MINISTRY OF POWER

CHAPTER: VIII

NTPC Limited

Gas Based Power Stations

Highlights

While 14.17 MCMD of gas was required to utilize the generating capacity of 3657.64 MW created at six gas-based power projects, the actual availability of gas was 12.75 MCMD, sufficient only to operate the plants at 66 *per cent* of the capacity.

(Para 8.8.7)

The Company entered into an inequitable gas supply agreement with GAIL which cast an obligation on it to pay for a minimum guaranteed off take of gas whereas no corresponding liability fell on GAIL for short supply of gas. This made the Company liable for an amount of Rs.12.09 crore.

(Paras 8.9.1.1 and 8.9.1.2)

Considering utilization factor of 80 *per cent* of gas-based plants, generation capacity of 375.68 MW remained unutilised.

(Para 8.10.1.2)

The tariff fixation policy of CERC allowed the generating company to recover full fixed charges based on declared capacity, even though actual generation was below the declared capacity. As a result, the beneficiaries had to bear an excessive charge of fixed cost to the tune of Rs.123.45 crore.

(Para 8.10.4.4)

The Company sustained a loss of Rs.157.57 crore due to not achieving the qualifying requirement by Gandhar station for recovery of full fixed charges.

(Para 8.10.5.2)

Despite underutilisation of the existing capacity due to inadequate gas supply, the Company planned to expand the capacity of four gas-based plants in the 9th Five Year Plan. As beneficiaries declined to take costlier power generated on naphtha, the Company deferred the expansion after incurring an expenditure of Rs.23.68 crore, out of which the sum of Rs.17.56 crore was not likely to be utilized till the end of 2011-12.

(Paras 8.11.2 and 8.11.4)

Because of change in technology of Kayamkulam project, land measuring 811 acres became surplus, resulting in blocking of funds amounting to Rs.25.29 crore.

(Para 8.13.1.3)

Gist of Recommendations

- There was an urgent need for the nodal Ministries to ensure that the availability of gas was realistically assessed, the committed quantity was supplied and interests of the Company were safeguarded.
- In view of the precarious state of availability of gas and the underutilised capacity of existing gas-based plants, the Company's plans of expansion of existing gas-based plants require a re-look.

8.1. Introduction

8.1.1 NTPC Limited (Company) was incorporated on 7 November 1975 as a wholly owned company of the Central Government with the objective of planning, promoting and organizing an integrated and efficient development of thermal and hydel power; including construction, generation, operation, maintenance, renovation and modernization of power stations in India and abroad.

8.1.2 In pursuit of these objectives, the Company had programmes of establishing power plants in the country. As on 31 March 2005, the Company was operating 13 coal-based power plants and seven gas-turbine based power plants all over the country with a total generating capacity of 23435 Mega Watt (MW). Apart from this, the Company planned capacity addition of 9370 MW in the 10th Five Year Plan (2002-07) and 17052 MW in 11th Five Year Plan (2007-12) by establishing new thermal and hydro-electric power plants in addition to expansion of the capacity of some of the existing power plants.

8.2 Scope of Audit

The review covers the operational performance of all the seven gas-based power plants of the Company (Anta, Auraiya, Kawas, Dadri, Gandhar, Faridabad and Kayamkulam) during the period of five years from 1999-2000 to 2003-04.

8.3 Audit Objectives

The audit objectives were to examine:

(i) The economic prudence of conceptualization, planning and setting up of the gas-based power plants.

(ii) The operational efficiency of the gas-based plants.

(iii) The expansion plans of four gas-based plants.

8.4 Audit Criteria

In order to achieve the aforementioned audit objectives, following criteria were fixed:

(i) Conceptualization Stage: Consideration of availability of primary fuel, water, appropriate technology, financing of the projects and suitability of location.

(ii) Operation Stage: Actual achievements against norms of operation including the norms of target availability and plant load factor (PLF) prescribed by the Central Electricity Regulatory Commission (CERC); renovation and modernization of the plants.

8.5 Acknowledgement

Audit is thankful for the co-operation received from the Management in obtaining information, data, clarifications to the queries raised from time to time and for arranging discussions with the concerned officers of the Company as and when the need was felt. Without their co-operation it would not have been possible to complete the review within the given time frame.

8.6. Audit Findings

8.6.1 The performance audit of the gas-based power plants of the Company revealed that availability of committed supply of primary fuel was not ensured at the time of conceptualization of the plants and actual supply was much less than the quantity assured by the Government of India (GOI). Despite having experience of failure in getting assured supply of primary fuel, expansion of four projects was undertaken by the Company, without ensuring availability of primary fuel. On the other hand, the cost of underutilisation of capacity due to non availability of gas got passed on to the beneficiaries by taking benefits of the present tariff system.

