CHAPTER V: GOVERNMENT COMMERCIAL AND TRADING ACTIVITIES

5.1 Overview of State Public Sector Undertakings

Introduction

5.1.1 The State Public Sector Undertakings (PSUs) consist of State Government Companies and Statutory Corporations. The State PSUs are established to carry out activities of commercial nature while keeping in view the welfare of people. The State PSUs registered a turnover of ₹ 288.48 crore as per their latest finalised accounts as of September 2010. This turnover was equal to 2.65 *per cent* of State Gross Domestic Product (GDP) for 2009-10. Thus, the State PSUs occupy an insignificant place in the State economy. Major activities of Tripura State PSUs were concentrated in power and agriculture sectors. The State PSUs incurred a loss of ₹ 1.97 crore in the aggregate for 2009-10 as per their latest finalised accounts. They had employed 8,314 employees as of 31 March 2010. The State PSUs do not include Departmental Undertakings (DUs), which carry out commercial operations but are a part of Government departments.

5.1.2 As on 31 March 2010, there were fourteen PSUs as per the details given below. None of the companies were listed on the stock exchange.

Table No. 5.1.1

Type of PSUs	Working PSUs	Non-working PSUs[2]	Total
Government Companies[3]	12	1	13
Statutory Corporations	1	-	1
Total	**13**	**1**	**14**

5.1.3 During the year 2009-10, one PSU *viz*. Tripura Tourism Development Corporation Limited was established under the Companies Act, 1956.

Audit Mandate

5.1.4 Audit of Government companies is governed by Section 619 of the Companies Act, 1956. According to Section 617, a Government company is one in which not less than 51 *per cent* of the paid up capital is held by Government(s). A Government company includes a subsidiary of a Government company. Further, a company in which not less than 51 *per cent* of the paid up capital is held in any combination by Government(s), Government companies and Corporations controlled by Government(s) is treated as if it were a Government company (deemed Government company) as *per* Section 619-B of the Companies Act.

[1] As per the details provided by 13 PSUs. Remaining one non-working PSUs did not furnish the details.
[2] Non-working PSUs are those which have ceased to carry on their operations.
[3] Includes two 619-B companies.

5.1.5 The accounts of State Government companies (as defined in Section 617 of the Companies Act, 1956) are audited by Statutory Auditors, who are appointed by CAG as per the provisions of Section 619(2) of the Companies Act, 1956. These accounts are also subject to supplementary audit conducted by CAG as per the provisions of Section 619 (4) of the Companies Act, 1956.

5.1.6 Audit of statutory corporations is governed by their respective legislations. CAG is the sole auditor of the only statutory corporation in the State *viz.* Tripura Road Transport Corporation.

Investment in State PSUs

5.1.7 As on 31 March 2010, the investment (capital and long-term loans) in 14 PSUs was ₹ 633.61 crore as *per* details given below.

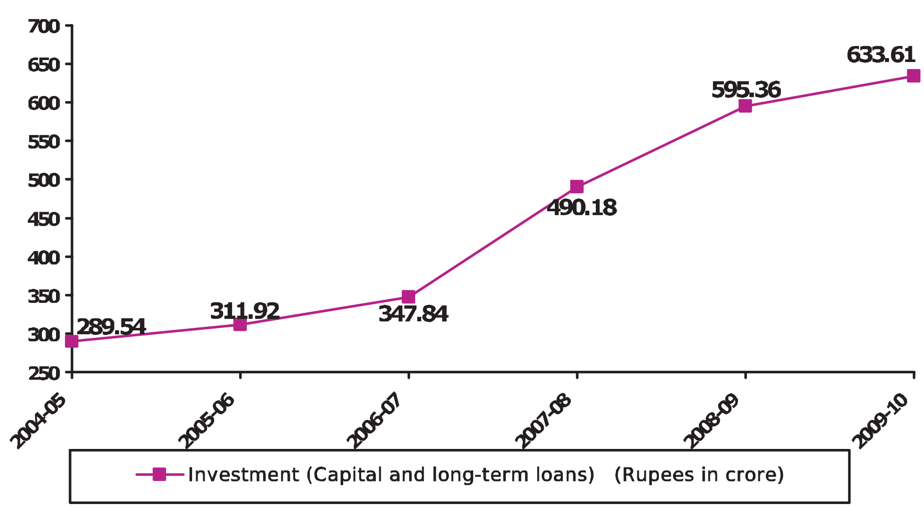
Table No. 5.1.2

(Rupees in crore)

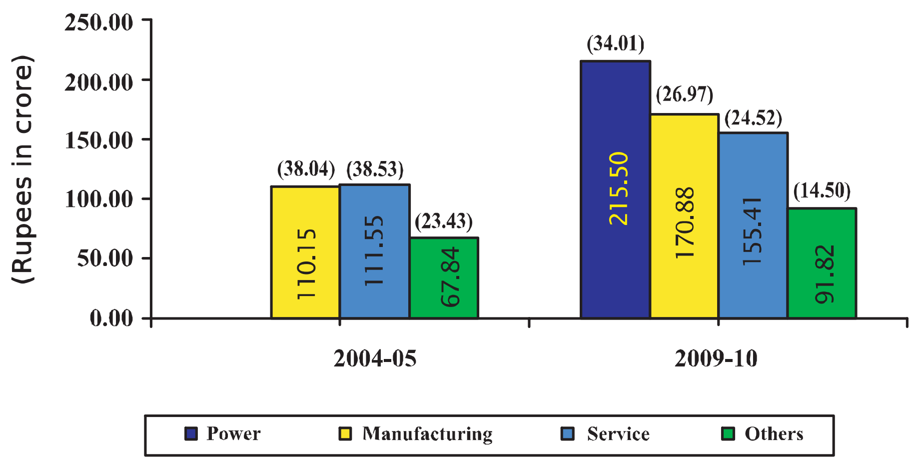
Type of PSUs	Government Companies			Statutory Corporations			Grand Total
	Capital	Long Term Loans	Total	Capital	Long Term Loans	Total	
Working PSUs	370.45	108.12	478.57	154.75	0.25	155.00	633.57
Non-working PSUs	0.04	-	0.04	-	-	-	0.04
Total	**370.49**	**108.12**	**478.61**	**154.75**	**0.25**	**155.00**	**633.61**

A summarised position of Government investment in State PSUs is detailed in **Appendix - 5.1**.

5.1.8 As on 31 March 2010, of the total investment in State PSUs, 99.99 *per cent* was in working PSUs. This total investment consisted of 82.90 *per cent* towards capital and 17.10 *per cent* in long-term loans. The investment has grown by 118.83 *per cent* from ₹ 289.54 crore in 2004-05 to ₹ 633.61 crore in 2009-10 as shown in the graph below.



5.1.9 The investment in various important sectors and percentage thereof at the end of 31 March 2005 and 31 March 2010 are indicated below in the bar chart.



(Figures in brackets show the percentage of total investment)

The thrust of investment in the power sector arose from transfer of the generation, transmission and distribution of electricity from the Power Department, Government of Tripura since January 2005 to a new company *viz.* Tripura State Electricity Corporation Limited, set up in June 2004. The other major sectors for investment were manufacturing and service.

Budgetary outgo, grants/subsidies, guarantees and loans

5.1.10 The details regarding budgetary outgo towards equity, loans, grants/ subsidies, guarantees issued, loans written off, loans converted into equity and interest waived in respect of State PSUs are given in **Appendix - 5.2**. The summarised details are given below for three years ended 2009-10.

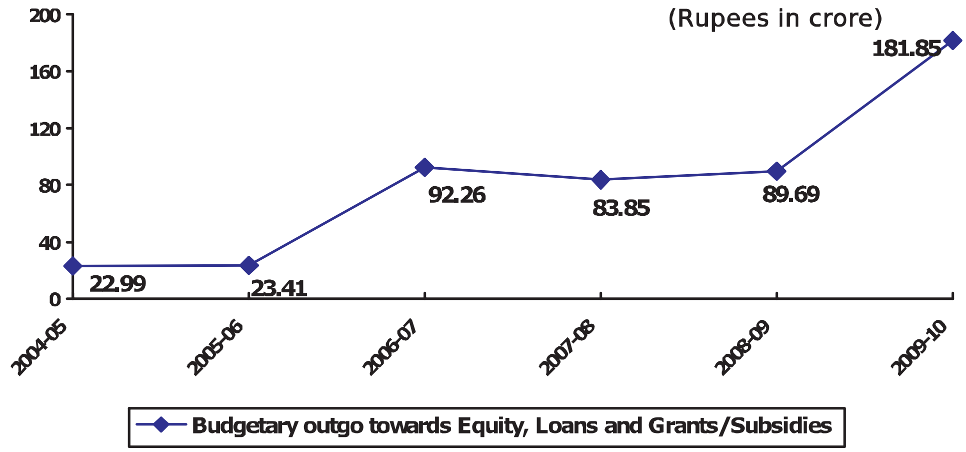
Table No. 5.1.3

(Rupees in crore)

Sl. No.	Particulars	2007-08		2008-09		2009-10	
		No. of PSUs	Amount	No. of PSUs	Amount	No. of PSUs	Amount
1.	Equity Capital outgo from budget	7	29.07	7	31.13	8	25.79
2.	Loans given from budget	1	4.78	1	30.50	1	16.50
3.	Grants/Subsidy received[4]	1	50.00	3	28.06	4	139.56
4.	Total Outgo (1+2+3)	8[5]	83.85	9[5]	89.69	10[5]	181.85

5.1.11 The details regarding budgetary outgo towards equity, loans and grants/ subsidies for six years are given in a graph below.

[4] Amount represents outgo from State Budget only.
[5] The figure represents number of companies which have received outgo from budget under one or more heads i.e. equity, loans, grants/subsidies.



The increase in annual budgetary outgo during 2005-10 was mainly directed to the power sector. The State Government provides financial support, mainly to Tripura State Electricity Corporation Limited, Tripura Jute Mills Limited and Tripura Road Transport Corporation, to bridge the gap of income and expenditure of these PSUs. This indirectly becomes a subsidy support.

5.1.12 Since May 2007, guarantee fee was fixed at one *per cent* for any fresh guarantee. No fresh guarantees were issued in the last three years.

Reconciliation with Finance Accounts

5.1.13 The figures in respect of equity, loans and guarantees outstanding as per records of State PSUs should agree with that of the figures appearing in the Finance Accounts of the State. In case the figures do not agree, the concerned PSUs and the Finance Department should carry out reconciliation of differences. The position in this regard as at 31 March 2010 is stated below.

Table No. 5.1.4

(Rupees in crore)

Outstanding in respect of	Amount as per Finance Accounts	Amount as per records of PSUs	Difference
Equity	722.62	517.24	205.38
Loans	33.50	107.51	(74.01)
Guarantees	2.68	-	2.68

5.1.14 Audit observed that the differences occurred in respect of 10 PSUs and some of the differences were pending reconciliation since 1986-87. The matter was taken up, demi-officially with the Finance Secretary and copy to the concerned PSUs. The last occasion was in April 2009. The Government and the PSUs should take concrete steps to reconcile the differences in a time-bound manner.

Performance of PSUs

5.1.15 The financial results of PSUs, financial position and working results of the Tripura Road Transport Corporation are detailed in **Appendices 5.3, 5.4 and 5.5**

respectively. A ratio of PSU turnover to State GDP shows the extent of PSU activities in the State economy. Table below provides the details of working PSU turnover and State GDP for the period 2004-05 to 2009-10.

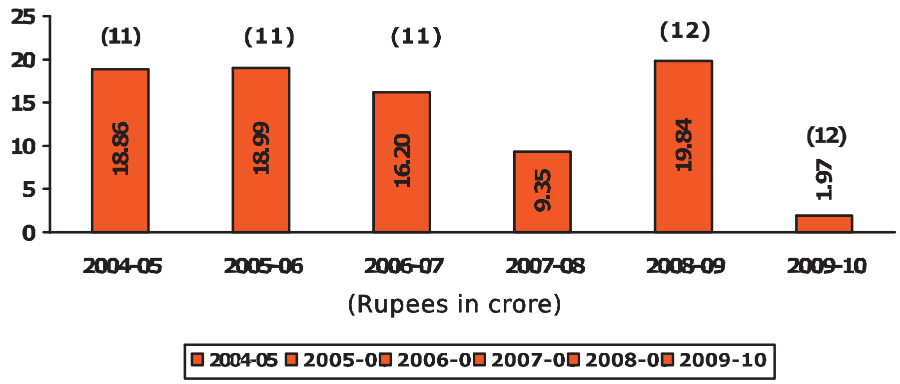
Table No. 5.1.5

(Rupees in crore)

Particulars	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
Turnover[6]	38.93	53.79	50.43	251.65	260.69	288.48
State GDP	6,639.24	7,296.61	7,888.98	8,521.68	10,008.26	10,905.00
Percentage of Turnover to State GDP	0.59	0.74	0.64	2.95	2.60	2.65

The increase in turnover from 2007-08 onwards was on account of inclusion of turnover of Tripura State Electricity Corporation Limited.

5.1.16 Losses incurred by State working PSUs during 2004-05 to 2009-10 are given below in a bar chart.



(Figures in brackets show the number of working PSUs in respective years)

There was drastic reduction in loss in 2009-10 as seven[7] working PSUs out of 12, earned profit as per their latest finalised accounts. The major contributors to profit were Tripura Forest Development & Plantation Corporation Limited (₹ 14.97 crore) and Tripura State Electricity Corporation Limited (₹ 8.81 crore). The heavy losses were incurred by Tripura Road Transport Corporation (₹ 16.25 crore) and Tripura Jute Mills Limited (₹ 8.61 crore).

5.1.17 The losses of PSUs are mainly attributable to deficiencies in financial management, planning, implementation of project, running their operations and monitoring. A review of latest Audit Reports of CAG shows that the State PSUs incurred losses to the tune of ₹ 118.20 crore and infructuous investment of ₹ 0.48 crore which were controllable with better management. Year-wise details from Audit Reports are stated below.

[6] Turnover as per the latest finalised accounts as of 30 September of respective years.
[7] Sl. Nos. A(1), A(3), A(5), A(6), A(9), A(10) & A(12) of **Appendix - 5.3**.

