Aux	%	3%	3%	3%	3%
	Differential SHR	%		2%	2%	
	SHR	Kcal/kwh	2000	2040	2040	2040
	Gas	%	100%	100%	100%	100%
	Naptha	%	0%	0%	0%	0%
Fuel Data	GCV - Gas/~~RLNG~~	Kcal/scm	9000	9000	9000	9000
	GCV - Naptha	Kcal/kg	11300	11300	11300	11300
	Base Price --Gas/~~RLNG~~	Rs/scm	8.70	8.70	8.70	8.70

	Base Price - Naptha	Rs./kg	42	42	42	42
I. Tax	Rate	%	33.99%	33.99%	33.99%	33.99%
Working Hours	Normative	hrs/day	24	6	18	24
	Start/Stop	Nos.	0	0	0	0
	Start up time	Minute	15	15	15	15
	Starting time	hrs/day	0	0	0	0
	Actual RH	hrs/day	24	6	18	24
	Normative	hrs./yr.	8760	2190	6570	8760
	Actual RH	hrs./yr.	8760	2190	6570	8760
weightage for Fixed Charge allocation	NetGen	MU	595	191	392	583
	Weightage to peak tariff	%		25%		
	FC per Unit	Rs/Unit	1.84	2.17	1.73	1.88
	AFC	Rs. Lakh	10940	4144	6796	10940
	Weightage Factor		1.00	0.38	0.62	1.00

<u>SUMMARY SHEET</u> (Existing Gas-based thermal power station Combined Cycle)

Particulars	Unit	Normative	Peak	Off-Peak	Total
Levellised Tariff, CC	Rs/kWh	1.67	1.97	1.57	1.70
Levellised Tariff, VC	Rs/kWh	2.20	2.25	2.25	2.25
Levellised Tariff, TC	Rs/kWh	3.87	4.21	3.82	3.95
Levellised CC, LCC	Rs. Lakh/MW/Hr	0.0162	0.0191	0.0153	0.0162
IRR	%	23.64%	23.64%	23.64%	23.64%



Assumptions (New Gas-based thermal power station Open Cycle)				
Particulars		**Unit**	**Peak**	**Off-peak**
capacity	IC	MW	100	100
PAF	NPAF	%	85%	85%
	Actual PAF	%	95%	0%
Capital cost	Rate	Rs. Lakh/MW	275	275
	Capital cost	Rs. Lakh	27500	27500
Debt/Equity	Debt	%	70%	70%
	Equity	%	30%	30%
	Total Debt		19250	19250
	Total Equity		8250	8250
RoE	Base Rate of RoE	%	15.5%	15.5%
	Rate of RoE	%	23.481%	23.481%
IoL	Interest rate	%	10.75%	10.75%
	Moratorium period	yrs.	0	0
	Normative loan period	yrs.	12	12
	Repayment	%	Depn	Depn
Depreciation	Salvage Value	%	10%	10%
	Rate - 12 yrs	%	5.28%	5.28%
	Rate - after 12 yrs	%	2.05%	2.05%
O&M Expenses	O&M	Rs. Lakh/Yr/MW	14.8	14.8
		Factor	50%	50%
		Peak	22.2	22.2
IoWC	Interest Rate	%	12.25%	12.25%
	Fuel cost	Months	0.5	0.5
	maintenance spares	%	30%	30%
	O&M	Months	1	1
	Receivables	Months	2	2
Escalatio rate	O&M	%	5.72%	5.72%
	Gas Price	%	1.31%	1.31%
	Naptha price	%	18.80%	18.80%
	Discounting Factor	%	10.19%	10.19%
Operational Data	Normative life	yrs.	25	25
	Aux	%	1%	1%
	SHR	Kcal/kwh	2685	2685
	Gas	%	100%	100%
	Naptha	%	0%	0%
Fuel Data	GCV - Gas/~~RLNG~~	Kcal/scm	9000	9000
	GCV - Naptha	Kcal/kg	11300	11300
	Base Price --Gas/~~RLNG~~	Rs/scm	8.70	8.70
	Base Price - Naptha	Rs./kg	42	43
I. Tax	Rate	%	33.990%	33.990%
Working Hours	Normative	hrs/day	24	24

	Start/Stop	Nos.	2	2
	Start up time	Minute	15	15
	Starting time	hrs/day	0.5	0.5
	Actual RH	hrs/day	6	18
	Normative	hrs./yr.	8760	8760
	Actual RH	hrs./yr.	2190	6570
weightage for Fixed Charge allocation	Gross Gen	MU	208	0
	Gross Gen/Hr	MU/Hr	35	0
	Average Gross Gen/Hr		17	17
	Weightage		1.00	0.00

<u>SUMMARY SHEET</u> (New Gas-based thermal power station Open Cycle)

Particulars	Unit	Normative	Peak Hour	Off-Peak	Total
Levellised Tariff, FC	Rs/kWh	1.00	4.00		4.00
Levellised Tariff, VC	Rs/kWh	2.90	3.15		3.15
Levellised Tariff, TC	Rs/kWh	3.89	7.15		7.15
Levellised FC, LFC	Rs. Lakh/MW/Hr	0.0088	0.0396		0.0396
IRR	%	23.64%	23.64%		23.64%