CHAPTER-III

Performance review relating to Statutory Corporation

3. Power Generation Activities of Tamil Nadu Electricity Board

Executive Summary

The availability of reliable and quality power is crucial for sustained growth of the economy. The National Electricity Policy envisaged providing at least 1,000 units per capita electricity by 2012. The Performance Audit of power generation stations of Tamil Nadu Electricity Board (Board) was taken up between January and May 2010 to assess the adequacy of power supply with reference to the State's demand and the National Mission. Our findings indicated the following.

Planning and Project Management

To meet the generation requirement of the State, a capacity addition of 3,977 MW was required against which the Board added only 290 MW during 2005-10. The low capacity addition was attributable to non-completion of planned projects in time and non taking-up of identified hydro projects. All the five projects completed during the review period missed their time schedules due to improper project management resulting in avoidable time overrun with consequent cost overrun of ₹392.37 crore. Further, the Board took up life extension programme only in two out of 16 hydro stations which had completed their normative life of 35 years.

Contract Management

The Board became ineligible for duty exemption of ₹133.26 crore due to award of work valuing ₹2,175 crore on nomination basis.

Input efficiency

The supply of coal suffered from deficiencies such as short receipt of coal against linkage, which resulted in loss of generation of 812.77 MUs during 2008-10 valued at ₹266.44 crore. Deficiencies were also noticed in the system of coal handling at NCTPS and TTPS resulting in extra expenditure of ₹20.58 crore. A comparison of the rates finalised by the Board for the purchase of imported coal with that of the rates of similar grade coal imported by another State PSU indicated that the Board had incurred extra expenditure of ₹337.76 crore. Excess consumption of 45.25 lakh MT of coal at TTPS with reference to TNERC norms resulted in additional expenditure of ₹1,103.30 crore. The manpower in excess of the norms in thermal and gas stations resulted in extra expenditure of ₹279.65 crore.

Output efficiency

The Board continued to operate unviable Ennore Thermal Power Station and Basin Bridge Gas Station. Low plant load factor at Ennore Thermal Power Station was due to low capacity utilisation, major shutdowns and delays in repairs and maintenance. The gas station at Basin Bridge was not able to break even due to usage of high cost naptha and non-conversion of the station from single cycle mode to combined cycle mode. The hydel stations could only be partially operated due to not carrying out desilting, river training courses, repair to turbo generator, non-availability of dedicated feeders etc. Excess auxiliary consumption as compared to TNERC norms resulted in lesser availability of 859.34 MUs of generated power valued at ₹281.63 crore.

Financial Management

The Board incurred continuous losses during the review period. Consequently, the dependence on borrowings increased over the review period from ₹9,583.68 crore in 2005-06 to ₹32,039.26 crore in 2009-10. The Board was dependent on costlier power from other sources. The Board did not file with TNERC

the application for tariff revision every year. Instead, they filed the application only in February 2010 after a gap of seven years despite increased cost of operation and consequent poor financial position.

Environmental issues

Two thermal stations of the Board (TTPS and NCTPS) were operating without the consent of TNPCB. The air pollution levels at TTPS were much more than the norms prescribed. The Board relied on manual data for evaluating SPM levels even after installation of the online monitoring system. The ash disposal by the thermal stations was lower than the quantity generated.

Conclusion and Recommendations

The Board's inability to meet the power demand of the State was mainly due to insignificant capacity additions and not optimising the existing power generating capacity coupled with stoppage of generation though controllable. These problems could be managed by better planning and proper monitoring of the existing facilities. This review contains seven recommendations. Taking up capacity additions to the levels of demand, avoiding pre-construction and execution delays, avoiding shortage of coal, improving coal handling system and minimising forced outages are some of these.

Introduction

3.1 Power has been recognised as a basic human need. The availability of reliable and quality power at economical rates is crucial to sustain growth of all sectors of the economy. In compliance with Section 3 of the Electricity Act, 2003, the Government of India (GOI) prepared (February 2005) the National Electricity Policy for development of the Power Sector based on optimal utilisation of resources like coal, gas, hydro and renewable sources of energy. It also requires Central Electricity Authority (CEA) to frame National Electricity Plan (NEP) once in five years and give a 15 years' perspective.

3.2 During 2005-06, the average electricity requirement in Tamil Nadu was assessed as 55,479 Million Units (MUs) of which 54,380 MUs were available leaving a shortfall of 1,099 MUs (1.98 *per cent*). During the same period, the State's total installed generation capacity including the share from Central Generating Stations was 9,531 Mega Watt (MW) and effective available capacity was 7,625 MW[•] against the peak demand of 9,375 MW leaving a deficit of 1,750 MW (22.95 *per cent*) with reference to effective available capacity. As on 31 March 2010, the comparative figures of requirement and availability of power were 75,011 MUs and 70,457 MUs with deficit of 4,554 MUs (6.07 *per cent*). Whereas the installed generation capacity including the share from Central Generating Stations was 10,214 MW (**Annexure-11)** and effective available capacity was 8,040 MW[#] against the peak demand of 11,125 MW leaving a deficit of 3,085 MW (38.37 *per cent*). Thus, there was a growth in peak demand of 1,750 MW during 2005-2010, whereas the net capacity addition was only 683 MW (Board: 290 MW and Share from Central Generating Stations (CGSs)/Independent Power Producers (IPPs): 393 MW).

• 80 *per cent* of the installed capacity as per TNERC's norm for Plant Load Factor.
As assessed by the Board.

3.3 In Tamil Nadu, generation of power is carried out by Tamil Nadu Electricity Board, Chennai (Board) incorporated as a statutory body on 1 July 1957 under Electricity Supply Act, 1948. The Management of the Board is vested with a Board of Members comprising the Chairman, three full-time Members in charge of Accounts, Generation and Distribution and three part-time Members nominated by the State Government from the Departments of Energy, Finance and Industries. The Board has four thermal generation Stations, 39 hydro generation Stations, five gas turbine Stations and 10 renewable energy Stations with an installed capacity of 2,970 MW, 2,187 MW, 516 MW and 17 MW respectively as on 31 March 2010. The turnover of the Board was ₹18,845.88 crore (provisional) in 2009-2010, which was equal to 39.61 *per cent* and 7.82 *per cent* of the State PSUs' turnover (₹47,578.58 crore) and State Gross Domestic Product (₹2,41,122 crore) for the year 2009-10. It employed 81,582 employees as on 31 March 2010 including 14,816 employees in the generating stations.

3.4 The Government ordered (October 2008) restructuring of the Board by establishing a holding Company *viz*., TNEB Limited and two subsidiary companies *viz*., Tamil Nadu Transmission Corporation Limited (TANTRANSCO) and Tamil Nadu Generation and Distribution Corporation Limited (TANGEDCO). The Holding/Subsidiary companies were formed in June/December 2009. Based on the State Government order dated 19 October 2010, the Board ceased to exist from 1 November 2010 and its activities were transferred to the three new companies. Pending finalisation of transfer scheme, the transfer of assets and liabilities to these companies from the Board was done on provisional basis.

Scope and Methodology of Audit

3.5 The operational performance of a thermal unit, three gas power stations and implementation of two hydro projects were included in the Report of the Comptroller and Auditor General of India for the year 2000-01, 2002-03, 2005-06 and 2007-08 (Commercial), Government of Tamil Nadu respectively. These reviews except the review on one of the hydel projects are yet to be discussed by COPU (November 2010). The present review conducted during January to May 2010 covers the power generation activities of the Board during the period from 2005-06 to 2009-10. The review mainly deals with planning, contract and project management, operational performance, financial management, environmental issues and monitoring. The audit examination involved scrutiny of records at the Head Office, all the four[€] thermal generating Stations, 12 out of 39 hydro generating Stations having generation capacity of more than 25 MW and all the five gas turbine stations, thereby covering 91.37 *per cent* of the installed capacity of the Board as on 31 March 2010.

€ 1. Ennore Thermal Power Station (ETPS), 2. Mettur Thermal Power Station (MTPS), 3. North Chennai Thermal Power Station (NCTPS) and 4. Tuticorin Thermal Power Station (TTPS).

3.6 The Audit methodology consisted of explaining audit objectives to top management, scrutiny of records at Head Office and selected units, interaction with the auditee personnel, analysis of data with reference to audit criteria, discussion of audit findings with the Management and issue of draft review to the Management.

Audit Objectives

3.7 The Audit objectives were to assess whether:

Planning and Project Management

- capacity additions were planned for meeting the shortage of power and was in line with the National Policy of Power for all by 2012;
- there was a plan of action for optimisation of generation from the existing capacity;
- the contracts were awarded with due regard to economy and in transparent manner; and
- the execution of projects was managed economically, effectively and efficiently.

Operational Performance

- operation of the power plants was efficient and preventive maintenance carried out to minimise the forced outages;
- requirements of fuel worked out realistically, procured economically and utilised efficiently;
- the manpower utilisation was optimal;
- the life extension (renovation and modernisation) programme were carried out in an economic, effective and efficient manner; and
- the impact of Renovation and Modernisation/Life Extension activity on the operational performance of the unit.

Environmental Issues

- Air and water pollutants in power stations were within the prescribed statutory norms; and
- the adequacy of waste management system and its implementation.

Monitoring and Evaluation

- adequate Management Information System existed to monitor the power plants.

Audit Criteria

3.8 The criteria adopted for assessing the achievement of the audit objectives were:

- National Electricity Plan, norms/guidelines of CEA, Central Electricity Regulatory Commission (CERC)/ Tamil Nadu Electricity Regulatory Commission (TNERC) regarding planning and implementation of the projects;
- Transparency in Tender Act of 1998 formulated by the State;
- targets fixed for generation of power ;
- parameters fixed for plant availability, Plant Load Factor (PLF) *etc*;
- comparison with best performers in the regions/all India averages;
- prescribed norms for planned outages; and
- Acts relating to Environmental laws.

Financial Position and Working Results

3.9 The financial position of the Board as a whole covering Generation, Transmission and Distribution business for the five years ending 2009-10 is given in **Annexure – 12**.

An analysis of financial position revealed as under:

- The paid up equity capital increased from ₹535 crore during 2005-06 to ₹2,470.50 crore during 2009-10.
- The borrowings increased to ₹32,039.26 crore in 2009-10 as compared to ₹9,583.68 crore in 2005-06. Out of the increase in borrowings of ₹22,455.58 crore during 2005-10, ₹12,849.88 crore was utilised for capital expenditure indicating that Board's revenue gap was met out of borrowings.
- The increase of ₹6,180.83 crore in current liabilities during 2005-10 was mainly due to increase in electricity duty and other levies payable to Government and increase in security deposit from consumers.
- The debt-equity ratio, which was at 17.43:1 in 2005-06 improved to 10.85:1 in 2009-10 due to induction of share capital. But it continued to be adverse, compared to the ideal ratio of 4:1 in respect of power generating companies.

- The accumulated losses of the Board increased from ₹4,911.51 crore in 2005-06 to ₹27,094.17 crore in 2009-10 indicating the deteriorating financial health of the Board.

3.10 The details of working results like cost of generation of electricity, revenue realisation, net surplus/loss and earnings and cost *per* unit of operation are given in **Annexure-13**. From the annexure it could be seen that:

- The realisation per unit increased by 1.24 *per cent* only over 2005-10 whereas the cost per unit increased by 40.34 *per cent* in the same period indicating that the recovery of cost from the sales was on decreasing trend.