8.6.2 The findings of audit are detailed in the succeeding paragraphs.

8.7 **Conceptualization of Gas Based Power Projects**

8.7.1 Use of natural gas in the country was initially restricted only for the purposes of fertilizer, petro-chemicals and extraction of liquefied petroleum gas. However, discovery of natural gas in the early 80's in large quantity in the Western off-shore region influenced GOI to consider utilisation of this gas for power generation. The question of coal-oil-gas substitution, including allocation of hydrocarbon fuels for power generation, was discussed (February1984), in a meeting convened by the Economic Advisory Council with follow up meetings by the Department of Power and the Planning Commission. Based on these meetings, a working group, under the convenorship of Advisor (Energy), Planning Commission, submitted a report in June 1984, regarding the availability of lean gas from the Western offshore fields for power generation. The group concluded that approximately four to six million cubic meters per day (MCMD) of lean gas could be made available for power generation on a combined cycle using gas turbines and steam turbines. This quantity of gas was considered sufficient to sustain power plants of 1000 – 1500 MW capacity in a combined cycle mode of operation. On the basis of these recommendations, GOI requested the Company to set up three Combined Cycle Power Projects. Based on the availability of four to six MCMD of gas as indicated by the Ministry of Petroleum and Natural Gas (MOP&NG), the Company took up (1985) the work of three gas-based power projects namely, Kawas (600 MW) in Gujarat, Anta (430 MW) in Rajasthan and Auraiya (600 MW) in Uttar Pradesh, with a total capacity of 1630 MW.

8.7.2 As MOP&NG confirmed (December 1985) availability of only four MCMD of gas against requirement of six MCMD, the Company decided that Anta and Auraiya would operate as base load stations on gas with facility to switchover to naphtha in case of contingencies and Kawas would operate on naphtha till gas was available for all the three projects.

8.7.3 GOI confirmed (January/February 1986) naphtha linkages of 0.75 million ton per annum for Kawas and gas linkage of only 3.75 MCMD (1.50 MCMD for Anta and 2.25 MCMD for Auraiya). Further gas linkage of 2.25 MCMD to Kawas project was accorded subsequently in September 1990. Based on further gas commitment/ linkage by the Government, projects at Dadri, Gandhar and Faridabad were taken up by the Company subsequently. Thus, during the period from 1989 to 1999, the Company commissioned seven gas-based plants at Anta, Auraiya, Kawas, Dadri, Gandhar, Faridabad and Kayamkulam as given in **Annexure-20.**

8.8. Incorrect Assessment of Gas Requirement

8.8.1 For obtaining supply of primary fuel of gas, the Company is dependant upon the Gas Authority of India Limited (GAIL). GAIL supplies gas to the power stations at Anta, Auraiya, Kawas, Dadri and Faridabad through the Hazira-Bijaipur-Jagdishpur (HBJ) gas pipeline. Gandhar power station was initially to get gas supply only from Gandhar gas fields through Jhanor gas pipeline and was not designed to operate on alternate fuel. Subsequently, due to depletion of Gandhar gas fields, this station was also provided a linkage to HBJ pipeline (August 2000) through Kawas station resulting in sharing of gas committed for Kawas between the two stations. GOI has not taken any concrete action to provide gas linkage to Kayamkulam Power Station so far (August 2005).

8.8.2 The plant-wise position of requirement, availability and shortage of gas during the period from 1999-2000 to 2003-04 is given at **Annexure-21.** Based on this data, the performance of the gas-based plants along with the resultant observations are given in succeeding paras.

8.8.3 **Anta, Auraiya and Kawas gas-based power plants**

8.8.3.1 The gas stations at Anta, Auraiya and Kawas were commissioned (1989 to 1992) with 1738.89 MW capacity, which required gas supply of 9.17 MCMD to operate at 100 *per cent* PLF. According to the Management, the annual utilization factor of gas plants was 73.5 *per cent* after taking into account maintenance period (planned and unplanned) and grid demand pattern. With this, 6.74 MCMD of gas was required to operate these three plants at 73.5 *per cent* PLF. However, the Company had a commitment from GAIL for supply of 6.43 MCMD of gas which meant that even ab-initio, PLF would only be 70 *per cent* i.e. less than the utilization factor. This gap in requirement of gas resulted in ab-initio underutilisation of the capacity of Auraiya plant by three *per cent* and Kawas by 14 *per cent*, making these plants inherently dependent on alternate fuel to operate them up to the utilization factor.

8.8.3.2 The GOI is primarily responsible for assignment of requisite gas for power stations. However, neither the GOI, nor the Company took measures to properly assess availability of gas at the initial stage of DPR/FR to effectively control cost in the interest of the beneficiaries.

8.8.4 Dadri gas-based power plant

8.8.4.1 Dadri gas-based power station was established (1992) with generating capacity of 829.78 MW and a gas requirement of 4.38 MCMD for 100 *per cent* PLF. Taking into consideration the annual utilization factor of 73.5 *per cent*, 3.22 MCMD of gas was required to utilize the installed capacity of this plant against which commitment of only three MCMD was taken from GAIL. Therefore, this plant was also created with inherent underutilisation of capacity by 6.83 *per cent* (with reference to 73.5 *per cent* PLF) and was dependent on alternate fuel. During 2000-01, actual average supply of gas was 2.72 MCMD, which further depleted to 2.45 MCMD during 2003-04 increasing thereby its dependence on alternate fuel. This pushed up the cost of generation, as the per unit variable cost of generation on alternate fuel (high speed diesel) was much higher in the range of Rs.2.45 to Rs.4.10, as compared to the cost of generation on gas ranging between Re.0.80 to Re.0.88 during the five years ending 31 March 2004.