Table No. 5.1.6

(Rupees in crore)

Particulars	2007-08	2008-09	2009-10	Total
(Loss)	(9.35)	(19.84)	(1.97)	(31.16)
Controllable losses as per CAG's Audit Report	66.70	2.76	48.74	118.20
Infructuous Investment	0.48	-	-	0.48

5.1.18 The above losses pointed out by Audit Reports of CAG are based on test check of records of PSUs. The actual controllable losses would be much more. The above table shows that with better management, the losses can be eliminated. The PSUs can discharge their role efficiently only if they are financially self-reliant. The above situation points towards a need for professionalism and accountability in the functioning of PSUs.

5.1.19 Some other key parameters pertaining to State PSUs are given below.

Table No. 5.1.7

(Rupees in crore)

Particulars	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
Return on Capital Employed (*Per cent*)	NEGATIVE IN ALL YEARS					0.59
Debt	9.85	8.81	8.50	23.74	98.29	108.37
Turnover[8]	38.93	53.79	50.43	251.65	260.69	288.48
Debt/ Turnover Ratio	0.25	0.16	0.17	0.09	0.38	0.38
Interest Payments[8]	8.13	5.68	5.69	6.31	5.89	7.27
Accumulated losses[8]	176.38	196.39	197.98	210.18	243.74	303.21

(Above figures pertain to all PSUs except for turnover which is for working PSUs)

5.1.20 Debt had increased in the past three years on account of loans of Tripura State Electricity Corporation Limited.

5.1.21 The State Government had not yet formulated a dividend policy. As per their latest finalised accounts, seven PSUs earned an aggregate profit of ₹ 26.80 crore, of which two PSUs (TIDC & TFDPC) declared a total dividend of ₹ 54.18 lakh[9].

Arrears in finalisation of accounts

5.1.22 The accounts of the companies for every financial year are required to be finalised within six months from the end of the relevant financial year under Sections 166, 210, 230, 619 and 619-B of the Companies Act, 1956. Similarly, in case of Statutory corporations, their accounts are finalised, audited and presented to the Legislature as per the provisions of their respective Acts.

The table below provides the details of progress made by working PSUs in finalisation of accounts by September 2010.

[8] Turnover of working PSUs and interest as well as accumulated losses as *per* the latest finalised accounts as of 30 September.
[9] TIDC –₹ 12.19 lakh (2004-05) and ₹ 14.39 lakh (2008-09), TFDPC –₹ 27.60 (2005-06).

Table No. 5.1.8

Sl. No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
1.	Number of working PSUs	12	12	12	12	13
2.	Number of accounts finalised during the year by the Managements	7	5	6	24	38
3.	Number of accounts in arrears	73	80	86	74	49
4.	Average arrears per PSU (3/1)	6.08	6.67	7.17	6.17	3.77
5.	Number of Working PSUs with arrears in accounts	12	12	12	12	13
6.	Extent of arrears	1 to 12 years	1 to 13 years	2 to 14 years	2 to 15 years	1 to 9 years

5.1.23 The finalisation of accounts showed remarkable improvement in 2009-10. The reasons for arrears in accounts were lack of skilled personnel in PSUs as well as delays in preparation of accounts.

5.1.24 The only non-working PSU is under liquidation process since 1971.

5.1.25 The State Government had invested ₹ 490.94 crore (Equity: ₹ 187.79 crore, loans: ₹ 55.13 crore, grants: ₹ 207.08 crore and others: ₹ 40.94 crore) in 13 PSUs during the years for which accounts have not been finalised as detailed in **Appendix - 5.6**. In the absence of accounts and their subsequent audit, it can not be ensured whether the investments and expenditure incurred have been properly accounted for and the purpose for which the amount was invested has been achieved or not and thus Government's investment in such PSUs remain outside the scrutiny of the State Legislature. Further, delay in finalisation of accounts may also result in risk of fraud and leakage of public money apart from violation of the provisions of the Companies Act, 1956.

5.1.26 The administrative departments have the responsibility to oversee the activities of these entities and to ensure that the accounts are finalised and adopted by these PSUs within the prescribed period. Though the concerned administrative departments and officials of the Government were informed of the arrears in finalisation of accounts by Audit every quarter, remedial measures were taken belatedly. As a result of this, the net worth of these PSUs could not be assessed in audit. The matter of arrears in accounts was also taken up from time to time with the State Government. In the light of relaxed norms of CAG for expeditious clearance of the backlog in arrears, all PSUs had been categorically instructed by the State Government to show results in overcoming arrears in accounts. Though overall response of the State Government and some PSUs have been very good, four[10] PSUs did not submit their accounts in the whole year.

5.1.27 In view of above state of arrears, it is recommended that:

- **The Government may set up a cell to oversee the clearance of arrears and set the targets for individual companies which would be monitored by the cell.**

[10] Sl. Nos. A(2), A(9), A(10) & A(12) of **Appendix - 5.3**.

- **The Government may consider outsourcing the work relating to preparation of accounts wherever the staff is inadequate or lacks expertise.**

Winding up of non-working PSUs

5.1.28 There was one non-working Company *viz*. Tripura State Bank Limited, as on 31 March 2010, which had been non-functional for around 40 years. It was in the process of liquidation under Section 560 of the Companies Act, 1956. The non-working PSU is required to be closed down since its existence is not going to serve any purpose. The Company continues to await liquidation for almost four decades. The Government may expedite winding up of the Company.

Accounts Comments and Internal Audit

5.1.29 Seven working companies forwarded their audited 35 accounts to AG during the year 2009-10. Of these, 28 accounts of seven companies were selected for supplementary audit. The audit reports of statutory auditors appointed by CAG and the supplementary audit of CAG indicate that the quality of maintenance of accounts needs to be improved substantially. The details of aggregate money value of comments of statutory auditors and CAG are given below.

Table No. 5.1.9

(Rupees in crore)

Sl. No.	Particulars	2007-08		2008-09		2009-10	
		No. of accounts	Amount	No. of accounts	Amount	No. of accounts	Amount
1.	Increase in profit	1	0.11	1	0.02	7	0.29
2.	Decrease in loss	1	-	5	1.71	11	0.42
3.	Decrease in profit	1	0.02	1	0.01	9	11.94
4.	Increase in loss	1	2.94	8	9.73	9	8.79
5.	Non-disclosure of material facts	1	5.96	5	12.17	4	3.91
6.	Errors of classification	4	2.35	9	17.06	11	34.41

5.1.30 During the year, the statutory auditors had given qualified certificates on all the accounts received upto September 2010. The compliance of companies with the Accounting Standards (AS) remained poor as there were 43 instances of non-compliance in 27 accounts during the year. This non-compliance related to AS-1 (Disclosure of Accounting Policies), AS-2 (Valuation of Inventories), AS-3 (Cash Flow Statement), AS-4 (Contingencies and Events occurring after the Balance Sheet date), AS-9 (Revenue Recognition), AS-10 (Accounting for Fixed Assets), AS-15 (Employee benefits) and AS-22 (Accounting for taxes on income).

5.1.31 Some of the important comments in respect of accounts of companies audited during October 2009 to September 2010 are stated below.

Tripura Rehabilitation Plantation Corporation Limited (2007-08)

- The Company did not account for dividend earned of ₹ 11.08 lakh resulting in understatement of profit by the same amount.

- Closing stock included rubber sheets and scrape destroyed by fire or stolen leading to over valuation of stock by ₹ 12.62 lakh.

Tripura Forest Development Plantation Corporation Limited (2003-04)

- Non-provisioning of liabilities towards retirement benefits as per AS-15 resulted in overstatement of profit by ₹ 2.77 crore.
- Non-accounting of Board's decision to write off plantations damaged by fire resulted in overstatement of Fixed Assets by ₹ 14.81 lakh.

Tripura Industrial Development Corporation Limited (2007-08)

- The Company accounted an amount of ₹ 1.21 crore as its own income in contravention of a Government decision to transfer that amount to Corpus Fund for capital expenditure resulting in understatement of Accumulated loss by the same amount.

Tripura Jute Mills Limited (2007-08)

- Goods damaged in transit were not accounted for resulting in understatement of loss by ₹ 40.37 lakh.

5.1.32 The only working Statutory corporation had forwarded three accounts to AG during the year 2009-10. All the accounts were audited, replies of the Management were awaited (October 2010). The details of aggregate money value of comments of CAG in previous years are given below.

Table No. 5.1.10

(Rupees in crore)

Sl. No.	Particulars	2007-08		2008-09		2009-10	
		No. of accounts	Amount	No. of accounts	Amount	No. of accounts	Amount
1.	Decrease in profit	-	-	-	-	-	-
2.	Increase in loss	1	1.95	-	-	-	-
3.	Non-disclosure of material facts	1	0.02	-	-	-	-
4.	Errors of classification	1	0.41	-	-	-	-

5.1.33 The Statutory Auditors (Chartered Accountants) are required to furnish a detailed report upon various aspects including internal control/ internal audit systems in the companies audited in accordance with the directions issued by the CAG to them under Section 619(3)(a) of the Companies Act, 1956 and to identify areas which needed improvement. Supplementary reports were received on 12 accounts in 2008-09 and fifteen accounts in 2009-10. An illustrative resume of major comments made by the Statutory Auditors on possible improvement in the internal audit/ internal control system in respect of four companies[11] for the year 2009-10 are given in Table No. 5.1.11.

[11] Sl. No. A(1), A(3), A(4), & A(7) in **Appendix - 5.3**.

Table No. 5.1.11

Sl. No.	Nature of comments made by Statutory Auditors	Number of companies where recommendations were made	Reference to serial number of the companies as *per* Appendix - 5.2
1.	Non-fixation of minimum/ maximum limits of store and spares	Four	A(1), A(3), A(4), A(7)
2.	Absence of internal audit system commensurate with the nature and size of business of the company	Two	A(4), A(7)
3.	Non maintenance of cost record	Three	A(1), A(3), A(7)
4.	Non maintenance of proper records showing full particulars including quantitative details, situations, identity number, date of acquisitions, depreciated value of fixed assets and their locations	Four	A(1), A(3), A(4), A(7)

Recoveries at the instance of audit

5.1.34 During the course of propriety audit in 2009-10, recoveries of ₹ 0.20 lakh were pointed out to the Management of a PSU (Tripura Rehabilitation Plantation Corporation Limited), of which ₹ 0.12 lakh was admitted by the Management and got recovered.

Status of placement of Separate Audit Reports

5.1.35 Separate Audit Reports (SARs) issued by the CAG on the accounts of Tripura Road Transport Corporation was placed in the Legislature by the Government upto 2002-03.

The SAR for the year 2002-03 was issued in February 2008 and was placed in the Assembly in July 2009 after a delay of 17 months. The Government should ensure prompt placement of SARs in the Legislature.

Disinvestment, Privatisation and Restructuring of PSUs

5.1.36 No disinvestment, privatisation or restructuring of PSU occurred during 2009-10.

Reforms in Power Sector

5.1.37 The State has the Tripura Electricity Regulatory Commission (TERC) formed in November 2003 and operational since May 2004 under the Electricity Act, 2003 with the objective of rationalisation of electricity tariff, advising in matters relating to electricity generation, transmission and distribution in the State and issue of licenses. TERC did not issue tariff order in 2009-10 due to non-receipt of tariff petitions, annual revenue requirements and audited annual accounts from the sole licensee *i.e.* Tripura State Electricity Corporation Limited.

5.1.38 Memorandum of Understanding (MoU) was signed in August 2003 between the Union Ministry of Power and the State Government as a joint commitment for implementation of reforms programme in power sector with identified milestones. The progress achieved so far in respect of important milestones is stated below.

Table No. 5.1.12

Sl. No.	Milestone	Achievement as at March 2010
1.	Installation of meters on 11 KV feeders by 31 December 2003.	100 *per cent*
2.	100 *per cent* metering of all consumers by 31 December 2003.	Commercial consumers - 100 *per cent* Urban/ semi-urban - 100 *per cent* Individual consumers - 90.21 *per cent* Rural consumers - 78.65 *per cent*
3.	100 *per cent* metering on the LT side of distribution transformers.	34.51 *per cent* (2,730 out of 7,910 distribution transformers)
4.	Development of Distribution Management Information System.	Computerized Energy Billing System (EBS) implemented in Electrical Sub divisions.

Source : Information furnished by TSECL.

While significant progress had been achieved, the impact on Tripura State Electricity Corporation Limited was yet to be quantified and duly verified in absence of current accounts.

SECTION - A

5.2 Performance Audit of the Power Generating stations – Tripura State Electricity Corporation Limited

Executive Summary

Power is an essential requirement for all facets of life and has been recognised as a basic human need. In Tripura, generation, transmission, distribution and trading activity has not been unbundled. These activities are carried out by Tripura State Electricity Corporation Limited (Company), which was incorporated on 9 June 2004 under the Companies Act 1956. The Management of the Company is vested with a Board of Directors comprising five members, all appointed by the State Government.

The Company operates two gas thermal power stations (GTPS) at Baramura and Rokhia and a hydro power generating station at Gumti. As on 31 March 2010, the total installed power generation capacity was 110 Megawatt (MW) against the peak demand of 187 MW, while effective capacity was 74 MW leaving a deficit of 113 MW. In 2009-10, electricity requirement in Tripura was assessed as 818.74 million units (MU) against which 567.98 MU were available. During review period (2005-2010), there was growth in demand of 162.60 MU, whereas net capacity addition was only five MW or 43.80 MU.

Finances and Performance

The Company had prepared accounts up to 2005-06. Thereafter, the accounts have not been compiled. Based on estimates, the Company's aggregate profit for the past five years was ₹131.32 crore after accounting for subsidy of ₹144.56 crore.

The Company had earned aggregate profit of ₹320.87 crore from power trading. There was, however, no documented policy for trading of power with regard to either quantum or floor prices. Consequently, the realisation between August 2008 and March 2010 were below the monthly weighted average market prices, with the resultant shortfall of ₹11.55 crore.

Planning and Project Management

With the view to provide 1,000 units of electricity per capita by 2012, the Company would require 4,755 MU. Even if the existing capacity and all projects under implementation were to come up on schedule, the availability of power in 2014 would work out to only 695 units per capita.

Total Central sector allocation ranged from 99.37 MW to 132.22 MW during 2005-2010. Yet, there was shortfall of 36 to 54 MW that was about 22.22 per cent to 28.88 per cent of the peak demand, due to trading of electricity and transmission constraints. During 2005-2010, the Company had traded 1,838.02 MU of power i.e. 71 per cent of Central sector purchases.

Construction of two 21 MW gas turbine units was not completed on time due to slippages arising from delays in obtaining sanctions, release of advances, obtaining quotations, placement of orders, despatch of materials, receipt of design/ drawings for civil works, transportation bottlenecks etc. These led to increase in cost by ₹23.79 crore.