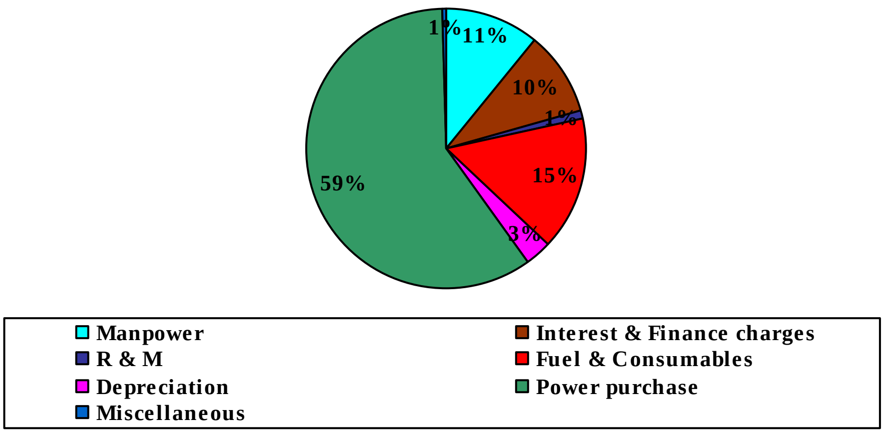
- The contribution per unit from purchase of power remained negative during the review period and increased from (-) ₹0.28 in 2005-06 to (-) ₹1.34 in 2009-10 against the positive contribution from own generation ranging between ₹1.61 to ₹0.98 during the review period. Further, the Board continued to depend heavily on purchase of power (55 *per cent* to 64 *per cent*), which led to increase in losses of the Board over the review period.

- We observed that the quantum of power purchased every year by the Board was more than what it itself generated annually. In view of the same, it is likely that in the future an increasing proportion of its income would go to meet its obligations on account of purchase of power. This will have an adverse impact on the Board's finances.

Elements of Cost

3.11 The cost of power purchased from central/private generating undertakings, fuel, consumables and manpower cost of own generating units constitute the major elements of costs. The percentage break-up of costs for 2009-10 is given below in the pie-chart.

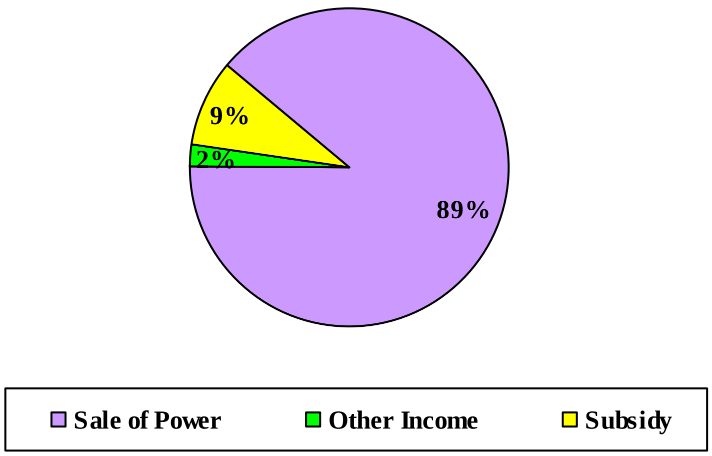
Components of various elements of cost



Elements of revenue

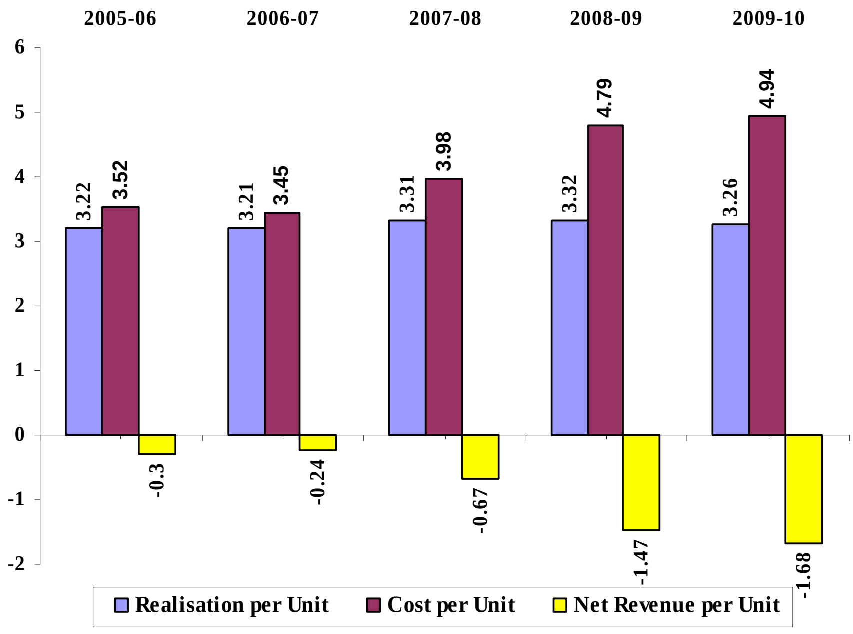
3.12 Sale of Power and subsidy constitute the major elements of revenue. The percentage break-up of revenue for 2009-10 is given below in the pie-chart.

Components of various elements of revenue



Recovery of cost of operation

3.13 During the last five years ending 2009-10, the Board was not able to recover its cost of operations as given in the graph below:



The main reasons for high cost of operation were increased dependence (from 7.29 *per cent* of the total power available for sale in 2005-06 to 19.38 *per cent* in 2009-10) on purchase of costlier power[£] from independent power producers and traders, poor capacity utilisation of thermal station at Ennore and gas station at Basin Bridge, high level of auxiliary consumption and high interest cost. The other reasons are O&M cost in excess of the norms and over staffing.

Further, as per the Board's commitment to the Ministry of Power, GOI, it should have reduced its Transmission and Distribution (T&D) losses to 15 *per cent* before December 2003, but the Board had been showing T&D losses at 18 *per cent* without any scientific study. Had the Board reduced the T&D losses to 15 *per cent*, it could have saved 9,454 MUs of energy and reduced its losses by ₹3,087.62 crore.

Audit Findings

3.14 We explained our objectives to the Board during an 'entry conference' held on 22 January 2010. Subsequently, our findings were reported to the Board and the State Government in June 2010 and discussed in an 'exit conference' held on 17 September 2010 which was attended by Chairman, Member (Generation) and Member (Distribution) of the Board. The Board replied to our findings in November 2010. The views expressed by them have been considered while finalising this review.

The operational performance of the Board for the five years ending 2009-10 given in the **Annexure – 14** was evaluated on various parameters as described below. It was also seen whether the Board was able to maintain its capacity with the growing demand for power. Our findings in this regard discussed in the subsequent paragraphs show that the losses were controllable and there was scope for improvement in performance.

Planning

3.15 During the review period 2005-10, the Board's own generation was substantially lower than the peak as well as average demand as shown below:

(In MW)

Year	Generation	Peak Demand	Average Demand	Percentage of actual generation to Peak Demand	Percentage of actual generation to Average Demand
2005-06	2,805	9,375	6,212	30	45
2006-07	3,092	8,860	6,988	35	44
2007-08	3,066	10,334	7,452	30	41

£ ₹4.87 per unit in 2006-07 to ₹6.31 per unit in 2008-09 against the average realisation up to ₹3.32 per unit during the above period.

Year	Generation	Peak Demand	Average Demand	Percentage of actual generation to Peak Demand	Percentage of actual generation to Average Demand
2008-09	3,051	9,799	7,842	31	39
2009-10	2,903	11,125	8,424	26	34

The actual generation was only 34 to 45 *per cent* of the average demand and 26 to 35 *per cent* of the peak demand. The total supply was not sufficient to meet the peak demand as shown below:

(in MW)

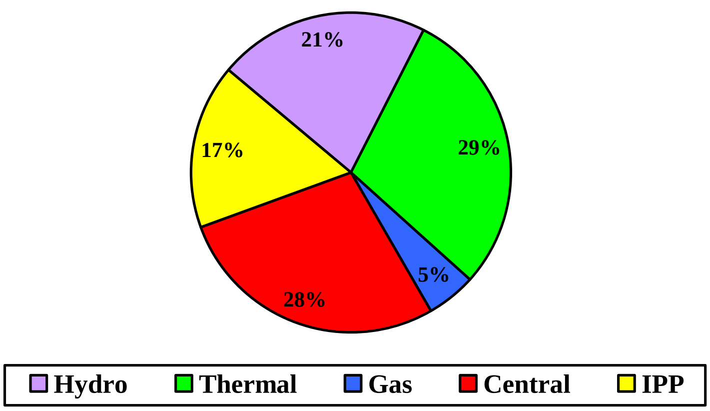
Year	Peak Demand	Peak Demand met	Sources of meeting peak demand		Peak Deficit (Percentage of Peak Demand)
			Own	Import	
2005-06	9,375	8,297	2,805	5,492	11
2006-07	8,860	8,624	3,092	5,532	3
2007-08	10,334	8,690	3,066	5,624	16
2008-09	9,799	9,211	3,051	6,160	6
2009-10	11,125	9,813	2,903	6,910	12

The Board was not able to meet 3 to 16 *per cent* of the peak demand during 2005-2010.

In 2005-06, 30 *per cent* of peak demand was met out of Board's own sources, but in 2009-10, it declined to 26 *per cent* due to inadequate capacity addition programme since 1995 onwards. Consequently, the Board had to rely on import of power from Central and private sources. Even after such import, there was a shortfall of 236 to 1,644 MW (about 3 to 16 *per cent* of the peak demand). Therefore, rotational load shedding was enforced.

Capacity additions

3.16 The State had total installed capacity of 9,531 MW at the start of 2005-06 which increased to 10,214 MW at the end of 2009-10. The break up of generating capacities, as on 31 March 2010, under Thermal, Hydro, Gas, Central, IPP and others is shown in the pie chart below:



To meet the generation requirement of 75,011 MUs in the State during 2009-10, a capacity addition of about 3,977 MW was required during 2005-06 to 2009-10 at 80 *per cent* PLF.

3.17 The projects categorised as 'Projects under Construction' (PUC) and 'Committed Projects∞' (CP) earmarked for capacity additions during review period according to NEP are detailed below.

(In MW)

Sector	Thermal	Hydro	Nuclear	Non-conventional energy	Total
PUC	417	60	1,015	0	1,492
CP	0	0	0	0	0
Uprating of existing stations	0	56	0	0	56
Total	**417**	**116**	**1,015**	**0**	**1,548**

The particulars of capacity additions envisaged, actual additions and peak demand *vis-a-vis* energy supplied during review period are given below:

Sl. No	Description	2005-06	2006-07	2007-08	2008-09	2009-10 (Provisional)
1.	Capacity at the beginning of the year (MW)	9,531	10,031	10,098	10,122	10,214
2.	Additions Planned for the year as per NE Plan(MW)(11th Plan) (including uprating of existing stations)	4	10	182	639	713
3.	Additions planned by the State (MW) included in 2. above	4	10	92	79	56
4.(a)	Actual Additions by the State (MW)	151♦	46⊗	1	92	-
4(b)	Share from CGSs &IPPs and others	349	21	23	---	---
5.	Capacity at the end of the year (MW) {1 + 4(a)+4(b)}	10,031	10,098	10,122	10,214	10,214
6.	Shortfall in capacity addition (MW) (3-4(a))	---	2	91	(+)13	56
7.	Energy requirement (MUs)	55,479	59,824	64,510	69,565	75,011

∞ National Electricity Plan defines Committed Projects as Projects for which the formal approval to take up the same has been granted by the CEA.

♦ Represents Pykara Ultimate Hydro Electric Projects (150 MW) and Perunchani Mini HEP (1 MW) planned by the State during earlier years.

⊗ This includes 34 MW relating to BKB-I (30 MW), Amaravathy Small HEP (4 MW) planned by the State during earlier years.