8.8.5 Gandhar gas based power plant

8.8.5.1 Gandhar gas-based power station was set up (1994) with a capacity of 657.39 MW and a gas requirement of 3.47 MCMD for 100 *per cent* PLF. At 73.5 *per cent* utilisation factor, the requirement of gas was 2.55 MCMD, against which the commitment by GAIL was for 1.50 MCMD which was sufficient to operate the plant up to a PLF of 43.22 *per cent*. As the plant was solely dependent on gas and was not designed to run on alternate fuel, the plant was created with a potential underutilisation of capacity. In 2000, the gas supply to Gandhar plant was augmented by connecting it with Kawas station, following which the gas supply initially committed to Kawas was shared with Gandhar, increasing the dependence of Kawas on alternate fuel.

8.8.5.2 The Management stated (August 2005) that necessity of creating alternate fuel facility for Kawas plant was reviewed as suggested by the Central Electricity Authority (CEA). Based on this review, the creation of alternate fuel facility was deleted while finalising the feasibility report for Gandhar power plant.

The reply is not convincing as even the assured supply of gas (1.50 MCMD) was sufficient for running the plant only at 43.22 *per cent* PLF, which called for availability of facility in the design of the plant for using alternate fuel.

8.8.5.3 The Management further stated (August 2005) that the Company did its best to augment the generation but time and again GAIL showed its inability to augment gas supplies citing reasons of depletion of gas fields in the Gandhar belt. They added that due to persistent follow up as also due to the Kawas link, gas supplies to Gandhar improved to about 3.03 MCMD in June 2005, which corresponded to almost 90 *per cent* PLF level.

8.8.5.4 The reply is not tenable, as the stated improvement in gas supplies to Gandhar was due to diversion of gas supplies meant for Kawas, which increased the dependence of the latter on costlier fuel (naphtha). Further, the availability of gas was assured by the GOI at the time of approval of power plants which in fact did not happen and proved to be incorrect.

8.8.6 Kayamkulam plant

8.8.6.1 Kayamkulam plant was commissioned in 1998 with installed capacity of 359.56 MW. Though the plant was designed to be operated on naphtha, with the provision for operation on gas, no linkage for supply of gas was ensured for more than seven years since inception.

8.8.6.2 The Management stated (August 2005) that since there was no gas supply infrastructure in the region, the question of taking gas linkage did not arise at the inception stage and also that gas procurement was in process.

8.8.6.3 The reply is not convincing since the cost of power generation by use of naphtha was much higher than that of gas. During the years 2002-03 to 2004-05, the plant capacity was grossly underutilised due to lack of generation schedule from the beneficiaries as they declined to take costlier power. The position was worst during the year 2004-05 when three units of the plant had to be shut down for 5463 hours, 4703 hours and 5305 hours respectively and the plant could not be utilized at all during the period from July 2004 to December 2004 due to unwillingness of beneficiaries to accept costlier power. Hence, availability of gas for this plant should have been envisaged right from inception to overcome such eventualities while changing the mode of operation from coal to naphtha.

8.8.7 From the above analysis it can be seen that while the capacity created by the Company was 3657.64 MW (excluding Kayamkulam plant) and 14.17 MCMD of gas was required to run the six gas-based plants at 73.5 *per cent* PLF, the actual commitment from GAIL for supply of gas was only 12.75 MCMD which was sufficient to operate the created capacity at only 66.1 *per cent* PLF. Thus, even at the initial stage, there was a mis-match between the requirement of primary fuel for generating capacity and the quantity tied up by the GOI for various gas based power plants of the Company. As the GOI was primarily responsible for assignment of requisite gas for power stations, it needed to ensure availability of requisite gas to cater to the generation capacity created by the Company. The Company also needed to properly assess availability of gas at the initial stage of DPR/FR to effectively control cost in the interest of the beneficiaries.

8.9 Gas Supply Tie Ups

8.9.1 Inequitable agreement

8.9.1.1 The Company executed agreements with GAIL for station-wise supply of gas. In terms of the agreements, the Company had to pay for actual quantity of gas supplied by GAIL subject to minimum of 80 *per cent* of the agreed quantity [known as minimum guaranteed off-take (MGO) quantity of gas]. As such, if the quantity actually lifted by the Company fell short of MGO, it had to pay for quantity of gas not drawn by it. However, there was no reciprocal clause for payment of any penalty by GAIL in the event of its failure to supply gas as committed in the agreement. Thus, the Company failed to safeguard its interest by not insisting on incorporating a penalty clause in the agreements for short supply of gas by GAIL against the committed quantities.

8.9.1.2 The Company became liable to pay an amount of Rs.12.09 crore to GAIL towards MGO charges in respect of Anta and Gandhar power plants for the period from March 1994 to March 2001.

8.9.1.3 The Management stated (August 2005) that the matter regarding levy of penalty was taken up with the Ministry of Petroleum and Natural Gas.

8.9.1.4 There is an urgent need for the nodal Ministries to ensure that interests of the Company were safeguarded.

8.9.2 Short supply of gas

8.9.2.1 Analysis of data regarding supply of gas by GAIL to each plant **(Annexure-21)** during the period from 1999 to 2004 indicated that:

(i) The shortfall in supply of gas to Dadri plant ranged between 9-18 *per cent* and to Faridabad plant between 19-67 per cent. The combined supply to Kawas and Gandhar plants fell short by 10-34 *per cent*.