Operational Performance – Input Efficiency

Despite short receipt of 89.84 MMSCM of gas, both gas turbine stations achieved the generation targets fixed by Central Electricity Authority in three out of five years.

Due to short supply of gas and failure to tie up gas supply in time, the Company sustained loss of generation of 48.34 MU. Further, short-drawal of 31.02 MMSCM of gas led to payment of ₹8.81 crore. Also monopolistic arrangements for supply of gas led to additional cost of ₹4.12 crore as gas prices were pegged to a lower calorific value of gas.

Lower calorific value of gas and higher average heat rate resulted in excess consumption of gas to the tune of 187.94 MMSCM valued ₹41.80 crore during the review period.

During 2005-10, although the actual manpower of the generation wing dipped from 308 to 259, it was in excess of Central Electricity Authority's norm.

Operational Performance – Output Efficiency

Actual generation was in excess of CEA's targets in three out of five years. The aggregate generation for these five years was in excess of cumulative targets by 226.21 MU.

The PLF of both GTPS exceeded the national average in all five years. At Gumti, however, it was above the national average in three of five years.

Plant availability improved over the review period from 69.02 per cent to 90.15 per cent. The total hours forgone against planned and forced outages had also reduced. However, in the same period capacity utilisation declined from 89.48 per cent to 73.17 per cent. This was caused by operating units on partial load/ without load, reduced capacity of machines, non-operation of units and reduction in capacity of reservoir.

Auxiliary consumption was in excess of norms in all five years.

Repairs and Maintenance

Scheduled maintenance of units was undertaken or yet to be taken up after delays of five to ninety months. This delay and excessive time taken on repairs led to loss of generation.

Renovation and Modernisation

Advance planning for renovation of existing units at Rokhia was either not taken up or proposal not followed through. Renovation of two units at Gumti took almost two to two and a half years due to delays in preparation of estimates, obtaining sanctions and commencement of work.

Tariff fixation

There were delays of 98 and 245 days in filing petitions for revision of tariff for 2005-06 and 2006-07 causing delays of

three months in implementation of revised tariffs. Moreover, delays in compilation of accounts had led to non-revision of tariffs since 2007-08.

Subsidy claims from State Government

Against overall subsidy commitment of ₹158.70 crore for 2005-2010, the State Government released ₹144.56 crore.

Environment issues and Energy conservation

Online monitoring equipment to measure emissions into the atmosphere at both GTPS had not been installed. Further, energy conservation through waste heat recovery plants was not implemented. None of the units commissioned after January 2000 had been registered under the Clean Development Mechanism. As a result, benefit of carbon credits could not be availed.

Monitoring & MIS

Estimates of some operational and financial parameters had been prepared without setting performance parameters. Management Information Systems had neither been prescribed nor performance reviewed by the top management.

Conclusion and Recommendations

The goal of per capita availability of 1,000 units by 2012 laid down in the NEP would not be achieved. Fresh power purchase agreements were signed without any cost benefit analysis. Existing generation capacity was not fully utilised. Manpower required rationalisation.

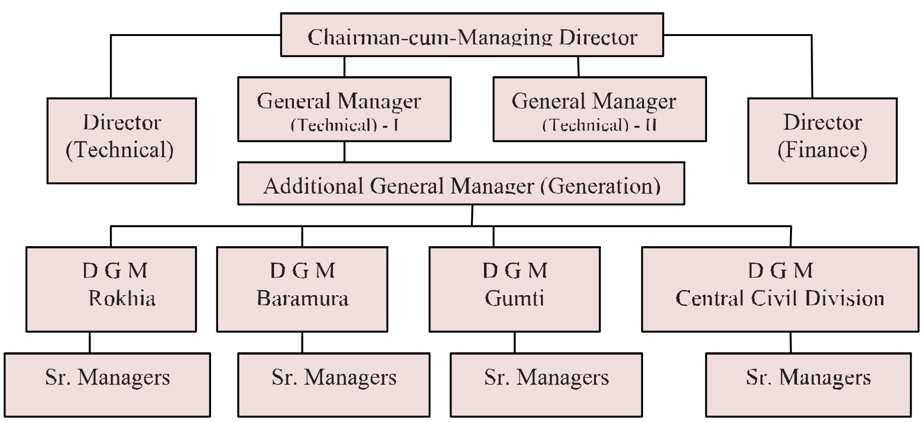
There were 10 recommendations including need to ensure energy availability in line with NEP, pulling up arrears in accounts and ensure timely revision of tariff annually in line with tariff regulations.

Introduction

5.2.1 Power is an essential requirement for all facets of life and has been recognised as a basic human need. The availability of reliable and quality power at competitive rates is very crucial to sustain growth of all sectors of the economy. The Electricity Act 2003 provides a framework conducive to development of the Power Sector, promote transparency and competition and protect the interest of the consumers. In compliance with Section 3 of the *ibid* Act, the Government of India (GOI) prepared the National Electricity Policy (NEP) in February 2005 in consultation with the State Governments and Central Electricity Authority (CEA) for development of the Power Sector based on optimal utilisation of resources like coal, gas, nuclear material, hydro and renewable sources of energy. The Policy aims at, *inter alia*, laying guidelines for accelerated development of the Power Sector. It also requires CEA to frame National Electricity Plan once in five years. The Plan would be short term framework of five years and give a 15 years' perspective.

5.2.2 During 2005-06, electricity requirement in Tripura was assessed as 656.14 Million Units (MU) of which only 487.94 MU were available in the State sector leaving a shortfall of 168.20 MU, which works out to 25.63 *per cent* of the requirement. As on 1 April 2005, the total installed power generation capacity in the State sector was 105 Mega Watt (MW) and effective available capacity was 70 MW against the peak demand of 156.10 MW leaving deficit of 86.10 MW. As on 31 March 2010, the comparative figures of requirement and availability of electricity were 818.74 MU and 567.98 MU with deficit of 250.76 MU (30.63 *per cent*), while installed capacity was 110 MW and effective available capacity was 74 MW. At the same time, peak demand was 187.00 MW leading to deficit of 113 MW. Thus, there was a growth in energy demand by 162.60 MU and load demand by 30.90 MW during review period, whereas the net capacity addition was only 43.80 MU i.e. 5 MW.

5.2.3 In Tripura, besides generation of electricity, its transmission, distribution and trading are also carried out by Tripura State Electricity Corporation Limited (Company), which was incorporated on 9 June 2004 under the Companies Act 1956. The Company is under the administrative control of the Power Department of the Government of Tripura. The Management of the Company is vested with a Board of Directors comprising five members, all appointed by the State Government. The day-to-day operations are carried out by the Chairman-cum-Managing Director, who is the Chief Executive of the Company with the assistance of the Director (Technical), Director (Finance) and two General Managers (Technical).
The organisational structure (generation) is depicted in the chart below:



5.2.4 As on 31 March 2010, the Company has two gas thermal power stations (GTPS) at Baramura and Rokhia and also a hydro power generating station at Gumti with installed capacities of 21 MW, 74 MW and 15 MW respectively.

The turnover of the Company was ₹ 241.58 crore (estimated in audit) in 2009-2010, which was equal to 83.74 *per cent* and 2.22 *per cent* of the State PSUs turnover and State Gross Domestic Product for 2009-10 respectively. It employed 4,465 employees as on 31 March 2010.

A review on the working of both gas thermal power stations of the Company was included in the Report of the Comptroller and Auditor General of India for the year

2006-07, Government of Tripura. The Report is yet to be discussed by COPU (September 2010).

Scope and Methodology of Audit

5.2.5 The present review conducted during February 2010 to July 2010 covers the performance of the generation activities of Tripura State Electricity Corporation Limited for the period of 2005-06 to 2009-10. The review mainly deals with planning, project management, financial management, operational performance, environmental issues and monitoring by the top management. The audit examination involved scrutiny of records at the Head Office, both the gas thermal power stations at Rokhia and Baramura and hydroelectric power station at Gumti.

The methodology adopted for attaining the audit objectives with reference to audit criteria 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, raising of audit queries, discussion of audit findings with the Company and issue of draft report to the Company for comments.

Audit Objectives

5.2.6 The objectives of the performance audit were to assess:

Planning and Project Management

- To assess whether capacity addition programme taken up/ to be taken up to meet the shortage of power in the State is in line with the National Policy of Power for All by 2012;
- To assess whether a plan of action is in place for optimisation of generation from the existing capacity;
- To ascertain whether the contracts were awarded with due regard to economy and in transparent manner; and
- To ascertain whether the execution of projects were managed economically, effectively and efficiently.

Financial Management

- To ascertain whether the projections for funding the new projects and upgradation of existing generating units were realistic including the identification and optimal utilisation for intended purpose; and
- To assess whether all subsidy claims were properly raised and recovered in an efficient manner.

Operational Performance

- To assess whether the power plants were operated efficiently and preventive maintenance as prescribed was carried out minimising the forced outages;
- To assess whether requirements of gas were worked out realistically and utilised efficiently;

- To assess whether the manpower requirement was realistic and its utilisation optimal;
- To assess whether the life extension/ renovation and modernisation (LE/ R&M) programme were ascertained and carried out in an economic, effective and efficient manner; and
- To assess the impact of LE/ R&M activity on the operations performance of the generating plants.

Environmental Issues

- To assess whether the various types of pollutants (air, water, noise, hazardous waste) in power stations were within the prescribed norms and complied with the required statutory requirements; and
- To assess the adequacy of waste heat management system and its implementation.

Monitoring and Evaluation

- To ascertain whether adequate MIS existed in the entity to monitor and assess the impact and utilise the feedback for preparation of future schemes.

Audit Criteria

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

- National Electricity Plan, norms/ guidelines of Central Electricity Authority (CEA) regarding planning and implementation of the projects;
- standard procedures for award of contract with reference to principles of economy, efficiency and effectiveness;
- 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

5.2.8 The Company had prepared accounts up to 2005-06. Thereafter, no annual accounts have been compiled. As the Company has not unbundled its generation, transmission, distribution and trading activities, a consolidated financial position for 2005-06 and estimated figures for 2006-07 to 2009-10 are shown as under.

(Rupees in crore)

Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
A. Liabilities					
Paid up Capital	9.55	9.55	109.30	109.30	109.30
Reserve and Surplus (including Capital Grants)	664.32	691.65	842.54	989.85	1,098.07
Borrowings (Loan Funds)					
Secured	Nil	Nil	Nil	Nil	Nil

(Rupees in crore)

Particulars	2005-06	2006-07	2007-08	2008-09	2009-10
Unsecured	104.66	130.35	56.60	87.10	106.21
Current Liabilities and Provisions	64.44	68.39	69.07	57.98	60.30
Total	**842.97**	**899.94**	**1,077.51**	**1,244.23**	**1,373.88**
B. Assets					
Gross Block	621.55	741.76	782.16	940.54	980.10
Less: Depreciation	25.55	53.05	82.05	113.37	146.05
Net Fixed Assets	596.00	688.71	700.11	827.17	834.05
Capital works-in-progress	99.87	83.13	73.86	112.92	100.00
Investments	Nil	Nil	Nil	Nil	Nil
Current Assets, Loans and Advances	146.33	127.41	302.92	303.58	439.34
Accumulated losses	Nil	Nil	Nil	Nil	Nil
Miscellaneous Expenditure	0.77	0.69	0.62	0.56	0.49
Total	**842.97**	**899.94**	**1,077.51**	**1,244.23**	**1,373.88**

(Figures for 2006-07 to 2009-10 are estimated and have been compiled by Audit from Annual Plans, information furnished to XIIIth Finance Commission, reconciliations for purchase and sales of energy, gas supply bills booked, cumulative receipt and payments of DGM(C&SO). These may undergo change on finalisation of accounts by the Company.)

5.2.9 An analysis of the above table showed that in the past five years, the main sources of finance were issue of share capital, interest-free unsecured loans from State Government and capital grants through the State Government. In addition, aggregate profits earned were ₹ 131.32 crore. The Company has been dependent on State Government assistance for its capital expenditure. Main reasons for dependence on government support were short recovery of subsidy, locking up of funds in capital projects and capital expenditure without adequate returns.

5.2.10 During 2005-2010, the Company has traded 1,838.02 MU of electricity for ₹ 760.43 crore primarily through bilateral agreements and power exchanges, and incurred expenditure of ₹ 439.56 crore thereon, to earn profit of ₹ 320.87 crore. Despite revenue from trading constituting 56.62 *per cent* of aggregate revenues, the Company did not have any documented policy for sale of power through trading with regard to quantum to be traded or the specified floor prices at which power should be traded. A comparison of the Company's average monthly realisation per unit through bilateral trading and energy exchanges during August 2008 to March 2010 *vis-à-vis* monthly weighted average market prices, showed that in eight months, the revenue realised through bilateral trading was below the prevailing market prices aggregating to ₹ 18.72 crore while in eleven months it was above by ₹ 9.70 crore. Similarly, revenue realised through Indian Electricity Exchange (IEX) was below the prevailing market price in eleven months and above in nine months by ₹ 4.33 crore and ₹ 1.80 crore respectively. The aggregate impact of this was shortfall in potential revenue of ₹ 11.55 crore. This indicated that the Company was not fully geared to collate and effectively utilise market intelligence.

The Company stated (September 2010) that at present, surplus power, though not much, was being traded and sold to outside States through traders and power exchange as permitted by the existing regulations of CERC. With the proposed availability of 350 MW power by 2013-14 from the Central Sector allocation, the Company would think of trading sizeable quantity of surplus power through open bidding. The minimum floor price being the capacity charge plus the energy charges, the price of the amount of power traded for will have to be more than this floor price.

We, however, observed that in the past five years, out of 2,589.95 MU purchased from the Central sector, the Company traded 1,838.02 MU (70.97 *per cent*). Further, in the same period, total energy made available in the State was 3,266.80 MU. As this was significant share, the Company ought to have formulated a policy for trading.

5.2.11 The Company had not re-organised its major activities of generation, transmission, distribution and trading into profit centres. Thus, actual profitability of each of these activities could not be assessed. The Company stated (September 2010) that segregated accounting system to determine the cost, revenue, assets and liabilities allocable to different activities would be examined by the Company. At the exit conference, the Government accepted the need to conduct a detailed study on unbundling of the generation, transmission, distribution and trading activities.