Sl. No	Description	2005-06	2006-07	2007-08	2008-09	2009-10 (Provisional)
8.	**Energy supplied (MUs)**	**54,380**	**61,170**	**64,430**	**64,715**	**70,457**
	a) Energy produced (MUs)	24,569	27,088	26,856	26,731	25,430
	b) Energy Purchased (MUs) (net of sale)	29,811	34,082	37,574	37,984	45,027
9.	**Surplus(+)/ Shortfall(-) in meeting demand (MUs) (7-8)**	**(-) 1,099**	**(+)1,346**	**(-)80**	**(-)4,850**	**(-)4,554**

As against the requirement of 3,977 MW, the Board planned for 241 MW and actually added 290 MW during 2005-2010.

To meet the estimated demand during 2005-10, a capacity addition of 3,977 MW was required, whereas 1,548 MW was planned during 2005-06 to 2009-10 under NEP (New projects: 1,492 MW and Uprating of existing power stations: 56 MW). Of this, the Board's share was 241 MW (including 33 MW uprating) and the balance capacity of 1,307 MW was to be contributed by the Central sector and IPPs. The Board's actual capacity addition was 290 MW[⊗]. Besides, there was increase of capacity of 393 MW[♣] contributed by the Central Generating Stations/IPPs and others. Thus, the total capacity addition (683 MW) was far less than the requirement of 3,977 MW. The reasons for shortfall in capacity addition against those planned by the State are given below:

- The Bhavani Kattalai Barrages II and III (2 x 30 MW) planned for commissioning in 2008-09 slipped its targeted date due to delay in award of work and further delay in execution of the work by the contractor as discussed in Paragraph 3.19.

- The uprating of Sholayar Power House-I by 14 MW and Periyar Power House by 28 MW planned under NEP for completion in 2008-09 and 2009-10 respectively, were neither included in State Plan nor taken up for implementation so far (November 2010).

- The uprating of Bhavani Barrage I and II (20 MW) and Periyar Vaigai Mini –I to IV (13 MW) planned for completion during 2008-10 are still under implementation (November 2010).

We further observed that the Board did not take up for capacity addition of the hydro projects as detailed below:

- The Kundah Pumped Storage Hydro Electric Project (500 MW) identified in 2005 was not taken up even after obtaining necessary

⊗ Comprising of 14 MW of Hydro projects and 92 MW of Gas project planned during the review period and 186 MW of Hydro projects which were pending from the earlier years less 2 MW deration in Non-conventional energy sources.

♣ The difference between the capacity of 4,524 MW at the end of 2009-10 and 4,131 MW at the beginning of 2005-06 contributed by CGSs/IPPs and others as mentioned in Annexure-14.

statutory/environmental clearances and acquisition of the land mainly due to its inability to mobilise the required fund of ₹488.84 crore for Stage-I of the project.

- The Board decided (July 2009) to execute the Kolli Hills Hydro Electric Project (20 MW) through private participation after having incurred preliminary expenditure of ₹12.26 crore between 1995-96 and 2007-08. There was no further progress in the project thereby blocking up ₹12.26 crore till date (May 2010).

- In addition, there were 28 small/mini hydro projects (capacity of 107 MW) which were proposed to be implemented through private promoters for which the policy decision was awaited from the State Government (November 2010).

The Board replied (November 2010) that it would add 8,376 MW of capacity in the next three to four years and there would not be shortfall of energy after commissioning of these projects. It further stated that the investment of ₹12.26 crore would be recovered from the prospective private promoters. We further noticed that:

- Board could not finalise exploration contracts within three months of the allotment (August 2006 and July 2007) of the two captive coal mines in Gare Pelma II and Mandhakini B with the Board's share of 893 million MT of coal as per GOI directions due to delay in incorporation of joint venture companies. These contracts were awarded only in March/January 2010. We further noticed that the Board's new thermal project at ETPS Annex (600 MW) was slated for completion in 2013 citing 'Mandhakini B' captive coal mine as fuel source. As the exploration of mines would normally take about six years from the date of award of contract (January 2010) the risk of not getting coal from allotted source by the prescribed dates is very high. This may lead to increased dependence on costly imported coal.

Optimum Utilisation of existing facilities

The Board took up life extension programme in respect of only two out of sixteen hydel stations, which have completed their normative life of 35 years.

3.18 A proper plan for carrying out timely repair and periodical maintenance and undertaking life extension programme/replacement of the facilities which are nearing completion of their age will ensure optimum utilisation of the existing facilities. Audit observed that, out of 16 hydro power stations which have completed the normative life of 35 years and required Life Extension Program (LEP), the Board has taken up LEP only in two hydro stations and in respect of balance stations has decided to postpone LEP beyond 2012 citing the need to maintain grid discipline and financial constraints.

We further noticed that the uprating works of Sholayar Power House-I from 70 MW to 84 MW was planned (March 2003) to be completed by 2008-09 at a cost of ₹40.68 crore by availing loans with three *per cent* interest subsidy from Power Finance Corporation. After calling for the tender (September 2003), the Board decided (April 2008) to execute the same in XII Plan due to receipt of higher rates in the quotation and to maintain grid discipline. However, the Board did not attempt to obtain fresh tender with reasonable rates before the expiry of the X Plan thereby depriving itself of not only the capacity addition of 14 MW but also the cheap financing option which expired at the end of X plan itself.

Project Management

Five projects completed during 2005-10 suffered time overrun ranging between 11 to 109 months with consequential cost overrun of ₹392.37 crore.

3.19 There were no thermal projects completed during the review period. The data on time/cost over-run of four hydro and one gas project completed and seven on-going projects are given in **Annexure-15**. It would be seen from the Annexure that in all the five projects completed, there were slippages in time schedule ranging between 11 and 109 months with consequential cost over-run of ₹392.37 crore. The delays also resulted in generation loss of 706.39 MUs in respect of completed projects valued at ₹230.69 crore. While the causes for time/cost over-run in respect of Pykara Ultimate Stage Hydro Electric Project and Bhavani Kattalai Barrage-I were discussed in the Report of the Comptroller and Auditor General of India for the year 2000-01 and 2005-06 (Commercial), Government of Tamil Nadu respectively, our findings in respect of balance projects are given below:

- The site for the Perunchani Power House was handed over to the contractor in December 1996 with the completion schedule of 24 months. But, the project was completed only in March 2006 with a delay of 86 months which was attributable to frequent stoppage of work by the contractor.

The Board replied that the main delays were attributed to the contractor for which maximum liquidated damages were imposed as per contract conditions. Further, the Power House site was flooded submerging the erected machineries during monsoon in November 2003. The reply was not convincing because the delays between 1996 and 2000 only were attributable to the contractor's inability to mobilise the resources. The Board had not analysed the reasons for subsequent delays upto March 2006 indicating ineffective follow up of the progress of work.

- Though the Board decided (March 2004) to execute Valuthur Phase-II Gas power project (92.2 MW) before expiry of Tenth plan period (March 2007), it could finalise the tender for execution of the project only in May 2006 due to non-fixing up of model of gas turbine. The work was commenced in May 2006 and was scheduled to be commissioned in February 2008. However, it was actually completed in February 2009 due to delay in execution of the civil works and problems faced during the trial run of the equipment *etc*., resulting in loss of generation of 471 MUs valued at ₹156.37 crore. Subsequently, the plant tripped in December 2009 due to heavy vibration in the turbine which was not rectified till date (November 2010). The contractor attributed the cause of vibration to usage of contaminated gas due to the negligence of the Board. During the shut down of the plant, the Board suffered loss of generation of 604.77 MUs (from January 2010 till November 2010) valued at ₹197.15 crore.

- The project approval for Bhavani Kattalai Barrages II & III was obtained in April 2000 and November 2000 respectively, but both the projects commenced only in February 2006, due to delay of five years in the award of work by the Board and subsequent delay of 22/26 months in execution of the work, which was attributable to the contractors' slow progress in execution of the work. The projects were still under execution (November 2010).

The Board attributed the delay to a court case, decision on mode of execution, width of barrage gates and optimisation of barrages. The delays except the delay of one year due to court case illustrate that the Board had not professionalised the execution despite the experience in similar hydro projects.

- The scheduled completion of January 2009 to January 2010 in respect of Periyar Vaigai I to IV was revised to November 2010 to July 2011 due to delayed execution and non-awarding of contract for Power House super structure and tail race channel.

- There was a total delay of 33 months in Bhavani Barrages-I and II projects due to delay in commencement of barrage civil works (18 months), erection of cranes (14/15 months). The Power House super structure civil works for the two projects were awarded in December 2009/January 2010 and the execution has commenced only during August 2010 and October 2010 respectively.

The Board stated that the delay in respect of Bhavani Barrages I and II was on account of land acquisition, abnormal increase in cost of cement and steel in 2008 and 2009. The reply indicated that Board had not coordinated the land acquisition along with commencement of work. The increase in cement/steel price was a general issue which could not be a reason for delay in progress of work.

Contract Management of Projects

3.20 During the review period, contracts valuing ₹8,666.93 crore were executed in respect of eleven on-going projects (three thermal and eight hydro projects). Our analysis of the execution of two thermal projects and two hydro projects indicated that:

(a) Thermal Projects

- The contract for Unit-I of North Chennai Thermal Power Project (600 MW) was awarded (January 2008) to the sole bidder *viz.*, BHEL selected through International Competitive Bidding (ICB) for an Engineering, Procurement and Construction (EPC) cum Finance

Contract for a price of ₹2,450 crore. But, invitation of tender for EPC cum financial contract was in contravention of the National Electricity Policy which prohibits inclusion of financial packages in the EPC contracts to encourage competition.

- There were adequate infrastructural facilities available at the existing NCTPS for simultaneous implementation of both Unit-I and Unit-II (600 MW each). To become eligible for benefits of exemption from customs/central excise duties for Mega Power Projects (more than 1,000 MW) under the Foreign Trade Policy of GOI, the contracts should have been finalised only through ICB route. However, the Board later awarded (June 2008) the contract for Unit-II to BHEL on nomination basis for a price of ₹2,175 crore. As the contract for Unit-II was on nomination basis, the Board became ineligible for an estimated duty exemption of ₹133.26 crore. Had the Board planned for simultaneous implementation of both the units at the time of inviting bids through ICB route, it could have taken the benefits available for Mega Power Projects.

The Board replied that BHEL was selected on nomination basis to avoid loss of time and to get the benefit of common spares, *etc*. The reply was not convincing because considering the common facilities at NCTPS, the Board could have selected the contractor for both the projects through tender and reaped the benefits applicable for 'Mega power projects'.

(b) Hydel Projects

The project contracts provided for payment of escalation for the periods beyond the scheduled completion dates of the projects only when the delays were attributable to the Board. We observed that in two projects (Bhavani Kattalai Barrage – II and III), the Board paid escalation of ₹4.73 crore beyond the contracted amount of ₹797.18 crore. However, the reasons for delay in these contracts were not analysed by the Board.