(ii) The shortfall in respect of Anta plant during the years 2000-01, 2002-03 and 2003-04 ranged between 3-16 *per cent*. In Auraiya, the short supply during the years 2000-01 to 2003-04 ranged between 4-16 *per cent*.

(iii) The quantity of gas committed by GAIL was always less than the respective requirement of Auraiya, Dadri, Gandhar and Kawas plants for generation at utilization factor of 73.5 *per cent*. GAIL did not generally supply gas even up to the committed level, which increased the dependence of the plants on costlier fuel.

8.9.2.2 The Management stated (August 2005) that the generation with alternate fuel was not against the concept of economic power generation.

8.9.2.3 This is not acceptable as the variable cost of power generated on alternate fuel was significantly higher than that of gas due to which the beneficiaries did not buy such power and generation capacities created by the Company remained under-utilised during the period under review. Besides, the Company could not effectively take up with the GOI for meeting shortfall in supply of gas.

8.10 Operational Efficiency

8.10.1 Underutilisation of generation capacity

8.10.1.1 The position of PLF achieved by various gas-based stations during the period from 1999-2000 to 2003-04 is given at **Annexure-22.** It may be observed that the gas-based stations could operate only up to PLF ranging between 39.5 *per cent* (Gandhar, 1999-2000) and 87.1 *per cent* (Auraiya, 1999-2000) of the respective installed capacity during the period from 1999-2000 to 2003-04[♦]. On an average, 29.74 *per cent* of the total installed capacity over a period of five years was not utilized, leaving an unutilised capacity of 1179.11 MW. This mainly resulted because of lesser supply of gas than the quantity assured by the GOI.

8.10.1.2 The Management stated (August 2005) that the difference between 100 *per cent* and the actual annual PLF could not be termed as under-utilisation and cost of under-utilised capacity as excess investment. They added that CERC had notified reasonable utilization factor as 80 *per cent*. However, even if the utilization factor of 80 *per cent* is considered, the under-utilization during last five years ended 31 March 2004 came to 375.68 MW.

8.10.2 Loss of generation due to operation of plants on naphtha

8.10.2.1 As the quantity of gas supplied by GAIL gradually declined, the plants increasingly depended on generation through alternate fuel of naphtha.

8.10.2.2 There was lower generation of power when operated on alternate fuel (naphtha) due to higher auxiliary power consumption leaving less units of power for sale. Accordingly, due to operation of the gas plants on alternate fuel, there was loss of generation of 5727.20 MUs of power during the period from 1999-2000 to 2003-04, of which maximum loss of 3393.69 MUs was attributed to Auraiya plant. Analysis of the loss of generation showed that the loss increased from 813.81 MUs in 1999-2000 to 1290.24 MUs in 2003-04.

[♦] ***PLF of Faridabad at 32.9 per cent and of Kayamkulam at 50 per cent achieved in 1999-2000 has not been considered, being the performance of the part of the year of commissioning.***

8.10.2.3 The Management stated (August 2005) that there was no loss of capacity with alternate fuel. The reply did not take into account the fact that the number of units available for sale got reduced due to higher auxiliary power consumption.

8.10.3 Loss of generation due to grid restriction

8.10.3.1 The plant-wise comparative cost of generation using gas and alternate fuel are placed at **Annexure-23**. While the variable cost per unit of power generated on gas in various stations during the period from 1999-2000 to 2003-04 was within a range of 72.43 paise/unit (Gandhar, 1999-2000) and 117 paise/unit (Faridabad, 1999-2000), the variable cost through alternate fuel was in the range of 228.93 paise (Kayamkulam, 1999-2000) and 410 paise (Dadri, 2003-04). Thus, the variable cost of generation of power on alternate fuel (naphtha/HSD) was two to four times the cost of generation of power on gas.

8.10.3.2 As the generation of power on alternate fuel was costlier than generation of power on gas, the beneficiaries had least preference for costlier power generated on alternate fuel as per the least cost merit order, according to which the beneficiaries had the option of choosing the cheaper power and gave first preference to hydro stations and the last preference to liquid fuel generation (naphtha, high speed diesel, etc.). Non acceptance of the costlier power by the beneficiaries resulted in operating the plant at a PLF lower than the machine availability/ declared capacity **(Annexure-24).** During the period from 1999-2000 to 2003-04, such loss of generation was 13586.85 MUs. Analysis of this loss showed that this trend was increasing in each gas plant with the total loss increasing from 1521.18 MUs in 1999-2000 to 5056.73 MUs in 2003-04.

8.10.3.3 The Management stated (August 2005) that low generation from gas stations was on account of low schedules given by the beneficiaries due to their demand / supply position. They added that cost of power from these stations was much lower than the rates at which power was available from other sources such as unscheduled interchange[♣] (UI) route and purchase through trading company.

8.10.3.4 The reply is not acceptable, as beneficiaries offered their schedule keeping in view the least cost merit order for power. This is apparent from the data for year 2003-04 given in **Annexure-25** which indicates that the beneficiaries preferred to place their schedule for generation capacity declared by plants on cheaper fuel i.e. gas and never placed schedule for whole of the capacity declared by the Company on alternate fuel. Further, the beneficiaries would not normally purchase costlier power through UI route and trading option by giving up their allocation in generation of power stations.