Audit Findings

5.2.12 Audit explained the audit objectives to the State Government and Tripura State Electricity Corporation Limited during an 'entry conference' held on 10 February 2010. Subsequently, audit findings were reported to the State Government and the Company in August 2010 and discussed in an 'exit conference' held on 30 September 2010, which was attended by the Secretary to the Government of Tripura, Power Department and the Chairman- cum- Managing Director of the Company. The Government/Company also replied to audit findings in September 2010. The views expressed by them have been considered while finalising this review. The audit findings are discussed below:

Operational Performance

5.2.13 The operational performance of the Company for the five years ending 2009-10 is given in the **Appendix - 5.7**. The operational performance of the Company was evaluated on various operational parameters as described below. It was also seen whether the Company was able to maintain pace in terms of capacity addition with the growing demand for power in the State. Audit findings in this regard are discussed in the subsequent paragraphs. These audit findings show that there was scope for improvement in performance despite problems such as purchase of fuel at higher cost from monopolistic suppliers, geographic isolation of Tripura, transportation bottlenecks, hilly terrain and absence of major industries/ industrial centres which can consume power during off-peak.

Planning

5.2.14 National Electricity Policy (NEP) aims to provide availability of over 1,000 units of per capita electricity by 2012. In line with NEP, if 1,000 units of per capita electricity are to be made available by 2012, for a population of 36.37 lakh by 2011-12, keeping in view the existing transmission and distribution (T&D) losses of 23.5 *per cent* and system load factor of 49.8 *per cent*, the energy requirement, average load and peak load would work out to 4,755 MU, 541 MW and 1,087 MW respectively.

However, the Company stated (September 2010) that since the present per capita consumption is of the order of 130/135 units, it would not be possible to achieve consumption of 1000 units per capita by 2012 as laid out in NEP. It was further stated that the available capacity including State Sector and Central Sector in 2012 would be 390 MW (470 units per capita) which would reach 592 MW in 2014 (695 units per capita).

The power availability scenario in the State indicating own generation, peak demand, average demand and off-peak demand was as under:

Year	Mean Generation[12] (MW)	Peak Demand (MW)	Average Demand (MW)	Off peak demand (MW)	Percentage of actual generation to Peak Demand	Percentage of actual generation to Average Demand	Percentage of Off-peak to Peak Demand
2005-06	65.44	156.10	125.55	95.00	41.92	52.12	60.86
2006-07	61.92	155.00	122.50	90.00	39.95	50.55	58.06
2007-08	70.61	160.00	125.00	90.00	44.13	56.49	56.25
2008-09	75.19	162.00	130.00	98.00	46.41	57.84	60.49
2009-10	75.15	187.00	153.50	120.00	40.19	48.96	64.17

Peak hours-17:00 hours to 23:00 hours (six hours); off peak hours-00:00 hours to 17:00 hours and 23:00 hours to 24:00 hours (eighteen hours).

As may be seen from the above, the actual generation was only 48.96 to 57.84 *per cent* of the average demand and 39.95 to 46.41 *per cent* of the peak demand. However, even after import, there was shortfall of 36 to 54 MW (22.22 *per cent* to 28.88 *per cent* of the peak demand), as shown in the following table :

Year	Peak Demand (MW)	Peak Demand met (MW)	Sources of meeting peak demand (MW)		Peak Deficit (MW) (Percentage of Peak Demand)
			Own[13]	Import	
2005-06	156.10	114.50	64.00	50.50	41.60 (26.65)
2006-07	155.00	119.00	74.00	45.00	36.00 (23.22)
2007-08	160.00	124.00	79.00	45.00	36.00 (22.50)
2008-09	162.00	126.00	81.00	45.00	36.00 (22.22)
2009-10	187.00	133.00	83.00	50.00	54.00 (28.88)

[12] Worked out in audit based on the installed capacity and PLF of the respective units in each year.
[13] The figures here will not tally with mean generation figures mentioned in the table above since the above table depicts mean generation while the table here depicts generation during peak demand.

To minimise the gap between supply and demand, National Productivity Council (NPC) had identified (2008-09) that potential energy demand can be reduced by 52.04 MU annually. To flatten the demand curve and reduce the gap between peak and off-peak demand, the Company had introduced from 2005-06, time of the day (TOD) tariff for industrial, commercial and bulk consumers with demand of one MegaVoltAmpere or more. However, given the consumer profile (domestic : 54 *per cent*), the Company had not explored the possibility of introducing TOD tariff for domestic consumers also.

The Company stated (September 2010) that TOD metering was optional and it was neither feasible nor possible to go for TOD metering of four lakh domestic consumers. Moreover, power was sold to outside States during off-peak hours to reduce the gap between peak and off peak requirement of generation.

However, Tripura Electricity Regulatory Commission (TERC) had already advised (June 2005/ September 2006) that the difference between power demand during peak periods and off-peak periods would have to be reduced through demand-side management.

At the exit conference, the Government agreed with the need to take measures for energy savings to reduce peak demand.

5.2.15 The Company informed (September 2010) that sale of power during peak hours out of allocation from central sector was due to the transmission constraints and not by compulsion. The entire allocation from the central sector could not be imported to Tripura due to limitations in the capacity of transformer and transmission line connecting Kopili to Khandong.

We, however, observed that Tripura was connected with the North Eastern Regional grid and central sector generating stations through four 132 KV transmission lines each capable of carrying 50-60 MW i.e., total of 200 to 240 MW. Nevertheless, the Company imported about 50 MW through the existing network, leaving a shortfall of 54 MW leading to rotational load shedding of at least one and a half hours during peak hours.

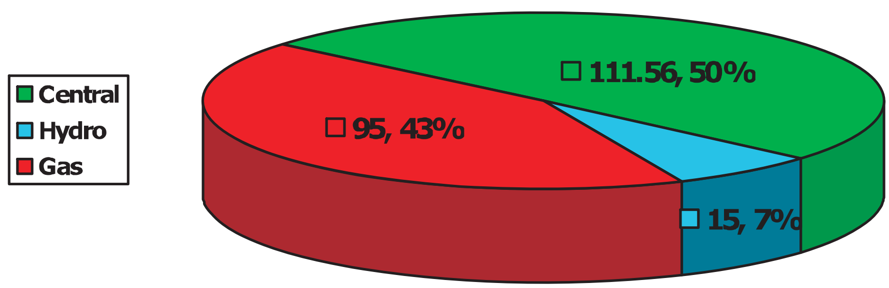
5.2.16 This section deals with capacity additions and optimal utilisation of existing facilities. Environmental aspects have been discussed in subsequent paragraphs at later stage.

Capacity Additions

WBSEDCL, West Bengal made highest capacity addition of 1000 MW in hydro sector during 2007-08 and PRVUNL, Rajasthan made highest capacity addition of 330 MW in Gas based project during 2007-08

5.2.17 In the State sector, total installed capacity was 105 MW at the beginning of 2005-06 and increased to 110 MW at the end of 2009-10. Besides, the State had a share in Central sector generation ranging from 99.37 MW to 132.22 MW during the same period. The break up of generating capacities, as on 31 March 2010, under hydro, gas and central sector generating stations, mainly North Eastern Electric Power Company Limited (NEEPCO) and National Hydroelectric Power Corporation Limited (NHPC) is shown in the pie chart below:

Component of generating capacities



5.2.18 To meet the energy generation requirement of 818.74 MUs in the State, a capacity addition of about 54 MW was required during 2005-06 to 2009-10. As per National Electricity Plan (April 2007), the projects categorised as 'Projects under Construction' (PUC) and 'Committed Projects[14]' (CP) earmarked for capacity addition during review period are detailed below:

(In MW)

Sector	Thermal	Hydro	Non-conventional Energy	Total
PUC	Nil	Nil	Nil	Nil
CP	726.60	Nil	Nil	726.60
Total	726.60	Nil	Nil	726.60

5.2.19 Besides the above, two more projects were under construction though not featuring in the Plan. The Company entered into agreements for purchase of 350 MW power from generating stations proposed and under construction as under:

	Name of Company	Name of generating station	Date of agreement	Capacity under installation (MW)	Allocated quantity (MW)	Expected/ scheduled commissioning
1.	NTPC Limited (NTPC)	Bongaigaon Thermal Power Station	29.09.2007	750.00	50.00	June 2011, October 2011 and February 2012
2.	NEEPCO	Monarchak Gas Turbine Station	19.03.2008	104.00	104.00	2013-2014
3.	ONGC-Tripura Power Company Limited (OTPCL)	Pallatana Combined Cycle Gas Turbine Station	20.05.2009	726.60	196.00	November 2011 and June 2012

5.2.20 The particulars of capacity additions envisaged, actual additions and energy requirement *vis-à-vis* energy supplied during review period are given below:

[14] National Electricity Plan defines Committed Projects as Projects for which the formal approval has been granted by the CEA.

Sl. No.	Description	2005-06	2006-07	2007-08	2008-09	2009-10
1.	Capacity at the beginning of the year (MW)	105.00	110.00	110.00	110.00	110.00
2.	Additions planned as per National Electricity Plan (MW)	Nil	Nil	Nil	Nil	Nil
3.	Additions planned by the State (MW)	5.00[15]	Nil	Nil	Nil	21.00[16]
4.	Actual Additions (MW)	5.00	Nil	Nil	Nil	Nil
5.	Capacity at the end of the year (MW) (1 + 4)	110.00	110.00	110.00	110.00	110.00
6.	**Shortfall in capacity addition (MW) (4 – 3)**	Nil	Nil	Nil	Nil	21.00
7.	Annual energy requirement (MU)	656.14	655.19	661.77	749.94	818.74
8.	Energy supplied (MU)					
	a) Energy produced	487.94	536.67	534.86	578.31	567.98
	b) Energy Purchased (Net)	112.68	79.10	87.49	114.69	167.08
9.	**Shortfall (-) in energy (MU) (7-8)**	**(-) 55.52**	**(-) 39.42**	**(-) 39.42**	**(-) 56.94**	**(-) 83.68**

It may be observed that during review period, effective capacity addition was only 5 MW and 21 MW which was scheduled to be completed in 2009-10, was commissioned in August 2010.

The Company stated (September 2010) that with addition of 21 MW capacity at Baramura, the existing installed generating capacity had reached 131 MW. The share of Central Sector generation capacity was treated as own capacity since capacity charge was being borne by the Company. Further capacity addition would arise only when demand exceeded available generation not only from State Sector but also from Central Sector and with the contracted 350 MW for 2013-14 in Central Sector, there will be no need for addition of capacity in the State Sector till 2016-17. It further stated that to achieve the load growth envisaged in the National Electricity Policy, instead of capacity augmentation the State has to go in first for massive industrialisation and commercialisation in the State.

We noticed that the Company's own cost of generation per unit (₹ 1.14 to ₹ 1.45) was lower than the corresponding average[17] cost of generation (₹ 1.66 to ₹ 2.42 per unit) for generating stations in the North East. Moreover, cost of generation was also 31 to 46 *per cent* below the average annual rates at which the Company purchased power from Central Sector generating stations. Hence, the Company could have explored the possibility of additions to its own generating capacity.

[15] The Company added one a 21 MW unit at Rokhia and scrapping (16-05-2006) of Unit Nos. 1 and 2 of eight MW capacity each not operated since 28-02-2005 and 10-12-2002. Net addition was five MW.
[16] One unit proposed at Baramura.
[17] Source: Statement showing rate of sale of power for generating stations in the country for the years 2006-07, 2007-08 and 2008-09- Central Electricity Authority (CEA).

The Government agreed to carry out an analytical study on generation mix and also come up with Perspective Plan for Power sector in Tripura.

Optimum Utilisation of existing facilities

GSECL, Dhuvaran (280 MW) made highest improvement in performance (41%) after the 'Partnership in Excellence' programme launched by Ministry of Power in August 2005

5.2.21 In order to cope with the rising demand for power, not only the additional capacity needs to be created as discussed above, the plan needs to be in place for optimal utilisation of existing facilities and also undertaking life extension programme/ replacement of the existing facilities which are nearing completion of their age besides timely repair/ maintenance.

The norms for renovation and modernisation/ life extension of gas turbine based generating units was 20 years or 1,60,000 hours as per CEA and 15 years as per manufacturer norms. Only two out of seven gas turbine based units *viz*. Unit Nos. 3 and 4 at Rokhia, would fall due for renovation and modernisation in 2010-11. The Company has planned for major inspection of Unit No. 4 at Rokhia in 2010-11 and had placed (May 2009) supply order on BHEL for spares. Inspection was scheduled in July 2010. No proposal has been drawn up for Unit No. 3. The Company has also at the same time proposed (February 2010) to the State Government to replace these two ageing units (No.3 and 4) with one unit of 21 MW capacity at an estimated cost of ₹ 85 crore, on equal sharing basis. The Government's approval to this proposal was awaited (July 2010).

For hydro-electric units, CEA's norms were 30 to 35 years. Unit No. I and II at Gumti, due in 2010-11 for renovation and modernisation, were actually taken up in 2007-08 and 2008-09.

At the exit conference, Company stated that renovation and modernisation/ life extension of existing units would be undertaken after assessing the feasibility.

5.2.22 A review of the existing facilities which are ageing and may need replacement/ refurbishment within the next five years showed that the Company had initiated (August 2005) a proposal for renovation of Units Nos. 4, 5 and 6 at Rokhia. It sought for ₹ 17.55 crore from the Ministry of Power, Government of India under Accelerated Generation and Supply Programme, but sanction from the Ministry of Power was awaited till July 2010.

Project Management

5.2.23 Preparation of an accurate and realistic Draft Project Reports (DPR) after considering feasibility study, factors like creation of infrastructure facility, addressing bottlenecks likely to be encountered in various stages of project planning are critical activities in planning stage of the project. Project management includes timely acquisition of land, effective actions to resolve bottlenecks, obtain necessary clearances from Ministry of Forest and Environment and other authorities, rehabilitation of displaced families, proper scheduling of various activities etc. For execution of the project, consultants are also appointed for vigorous monitoring. Notwithstanding, time and cost overrun were noticed due to absence of coordinating mechanism throughout the implementation of the projects during review period as discussed in succeeding paragraphs.

5.2.24 The following table indicates the scheduled and actual dates of completion of the power stations, date of start of transmission, commissioning of power stations and the time overrun.