Input Efficiency

Procedure for procurement of coal

3.21 The CEA fixes power generation targets considering the capacity of the thermal plants, average Plant Load Factor (PLF), and past performance. Till December 2008, the Board worked out coal requirement on the basis of generation targets and past consumption trends and conveyed to the Standing Linkage Committee (SLC) of the Ministry of Energy (MOE), GOI, which decided the source and quantity of coal on quarterly basis. Consequent to introduction of New Coal Distribution Policy of GOI (October 2007), the Board entered into (November 2008/April 2009) Fuel Supply Agreements (FSA) with Mahanadi Coalfields Limited (MCL) and Eastern Coalfields Limited (ECL). The position of coal linkages fixed till December 2008 and Annual Contracted Quantity (ACQ) thereafter as per Fuel Supply Agreements, coal received, generation targets and actual generation during the review period covering all the Thermal Power Stations of the Board was as under:

(Quantity in lakh MT)

Particulars	2005-06	2006-07	2007-08	2008-09	2009-10	Total
1. Coal Linkage /ACQ	149.2	146.5	181.8	166.3 $^{\propto}$	138.9	782.7
2. Coal received against linkage/ACQ	132.1	132.6	133.4	132.7	127.9	658.7
3. Shortfall (1-2)	17.1	13.9	48.4	33.6	11.0	124.0
4. Import of coal by the Board	10.7	10.8	18.0	22.7	20.2	82.4
5. Total coal available (2+4)	142.8	143.4	151.4	155.4	148.1	741.1
6. Total shortfall with reference to linkage/ACQ (1-5)	6.4	3.1	30.4	10.9	(-) 9.2	41.6
7. Generation targets (MUs)	20,885	21,517	21,725	22,000	21,870	1,07,997
8. Actual generation achieved (MUs)	18,795	21,228	21,355	21,023	19,882	1,02,283
9. Shortfall in generation targets (MUs)	(-)2,090	(-)289	(-)370	(-) 977	(-)1,988	(-)5,714

Against the agreed quantity of 782.7 lakh MT, the Board received 741.1 lakh MT of coal leaving a shortfall of 41.6 lakh MT. The percentage of annual shortfall in receipt of coal ranged between 2.12 and 16.72. We observed that after entering into FSA, the linkage was reduced from 166.3 lakh MT in 2008-09 to 138.90 lakh MT in 2009-10 against which receipt of indigenous coal was 127.90 lakh MT.

Fuel supply arrangement

3.22 The analysis of FSA between the Board and MCL/ECL for supply of coal revealed that prior to introduction of FSA, the loading of optimum quantity of coal into the wagons was the responsibility of coal companies. However, in the FSA introduced after November 2008, the Board undertook the liability for over/under loading of coal with reference to the carrying capacity of the wagons enhanced from time to time by the Railways without corresponding modifications in FSA mentioning the enhanced capacity of wagons. A test check in Audit of the invoices for December 2008 revealed that the Board incurred additional expenditure of ₹50.63 lakh due to over/under-loading of coal.

The Board replied that the Ministry of Coal had been approached for the required amendment in the under/over loading clauses of the FSA as existing in the Model contract.

$\propto$ From April 2008 to December 2008, the quantity of coal was fixed based on linkage quantity decided by GOI and from January to March 2009, the quantity of coal was fixed as per FSA.

Quality of Coal

3.23 Usage of envisaged grade of coal at the thermal stations ensures optimising generation of power and economising cost of generation. We observed that out of total quantity of 530.80 lakh MT of coal received during the period from 2005-06 to 2008-09 during SLC regime, 5.37 lakh MT of coal was not of the required grade but was inferior. Though the differential cost for grade slippage was recovered regularly, the statutory cess and royalty of ₹2.16 crore paid on the higher grade of coal could not be recovered due to non-availability of an enabling provision in the agreement.

The Board replied that necessary follow up for recovery of excess statutory levies was being taken up with the coal companies.

Loss of generation due to inadequate coal stock

There was loss of generation of 812.77 MUs during 2008-10 valued at ₹266.44 crore in thermal stations due to shortage of coal.

3.24 TTPS and MTPS were operated at partial loads during 2008-09 and 2009-10 due to shortage of coal at coal bunkers. At ETPS, the units were under forced shutdown for 2,794 hours during 2009-2010 due to similar shortage of coal resulting in loss of generation of 812.77 MUs valued at ₹266.44 crore as given in **Annexure-16.** This indicated defective planning in arranging availability of coal in the respective thermal stations and improper monitoring in feeding coal to coal bunkers.

The Board stated that loss of generation was due to non-availability of imported coal during 2008-09 and problems encountered in external coal handing system in 2009-10. However, we observed that the procurement of imported coal was an off-shoot of non-availability of indigenous coal in 2008-09. Further, the loss of generation on account of external coal handing system was also avoidable as discussed in the succeeding paragraphs.

System of Coal handling

There was no system for physical verification of coal at the loading points.

3.25 The Board did not have a system of assessing transit loss from loading point to the thermal stations even after the lapse was pointed out in the Report of the Comptroller and Auditor General of India for the year 2003-04 (Commercial), Government of Tamil Nadu. The Board carried out physical verification of coal stocked at generating stations annually. However, physical verification of coal stock at loading ports was not being carried out and is taken on book stock basis only. As such any variation in book stock and actual stock at loading ports remained unreconciled. A test check by the Board at Paradip Port between August 2008 and March 2010 showed variation of 53 to 99 *per cent* between book stock and actual stock. The Board attributed the non-conducting of physical verification at the loading ports to the non-closure of the handling contract (being under litigation in the Hon'ble Supreme Court since 2001). Even though the Board had obtained bank guarantee for the value of shortage, the shortage could not be recovered due to non-closure of the contract. However, considering the instances of huge shortage of coal in the last two years, there is an imminent need for the Board for working out the transit loss and recovering the excess transit loss from the contractors in case they were responsible.

The Board, while admitting the facts, replied that the present handling contract did not provide for periodical verification of coal stock. The fact remained that in such a situation, there was no protection of financial interest of the Board arising on account of shortage of coal.

(a) Coal handling at NCTPS

- A review of coal handling at NCTPS indicated that the percentage of 'hours of discharge operation' to the 'total hours of ship stay in the berth' deteriorated from 95.77 in 2005-06 to 66.31 in 2009-10 mainly due to frequent breakdown of conveyor belts carrying the coal from the Port-end to the power station/stock yard end. A test check in Audit of the entire 235 voyages made by two private vessels during 2005-2010 revealed that the Board had to incur idle hire charges amounting to ₹6.61 crore due to overstayal of ships because of delay in discharge.

While agreeing with the observations, Board stated that it was taking a number of remedial actions like outsourcing the operation and maintenance of External Coal Handling System, replacing worn out conveyor belts, *etc*.

- The operation and maintenance(O&M) of external coal handling systems at NCTPS was awarded (June 2006) to M/s Chennai Radha Engineering Works (REW) by offering minimum guaranteed quantity(MGQ)[≠] to be moved from the Port to NCTPS stockyard and from there to the two other power stations (ETPS and MTPS). During the contract period (June 2006 to December 2009), Board made payments for MGQ (343.50 lakh MT) against the actual quantity of 288.92 lakh MT, thereby it incurred unproductive expenditure of ₹4.03 crore.

The Board replied that no extra payment had been made to the contractor since it was done as per the contractual conditions. The fact, however, remained that the Board did not either ensure the movement of the MGQ to avoid such unproductive payments or take any effort for reducing the quantum of MGQ by amending the clause in the agreement.

Deficiencies in coal handling at NCTPS and TTPS led to extra expenditure of ₹20.58 crore.

- The contract with REW expired on 26 June 2009. To maintain continuity of operation beyond the expiry period of contract, the Board extended (July 2009) the contract with REW for three months up to September 2009 and further up to December 2009. However, the tender process for the next contract was not initiated till September 2009, the reasons for which were not on record. In the meantime, the Board decided (December 2009) to undertake the coal handling

≠ MGQ of 7.50 lakh MT per month from port to stock yard and 6.00 lakh MT per month from stock yard to MTPS and ETPS.

departmentally. During the period of departmental movement (till March 2010), the Board paid ₹0.83 crore towards idle hire charges to ships due to slow movement of coal and ₹0.99 crore for movement of coal by tippers to ease out critical coal stock, and also incurred ₹3.49 crore for diversion of coal from Tuticorin Port to MTPS. Had the Board arranged for a professional coal handling contract before December 2009, these expenditure could have been avoided.

The Board replied that the operation and maintenance of ECHS was carried out departmentally for effective utilisation of available departmental manpower. But the Board ventured into departmental movement without proper training of its staff, which led to the avoidable expenditure.

- A test check of freight charges for four months[∇] indicated that the Board paid idle railway freight amounting to ₹3.35 crore out of the total freight of ₹57.83 crore due to short loading of coal from NCTPS stockyard by the handling contractor. However, the Board failed to penalise the contractor for such under-loading.

The Board replied that continuous follow up would be taken with Railways to collect the excess freight. However, we are of the opinion that since the idle freight was caused by the handling contractor who failed to load the coal to the maximum capacity of wagon, the responsibility needed to be fixed on the handling contractor.

(b) Coal handling at TTPS

- A test check of discharge performance of two ships operating in Coal Jetty (CJ) - I carried out through Poompuhar Shipping Corporation Limited, a State Government Company and at CJ - II carried out by private agencies revealed that the average time taken for discharge at CJ – I was higher[¥] than that for discharge at CJ -II leading to extra expenditure of ₹5.31 crore (as worked out by Audit) on ship hire charges.

The Board replied that the additional expenditure incurred due to overstay of vessel at CJ -I was unavoidable due to reasons like size of the conveyor chutes at the jetty being smaller resulting in frequent choking of coal. The fact was that the Board itself had proposed (March 2004) to provide shore unloaders at a cost of ₹56 crore with a pay back period of 20 months for speedy discharge of coal. But the same was yet to be installed (November 2010).

The proposal for interconnectivity of the bunker conveyors among the five units of TTPS, put up for approval four times between February 2001 and May 2009 (latest cost ₹27.14 crore) did not materialise so far (November 2010). Due to absence of interconnection between the bunkers, Units-II and III were

∇ July 2006, 2007, 2008 and 2009.

¥ MV Akhil 64-109 hours at CJ-I and 58-72 hours at CJ-II, MV Gem of Paradip 90-120 hours at CJ-I and 67-91 hours at CJ-II.

under forced outage (189 hours during October – November 2006) on account of coal feeding problems in their conveyors. This resulted in generation loss of 39.73 MUs valued at ₹12.75 crore.

The Board stated that the tender for carrying out the above work was in progress (November 2010).

Extra expenditure on Import of coal

The Board incurred additional expenditure of ₹337.76 crore on import of coal as compared to another State PSU.

3.26 A comparative analysis of the cost of imported coal incurred by the Board with reference to the rates paid for the similar type/grade of coal imported by Tamil Nadu Newsprint and Papers Limited (TNPL – a deemed State Government Company) indicated that the Board had incurred an additional expenditure of ₹337.76 crore towards import of coal made through MMTC during the period 2007-08 to 2009-10.

The Board replied that it needed imported coal continuously compared to purchase of only 3 to 4 shipments in a year by TNPL in which the rates were decided on spot. It added that the imported coal with specified grindability factor of 45 to 60 was required by it whereas such specification was not mentioned by TNPL. However, both the Board and TNPL contracted the price based on the Gross Calorific Value (GCV), moisture and ash content of coal and not on grindability factor. Further, large quantities imported by the Board would have economies of scale compared to the small quantities imported by TNPL.

Excess consumption of coal

3.27 The consumption of coal depends on its calorific value. The norms fixed by TNERC for various thermal power generation stations for production of one unit of power in the State *vis-a-vis* the maximum and minimum consumption of coal during the period of five years ending 2009-10 is given in the table below:

(Kg/Kwhr)

Name of the station	Norms fixed by TNERC	Average minimum consumption during the year	Average maximum consumption during the year
TTPS	0.630	0.726 (2006-07)	0.777 (2007-08)
NCTPS	0.750	0.633 (2005-06)	0.698 (2009-10)
MTPS	0.750	0.642 (2005-06)	0.714 (2009-10)
ETPS	1.020	0.900 (2006-07)	1.010 (2009-10)

(Figures in bracket indicate the year in which the maximum/minimum consumption was obtained)

Excess consumption of 45.25 lakh MT of coal at TTPS during 2005-10 with reference to the norms worked out to ₹1,103.30 crore.