8.10.4 Recovery of fixed charges without attaining normative plant load factor

8.10.4.1 The tariff as fixed by CERC for sale of electricity comprised of annual fixed charges and variable charges. The fixed charges consist of interest on loan capital, depreciation, return on equity, operation and maintenance expenses and interest on working capital. The variable charges cover fuel cost.

8.10.4.2 In 2002-03, CERC introduced the Availability Based Tariff (ABT) system covering all the generating stations (except Faridabad and Kayamkulam). Under ABT system, the recovery of full fixed charges depended upon declaration of availability equal

[♣] ***Represented variation between actual generation/drawal and scheduled generation/drawal*** to 80 *per cent* or above by a generating station. While each generating station was required to declare its generating capacity to the Regional Load Dispatch Centre in advance, the beneficiary placed schedule on the generating station for purchase of power by applying the least cost merit order preference.

8.10.4.3 Analysis of performance of the gas stations **(Annexure-25),** where ABT was implemented, for the year 2003-04 revealed that all the gas-based stations (except Faridabad and Kayamkulam) recovered full fixed charges on the basis of their declared capacity, though actual generation ranged from 62.5-75 *per cent*. The actual PLF attained by these stations was lower than the normative PLF of 80 *per cent* mainly because the beneficiaries did not buy power generated on costlier fuel due to non-availability of gas.

8.10.4.4 Thus, the tariff fixation policy of CERC allowed the generating company to recover full fixed charges based on declared capacity, even though actual generated units were below the declared capacity. As a result, the beneficiaries had to bear an excessive charge of fixed cost to the tune of Rs.123.45 crore during the year 2003-04. This issue needs to be revisited by the GOI.

8.10.5 Non-recovery of fixed charges

8.10.5.1 Gandhar gas station could not achieve the qualifying requirements for recovery of fixed charges in full and consequently failed to recover fixed charges amounting to Rs.115.19 crore from the beneficiaries during 1999-2000 and 2000-01, mainly because of inadequate gas supply to operate the station up to the normative PLF and absence of facility in the design of the station to use alternate fuel.

8.10.5.2 In order to facilitate recovery of full fixed charges by the Gandhar plant, a special arrangement was allowed by CERC for considering the combined PLF of this plant with that of Kawas gas plant, which continued from July 2002 to the end of 2003-04. After cessation of this arrangement from the year 2004-05, the Gandhar plant again failed to recover fixed charges to the extent of Rs.42.38 crore during the year 2004-05 due to inadequate gas supply. Thus, Gandhar station could not recover fixed charges amounting to Rs.157.57 crore during the last six years ended 31 March 2005.

8.11 Expansion of existing plants

8.11.1 Despite underutilisation of the existing capacity due to inadequate gas supply, the Company planned (1997) to add a capacity of 2600 MW during the 9th Five Year Plan (1997-2002) by way of expansion of the existing capacity of Anta, Auraiya, Gandhar and Kawas gas-based power stations by 650 MW each. The proposed expansion was on the assumption that the additional capacity would be run on naphtha till additional supply of gas became available, though the prices of naphtha in April 1997 and the anticipated variable cost per unit of electricity generated on this fuel was 2.07 to 2.70 times the variable cost of energy on gas as shown in **Annexure-26.** Even then, the Company went ahead with the expansion of these plants and obtained techno-economic approval of the Central Electricity Authority.

8.11.2 Subsequently in 1998, the Company anticipated that the variable cost of generation with naphtha would be Rs.2.04 per unit, which was expected to increase to Rs.3.33 during the year 1999. The Project Sub-Committee of the Board of Directors recommended (October 1999) that no investment approval and contract for plant and equipment should be awarded before signing Power Purchase Agreement (PPA) with the customers. However, the Company continued to incur expenditure in connection with the additional capacity installation beyond October 1999 without signing PPAs with the beneficiaries. The Company incurred an expenditure of Rs.23.68 crore till August 2003 on the expansion programmes of the four projects that had been deferred.

8.11.3 The Management stated that the recommendations were not applicable to the advance expenditure to be incurred for facilitating faster implementation of the project for which the Board had delegated powers separately. The contention is not tenable as advance expenditure was also an integral part of the total investment/expenditure likely to be incurred on a project.

8.11.4 Further, in the revised capacity addition programme for 10^{th} (2002-07) and 11^{th} (2007-12) Five Year Plans, the Company did not consider expansion of Anta and Auraiya plants though a substantial expenditure of Rs.17.56 crore had been incurred for expansion of these plants, thus leaving no prospects of utilizing this expenditure till the end of 2011-12. The Management stated (August 2005) that expansion of Anta and Auraiya could be considered in future subject to availability of basic inputs and fuel and confirmation by the beneficiaries. The fact, however, remained that the Company did not contemplate the revival of the expansion of these plants even up to the end of 2012.

8.11.5 The Management stated (August 2005) that the Company planned to add additional capacity in line with the GOI plan for gas based power generation capacity to increase to 20 *per cent* of total installed capacity as against the current figure of about 10 *per cent*.

8.11.6 In view of non-availability of gas and the rising trend of cost of gas, the Company's plan to add another 4550 MW in the 10^{th} and 11^{th} Plans, on gas, may require re-look given the present scenario.