Time overrun

Sl. No.	Phase-wise name of the Unit	Details	Scheduled date of completion as per Contract	Actual date of completion	Time overrun (In months)
Rokhia Gas Thermal Project					
1.	Unit No. 8	Date of completion of unit	07-11-05	31-03-2006	5
		Date of start of transmission	07-11-05	31-03-2006	5
		Date of commercial operation/ commissioning of unit	07-11-05	04-04-2006	5
Baramura Gas Thermal Project					
2.	Unit No. 5	Date of completion of unit	18-11-09	03-08-2010	9
		Date of start of transmission	18-11-09	03-08-2010	9
		Date of commercial operation/ commissioning of unit	18-11-09	Not available	9 *(up to August 2010)*

It would be seen from the table that both the projects implemented/ under implementation during the review period were not completed in time and slippages in time schedule were avoidable at various stages of implementation as under:

Unit No. 8 at Rokhia

- Delay of three months in release of initial advance to Bharat Heavy Electricals Limited (BHEL), the turnkey contractor for the plant (July 2004 instead of March 2004).
- Delay in receipt of materials due to transportation bottlenecks in rainy season indicating inadequate planning.

The Company stated (September 2010) that Tripura being situated at the tail end of the North East Region, there were always transportation limitation particularly in the rainy season. Further, there was delay in paying initial advance because of late receipt of fund from the Ministry.

Unit No. 5 at Baramura

- Design defects, delay in receipt of design and drawings for civil works from BHEL.

- Delay in dispatch of materials by BHEL due to law and order and transportation problems (supply to be completed within July 2009 but continued till July 2010).

Thus, it would be seen that time overrun varied between five to nine months in the execution of the power projects which mainly led to cost overrun as discussed in the succeeding paragraphs.

5.2.25 The estimated cost of the power stations executed, actual expenditure, cost escalation and the percentage increase in the cost are tabulated below:

Cost overrun

(Rupees in crore)

Sl. No.	Phase-wise name of the Unit	Estimated cost as per DPR	Awarded Cost	Actual Expenditure (Up to 03/ 2010)	Expenditure over and above estimate 5=(4-2)	Percentage increase as compared to DPR 6=(5)/(2)
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rokhia GTPS Unit No. 08	73.65	79.50	92.68	19.03	25.84
2	Baramura GTPS Unit No. 05	93.56	98.32	63.53	Incomplete	

It would be seen from above that:

Rokhia GTPS

Unit No. 8, targeted for completion in November 2005, was completed in March 2006. It had incurred cost overrun of 25.84 *per cent* of the estimated cost and the main reasons noticed were as under:

- DPR was prepared in October 2002 and sanction accorded by Ministry for Development of North Eastern Region (MoDoner) in December 2003. The delay was mainly due to late furnishing of replies to the observation of CEA. Further, the work was awarded to BHEL for main plant in March 2004 after delay of four months of sanction and for switchyard (September 2005) after a delay of nine months. These led to increase in awarded cost by ₹ 5.85 crore.
- The DPR had overlooked the applicability of State taxes on works contracts. Consequently, payment of ₹ 7.48 crore towards Tripura Value Added Tax (TVAT) and price variation of ₹ 5.70 crore on the main equipments and spares after the base date were later added directly to the actual expenditure.

The cost overrun of ₹ 19.03 crore resulted in increase in cost of power generation from the envisaged ₹ 2.01 to ₹ 2.05 per unit and the cost per MW from ₹ 3.51 crore in 2002-03 to ₹ 4.41 crore in 2006-07.

Baramura GTPS

- Unit No. 5 scheduled for completion in November 2009 was completed in August 2010. It had already incurred cost overrun of ₹ 4.76 crore as awarded cost exceeded the estimated cost by 5.09 *per cent*. The main reason was that while the DPR was prepared in September 2005, due to differences among the State

Government, North Eastern Council (NEC) and Ministry of Finance, Government of India regarding the funding pattern of the project, sanction was accorded by NEC only in August 2007. Thereafter, BHEL was invited (September 2007) to make an offer for setting up the project and was awarded the work in March 2008 after eight months of the sanction.

Contract Management

5.2.26 Contract management is the process of efficiently managing contract (including inviting bids and award of work) and execution of work in an effective and economic manner. The work is generally awarded on turn key basis to a single party *viz.* BHEL for design, supply, erection and commissioning of machines and ancillary works. Civil works were undertaken separately by the Company through civil contractors.

5.2.27 During review period contracts valuing ₹ 177.82 crore were executed. The instances of slow progress of work leading to time and cost overrun at Baramura are given below.

- The cost of machine foundation rose from the contractual value of ₹ 1.41 crore to ₹ 1.78 crore due to wrong assessment in the quantity of concrete works (₹ 37.30 lakh). The Company attributed (September 2010) this additional expenditure to mismatch of the initial estimate for foundation work due to late receipt of foundation design and drawings from BHEL.
- Due to faulty design in the foundation for placement of load gear box (LGB), the project was delayed by nine months. The Company incurred additional expenditure of ₹ 5.00 lakh on rectification. The Company ascribed (September 2010) this to ambiguity in drawing of LGB foundation from BHEL.
- The plant was scheduled to be commissioned in November 2009. Accordingly, the Company had tied up with ONGC for supply of additional gas. Due to delay in commissioning of the plant, the Company obtained three extensions till June 2010 for supply of gas. Consequently, as per contract, the Company was liable to pay minimum guaranteed off take charges to ONGC at the rate of ₹ 9.08 lakh daily from July 2010 towards gas. This worked out to an aggregate of about ₹ 3.00 crore till commissioning of the plant in August 2010.

While accepting the observations, the Company stated (September 2010) that the additional expenditure would be recovered from BHEL.

Operational Performance

5.2.28 Operations of the Company are dependent on input efficiency consisting of material and manpower and output efficiency in connection with Plant Load Factor, plant availability, capacity utilisation, outages and auxiliary consumption. These aspects have been discussed below.

Input Efficiency

Procedure for procurement of natural gas

5.2.29 The Central Electricity Authority (CEA) fixes generation targets for gas thermal and hydroelectric power stations considering capacity of plant, average plant load factor and past performance. The Company works out requirement of gas on the basis of design norms and past gas consumption trends. The company entered into gas supply agreements (gas linkage) with Gas Authority of India Limited (GAIL) and Oil and Natural Gas Corporation Limited (ONGCL). The allocated quantities under the administered pricing mechanism (APM) were 0.2 million metre standard cubic metres per day (MMSCMD) and 0.5 MMSCMD for Baramura and Rokhia respectively and an additional quantity of 0.1 MMSCMD at Market Determined Prices (MDP) for Rokhia from 1 April 2008. The additional allocation was reduced to 0.08 MMSCMD since 20 November 2009 at the request of the Company.

5.2.30 The position of gas linkages fixed, gas received, generation targets prescribed and actual generation achieved during the period from 2005-06 to 2009-10 covering the units of GTPS at both Rokhia and Baramura was as under:

Particulars	2005-06	2006-07	2007-08	2008-09	2009-10	Total
Gas Linkage fixed (MMSCM)	255.50	255.50	256.20	292.00	289.16	1,348.36
Quantity of Gas received (MMSCM)	208.26	245.35	256.10	273.38	275.43	1,258.52
Generation Target (MU)	456.00	584.00	490.00	474.00	523.50	2,527.50
Actual generation achieved (MU)	428.68	520.20	583.86	608.49	612.48	2,753.71
Excess (+)/ Shortfall (-) in generation to target (MU)	(-)27.32	(-)63.80	(+)93.86	(+)134.49	(+)88.98	(+)226.21

It would be seen from the above that the total linkage of gas during the five years fixed was 1,348.36 MMSCM for the State. Against this, only 1,258.52 MMSCM of gas was received, resulting in short receipt of 89.84 MMSCM (6.66 *per cent*) of gas. We observed that the current and earlier agreements with GAIL specified that the Company would create requisite facilities to operate both the GTPS on liquid fuel in addition to natural gas. But, the Company had not done the same. Consequently, due to short supply of gas it could not generate power using the potential capacity.

The Company stated (September 2010) that running with high speed diesel will abruptly increase the cost of generation and enhance fixed cost of generation.

5.2.31 Some instances of loss of generation due to short supply of gas, failure to tie up gas requirement in time as well as non-drawal of the minimum guaranteed off-take of gas during the review period are as follows :

- The Company faced problems of shortage of gas from time to time. Loss in generation in both the GTPSs due to short supply gas was 13.39 MU, as given in **Appendix - 5.8**.
- The gas allocation (0.5 MMSCMD) available at Rokhia GTPS till March 2008 was sufficient for operation of plant units no. 3, 4, 5, 6 and 7. However, when

additional unit no. 8 was commissioned in March 2006, the corresponding additional gas requirement was tied up in April 2008 only since the Company wanted the additional gas to be supplied at APM rates which was not according to policy. During the intervening period, the plants were operated on internal arrangement based on the available gas. During 2006-07 and 2007-08, unit no. 4 could be operated only when unit nos. 3, 5, 6, 7 or 8 were under forced outage. Even in such case, whereas unit no. 4 was operated for 550 days, it was kept idle for about 180 days due to non-availability of gas. Non-operation of unit no. 4 due to shortage of gas resulted in shortfall of generation of 34.95 MU. This indicated inadequate planning in arranging for supply of gas in time.

- During 2005-06[18], Rokhia GTPS could consume 57.66 MMSCM of gas against minimum guaranteed offtake of gas (MGOG) of 72.80 MMSCM due to planned/ forced outages of unit nos. 3, 4 and 6. As a result, the Company had to pay GAIL ₹ 2.41 crore for short consumption of 15.14 MMSCM of gas. Further, in 2008-09 and 2009-10, Rokhia GTPS consumed 45.64 MMSCM against MGOG of 61.52 MMSCM from ONGC. Consequently, the Company had to pay ONGC ₹ 6.40 crore in advance for 15.88 MMSCM which could be utilised in subsequent periods.

Fuel supply arrangement

5.2.32 The Ministry of Petroleum and Natural Gas (MoPNG), Government of India decided (September 1997) to progressively link the consumer price of gas to the price of a basket of international fuels. Thereafter, it directed (June 2005) that gas would continue to be supplied to the power sector under APM up to allocations contracted till June 2005. The APM allocations for Rokhia and Baramura GTPSs were 0.5 MMSCMD and 0.2 MMSCMD respectively and would be supplied by GAIL. Additional requirements would be supplied by ONGC at market determined prices (MDP), subject to availability. It was noticed that :

- The current agreements with GAIL effective from April 2008 had increased the minimum guaranteed off-take of gas (MGOG) to 90 *per cent* from 80 *per cent* of gas allocation. Consequently, when taking up (January-February 2009) major inspection of Unit No. 4 at Baramura, the Company decided not to overhaul the generator to avoid payment for gas under MGOG clause. This reduced the outage period from 35 days envisaged to an actual of 22 days and thereby foregoing the prescribed overhauling of the generator.

- The agreement with ONGC provided (April 2008) for compensation if supply was below 90 *per cent* as well. The difference between MGOG and actual supply can be drawn free of cost in subsequent years during validity of the agreement. The agreements with GAIL did not have such provision to the disadvantage of the company.

[18] July, August, September, October 2005, February and March 2006.

- Both ONGC and GAIL supplied gas through the same pipe line and metering arrangements. However, the price of gas supplied by GAIL was benchmarked to net Calorific Value (NCV) of 10,000 Kcal; while the price of gas from ONGC was pegged to NCV of 8,000 Kcal. The average calorific value of gas in 2008-09 and 2009-10 was 8,225 Kcal. Had the price of gas from ONGC also been benchmarked to 10,000 Kcal, the Company would have received rebate of 81 paise and 84 paise per SCM in 2008-09 and 2009-10 respectively. Instead, it had to pay premium of around 13 paise per SCM. This worked out to additional cost of ₹ 4.12 crore on purchase of 43.12 MMSCM gas from ONGC due to monopolistic arrangement for supply of fuel.

The Company stated (September 2010) that terms and conditions of the agreement with ONGC and GAIL for purchase of gas at APM rate and MDP were fixed by the MoPNG. Moreover, gross caloric value of 8,000K Cal/SCM in determining the rebate/premium is all India norms also fixed by the MoPNG. However, documents in support of norms and correspondence with the suppliers/ MoPNG were not furnished.

Consumption of gas

Excess consumption of gas

5.2.33 Consumption of gas depends on its calorific value, generation levels, ambient temperature and prevailing frequency of the power system. Besides, in case of trippings of units due to technical problems and power system disturbances, gas gets flared till such time the supply valves at GAIL/ ONGCL end can be controlled. The norms[19] fixed in the project report for various power generation stations for production of one unit of power in the State *vis-à-vis* maximum and minimum consumption of gas during the period of five years ending 2009-2010 is depicted in the table below:

(In SCM per unit)

Name of the Station	Norms fixed in the project report	Average minimum consumption	Average maximum consumption
Rokhia GTPS	0.39	0.42 (2007-08)	0.62 (2005-06)
Baramura GTPS	0.41	0.42 (2009-10)	0.44 (2007-08)

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

From the above it may be seen that in both GTPS, the consumption remained higher than the norms in all years under review. Audit noticed that consumption above the norms resulted in excess consumption of gas to the tune of 187.94 MMSCM valued ₹ 41.80 crore during the review period in the State as detailed in **Appendix - 5.9**. Apart from the lower calorific value of gas, excess heat rate also contributed to excess gas consumption, which could be *prima facie* controlled by the Company.

The Company stated (September 2010) that excess consumption of gas had come down from 28.32 *per cent* to 5.93 *per cent* and both GTPS had performed much better in 2009-10 as compared to 2005-06.

[19] Fixed for Net Calorific Value (NCV) of 9000 Kcal/SCM.

Heat rate

5.2.34 Tripura Electricity Regulatory Commission (TERC) had not specified the heat rate of gas for Baramura and Rokhia. Consequently, consumption of gas was to be regulated at the heat rate of 3,125 Kcal/unit and 3,500 Kcal/unit allowed by Central Electricity Regulatory Commission (CERC) for 2005-06 to 2008-09 and 2009-10 respectively. The average heat consumed by the Power Stations during 2005 -10 ranged from 3,619.48 Kcal/unit to 4,011.89 Kcal/unit during 2005-06 to 2008-09 and 3,707.91 Kcal/unit in 2009-10. This contributed to excess consumption of gas as discussed in the previous paragraph.

The Company stated (September 2010) that plant performance loss was a design phenomenon with respect to the ageing and firing hours of the units. However, the norms are fixed by CERC with consideration of all parameters.

At the exit conference, Company stated that for old units the normative heat rate would be re-assessed.