From the above table it may be seen that consumption of coal was within the norms fixed by TNERC in all the stations except at TTPS where it resulted in excess consumption of coal of 45.25 lakh MT valued at ₹1,103.30 crore as detailed below:

Sl No	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
1	Units generated (MUs)	7,674.14	8,083.29	7,974.38	7,850.33	7,166.61
2	Coal required as per norms (in lakh MT)	48.35	50.93	50.24	49.46	45.15
3	Coal consumed (in lakh MT)	56.96	58.67	61.96	58.19	53.60
4	Excess consumption (in lakh MT) (3 – 2)	8.61	7.74	11.72	8.73	8.45
5	Rate per MT (₹)	2,174	2,157	2,212	2,982	2,717
6	Coal consumed per unit (Kg.) [(3 x 100) / 1]	0.742	0.726	0.777	0.740	0.748
7	Value of excess coal (₹ in crore) (4 x 5)	187.18	166.95	259.25	260.33	229.59

The excess consumption was due to excess station heat rate and receipt of low grade coal. The first three units of the station were designed for using coal with GCV of 5,950 whereas the actual value was only around 3,360. Apart from this, the Thermal and Gas power stations also consumed excess fuel due to high heat rate of the Stations as indicated in **Annexure-17**. Consequently, these stations consumed excess fuel (coal-13.92 lakh MT, naptha–4,702 MT and natural gas-23 million sm^3) valued at ₹347.46 crore.

The Board replied that if only coal with calorific value nearer to design value along with lesser ash content was supplied, the coal consumption could be reduced. It also stated that a proposal had been sent to TNERC requesting to revise the Station Heat Rate and specific coal consumption of TTPS.

Energy Audit

3.28 Under Energy Conservation Act, 2001, the thermal and hydel power generating stations have been notified as the 'Designated Consumers' by the GOI and hence it has become mandatory for the Board to carry out energy audit on a regular basis to improve the efficiencies of generating stations and control input costs and report the energy conservation measures to the Bureau of Energy Efficiency. However, the Board had not conducted Energy Audit in any of its generating stations so far (November 2010).

The Board replied that it was proposing to form a centralised Energy Audit Wing for thermal stations.

Manpower Management

3.29 As per National Electricity Plan (April 2007), the norms of manpower per MW were as follows:

	Plan Period	Technical	Non Technical	Total
Thermal stations	X	1.15	0.61	1.76
	XI	1.03	0.55	1.58
Hydel stations	X	1.53	0.26	1.79
	XI	1.38	0.23	1.61
Gas Stations	X	0.36	0.17	0.53
	XI	0.32	0.15	0.47

The details of sanctioned strength, actual manpower, expenditure on salaries in respect of the generating stations are as given in **Annexure–18.** The Annexure shows that the actual manpower was more than the prescribed norm in thermal and gas stations during the period 2005-10 which resulted in extra expenditure of ₹279.65 crore.

The Board replied that the norms for thermal stations as per 10th and 11th Plan might not be applicable for its thermal plants which were designed before 30 years. In respect of gas stations, it stated that the actual manpower was below the norm of National Productivity Council.

Output Efficiency

Shortfall in generation

3.30 The annual targets for generation of power are fixed by the Board and approved by the CEA. We noticed that as against the targeted generation of 1,41,206 MUs, the actual generation was 1,42,480 MUs resulting in excess generation of 1,274 MUs as shown below:

Year	Target (MUs)	Actual (MUs)	Shortfall (-)/Excess(+) (MUs)
2005-06	26,907	26,915	(+)8
2006-07	27,925	29,481	(+)1,556
2007-08	27,837	29,241	(+)1,404
2008-09	28,733	28,983	(+)250
2009-10	29,804	27,860	(-)1,944
Total	**1,41,206**	**1,42,480**	**(+)1,274**

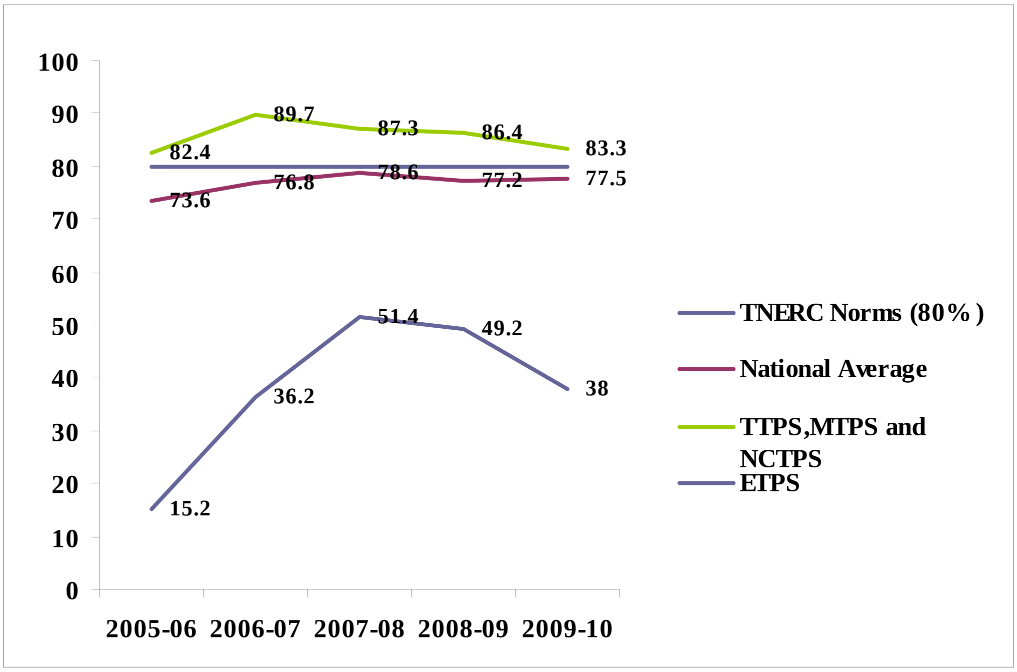
Detailed analysis of target *vis-a-vis* actual generation in thermal, gas and hydel stations revealed that during 2005-10, there was shortfall in generation in thermal and gas stations (5,714 MUs and 875 MUs respectively) and excess generation in Hydel stations (7,887 MUs) besides shortfall in others (Non-renewable) of 24 MUs. Considering the average PLF of 35 *per cent* achieved by the Hydel stations, the possible generation worked out to 6,705 MUs against which an average annual target of 4,400 MUs only was fixed indicating that the fixation of target was not realistic.

Since the generation targets were fixed by CEA based on past performance after considering the prevailing conditions of the stations, the shortfall in thermal and gas generation indicated that resources and capacity were not being utilised to the optimum level due to frequent breakdown of units in Gas stations and delay in timely rectification of defects as discussed subsequently.

Low Plant Load Factor

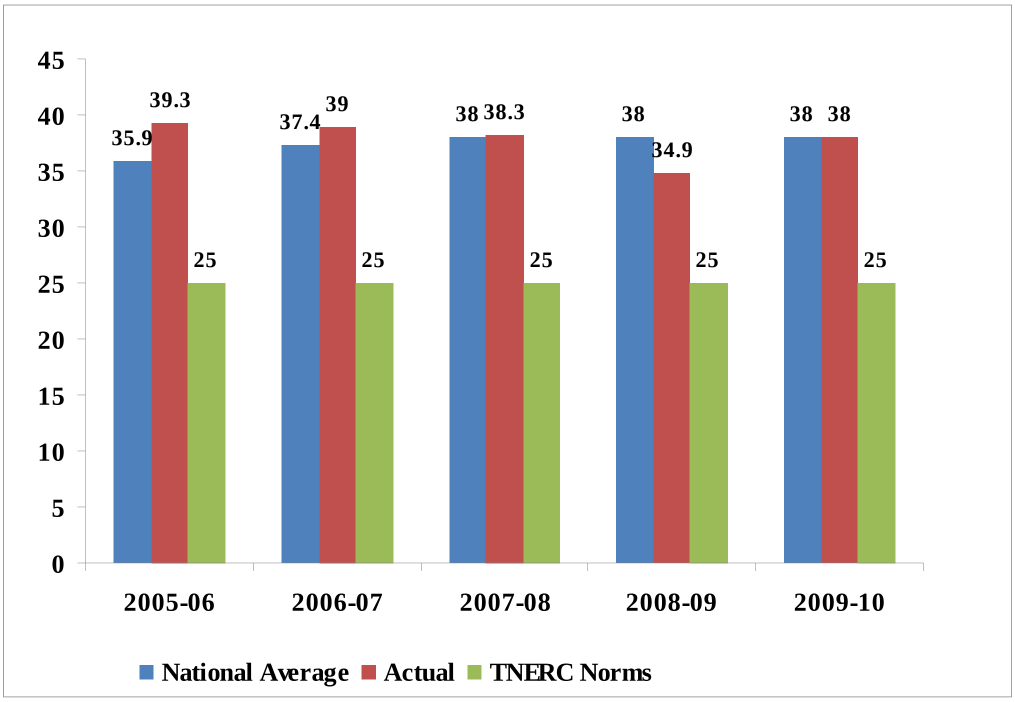
3.31 Plant load factor (PLF) refers to the ratio between the actual generation and the maximum possible generation at installed capacity. The following graphs indicate the actual performance of the generating stations in comparison with the CERC/TNERC norms and National average♦.

a) Thermal Stations

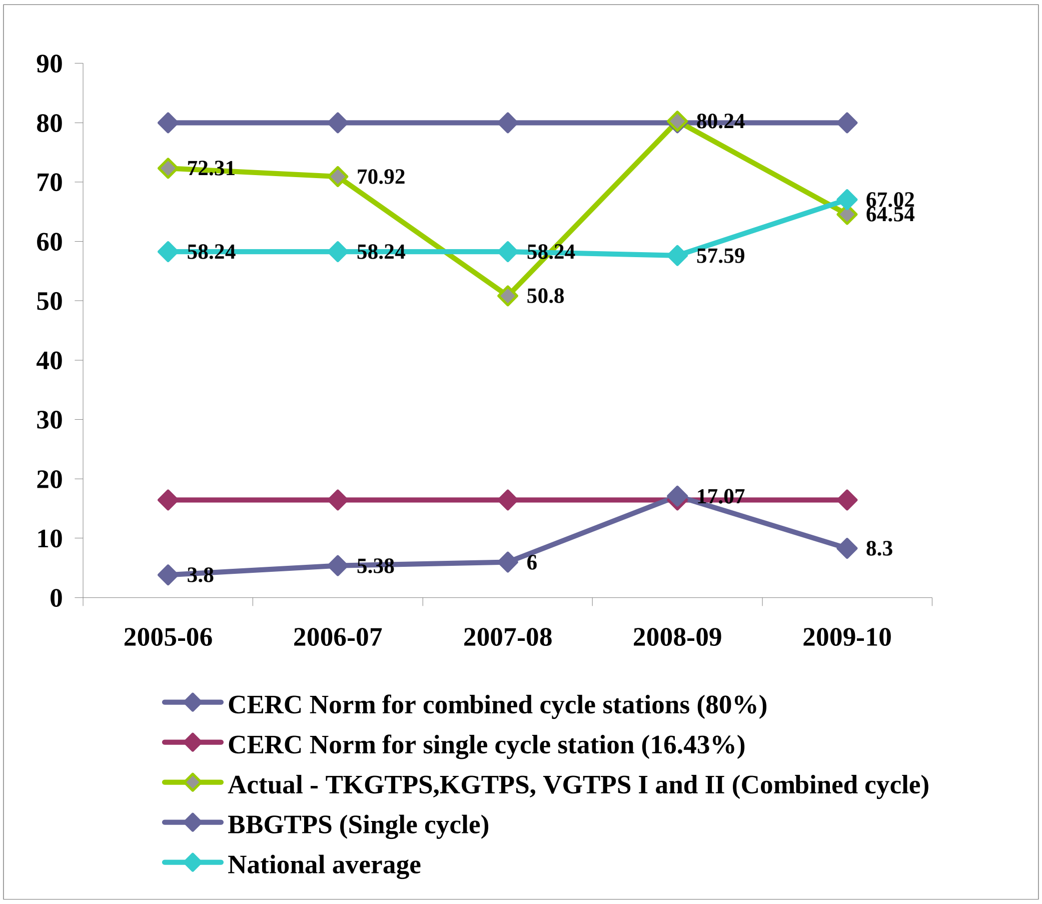


♦ National Average for Hydel and Gas Stations extrapolated based on available national averages.

b) Hydel stations



c) Gas Stations



The PLF of Guru Hargobind Singh Thermal Power Station was the highest among all State sector Power Stations (95.99 *per cent*).