8.12 Renovation and Modernization of Plants

8.12.1 The Company framed a renovation and modernization policy (May 2002) for the gas-based power plants with a view to extend useful life of plant equipment/ systems. The policy provided that the renovation and modernization (R&M) of gas plants would begin on completion of 80,000 hours of operation to sustain the expected production/ generation level.

8.12.2 Status of completion of equivalent operating hours (EOH) as on 31 March 2004 by different units of all the gas power plants and expected date of their becoming due for renovation and modernization in the light of the guidelines are given in **Annexure-27.** It may be seen that units of Anta, Auraiya, Dadri and Kawas stations became due for R&M after completion of 80,000 EOH by November 2004. However, despite finalizing renovation and modernization policy in May 2002, the Company could not implement R&M schemes at these stations due to delay in initiating action for obtaining clearance from CERC (October 2005).

8.12.3 The Management stated (August 2005) that the Company prepared guidelines based on operating experience and manufacturer's recommendation and that as per GOI notification of January 1992 for depreciation of assets, the life of gas turbines was considered as 15 years. Accordingly, R&M of Anta and Auraiya plants became due from 2004 onwards. The reply is not acceptable as Anta and Auraiya plants had already completed more than 80,000 EOH by December 2000 and as such implementation of R&M at these stations had already been delayed as per the Company's own policy.

8.12.4 The Company needs to carry out the repair and maintenance of the gas-based power stations without any delay in accordance with its policy of May 2002.

8.13 Setting up of Kayamkulam project

8.13.1 Blocking of funds

8.13.1.1 Kerala State Electricity Board (KSEB) originally conceived a power project at Kayamkulam based on coal availability from Talcher coalfields. Subsequently, the Ministry of Power (MOP), assigned (June 1994) this project to the Company for implementation in the Central sector as resources with the State Government for this purpose were not sufficient.

8.13.1.2 The Company conceived the project with ultimate capacity of 2420 MW. On finding the estimated capital cost of two units (210 MW each) at Rs.1681.85 crore and cost of generation at 283.21 paise per unit, MOP desired (September 1994) to explore more economic modes of power generation. Accordingly, the cost of generation for a Combined Cycle Plant based on imported naphtha was assessed to be the lowest and a power project of 400 MW was approved (September 1996) by GOI at a cost of Rs.1310.58 crore and the plant was set up with a capacity of 359.56 MW at a cost of Rs.1125.31 crore.

8.13.1.3 Before switching over to naphtha based plant, the Company had acquired 1166 acres of land for the coal based plant for Rs.36.36 crore. However, because of change in the technology and scope of the project, the land actually utilized was 335 acres. Of the surplus 831 acres land, 20 acres were transferred to Power Grid Corporation of India Limited (PGCIL) in March 1999 for switchyard at a cost of Rs.42 lakh, payment for which had not been received so far (October 2005). Thus, an amount of Rs.25.29 crore, paid towards cost of the surplus land of 811 acres, remained blocked (December 2005).

8.13.1.4 Further, the objective of changing the technology and scope of the project could not be realized as the cost per MW of installation could not be reduced significantly as it came down from Rs.4 crore per MW for a coal station to Rs.3.13 crore for a naphtha based station. Besides, the cost of generation on naphtha remained higher in the range of Rs.3.34 to Rs.4.08 during 1999-2000 to 2003-04 as compared to the cost of generation of Rs.2.83 per unit of thermal power stations. This uneconomic cost of power generated by the station deprived the State of full benefits of the power plant, besides bearing the unfruitful fixed charges.

8.13.1.5 The Management stated (August 2005) that the acquired land would be utilized as stage-II (1950 MW) of the project was to be developed on the surplus land. However, no tie up for gas-linkage for this project had been firmed up so far.

8.14 Conclusions

8.14.1 While 14.17 MCMD of gas was required to utilize the generating capacity of 3657.64 MW created at six gas-based power projects, the actual commitment from Gas Authority of India Limited was for 12.75 MCMD gas only, which was sufficient to operate the plants at 66 *per cent* of the capacity. Further, GAIL did not supply gas even up to the committed level. As a result, the Company was forced to depend on alternate fuel of naphtha/ HSD, which in turn led to a cascading effect on the cost of generation. The beneficiaries were reluctant to purchase costlier power generated on naphtha resulting in impairment of the efficient working of the plants. The GOI, which was primarily responsible for assignment of requisite gas for power stations, had obliviously failed in this regard.

8.14.2 In the agreement entered into with GAIL, in the event of short lifting of gas, the Company was required to pay for the minimum guaranteed quantity of gas. While there was no corresponding clause in case of short supply of gas by GAIL. The Company's financial interests were not, thus, equally guarded.

8.14.3 The tariff fixation policy of CERC allowed the generating company to recover full fixed charges based on declared capacity, even though actual generated units were below the declared capacity. As a result, the beneficiaries had to bear an excessive charge of fixed cost to the tune of Rs.123.45 crore during 2003-04.

8.14.4 Despite underutilisation of the existing capacity due to inadequate gas supply, the Company planned to expand the capacity of four gas-based plants in the 9th Five Year Plan. As beneficiaries declined to take costlier power generated on naphtha, the Company deferred the expansion after incurring an expenditure of Rs.23.68 crore, out of which the sum of Rs.17.56 crore was not likely to be utilized till the end of 2011-12.