Manpower Management

5.2.35 Consequent to the corporatisation (April 2005) of the erstwhile departmental undertaking without unbundling of its activities, the Government deputed all 5,084 employees of the Power Department to the Company. Neither the Government nor the Company had assessed the required strength or specified the sanctioned strength. However, the position of manpower at the three generating stations for the past five years as compared to CEA norms was as under:

Sl. No	Particulars	Technical	Non-Technical	Total
1	Requirement as per CEA norms	57	20	77
2	Actual			
	2005-06	166	142	308
	2006-07	148	170	318
	2007-08	142	168	310
	2008-09	155	117	272
	2009-10	166	93	259

5.2.36 The above table shows that actual manpower was in excess of the norms of CEA during the years 2005-06 to 2009-10. Despite having excessive manpower, the generating stations were regularly employing temporary/contract staff. During 2005-10, generating stations deployed temporary employees for different jobs by incurring an expenditure of ₹ 67.01 lakh. Besides, overtime of ₹ 30.19 lakh had been paid to the regular staff. No action was taken to rationalise its staff strength or explore ways to utilise them optimally.

The Company stated (September 2010) that efforts were being taken to redistribute the existing manpower in all activities.

Output Efficiency

Generation performance

5.2.37 The targets for generation of power for each year are fixed by the CEA. It was observed that the gas stations of the Company generated 2,753.71 MU of power during 2005-06 to 2009-2010 against a target of 2,527.50 MU. This resulted in a net excess of 226.21 MU as shown in the following table:

Year	Target (In MU)	Actual (In MU)	Excess (+)/ Shortfall (-) (In MU)
2005-06	456.00	428.68	(-) 27.32
2006-07	584.00	520.20	(-) 63.80
2007-08	490.00	583.86	(+) 93.86
2008-09	474.00	608.49	(+) 134.49
2009-10	523.50	612.48	(+) 88.98
Total	**2,527.50**	**2,753.71**	**(+) 226.21**

The year-wise details of energy to be generated as per design, actual generation, plant load factor (PLF) as per design and actual plant load factor in respect of the power Projects commissioned up to March 2010 are as given in **Appendix - 5.10.**

The details in the Appendix indicate that:

- The actual generation and actual PLF achieved at Baramura were above the energy to be generated and PLF as per design during all five years while PLF at Rokhia and Gumti were far below the target.
- As against the total designed generation of 3,039.94 MU of energy at Rokhia and Gumti during the five years ended 2009-2010 the actual generation was 2,164.94 MU leading to the shortfall of 875 MU.
- As the PLF had been designed considering the availability of inputs the loss of generation (total 875 MU) during the period 2005-2006 to 2009-2010 indicated that resources and capacity were not being utilised to the optimum level due to non operation of plants and delay in timely renovation as discussed subsequently.

The Company stated (September 2010) that two 8 MW units and one 21 MW unit at Rokhia were out of bus (grid) due to shortage of gas and forced outages and units at Gumti were out of bus in lean season. However, we observed that the gas allocation for two 8 MW units at APM rates was being diverted to operate one 21 MW unit (No. 8), instead of obtaining separate allocation at MDP.

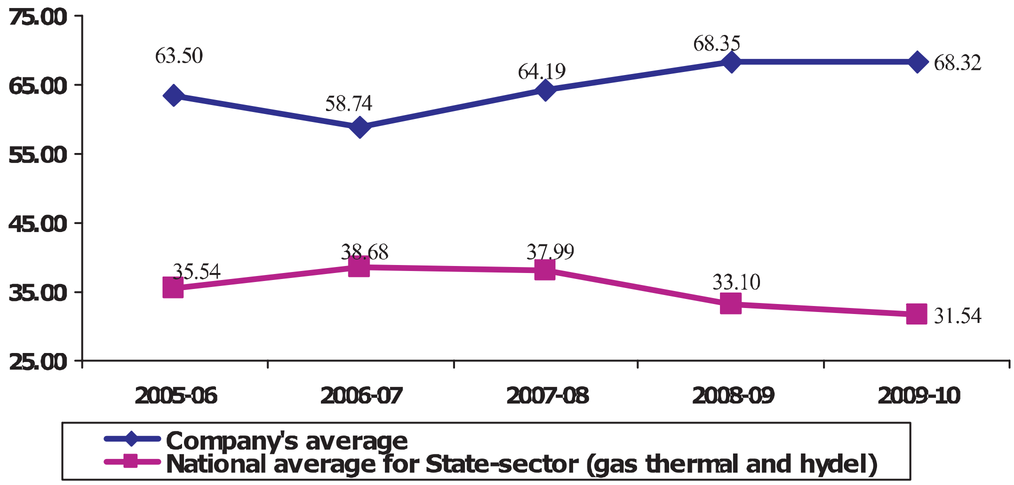
Plant Load Factor (PLF)

GHTPS at Lehra Mohabbat (2x210MW) registered 95.99% PLF among all State Sector Stations during 2008-09. PLF of 101.10% of Unit No. 6 of Kota TPS (195 MW) of RRVUNL registered highest among all state sector units in 2008-09.

5.2.38 Plant load factor (PLF) refers to the ratio between the actual generation and the maximum possible generation at installed capacity. According to norms fixed by Central Electricity Regulatory Commission (CERC), the PLF for thermal power generating stations should be 80 *per* cent during 2005-06 to

2008-09 and 85 *per cent* in 2009-10, against which the aggregate national average for gas turbine and hydro was 31.54 *per cent*. The following graph presents the comparative position of PLF for aggregate national average for gas thermal and hydro power stations in the State sector as well as for the Company.

Comparative position of PLF *(in per cent)*



It would be apparent from the above chart that the Company's PLF was above the National average for State-sector gas thermal and hydro in all five years from 2005-06 to 2009-10. The comparative performance for each power station was as follows :

- PLF at Baramura and Rokhia were 86.32 to 95.40 *per cent* and 54.07 to 69.29 *per cent* respectively was higher than corresponding National average in all five years.
- PLF at Gumti ranged from 27.60 to 50.50 *per cent* which exceeded the comparable national average in 2005-06, 2008-09 and 2009-10, while being lower in 2006-07 and 2007-08.

The Company attributed (September 2010) the low PLF at Rokhia as compared to the other GTPS at Baramura to shortage of gas at APM rate and at Gumti due to drought. However, we noticed that in addition to 0.7 MMSCMD at APM price, ONGC has allocated (2008) supply of additional 0.4 MMSCMD at Market Determined Price (MDP) for Rokhia (0.2 MMSCMD) and Baramura (0.2 MMSCMD). Of this additional allocation, the Company was drawing (September 2010) 0.28 MMSCMD at Rokhia (0.08 MMSCMD) and Baramura (0.2 MMSCMD). The Company had no plans to utilise the balance (0.12 MMSCMD) allocation of gas at Rokhia indicating that allocation of gas was not a constraint.

At the exit conference, the Government accepted the need to conduct a study into the reasons for reduction in holding capacity of the reservoir at Gumti. It was also stated that an evaluation of existing generation capacity *vis-à-vis* gas linkages allocated would be undertaken.

5.2.39 The details of maximum possible generation at installed capacity, actual generation and corresponding Plant Load Factor achieved in respect of each generating unit for the five years up to 2009-2010 are given in **Appendix - 5.10**. The PLF at Baramura exceeded the norms prescribed by CERC in all years under review. However, Rokhia and Gumti could not achieve the CERC norms in any of the years under review. The main reasons for the low PLF at Rokhia and Gumti, as observed in audit were:

- Low plant availability
- Low capacity utilisation
- Major shutdowns and delays in repairs and maintenance

These are discussed in the following paragraphs.

Plant availability

The overall plant availability in the State Sector was 82.67 % during 2008-09

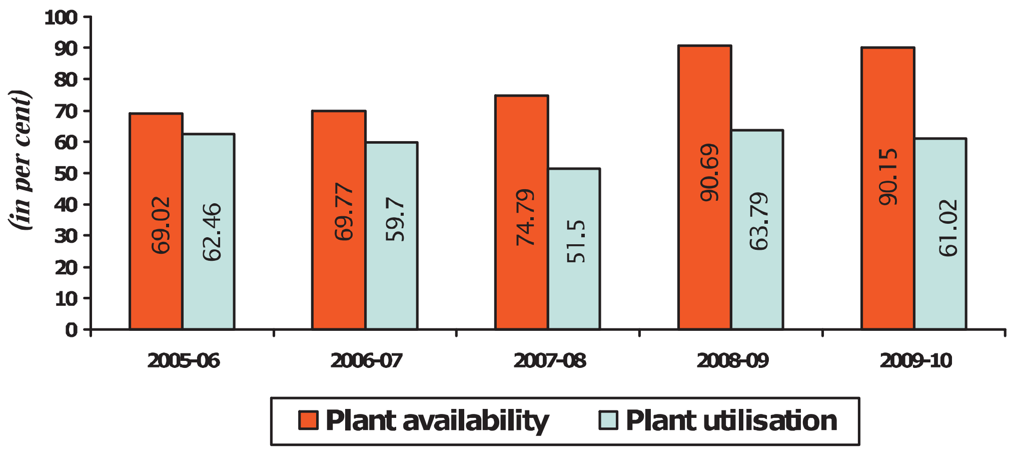
5.2.40 Plant availability means the ratio of actual hours operated to maximum possible hours available during certain period. As against the CERC norm of 80 *per cent* plant availability during 2004 – 2009 and 85 *per cent* during 2009 – 2014, the average plant availability of power stations was 79.08 *per cent* during the five years up to 2009-10.

5.2.41 The details of total hours available, total hours operated, planned outages, forced outages[20], reserve outages[21] and overall plant availability in respect of the Company as a whole are shown below:

Sl No.	Particulars	2005-06	2006-07	2007-08	2008-09	2009-10	Total
1	Total hours available	78,840	87,600	87,840	87,600	87,600	4,29,480
2	Planned outages (in hours)	11,996	19,988	9,767	5,985	6,930	54,666
3	Forced outages (in hours)	12,428	6,493	12,374	2,172	1,699	35,166
4	Total outages (2+3)	24,424	26,481	22,141	8,157	8,629	89,832
5	Plant availability (1-4)	54,416	61,119	65,699	79,443	78,971	3,39,648
6	Reserve outages	5,174	8,823	20,459	23,565	25,517	83,538
7	Operated hours	49,242	52,296	45,240	55,878	53,454	2,56,110
8	Plant availability (*per cent*) (5x100/1)	69.02	69.77	74.79	90.69	90.15	79.08
9	Plant utilisation (*per cent*) (7x100/1)	62.46	59.70	51.50	63.79	61.02	59.63

5.2.42 The graph below shows percentage of plant availability *vis-à-vis* percentage of plant utilisation:

[20] Forced outages are closure of plant in excess of prescribed limit due to break down in the system.
[21] Reserve outages are when units are ready for generation but not operated.

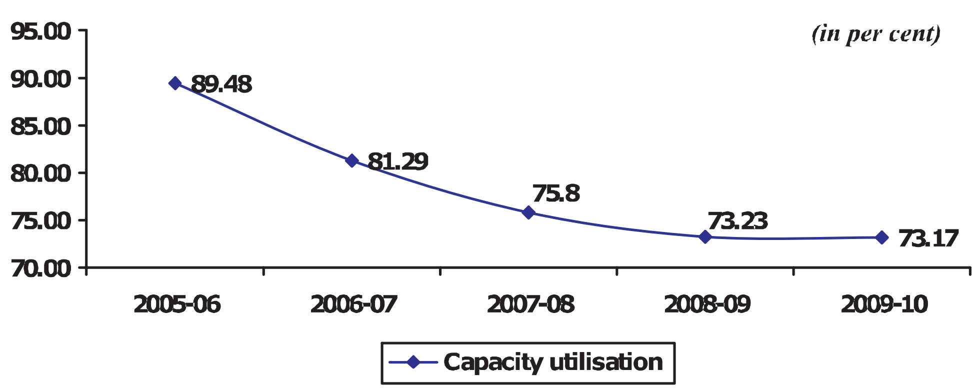


The plant availability, though below the norms from 2005-06 to 2007-08, improved over the review period from 69.02 *per cent* to 90.15 *per cent.* The low availability of power plants during 2005-06 to 2007-08 was due to longer duration of outages caused by inordinate delays in repair and maintenance. Moreover, even when the plants were available for generation, they were not operated due to non-availability of required quantity of gas and non-operation of the unit no. 5 and 6 leading to low plant utilisation as discussed in *Paragraphs 5.2.30 and 5.2.43*.

The Company stated (September 2010) that plant availability fell marginally short than the CERC fixed average due to long outage of few units at Rokhia.

Declining Capacity Utilisation

5.2.43 Capacity utilisation means the ratio of actual generation to possible generation during actual hours of operation. Based on this, the graph below shows the Company's capacity utilisation during the review period reduced from 89.48 to 73.17 *per cent*.



We observed that 10.52 to 26.83 *per cent* of the available capacity remained unutilised. The main reasons for the declining utilisation of available capacity during 2005-10 were:-

- Running of units with partial load/without load due to substantial variation in peak and off-peak demand;
- Reduced capacity of old generating units;
- Non operation of units (Unit No. 5 and 6) at Rokhia (aggregate capacity: 16 MW) since February 2007 and July 2005 respectively to avoid sharing half the generation with Mizoram and Manipur, as required under the financial assistance sanctioned by NEC for setting up these units. This led to loss of potential generation of 312.07 MU.

The Company stated (September 2010) that Unit No. 5 and 6 at Rokhia were non-operational due to non-availability of gas at APM rate. However, at the exit conference, the Government agreed that an evaluation of existing generation capacity *vis-à-vis* gas linkages allocated would be undertaken.

- Reduction (32.24 *per cent*) in capacity of reservoir at Gumti was due to siltation. The water spread came down from 4,500 ha during construction (1977) to 3,049.34 ha (2004). Thus, despite rainfall in the district being in excess of the long period (1941-90) averages by 2.04 to 69.63 *per cent* in the past five years till 2009-10, only two of three units were operated.