Out of four thermal stations, three stations (TTPS, NCTPS and MTPS) were having PLF more than the national average and TNERC norms and only ETPS has been operating at far below the norm and national average. The reasons for lower PLF at ETPS, were low plant availability, low capacity utilisation and major shutdowns and delays in repairs and maintenance.

The Board replied that being an old station, outages occur at various equipments in ETPS decreasing the gross generation and stated that rectification works were being taken up to improve generation and PLF.

The average PLF of gas stations♣ (except BBGTPS) was lower than the norms except during 2008-09 which was attributable to under performance of gas turbine generator and short supply of contracted quantity of gas (TKGTPS), a major breakdown in 2006-07 and major overhauling in 2007-08 in KGTPS and complete breakdown of the VGTPS Unit-II during January 2010 after conducting performance guarantee test in June 2009.

We analysed the performance of ETPS and BBGTPS as regards PLF. The details of average realisation *vis-a-vis* average cost per unit, PLF achieved and the PLF at which ETPS and Basin Bridge Gas Station could break-even as worked out by us are as below:

Sl.No.	Description	2005-06		2006-07		2007-08		2008-09		2009-10	
		ETPS	BBGTPS	ETPS	BBGTPS	ETPS	BBGTPS	ETPS	BBGTPS	ETPS	BBGTPS
1	Average realisation (Paise per unit)	322	322	321	321	331	331	332	332	326	326
2	Average cost of generation (Paise per unit)♦	430	3149	327	2479	319	2414	392	1290	404	1151
3	Variable cost (Paise per unit)	288	810	253	1017	279	1157	247	985	239	934
4	Fixed cost per unit	142	2339	74	1462	40	1257	145	305	165	217
5	Contribution per unit (1-3)	34	(-)488	68	(-)696	52	(-)826	85	(-)653	87	(-)608
6	Net Generation (in MUs)	504	39.64	1230	56.24	1754	62.91	1656	178.33	1281	85.77

♣ 1. Basin Bridge Gas Turbine Power Station (BBGTPS), 2.Tirumakkottai Gas Turbine Power Station (TKGTPS), 3.Kuttalam Gas Turbine Power Station (KGTPS) and 4. Valuthur **Gas** Turbine Power Station (VGTPS).

♦ Average cost of generation as worked out by the Board differs from station to station.

Sl.No.	Description	2005-06		2006-07		2007-08		2008-09		2009-10	
		ETPS	BBGTPS	ETPS	BBGTPS	ETPS	BBGTPS	ETPS	BBGTPS	ETPS	BBGTPS
7	Actual PLF (%)	15.20	3.80	36.20	5.38	51.40	6.00	49.20	17.07	38.00	8.30
8	Fixed costs (₹. in crore) (4 X 6)	71.57	92.72	91.02	82.22	70.16	79.08	240.12	54.39	211.35	18.61
9	Break-even PLF level {(8/(5*6))*7}	63.48	N.A.[€]	39.39	N.A.	39.54	N.A.	83.93	N.A.	72.07	N.A.

ETPS could break even only at a very high PLF which is not possible considering its age and past performance. The low PLF of BBGTPS was due to operation of the Plant only for few hours in a day as a peak hour station. The proposal made (August 2007) by the Board for conversion of the plant into a combined cycle plant of 220 MW from the existing 120 MW and using alternative compatible natural gas fuel and to convert the existing peak load station into a base load station did not fructify so far (November 2010) due to non-availability of fuel linkage.

Plant availability

3.32 Plant availability means the ratio of actual hours operated to maximum possible hours available during certain period. TNERC has fixed a norm of 80 *per cent* plant availability for the thermal power stations and 85 *per cent* for hydel stations of the Board.

The details of total hours available, hours operated, planned outages, forced outages and overall plant availability in respect of thermal, hydel and gas stations of the Board are shown below:

Sl. No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
Thermal Stations						
1.	Total hours available	148920	148920	149328	148920	148920
2.	Operated hours	99213	117383	126045	126843	119380
3.	Planned outages (in hours)	23504	15055	10236	10263	9612
4.	Percentage of planned outages	15.78	10.11	6.85	6.89	6.45
5.	Forced outages (in hours)	26203	16482	13047	11814	19928
6.	Percentage of forced outages	17.60	11.07	8.74	7.93	13.39
7.	Plant availability (*per cent*)	66.62	78.82	84.41	85.18	80.16

€ Break even PLF could not be worked out due to negative contribution throughout the review period.

Sl. No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
Hydel Stations						
1.	Total hours available	330380	366110	384354	357441	323641
2.	Operated hours	252330	283576	277072	270436	240817
3.	Planned outages (in hours)	55991	48837	63631	52221	60406
4.	Percentage of planned outages	16.95	13.34	16.55	14.61	18.66
5.	Forced outages (in hours)	22059	33697	43651	34784	22418
6.	Percentage of forced outages	6.67	9.20	11.36	9.73	6.93
7.	Plant availability (*per cent*)	76.38	77.46	72.09	75.66	74.41
Gas stations						
1.	Total hours available♣	26280	26280	26352	29925	35040
2.	Operated hours	23848	22232	15939	27447	31575
3.	Planned outages (in hours)	760	2819	1873	630	1018
4.	Percentage of planned outages	2.90	10.73	7.11	2.11	2.91
5.	Forced outages (in hours)	1672	1229	8540	1848	2447
6.	Percentage of forced outages	6.35	4.67	32.41	6.17	6.98
7.	Plant availability (*per cent*)	90.75	84.60	60.48	91.72	90.11

It could be seen from the table above that the plant availability of the thermal stations was above norms except during 2005-06 and 2006-07 mainly due to the poor performance of ETPS and the fire accident at NCTPS. In the hydel stations, the plant availability decreased from 76.38 *per cent* in 2005-06 to 74.41 *per cent* in 2009-10 due to increase in forced outages. The performance of gas stations had already been commented in the Report of the Comptroller and Auditor General of India for the year 2007-08 (Commercial), Government of Tamil Nadu.

The overall plant availability for all the States as a whole was 82.67 *per cent* during 2008-09.

Low Capacity Utilisation

3.33 Capacity utilisation means the ratio of actual generation to possible generation during actual hours of operation. Based on national average PLF of 76.74 *per cent* (as applicable to thermal stations) and plant availability (80 *per cent*) as per norms of TNERC/CERC, the standard capacity utilisation factor works out to be 95.87 *per cent* for thermal power plants. For Hydel stations, the same was worked out to 43.68 *per cent* (National Average PLF 37.13 and Plant Availability factor 85 *per cent*). Our analysis of actual capacity utilisation for the generating stations (excluding ETPS and BBGTPS due to their very low PLF below break even point) during the review period was as below:

♣ Excluding BBGTPS which is a peak hour station, the performance of which is commented separately.

(In percent)

Year	Thermal		Hydel		Gas	
	Std. Capacity Utilisation	Actual Capacity Utilisation	Std. Capacity Utilisation	Actual Capacity Utilisation	Std. Capacity Utilisation	Actual Capacity Utilisation
2005-06	95.87	96.84	43.68	51.46	95.87*	79.46
2006-07		98.02		50.44		83.43
2007-08		97.53		53.12		84.67
2008-09		96.59		46.14		81.88
2009-10		93.04		48.90		71.71

We observed that the capacity utilisation of Hydel stations was above norms. However, there were instances of loss of generation to the extent of 192.39 MUs valued at ₹64.13 crore due to controllable factors as illustrated in **Annexure-19**.

The low capacity utilisation of gas stations was attributable to shortfall in supply of committed quantity of gas (up to 22 *per cent*) leading to generation loss of 2,114 MUs valued at ₹693 crore. Extension of planned maintenance at TTPS and TKGTPS also contributed to lower capacity utilisation during 2009-10.

Outages

The national average of energy loss on account of forced outages was 9.29 *per cent* during 2008-09. The State average for thermal stations was 11.74 *per cent* due to poor performance by ETPS.

3.34 Outages refer to the period for which the plant remained closed for attending planned/forced maintenance. Our analysis of the incidences of forced outages in the generating stations revealed the following:

(a) Thermal Stations

- The forced outages remained below the norm of 10 *per cent* fixed by CEA in all the five years in TTPS, MTPS and NCTPS (except during 2005-06 in NCTPS due to a fire accident). In ETPS, the same remained more than CEA norms in all the years under review. Compliance of the CEA norms would have entailed availability of plant for additional 43,600 operational hours at ETPS and 1,687 operational hours at NCTPS.

* The standard capacity utilisation applicable to thermal stations has been adopted for gas stations also.

- In ETPS, there was 65,512 hours of forced outages as shown below during 2005-10.

Year	2005-06	2006-07	2007-08	2008-09	2009-10
Total Hours available	43,800	43,800	43,920	43,800	43,800
Operated Hours	9,765	21,153	31,617	32,660	25,331
Planned outage	15,602	9,178	1,960	3,475	2,867
Forced outage	18,433	13,469	10,343	7,665	15,602
Percentage of operated hours to total hours	22.29	48.29	71.99	74.57	57.83
Percentage of forced outage to total hours	42.08	30.75	23.55	17.50	35.62

- The forced outage at ETPS was mainly due to trouble in turbine auxiliaries (50,513 hours) and in the boiler and its auxiliaries (5,816 hours).

The avoidable forced outage in NCTPS led to loss of generation of 436.81 MUs valued at ₹144.07 crore during 2006-09.

- The forced outages remained within norms at NCTPS in all the years except during 2005-06. However, the turbine installed in Unit-II of NCTPS was shut down between June 2006 and January 2009. It was designed by Siemens Limited and supplied by BHEL. Even though there was a generic defect in the turbine rotor, which persisted for ten years between 1998 and 2008, BHEL carried out piecemeal corrections without consultation with Siemens resulting in frequent shutdown of the unit. The problem was finally resolved by Siemens only in January 2009. Shutdown of the unit on this account resulted in loss of generation of 436.81 MUs of energy valued at ₹144.07 crore during the period June 2006 to January 2009.