The review was issued to the Ministry of Power and the Ministry of Petroleum and Natural Gas in December 2005; their replies were awaited (February 2006).

CHAPTER: IX

North Eastern Electric Power Corporation Limited

Gas Based Power Stations

Highlights

In case of Agartala Gas Turbine Power Project (AGTP), gas supply agreements with GAIL/ONGC did not permit waiver of MGO payment due to lower generation arising out of grid failure and no/low grid demand over which the Corporation could not exercise any control. As AGTP failed to draw/consume even the MGO quantity of gas due to evacuation constraints and low drawal of power by the beneficiaries, the project had to incur infructuous expenditure of Rs.3.16 crore.

(*Para 9.6.1.1*)

The impact of steadily falling calorific value of gas over the years and actual heat rate higher than the norm was not considered while working out the gas requirement and the Management failed to take timely initiative to enhance the quantity of gas to be supplied keeping in view the availability and future requirement.

(*Para 9.6.1.2*)

During post-ABT period (November 2003 to March 2005), Assam Gas Based Power Project (AGBPP) could not achieve the target availability because of lack of tie-up for supply of requisite gas. As a result, there was under-recovery of fixed charges of Rs.9.94 crore.

***(Para 9.6.1.4*)**

In none of the years (2000-01 to 2004-05) AGBPP could achieve its Design Energy. AGTP also could not achieve the Design Energy during 2000-01.

(*Para 9.6.2.1*)

Main causes for lower generation in AGBPP were transformation and transmission limitations in the NER, lower generation schedule given by NERLDC and priority in maximization of hydel generation during monsoon period.

(*Para 9.6.3.1*)

Non-availability of associated transmission line and weak state-owned transmission system, import of power by ASEB from Eastern Region due to high cost of AGBPP power and commissioning of gas based power stations by Government of Tripura during 2002-03 also led to under-utilisation of capacity of AGBPP and AGTP.

(*Paras 9.6.3.2 to 9.6.3.3*)

Both AGTP and AGBPP failed to restrict the auxiliary consumption within the norm fixed by CERC during 2000-01 to 2004-05. Loss due to excess auxiliary consumption during the said period worked out to and Rs.3.43 crore for AGTP and Rs.10.24 crore for AGBPP.

***(Para 9.6.4*)**

Gross Station Heat Rate (GSHR) for both the plants was much higher than the norm fixed by CERC leading to excess gas consumption.

***(Para 9.6.5*)**

Despite the gas based stations not achieving the normative auxiliary consumption as well as GSHR, the Corporation did not conduct any Energy Audit since commissioning of the plants in July 1998.

(*Para 9.6.6*)

In the absence of determination of the sanctioned strength for O&M Projects, the deployment of manpower at both the plants exceeded the Man/MW ratio of 0.61 set by National Power Plan (1985-2000). Man/MW ratio in both the plants was consistently higher varying from 1.20 to 1.33 in case of AGBPP and from 1.69 to 2.0 in case of AGTP.

***(Para 9.6.7*)**

Expenditure incurred in operation and maintenance of both the gas based generating stations was substantially higher than the normative O&M expenses recoverable as a component of Annual Fixed Charge in the tariff.

(*Para 9.6.8*)

Though both the gas based power plants were commissioned seven years back, the Corporation had not developed any documented maintenance policy incorporating its own inspection schedules and associated procedures as well as defining responsibility of various functions e.g. Operations, Maintenance, Stores etc.

(*Para 9.7.1*)

Recommended periodicity of preventive maintenance of the machines was not adhered to both in AGBPP and in AGTP.

(*Para 9.7.2*)

Non commissioning the fire protection system and DM plant resulted in non-compliance of environmental requirements as stipulated by various statutory authorities

(*Para 9.8*)

Gist of Recommendations

- Terms of the agreement entered into with GAIL and OIL for supply of gas to AGTP and AGBPP need to be amended to incorporate a clause allowing waiver of MGO payment due to lower generation arising out of grid failure and no/low grid demand, factors over which the Corporation had no control. Accordingly, the issue may be taken up appropriately through the MOP.
- The Management needs to explore the possibility of including a clause in the agreement with AGTP as it was done in the recent agreement with AGBPP (January 2005) to provide for supply of additional quantity of gas (at same price and other terms and conditions) required by the Corporation for fall in calorific value of gas supplied.
- One of the two Double Circuit (D/C) 132 KV lines proposed for construction by NEEPCO from the Tripura Gas Based Power Project (280 MW), Monarchak, to Agartala Sub-Station may be considered for looping in and looping out at AGTP which will provide additional facility for evacuation of power from AGTP and avoid hindrance in the existing system.
- Corporation should create its own internal Energy Audit Group consisting of adequate skilled manpower for conducting regular energy audit at the earliest.
- The Corporation should immediately assess the requirement of manpower in different categories for its O & M projects and get the same formally approved.
- The Corporation should also take effective steps to bring down the Man/MW ratio in both the gas based power plants to conform with the manpower norm set in the National Power Plan (1985-2000).
- Both the power stations may initiate steps for limiting the O&M expenses within the level set by CERC to avoid under-recovery on this count.
- The Corporation should strictly follow the prudent maintenance practice recommended by OEMs. The Corporation may manualise the 'Maintenance Policy' of each plant defining responsibilities of various functional wings e.g. Operations, Maintenance, Stores etc to ensure accountability and to further improve productivity, plant availability and safety.
- Compliance with environmental requirements as stipulated by various statutory authorities should be given high priority.
- To avoid mismatch between the construction of generation system and evacuation and distribution, it is imperative to share information at the planning, implementation and operational stages and on monitoring and progress of

generation as well as matching transmission projects by the generation and transmission utilities and beneficiaries with active participation/intervention of the Ministry concerned.