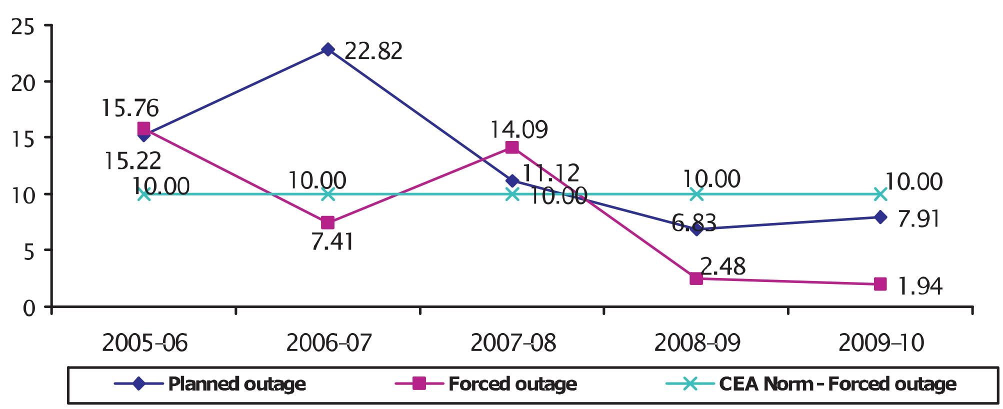
The Company stated (September 2010) that Gumti hydro electric project was designed to generate 50 MU annually with one unit being kept on stand by. The Government stated that a study would be conducted to see the reasons for reduction in holding capacity of the reservoir at Gumti.

Outages

Energy loss on account of forced outages was 9.29% during 2008-09 while the same was 7.71% during 2007-08.

5.2.44 Outages refer to the period for which the plant remained closed for attending planned/ forced maintenance. Percentage of annual forced and planned outages in the Company *vis-à-vis* norm for forced outage are shown in the graph below:

Comparative position of outages *(in per cent)*



In this regard, the following were observed:

- The total number of hours lost due to planned outages decreased from 11,996 hours in 2005-06 to 6,930 hours in 2009-10 i.e. from 15.22 *per cent* to 7.91 *per cent* of the total available hours in the respective years.
- The forced outages decreased from 12,428 hours in 2005-06 to 1,699 hours in 2009-10 i.e. from 15.76 to 1.94 *per cent* of the total available hours in the respective years. The forced outages remained more than the norm of 10 *per cent* fixed by CEA in two years *viz.* 2005-06 and 2007-08, mainly due to excessive time taken on repairs and maintenance.

The total outages had improved over the period under review. The Company attributed (September 2010) the higher rate of forced outage in 2005-06 to Unit Nos. 3 and 7 being out of bus (grid) for four years and eight months respectively.

Auxiliary consumption of power

5.2.45 Energy consumed by power stations themselves for running their equipments and common services is called auxiliary consumption. CERC specified (March 2004/ January 2009) one *per cent* of the power generated to be used as auxiliary consumption for gas turbines and 0.2 *per cent* for hydro electric stations up to 2008-09 and thereafter 0.7 *per cent*. However, as per the information furnished by the Company, the actual auxiliary consumption remained static at 1.5 *per cent* for gas turbines and around one *per cent* for hydro station, which was above the norms resulting in excess consumption of 15.50 MU which could not be dispatched to the grid.

The Company stated (September 2010) that the actual auxiliary consumption of power was one *per cent* of gross generation for gas turbine plants while at Gumti (hydro) it was only 0.12 *per cent*. At the exit conference, the Company agreed to reconcile the figures of auxiliary consumption.

Repairs and Maintenance

5.2.46 To ensure long term sustainable levels of performance, it is important to adhere to periodic maintenance schedules. The efficiency and availability of equipment is dependent on the strict adherence to prescribed maintenance and equipment overhauling schedules. Non-adherence to schedule carry a risk of the equipment consuming more gas and lubricants as well as a higher risk of forced outages which necessitate undertaking R&M works. These factors lead to increase in the cost of power generation due to reduced availability of equipments which affect the total power generated.

5.2.47 It was observed that scheduled maintenance of units was done after delays ranging from five to ninety months (details given in the **Appendix - 5.11**). Some other aspects of repair and maintenance are highlighted below.

- Due to delay in taking up the Major Inspection (MI) of Unit No. 4 at Rokhia in September 2009, there was short generation of 9.70 MU from October 2009 to

May 2010. MI was proposed for July 2010 but not taken up. It was also seen from the proposal initiated (February 2009) by Rokhia GTPS, that it was estimated that the generation capacity would enhance to 4.75 MU per month after MI.

- Unit No. 6 at Rokhia was under forced shutdown from June 2005 due to failure of LP Rotor and generator. It was repaired (June 2006) and put on trial operation for three days and thereafter the unit was not operated till date. Yet, the Company spent (August 2008) ₹ 27.42 lakh on repairs, followed by overhaul and shifting (January 2009) of turbo-generator of defunct Unit No. 1 at a cost of ₹6.92 lakh. Even though not operated, the unit consumed 19.20 Kl turbine oil (value: ₹13.43 lakh) during 2005-06 to 2009-10.

The Company stated (September 2010) that Unit No. 6 of Rokhia was under trial mode of operation and kept standby for want of gas which was not available at APM rate. However, it was seen from the records that the gas originally allocated for operation of Unit No. 6 at APM rate was diverted to operate Unit No.8 resulting in shutdown of Unit No. 6.

- Unit No. 7 at Rokhia was under shutdown from 12 January 2006 due to high vibration in the generator. BHEL inspected the damage and recommended major repairs at Hyderabad. Instead, the Company placed (31 January 2006) order on BHEL to supply a new generator by March 2006. The new generator reached the site in July 2006. Meanwhile, the transformer of Unit No. 7 was shifted (March 2006) to Unit No.8. The existing transformer was returned to Unit No.7 only in September 2006, after the new transformer and switchyard for unit No. 8 were commissioned. Thereafter, Unit No. 7 was re-assembled and resumed generation in October 2006. Consequently, the unit was under forced shutdown for 274 days from 12 January 2006 to 12 October 2006.

Renovation and Modernisation

5.2.48 Renovation and Modernisation (R & M) and refurbishment activities involve identification of the problems of unit of TPS, preparation of techno economic viability reports, preparation of detailed project reports (DPR) to lay down benefits to be achieved from these works.

5.2.49 Unit No. I at Gumti was out of bus from September 2007 for defects in turbine and generator and put into operation only in January 2010 after 29 months, due to delays in preparation of estimates, sanctions etc. Unit No. II at Gumti was also under forced shutdown for 1,461.50 hours out of 1,464 hours in June and July 2006 due to shaft and turbo generator vibration. The unit was then put under complete shutdown from August 2006 and put in operation in April 2008 after 21 months due to delay in commencement of work (April 2007) and non-availability of special materials identified after inspection (July 2007). This led to both the units being out of operation from September 2007 to March 2008, with loss of potential generation of 19.02 MU.

The Company stated (September 2010) that continuous efforts were being taken to assess and prepare action plan for R & M and LEP to enhance operational efficiency of the existing plants. Results were, however, dependent on the availability of required spares for these works.

Operation and Maintenance

5.2.50 CERC in its Regulation 2009 allowed O&M norm for 2009-10 as ₹ 22.90 lakh and ₹ 38.45 lakh per MW in respect of small gas turbine power generating stations[22] and hydroelectric power generating stations respectively. The overall O&M cost per MW, on weighted average method, based on above norms works out to ₹ 25.02 lakh. Against the norms, the total O&M cost per MW incurred by the Company was ₹ 11.83 lakh, ₹ 15.86 lakh, ₹ 8.48 lakh, ₹12.26 lakh and ₹13.53 lakh from 2005-06 to 2009-10. We observed that O&M expenses were lower than the norms fixed by CERC in this regard.

Financial Management

5.2.51 The details of consolidated working results (i.e. generation to distribution) have been prepared based on estimated figures made available to audit and are given in **Appendix - 5.12**.

Claims and Dues

5.2.52 The Company sells energy directly to consumers in the State at the rates specified by TERC in 2005-06 and 2006-07. Sale prices do not cover the total input costs. The differential amount is either subsidised through trading or claimed in the form of subsidy from the State Government. At the time of corporatisation, the entire manpower of the Department of Power was deputed to the Company, as discussed at paragraph *No. 5.2.35* which is partly subsidised by the Government. The table below gives the details of subsidy commitments by the Government *vis-à-vis* subsidy received for the review period.

(Rupees in crore)

Sl. No	Details	2005-06	2006-07	2007-08	2008-09	2009-10	Total
1.	Subsidy commitment[23] by the State Government	40.00	40.00	24.85	25.85	28.00	158.70
2.	Subsidy received from the State Government	45.56	22.00	24.00	25.00	28.00	144.56
3.	Difference (1 – 2)	5.56	(18.00)	(0.85)	(0.85)	0.00	(14.14)

(Figures in brackets indicate short receipt of subsidy)

[22] Stations with gas turbines in the capacity of 50 MW or below.

[23] Made by the State Government to TERC (June 2005/September 2006) when tariff for 2005-06 and 2006-07. From 2007-08 onwards, the State Government decided to convert Budgeted non-plan grants to the Company into subsidy.

It would be seen from the above table that in 2005-06 and 2009-10, out of aggregate subsidy commitment of ₹ 158.70 crore, the Government paid ₹ 144.56 crore with short realisation of ₹ 14.14 crore.

The Company stated (September 2010) that after compiling the accounts, the exact figure of each segment will be compared.

Tariff Fixation

5.2.53 The Tripura Electricity Regulatory Commission (Tariff Regulation, 2004), effective from 18 January 2005, specifies that the licensee i.e. the Company should file petition for revision of tariff 120 days before the proposed effective date of revision. TERC had also observed (June 2005) that tariff should be revised normally with effect from 1 April of each year.

5.2.54 Audit noticed that the Company filed (10 March 2005/ 4 August 2006) tariff petitions for revisions of tariff from 1 April 2005 and 1 April 2006 after delays[24] of 98 days and 245 days respectively. TERC approved tariffs on 28 June 2005 and 14 September 2006, effective from 1 July 2005 and 1 July 2006 respectively. This resulted in short realisation of revenue of ₹ 6.10 crore on sale of 358.68 MU and 251.58 MU energy between April-June 2005 and April-June 2006 respectively. Moreover, due to failure to compile accounts, TERC refused (September 2007) to revise the tariff for the remaining years. Consequently, the tariffs remained static till July 2010.

Environment Issues

5.2.55 In order to minimise the adverse impact on the environment, the GOI had enacted various Acts and statutes. At the State level, Tripura State Pollution Control Board (TSPCB) is the regulating agency to ensure compliance with the provisions of these Acts and statutes. Ministry of Environment and Forests (MoE&F), GOI and Central Pollution Control Board (CPCB) are also vested with powers under various statutes. Though periodically directed by the TSPCB, the Company has no separate Environmental Management Cell.

Our scrutiny relating to compliance with the provisions of various Acts in this regard revealed the following:

Air Pollution and on-line monitoring equipment

5.2.56 Exhaust from gas turbines include suspended particular matter (SPM), Nitrous Oxides (N_2O) and Sulphar-Di-Oxide (SO_2) which needs to be monitored. As per the provisions of the Environment (Protection) Act, 1986 and Consent to operate certificates, both GTPSs should provide on-line monitoring systems to measure stack emissions. However, it was observed that none of the GTPS had installed monitoring systems. Moreover, while issuing the Consent to operate certificates, TSPCB directed

[24] Due dates- 2 December 2004 and 2 December 2005.

that the ambient air quality and stack emissions should be monitored periodically. Yet, no monitoring stations were set up to measure ambient air quality. Non-installation of on-line monitoring equipment had resulted in violation of statutory provisions.

The Company stated (September 2010) that at the time of installation of the older units, installation of on-line monitoring equipment was not mandatory. The management also proposed to set up the equipment in those units in phases. However, we observed that in new unit (Rokhia Unit No. 8) also, the equipment was not installed.

Noise Pollution

5.2.57 Noise Pollution (Regulation and Control) Rules, 2000 aim to regulate and control noise producing and generating sources with the objective of maintaining ambient air quality. To achieve the above, noise emission from equipment be controlled at source, adequate silencing equipment should be provided at various noise sources and a green belt should be developed around the plant area to diffuse noise dispersion. The GTPSs are required to record sound levels in all the areas stipulated in the rules referred to above.

Our scrutiny revealed the following:

- Both Rokhia and Baramura GTPS did not record noise levels.
- Noise level measured in turbine area of Rokhia GTPS by TSPCB in December 2006 was 87 dB against maximum limit of 85 dB.

Energy conservation

5.2.58 The Company operates open cycle gas turbines where the exhaust gas carries away almost two thirds of the energy available from the burning of gas. The stack emission has a temperature of about 500^{0}C. If the Company goes in for combined cycle plant or waste heat recovery plant, the heat present in the exhaust gas can be recycled for generating further power. The Government prepared[25] (December 1988) feasibility study on setting up of waste heat recovery plant with a capacity of 11 MW at a cost of ₹ 31.28 crore at Baramura for utilising the energy of the exhaust gas system. However, no further action was taken. At Rokhia, the Company is considering setting up a waste heat recovery plant only in May 2010. Thus, due to lack of timely action, the Company could not harness the potential of non- renewable energy resources.

At the exit conference, Company agreed to examine the feasibility of arranging water for waste heat recovery plants at both the GTPS.

[25] Through CESCON, CESC Limited, Kolkata (a private company).

Non registration of new power projects under Clean Development Mechanism

5.2.59 To save the Earth from green house gases (GHG) a number of countries including India signed the 'Kyoto Protocol' (Protocol), which was adopted (December 1997) in the Third Conference of Parties to the United Nations Framework Convention on Climate Change (UNFCCC). Article 3 of the Protocol targeted reduction of emission of GHG by five *per cent* in the developed countries. UNFCCC had set the 'standard' level of carbon emission allowed for a particular industry or activity. The extent to which an entity is emitting less carbon (as per standard fixed by UNFCCC), it gets credited for the same. Only those power plants that meet the UNFCCC norms and take up new technologies will be entitled to sell these credits. There are parameters set and detailed audit is done before an entity gets the entitlement to sell the credit. The booking of such saving of GHG is called purchase of Certified Emission Reduction (CER), commonly called Carbon Credits. If the developed countries were unable to reduce their own carbon emissions, they could book the savings of GHG in developing countries in their account by paying some money to the concerned country. This whole system is named Clean Development Mechanism (CDM).

For sale of CER, registration of the power plant is required as a CDM project with UNFCCC. The power plants that commenced operations on or after 1 January 2000 are eligible for registration by submitting the request with Designated National Authority (DNA). In India, the Ministry of Environment and Forest (MoEF), Government of India is nominated as DNA. However, the Company has not taken any action for registration of its two new units namely, Rokhia Unit 8 and Baramura Unit 5 commissioned in March 2006 and August 2010 respectively with MoEF.