(b) Hydel Stations

The Board had not fixed any standard for planned outages in hydro stations. We observed that, the planned outages increased from 55,991 hours in 2005-06 to 60,406 hours in 2009-10 (16.95 and 18.66 *per cent* of the total available hours). During the above period, the forced outages ranged from 22,059 hours in 2005-06 to 22,418 hours in 2009-10 (6.67 to 6.93 *per cent* of the total available hours). Consequently, the Board suffered avoidable loss of generation of 123.28 MUs valued at ₹40.69 crore in respect of illustrative cases mentioned in **Annexure-20.**

Auxiliary consumption of power

3.35 Energy consumed by power stations themselves for running their equipments and common services is called Auxiliary Consumption. The norms for auxiliary consumption fixed by TNERC *vis-a-vis* the actual auxiliary consumption in respect of the generating stations of the Board test checked by audit are given below:

Wanakbori Thermal Power Station owned by Gujarat State Electricity Corporation Limited had achieved the lowest auxiliary power consumption of 7.05 *per cent* during 2008-09.

Year	**Thermal**		**Hydel**		**Gas**	
	TNERC Norm	**Actual ranged from**	**TNERC Norm**	**Actual**	**TNERC Norm**	**Actual**
2005-06 to 2009-10	8.5% for stations without cooling towers and 9 % for stations with cooling towers.	7.94 % (TTPS) to 16.1% (ETPS)	0.2% with rotating exciters and 0.5 % for static exciters	0.25 to 2.32% in six stations with rotating exciters and 0.54 to 1.42% in six stations with static exciters.	3%	5.26% (VGTPS-II) to 7.13% (TGTPS)

The auxiliary consumption was more than the TNERC norms in respect of NCTPS and ETPS, resulting in lesser availability of 543 MUs of generated power (valued at ₹177.57 crore) to the grid. We further noticed that there was delay in replacement of Boiler Feed Pumps (BFP) with energy efficient upgraded BFP in all the five units of ETPS due to delay of 22 months in placing order (June 2006) from the date of proposal (August 2004) and subsequent delay in commissioning after receipt of equipments at ETPS up to 13 months. Consequently, there was loss of savings in auxiliary consumption of ₹3.20 crore as estimated by the Board for the 35 months.

The Board replied that it was taking remedial measures like reduction of load current for auxiliary units, *etc*., at NCTPS and ETPS. It stated that the delay in commissioning of BFP at ETPS was due to procedural formalities for getting approval.

In respect of Hydel and Gas stations, the excess auxiliary consumption with reference to TNERC norms was worked out at 316.34 MUs valued at ₹104.06 crore which was attributable to the maintenance of auxiliaries even when plants were operated at partial loads, forced outages of generating units causing frequent startup, maintenance of auxiliaries at full level after restart of the power stations, which would take a minimum period up to six hours to obtain maximum generation.

Repairs & Maintenance

3.36 (a) Thermal stations

The Kukde Committee constituted by CEA recommended (May 2001) capital maintenance of boiler every alternate year with a shutdown period of 30 days and 15 days mini shutdown between the two capital overhauls. The Committee also recommended capital maintenance of turbo generators (including boilers) once in every five years with a 50 days shutdown period. We observed that the prescribed capital overhaul of units in TTPS, NCTPS, MTPS and ETPS was done after a delay ranging from 3 to 84 months as detailed in **Annexure-21**. At NCTPS, the time taken for overhaul was within norms. However in three Stations, TTPS, MTPS and ETPS, the excess time taken for annual overhaul of boilers, turbo generators beyond the time recommended by Kukde Committee led to loss of generation of 226.24 MUs valued at ₹73.45 crore. We further observed that the capital overhaul of Unit-IV of TTPS, required to be done once in five years, was last carried out in 1999. Delay in commencement of capital works in respect of Unit-I of TTPS by BHEL after release of the unit (11 days) and delay in agreeing to additional scope of work (12 days) caused loss of generation of 115.92 MUs valued at ₹37.79 crore.

The Board replied that R&M works were delayed due to grid conditions, non-availability of critical spares, rotors and non-carrying out Residual Life Assessment (RLA) studies, *etc*. However, if the Board had adhered to the R&M schedules with advance planning for procurement of critical spares, the same could have reduced the forced outages as discussed under Paragraph 3.32 and increase the overall capacity utilisation of the plant.

(b) Hydel stations

In Pillur, Kundah forebay and Pykara reservoirs in Kundha region, 5,827 Mcft of the surplus water was let out from the reservoir without any generation during 2005-06 to 2009-10 due to silt leading to loss of generation of 42.33 MUs valued at ₹13.88 crore. The desilting work in Pillur Dam was foreclosed (October 2009) due to objection raised by Forest Department as the Board did not obtain the requisite permission. The reason for such lapse of the Board was not on record.

The Board replied that desilting of Pillur and Kundah forebay had been proposed for execution during 2011-12 with funding by World Bank.

(c) Gas stations

As per the OEM's specification of the gas stations, the maintenance inspection was to be carried out after completion of every 8,000/24,000 hours. We noticed that the Board had not installed a supervisory mechanism to ensure timely inspection as prescribed. Consequently, the requisite inspections were not carried out in TKGTPS since 2005 (except carrying out inspection of combustion in July 2006). In addition, the major inspection to be carried out once after 48,000 fired hours was carried out in December 2007/January 2008 only after noticing vibration in the Gas Turbine. The major inspection for the Gas Turbine in VGTPS Phase-I was not carried out so far (March 2010) despite the unit crossing (March 2009) 48,000 fired hours prescribed for such inspection and the Board was aware of similar damages in turbine parts in TKGTPS in September 2007.

The Board maintained that the rotor problem in respect of TKGTPS did not relate to carrying out the required maintenance schedule and further stated that major inspection for VGTPS gas station was proposed in January 2011. The fact, however, remained that the maintenance schedules were not adhered to on both the occasions.

Renovation and Modernisation

3.37 Renovation & Modernisation (R&M) activities are aimed at overcoming problems in operating units caused due to generic defects, design deficiency and ageing by re-equipping, modifying, augmenting them with latest technology/systems. Refurbishment activities are aimed at extending economic life of the units by 15 to 20 years which have served for more than 20 years or operating at PLF below 40 *per cent*. Residual Life Assessment (RLA) study is also conducted for all Refurbishment activities and in major R&M works. During 2005-10, TTPS and ETPS carried out major R&M activities in their units. Our analysis of R&M activities revealed the following:

The renovation and modernisation carried out in ETPS and TTPS at a total cost of ₹373.63 crore remained largely unfruitful.

- The average PLF of ETPS during the five years up to 1999-2000 was 45.78 *per cent.* To improve the PLF, the Board carried out R&M works in all the five units of ETPS during September 1999 to January 2007 in the areas of boiler, turbine and generator at a cost of ₹322.71 crore. However, the Board did not fix any benchmark for evaluating the post R&M performance. The actual PLF and auxiliary consumption after R&M during 2007-2010 ranged between 38 to 51.4 *per cent* and 13.7 to 14.6 *per cent* respectively against the TNERC norm (after completion of R&M) of 80 *per cent* PLF and 8.5 *per cent* of auxiliary consumption. This implied that R&M carried out remained largely unfruitful.

- Similarly, the expenditure (₹50.92 crore) on R&M works carried out during 2005-10 in the Units-I, II and III of TTPS was also not fruitful as there was no appreciable improvement in PLF, auxiliary consumption, heat rate *etc.*, as detailed in the following table:

Year	Auxiliary consumption (in *Percent*)			Heat rate (in Kcl/Kwh)			PLF (in *Percent*)		
	I	II	III	I	II	III	I	II	III
2005-06	7.55	7.91	8.12	2525	2500	2500	84.5	83.7	79.4
2006-07	7.67	7.82	7.72	2526	2498	2495	86.2	86.4	85.8
2007-08	7.85	8.00	7.79	2581	2575	2574	80.6	83.9	88.4
2008-09	7.90	7.82	7.74	2605	2560	2611	82.5	75.8	86.1
2009-10	8.39	7.76	8.35	2600	2560	2615	71.83	85.33	82.93

- The Board carried out the Renovation and Modernisation & Uprating (RMU) works in Papanasam Hydro Power House (October 2005) and Mettur Dam Power House (April 2007) at a total cost of ₹52.80 crore.

However, the Board did not evaluate the guaranteed "weighted average efficiency" (89.83 *per cent* of the rated capacity) of Papanasam Power House so as to assess the effectiveness of the RMU. Further, the Board failed to levy Liquidated Damages (LD) of ₹2.76 crore (₹0.98 crore Papanasam PH and ₹1.78 crore for Mettur Dam PH) for the delay in completion of the work.

The Board replied that the weighted average efficiency of 90.106 recorded on 31 January 2009 was higher than the guaranteed efficiency. It further stated that LD worked out to ₹0.98 crore in respect of Papanasam Power House and ₹1.78 crore in respect of Mettur Power House would be recovered on closure of the work order. However, the actual efficiency mentioned by the Board was worked out by the contractor which included an uncertainty factor of 2.67 *per cent* without any basis. Due to this, the desired generation level might not be attained.

Excess O&M expenditure over norms

3.38 The norm for O&M expenditure fixed by CERC *vis-a-vis* actual expenditure in respect of thermal, hydro and gas stations during the review period is detailed below. The Manpower cost and Repairs and Maintenance cost have been separately discussed vide Paragraphs 3.29 and 3.36 respectively.

(₹ in lakh)

Sl.No.	Stations	2005-06	2006-07	2007-08	2008-09	2009-10
1.	**Thermal Stations**					
	Norm per MW	10.82	11.25	11.70	12.17	18.20
	Actual per MW: TTPS	8.83	8.41	10.05	11.20	12.24
	NCTPS	20.03	28.60	30.10	28.05	25.66
	ETPS	16.52	17.16	21.47	32.13	31.00
	MTPS	18.60	20.79	8.77	19.35	15.74
2.	**Hydel Stations**					
	Norm per MW	7.33	7.73	8.20	8.53	8.87
	Actual per MW	8.62	8.60	7.47	8.45	7.37
3.	**Gas Stations**					
	Norm per MW	5.41	5.62	5.85	6.08	14.80
	Actual per MW	6.59	8.34	16.15	10.40	15.82

From the above, it could be seen that the norm for O&M expenses was not adhered to in any of the thermal stations of the Board except TTPS for the period 2005-10 and MTPS for 2007-08 and 2009-10. Expenditure at NCTPS was above norms even during 2005-06 when Unit-II was under forced outage due to fire accident for four months. Consequently, the Board incurred ₹684.50 crore over and above the norms of CERC. In respect of Gas power stations, the extra expenditure over and above the norms for the period 2005-06 to 2009-10 worked out to ₹83.76 crore. However, the Board did not analyse the reasons for excess expenditure over the norms of CERC.

The Board attributed the reasons for excess O&M cost to inflation, carrying major repairs, *etc*., and low load operation of hydro generators. In respect of thermal stations, it stated that based on the budget committee's recommendations, the O&M expenditure for 2009-10 was brought down to ₹375.10 crore from ₹434.86 crore in 2008-09.

Financial Management

3.39 The main sources of funds for operation of the Board are realisation from sale of power, subsidy from State Government, loans from State Government/Banks/ Financial Institutions (FI), *etc*. These funds were mainly utilised to meet payment of power purchase bills, cost of fuel, debt servicing, employee and administrative costs and system improvement works of capital and revenue nature.

Details of sources and utilisation of resources on actual basis for the Board for the years 2005-06 to 2009-10 are given below:

(Amount-₹ in crore)

S.No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10£
	Sources					
1.	Net Profit/(loss)	(-)1,328.99	(-)1,218.94	(-)3,512.08	(-)7,771.39	(-)9,680.25
2.	Add: Adjustments	2,266.50	1,087.31	1,430.44	2,096.74	6,447.27
3.	Funds from operations (1+2)	937.51	(-)131.63	(-)2,081.64	(-)5,674.65	(-)3,232.98
4.	Cash deficit	705.77	2,220.48	4,602.96	8,413.60	7,664.75
5.	**Total (3+4)**	**1,643.28**	**2,088.85**	**2,521.32**	**2,738.95**	**4,431.77**
	Utilisation					
6.	Capital expenditure	1,569.62	2,093.92	2,333.17	2,706.26	4,146.91
7.	Investments	73.66	(-)5.07	188.15	32.69	284.86
8.	**Total**	**1,643.28**	**2,088.85**	**2,521.32**	**2,738.95**	**4,431.77**

The cash deficit was overcome by increased borrowings in the form of cash credit/loans from commercial banks/FIs, which amounted to ₹9,583.68 crore in 2005-06 and increased to ₹32,039.26 crore in 2009-10. Therefore, there is an urgent need to optimise internal resource generation by reducing excess

£ Figures are provisional.

fuel consumption, forced outages, auxiliary consumption, O&M and Manpower cost, *etc*.

Claims and Dues

3.40 The Board sells energy to its consumers at the rates specified by TNERC from time to time. TNERC fixed (April 2003) the tariff rates after considering various economic and other factors which was revised with effect from September 2010. Generally sale price does not cover the total input costs. The differential amount is claimed as subsidy from the State Government. The table below gives the details of subsidy claims raised and realised.

(₹ in crore)

Details	2005-06	2006-07	2007-08	2008-09	2009-10	Total
Subsidy claims towards tariff concession	1,179.49	1,330.10	1,457.02	1,831.61	1,672.17	7,470.39
Subsidy received towards tariff concession	1,161.15	1,340.38	1,433.16	1,834.57	1,698.93	7,468.19

As per the TNERC Regulations 2005, the Board should earn a reasonable rate of return (which has been estimated as three *per cent* on net fixed assets by the Board). Accordingly, the Board has been claiming the revenue gap from the State Government which amounted to ₹10,090.10 crore during 2005-09. However, the Government had not so far committed to reimburse the same (November 2010).

Tariff Fixation

The Board did not file annual tariff revision petitions between September 2002 and February 2010.

3.41 As per the TNERC's Regulations, the Board is required to file the application with TNERC for tariff revision 120 days before the commencement of the respective year. However, the Board did not file this application on annual basis but filed the Aggregate Revenue Requirement (ARR)[Σ] along with tariff revision petition only in February 2010 after a lapse of more than seven years from the date of filing (September 2002) of previous tariff petition. Based on the application, the TNERC had revised the tariff with effect from 1 August 2010. The delay in filing ARR was already commented in the Report of the Comptroller and Auditor General of India for the year ended 2005- 2006 (Commercial), Government of Tamil Nadu.

The Board replied that it did not file annual tariff petition for want of Government's clearance. The reply was not convincing because as per the TNERC regulations, the Board was not required to get the clearance from the State Government before filing the application for tariff revision.

We further noticed that the Board had not filed its Business plan containing its five years projections with the TNERC so far (April 2010) despite receipt of

Σ Which will explain the details of operating cost of the Board.

reminders from TNERC for such non-compliance. A business plan with projection up to 2012 prepared (2009) by the Board at a cost of ₹10 lakh was not approved by its Members so far (April 2010). Specific reasons for (i) non-filing of Business plan and (ii) delay up to February 2010 in filing ARR/Tariff revision petition were not available on record.

Environment Issues

3.42 To minimise the adverse impact on the environment, the Ministry of Environment and Forest (MOE&F), GOI and Central Pollution Control Board are vested with powers and various statutes. At the State level, Tamil Nadu Pollution Control Board (TNPCB) is the regulating agency to ensure compliance with the provisions of these Acts and statutes. Our scrutiny relating to compliance with the provisions of various Acts in this regard revealed the following:

Operation of plant without consent

3.43 For operation of thermal power stations, the consent of TNPCB is mandatory. Consequent upon expiry (30 September 2008 – TTPS and 30 September 2009 – NCTPS) of consent order, TNPCB issued notices between October 2009 and February 2010 to these stations for remittance of consent fee of ₹60.75 lakh for renewal of consent. But the Board neither remitted the fees nor obtained renewal of TNPCB's consent so far (April 2010).

The Board replied that action was being taken to remit the consent fee demanded by TNPCB.

Air pollution

3.44 Coal ash is a pollutant under certain conditions when it is airborne and its concentration in a given volume of atmosphere is high. Electrostatic Precipitator (ESP) is used to reduce dust concentration in flue gases. The ESPs at none of the thermal stations were able to achieve the norms fixed by TNPCB due to usage of poor quality of coal with ash content of around 45 *per cent*. It was noticed that the emission levels of two thermal stations *viz*., TTPS (2500 mg/Nm^3 during February 2010) and MTPS (575 mg/Nm^3 during June 2005) were the highest as against the norm of 150 mg/Nm^3 during the period under review.

We further noticed that:

- In TTPS, though there was a proposal (November 2006) to install Ammonia injection system in Unit-III to reduce the levels of Suspended Particulate Matter (SPM), it was not installed so far (November 2010).

- The TNPCB observed (May 2008) that TTPS had not brought down emission levels and issued direction to improve/maintain ESPs to meet the emission standards. However, it remained above the norms till date (November 2010).

The Board replied that the emission levels of all the units of TTPS (except Unit-III) have come down after carrying out overhauls in Unit-I and Unit-II and due to usage of imported coal in Unit-IV and Unit-V. However, the emission levels were still higher than the norms as on March 2010. In respect of Unit-III of TTPS, the Board stated that the emission level would get reduced after the forthcoming capital overhaul in 2010-11.

Installation of on-line monitoring equipment

3.45 As per the provisions of the Environment (Protection) Act, 1986, thermal power stations should provide on-line monitoring systems to record SPM levels. Online monitoring and other equipments purchased and installed at a cost of ₹34.05 lakh at TTPS and NCTPS were not functioning effectively with the result that SPM data were being collected manually. Further, the Board evaluated the SPM levels based on manual reading only. At ETPS, online monitoring system has not yet been installed (March 2010).

The Board replied that the equipments were working satisfactorily (except at Unit-III of TTPS). It was further stated that at ETPS, action was being taken to install online monitoring system. However, we observed that the Board was relying on manual data for evaluating SPM levels instead of on-line monitoring system.

Use of high ash content coal

3.46 As per MOE&F notification (June 1988 and September 1997) coal based power stations located in urban, sensitive and critically polluted areas are required to use coal having less than 34 *per cent* ash on an annual weighted average basis. Despite being highlighted in the Report of the Comptroller and Auditor General of India for the year ended 2003-2004 (Commercial), Government of Tamil Nadu, the benefits of usage of washed coal, the thermal stations continued to use high ash content coal. The thermal stations of the Board consumed 65.68 million MT of indigenous coal during 2005-10, whose weighted average ash content ranged from 37.18 to 43.50 *per cent*.

The Board replied that the pros and cons of usage of washed coal would be assessed before taking a decision in this regard.

Ash disposal

3.47 The four thermal stations of the Board generated an annual quantity of 56 lakh MT of fly ash. For disposal of fly ash, the Board entered into Memoranda of Understanding (MOU) (February 2003) with cement companies for provision of 'Pressurised dense fly ash collection system' for removal of fly ash. While 80 *per cent* of the collected fly ash would be lifted by these cement companies at the rate of ₹60 per MT, the remaining

20 *per cent* was to be given to Small Scale Units free of cost. Our scrutiny of disposal of fly ash revealed the following:

- There was a shortfall in removal of committed quantity of fly ash by the cement companies to the extent of 39.40 lakh MT resulting in foregoing of revenue of ₹23.64 crore during 2005-10. Despite continued shortfall, Board decided to levy penalty (₹5.70 crore) as per the terms of MOU only from April 2008 but such levy was challenged by the allottees in Court (May 2010) due to absence of clear terms of quantity and manner of levy of penalty in the MOU. The uncollected fly ash of 39.40 lakh MT in the four thermal power stations had to be pumped into ash dyke to convert the same into ash slurry by incurring extra expenditure of ₹31.52 crore. Further, there was accumulation of 710.88 lakh MT of wet ash in land as of October 2009 against MOE&F's guidelines which prescribed phasing out such accumulation before 2009 itself.

- As per design calculations, the ESP hoppers should collect fly ash equivalent to 70 *per cent* of the total ash generated. But the fly ash collection at NCTPS was around 59.52 *per cent* only. This resulted in loss of revenue to the Board amounting to ₹2.93 crore being the difference between the collectible ash at 70 *per cent* and the actual collection of 59.52 *per cent*.

The Board replied that the short collection of fly ash was due to inherent deficiency of Duct hoppers at NCTPS.

Monitoring by top management

3.48 There has to be a Management Information System (MIS) to report on achievement of targets and norms. The achievements need to be reviewed to address deficiencies and also to set targets for subsequent years. Our review of the system existing in this regard revealed the following:

- The details of generation by hydro generating units reflected in the records of Board's headquarters did not tally with any of its four hydro generation circle offices indicating that monitoring for collection of data was not effective.

- There was no system in place to get the final project cost approved by the competent authority immediately after the completion of the hydro projects.

The Board stated that the observation was noted for future guidance.

- The Aggregate Revenue Requirement was filed with TNERC belatedly by the Board only in 2010 after a lapse of more than seven years.

The matter was referred to Government in June 2010; their reply was awaited (November 2010).

Acknowledgement

We acknowledge the co-operation and assistance extended by the staff and the management of the Board in conducting this Performance Review.

Conclusion

- **The Board's actual generation which was at 45 *per cent* of the average demand in 2005-06, slipped down to 34 *per cent* in 2009-10 due to addition of only 290 MW during the last five years up to 2009-10 against the planned addition of 1,548 MW and requirement of 3,977 MW.**

- **The Board carried out life extension programmes in only two hydel stations out of 16 stations which have completed their normative life of 35 years.**

- **Inefficient planning by the Board for simultaneous implementation of both the units of NCTPS at the time of inviting bids led to foregoing of estimated duty exemption of ₹133.26 crore.**

- **ETPS and BBGTPS continued to be unviable due to ineffective renovation and modernisation of the thermal plant and non-conversion of gas plant from single cycle mode to combined cycle mode.**

- **The Board suffered generation loss of 812.77 MUs during 2008-10 valued at ₹266.44 crore due to shortage of coal at coal bunkers. Besides, problems in handling coal and excess consumption of coal in thermal stations persisted during 2005-2010.**

- **Manpower in excess of CEA norms at the generation stations during 2005-10 resulted in extra expenditure of ₹279.65 crore.**

- **The PLF of the generation stations of the Board remained more than the national average PLF during the review period except in ETPS and BBGTPS.**

- **Excess auxiliary consumption than TNERC norms during the review period resulted in lesser availability of 859.34 MUs of generated power valued at ₹281.63 crore.**

- **Despite the continuous loss, the Board did not file the application for the tariff revision annually as required.**

- **On the environmental side, the Board did not adhere to the provisions of various Acts, regulations and norms as prescribed resulting in adverse impact on the environment.**

Recommendations

The Board must

- **take up capacity addition to the levels of demand to avoid load shedding.**
- **avoid delays in pre-construction activities and delays in execution by proper monitoring of the projects.**
- **take up renovation and modernisation programmes and preventive maintenance as scheduled for optimising the existing generation capacity.**
- **plan for availability of adequate coal and avoid shortages besides improving the coal handling system.**
- **rationalise deployment of manpower at generation stations for its optimum utilisation.**
- **minimise forced outages and reduce the auxiliary consumption to be within the norms.**
- **ensure compliance of pollution control norms by the thermal stations.**