The Company stated (September 2010) it would review to register its new plants under the clean development mechanism to avail the benefits of carbon credit.

Monitoring by top management

5.2.60 The Company plays an important role in the State economy. To succeed in operating economically, efficiently and effectively, the Company should document management systems of operations, service standards and targets. Further, 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. The targets should generally be such that the achievement of which would make an organisation self-reliant. Audit review of the system existing in this regard revealed the following:

- The Company did not set targets for important operational parameters. It had, however, drawn up annual plans indicating budgeted and revised estimates for some operational and financial parameters. But, there was nothing on record to indicate regular assessment of actual performance *vis-à-vis* these estimates.
- The Company had appointed (October 2005) Ernst & Young Pvt. Ltd., Kolkata as consultant to develop fund flow pattern and accounting system including MIS

against the remuneration of ₹15.50 lakh, which was received as grant from Power Finance Corporation Ltd. (PFC). The Company had neither implemented recommendations in the reports for development of system prepared by the consultant nor documented the MIS reports to be generated.

- The Board of Directors (BoD) did not seek the operational/ financial performance of the Company for periodic review. Moreover, it had neither periodically monitored the implementation of projects nor evaluated the socio economic parameters to analyse the success rate of projects or positive impact on socio economic parameters. Further, the annual plans were never presented to the Board.
- In all five years, information on gross generation maintained by the generating stations was at variance with details maintained by the Commercial & Systems Operation circle. These differences were in the range of 0.441 MU to 10.867 MU indicating inadequate monitoring mechanism.

The Company stated (September 2010) that due to lack of trained manpower, all the systems for monitoring by top management were not yet implemented. The Company was, however, trying to set up a Management Information System (MIS) to report on achievements of targets and other aspects. The financial and operational performance was now being discussed by the Board of Directors.

Conclusion

- As per NEP, over 1,000 units of power per capita should be provided by 2012. However, 470 units per capita would be available by 2012 in the State.
- The cost of own generation was 31 to 46 *per cent* below cost of purchases from central sector generating stations. However, the Company had entered into agreements to import more power from central sector allocations without undertaking cost benefit analysis.
- There was under-utilisation of the existing generation capacity as two GTPS units were not operated in spite of plant availability.
- Despite siltation at Gumti reservoir hampering generation capacity, remedial measures had not been taken up by the Company.
- In absence of compiled accounts from 2006-07 onwards, the actual financial position of the Company could not be assessed.
- The Company does not have any documented policy for sale of power through trading with regard to either quantum of power to be traded or minimum floor prices for power traded.

- The Company had not correctly assessed its gas requirement which resulted in short supply of gas. Besides, delay in tie-up of gas supply on price considerations led to generation loss of 48.34 MU during the review period.

- Gas consumption exceeded CERC norms leading to additional expenditure of ₹ 41.80 crore during the review period.

- The Company has not rationalised its excess manpower as per CEA norms, thereby increasing the cost of operation.

- The PLF at Baramura and Rokhia GTPS was higher than the corresponding national average in all five years whereas at Gumti Hydro, it exceeded the comparable national average in three of five years.

- The Company had not only delayed filing tariff petitions with TERC for 2005-06 and 2006-07 but was also unable to seek revised tariffs thereafter due to non-preparation of accounts.

- The Company had not installed online monitoring equipment to measure emissions or set up monitoring stations to evaluate ambient air quality.

- The Company had not registered its new plants under the Clean Development Mechanism to avail benefit of carbon credits.

- The Company had not explored the possibility of harnessing the waste heat through waste heat recovery plants.

- The Company had not put in place MIS system for monitoring and for follow-up on the operational and financial performance by the top management despite engaging a consultant for that purpose.

Recommendations

- The Company may formulate a comprehensive plan for capacity addition to ensure energy availability required as per NEP.

- The Company may have a policy for capacity addition either by way of own generation or through allocation of central sector only after detailed cost benefit analysis.

- The Company may un-bundle its generation, transmission, distribution and trading activities in line with the Electricity Act, 2003.

- The Company may ensure maintenance and compilation of accounts in time and pull up the arrears in accounts in a time bound manner. The Company should also follow an activity based accounting system for segment reporting.

- The Company may delineate a policy for trading of power in respect of quantum of power to be traded and minimum floor prices for power being traded.

- The Company may take immediate steps to reduce its excess manpower as per CEA norms by formulating suitable schemes.

- The Company may take action in line with TERC's regulations in regard to tariff fixation.

- The Company may explore the possibility of availing carbon credits and harnessing waste heat through recovery plants.

- The Company may ensure regular reporting and monitoring of financial/ operational performance as well as put in place a follow up mechanism to ensure achievement of desired objectives.

- The Company may consider conducting training programmes for employees in Information Technology.

SECTION - B
POWER DEPARTMENT
(Tripura State Electricity Corporation Limited)

5.3 Additional expenditure on purchase of less efficient transformers

Failure of the Company to consider the capitalised value of inherent losses while evaluating the offers for purchase of distribution transformers resulted in incurring of additional expenditure of ₹ 22.69 lakh on the purchase of 100 transformers.

Tripura State Electricity Corporation Limited (Company) floated (September/ November 2007) tenders for purchase of 250 distribution transformers of 100 KVA capacity at an estimated cost of ₹ 3.02 crore.

Distribution transformers are static equipment for stepping down voltages for supply to consumers. All these transformers incur inherent losses comprising of 'No-Load Losses' *i.e.* the power required to energise the core of the transformers and 'Load Losses' i.e. additional losses occurring as a result of load currents flowing through the transformer, based on the resistance of the winding conductors. Thus, while procuring transformers, as a general rule[26] their effective costs should be determined by adding the capitalised value[27] of these inherent losses to the initial cost[28] of transformers.

Scrutiny (April-May 2010) of records of the Company revealed that the Company received offers from five[29] eligible bidders in which the initial cost per transformer of 100 KVA capacity ranged from ₹ 0.83 lakh to ₹ 1.22 lakh. The Company issued (July 2008) supply orders to the lowest tenderer, M/s East India Udyog Limited for supply of 150 transformers of 100 KVA capacity at ₹ 82,820/- each and also to M/s Prag Electricals Private Limited for supply of 100 transformers of 100 KVA capacity at the negotiated price of ₹ 82,820/- each, aggregating to ₹ 2.07 crore. Between October 2008 and September 2009, the Company had taken delivery of 216 transformers (116 from M/S East India Udyog Limited and 100 from M/s Prag Electricals Private Limited) the value of which was ₹ 1.76 crore[30].

It was noticed that while evaluating the offers, the Company considered only the initial cost but did not consider the capitalised value of inherent losses since the notice inviting tender contained no provision for consideration of these losses. It was seen from the type test certificates submitted by the manufacturers that the effective cost of 100 KVA transformers supplied by M/S Prag Electricals Private Limited was higher

[26] REC construction standard K-5/1997(R-1999) and CEA guidelines of August 2008.

[27] Net present value of energy losses based on 8,400 hours of operation, cost of energy (₹ 3.60 per unit), equipment life (25 years), rate of return (10.5 *per cent*) and average load factor (0.6) working out to ₹ 264.27 per watt of 'no load' losses and ₹ 114.16 per watt of 'load' losses.

[28] Includes supplier's price, taxes, duties, freight and insurance.

[29] Vijai Electricals Limited, East India Udyog Limited, Prag Electricals Private Limited, Abhay Transformers Private Limited and M & B Switch Gears Private Limited.

[30] ₹ 96.07 lakh to M/s East India Udyog Limited and ₹ 79.54 lakh to M/s Prag Electrical Private Limited (deducting ₹ 3.28 lakh as liquidated damages for delays in supply).

than those supplied by East India Udyog Limited by ₹ 22,689 per transformer, as detailed below:

Name of the tenderer	No-Load Loss (in Watt)	Load Loss (in Watt)	Initial cost (₹)	Capitalisation loss (₹)	Effective cost (4) + (5) (₹)
(1)	(2)	(3)	(4)	(5)	(6)
Prag Electricals Private Limited	247	1,744	82,820	2,64,376	3,47,196
East India Udyog Limited	197	1,661	82,820	2,41,687	3,24,507
Difference					**22,689**

Thus, failure of the Company to consider the capitalised value of inherent losses while evaluating the offers for purchase of distribution transformers resulted in incurring of additional expenditure of ₹ 22.69 lakh[31] on the purchase of 100 transformers from M/s Prag Electricals Private Limited.

The Management stated (September 2010) that the Company was enforcing the procedure for 'Loss Capitalisation' for procurement of all kinds of distribution transformers from the next tender process.

The matter was reported to the Government in July 2010; reply had not been received (October 2010).

INDUSTRIES AND COMMERCE DEPARTMENT
(Tripura Jute Mills Limited)

5.4 Excess expenditure due to defective contract management

Failure of the Tripura Jute Mills Limited to specify validity period in the Notice Inviting Quotations and in the offers received from Assam-based suppliers, issue of piecemeal supply orders instead of whole quantity tendered for and release of payments prior to post shipment inspection of jute resulted in excess expenditure of ₹ 18.39 lakh.

Tripura Jute Mills Limited (Company) purchased 1,795 MT *Tossa* jute during December 2005 to September 2006 at ₹ 2.75 crore. Scrutiny (May 2010) of records of the Company revealed the following:

(a) The Company issued (5 September 2005) supply orders for 250 MT *Tossa* jute of four grades to two Assam-based firms (125 MT each), based on their quotations of August 2005 for supplying 600 MT jute. On observing an upward trend in raw jute prices, the Company issued supply orders, within two days (7 September 2005), to the same firms for additional 350 MT jute (175 MT each). Since neither the Notice Inviting Quotations (NIQ) nor the offers specified validity period of offer, both firms sought (September 2005) enhancement of rates by ₹ 225/- per quintal for each grade. But the Company did not agree to enhance the rates.

Instead, the Company invited (November 2005) fresh quotations for supply of 500 MT *Tossa* jute of four grades F.O.R. company premises with provision for joint

[31] ₹ 22,689 X 100.

inspection by the Company and the supplier(s) before payment. Out of six bids received, the rates of M/S Uttara Pat Sangstha, Bangladesh (UPSB), received through M/S Pratistha Enterprise, Kolkata (an Indian agent of UPSB), being the lowest the Company placed three supply orders between December 2005 and May 2006 to UPSB for 630 MT *Tossa* jute of three grades; payment was to be made through bank against letter of credit (LC). The Company received (January-June 2006) 620.4051 MT jute at a landed cost of ₹ 1.10 crore.

It was noticed that the rates of jute purchased from UPSB were higher than the rates offered (August 2005) by the Assam-based firms for equivalent Indian grades by 13 to 24 *per cent*. Thus, failure to specify validity period in the NIQ as well as in the offers and issue of piecemeal supply orders instead of the whole quantity tendered for the Company had incurred excess expenditure of ₹ 8.86 lakh, as detailed in **Appendix - 5.13.**

The Government in reply stated (September 2010) that since the rates quoted by the Assam-based firms in August 2005 were higher than the rates of 2004-05, the Company had not placed orders for the full quantity initially with the expectation that the prices would come down. Due to abnormal price situation, a fresh tender was invited subsequently, wherein the lowest rate from a firm in Bangladesh was selected. The reply is not acceptable as although the prices of jute had started going up since 2004-05 and peaked in 2005-06, the Company still issued supply orders in a piecemeal manner without analysing the market trends of jute prices. Ultimately, the Company had to purchase jute at prices that were higher by about 13 to 24 *per cent*.

(b) For procurement of 1,200 MT *Tossa* jute or equivalent export quality/ grade jute during 2006-07, the Company invited (August 2006) quotations. The NIQ, *inter alia*, provided that offers from Indian importers/ Bangladeshi exporters mention status of their quoted grades *vis-à-vis* Indian Standard Grade along with document containing the quality specifications as per Bangladesh Standard as well as mutual inspection of each consignment at Company premises for assessment of quality/ grade. Of the seven bids received, the offers of M/S Paul & Co., Bangladesh (PCB) received through M/S Pratistha Enterprise, Kolkata (an Indian agent of PCB) were the lowest. The Company issued (September 2006) supply orders to the firm for 1,200 MT jute of four grades and opened (September 2006) an irrevocable letter of credit (LC) with bank. The clauses of the LC *inter alia* specified inspection on receipt of jute supplied at the Company's premises, to finally assess quality/ grade of each consignment in the presence of PCB's representative.

At the instance of PCB, the Company deleted (September 2006) the clauses of the LC regarding final inspection at Company's premises. Instead, it was agreed upon that final invoice would be settled on pre-shipment inspection carried out by a surveyor for quality, weight and moisture. During September to November 2006, PCB supplied 1,174.603 MT jute at a landed cost of ₹ 1.66 crore. The Company observed (January 2007) that out of 832.146 MT of grades BTR(KS) and BTR(CS) received (at landed cost of ₹ 1.19 crore), 5 to 10 *per cent* was fibre other than *Tossa* variety and 15 to 20 *per cent* of the supplied quantity was below specified grade. Though the Company requested (January 2007) PCB to send a representative to carry out joint inspection to settle the matter, no response was received from PCB. Due to inclusion of fibre other than *Tossa* variety and below specified grade in the supplied consignments, the Company incurred excess expenditure of ₹ 9.53 lakh. The Company's Board observed (July 2007) that poor quality Bangladesh jute had hampered production causing problems for good spinning.

In reply, the Government stated (September 2010) that since post-shipment mutual inspection at the Company's premises was objected to by PCB, there was no option but to accept pre-shipment inspection by a neutral inspection agency. The quality of the imported jute was acceptable. The reply is not acceptable as the Company had agreed to pre-shipment inspection through an agency nominated by the supplier instead of the post- shipment joint inspection originally agreed upon leading to supply of inferior material. We observed that the Company had lodged (December 2006/ January 2007) complaints with the bank to withhold payments against LC on account of sub-standard quality of jute and the supplier, but no positive outcome was noticed.

Thus, failure to specify validity period in the Notice Inviting Quotations and in the offers received from Assam-based suppliers, issue of piecemeal supply orders instead of whole quantity tendered for and release of payments prior to post shipment inspection of jute resulted in excess expenditure of ₹ 18.39 lakh[32].

(John K. Sellate)

Agartala **Accountant General (Audit),**

The **Tripura, Agartala**

Countersigned

New Delhi **(Vinod Rai)**

The **Comptroller and Auditor General of India**

32 (₹ 8.86 lakh + ₹ 9.53 lakh).