9.1 Introduction

North Eastern Electric Power Corporation Ltd., (NEEPCO) was incorporated in April 1976 as a wholly owned Government of India Enterprise under the Ministry of Power with mandate to plan, promote, investigate, survey, design, construct, generate, operate and maintain hydro and thermal power stations in the North Eastern Region (NER). The installed capacity of the Corporation was 1130 MW in March 2005,which was equivalent to 48.87 *per cent* of the total installed capacity in NER (2312.06 MW).

Though large oil and gas fields are located in Upper Assam Valley, due to lack of consumers, the demand for gas had not picked up in the NER even during mid-eighties. This led to flaring of around 52 *per cent* (2.94 million M^3) of gas produced (1984-85) in Assam. For utilisation of the associated gas, which was being flared up, setting up of gas turbine power station at Kathalguri in Assam, by NEEPCO, gestation period for which was quite low, was considered necessary by the Government of India. It was also envisaged (April 1986) that as the NER was expected to have a comfortable power supply position, it would be necessary to evacuate power available from this power station to the Eastern Region (ER) to meet the shortages in that region. Some of the basic considerations for selection of site for the proposed Gas Based Combined Cycle Power Station at Kathalguri, Assam were the proximity of the gas gathering stations and existence of basic infrastructure such as railways and roads, and proper approach to the site. It was estimated that about one million standard cubic metre gas per day (with an average calorific value of 10000 K.cal/M^3) would be available from Oil India Ltd. (OIL) at a pressure of about 7.7 Kg/CM2. To transmit the power generated, Kathalguri Power Station would be connected by a double circuit (D/C) 220KV transmission line with 400KV parameters to the proposed Misa Sub Station of NEEPCO. One circuit of the said D/C transmission line would be bussed at Mariani Sub-station of ASEB. For this arrangement it was proposed to have a 220KV Switchyard with a duplicate bus system at Kathalguri. The Combined Cycle Assam Gas Based Power Project (AGBPP) with 3x2x33.5 MW Gas turbines and 3x30 MW Steam Turbines (totalling 291 MW) was approved by the Government of India (GOI) in November 1987 at an estimated cost of Rs.203.17 crore. The Project, scheduled to be commissioned by March 1992, was commissioned in July 1998 after a delay of 76 months at a cost of Rs.1513.64 crore.

Subsequently, GOI approved (December 1994) the Open Cycle Agartala Gas Turbine Power Project (AGTP) of NEEPCO with an installed capacity of 84MW (4x21MW) at an estimated cost of Rs.294.05 crore to be commissioned during February to May 1996. As per the Detailed Project Report (DPR) (December 1992) of AGTP, it was envisaged, *inter-alia*, that the main source of gas would be Baramura Gas fields and approximately 20Km pipeline would have to be laid by Oil and Natural Gas Corporation (ONGC)/ Gas Authority of India Limited (GAIL). Gas linkage of 0.75 MCMD for the project was already available at concessional rate. The proposed 84 MW Plant would be commissioned in time to overcome the chronic shortage of power in Tripura, Mizoram and South of Assam. The project scheduled to be commissioned by May 1996, was commissioned in July 1998 after a delay of 24 months at a cost of Rs.322.55 crore.

Beneficiaries of the above two gas based stations were the seven states of the NER namely Assam, Meghalaya, Tripura, Arunachal Pradesh, Nagaland, Manipur and Mizoram.

9.2 Scope of Audit

The Performance Audit reviewed the Operation and Maintenance (O & M) of the AGBPP and AGTP, the two gas based Power Stations of NEEPCO for the last five years from 2000-01 to 2004-05.

9.3 Audit Objective

The audit was conducted to assess whether:

- adequate and assured availability of gas at a reasonable price was ensured for the plant;
- the gas based Power Plants could be operated and maintained efficiently;
- adequate and timely co-ordination existed between the Corporation and multilateral Government agencies for generation and evacuation of power;
- adequate and timely steps were initiated by the Corporation to overcome/minimize the operational inefficiencies/constraints;
- the beneficiaries/constituents of NER could get adequate and reliable power at a reasonable tariff;
- the Corporation complied with the stipulations prescribed by the Ministry of Environment and Forest (MOE&F), GOI and State/Central Pollution Control Boards for thermal projects and
- the gas based power plants served the purpose that was envisaged in the DPR.

9.4 Audit Methodology

Based on initial study, a discussion paper containing preliminary observations of audit was issued to the Corporation in August 2005. Further detailed study at field level was conducted during August - September 2005 when major findings were also deliberated with the Head of the Projects as well as the Management at corporate level. Finally, an Exit Conference was held on 28 September 2005.

9.5 Acknowledgement

For conducting this performance audit, the audit team visited both the gas based power plants (AGBPP and AGTP) as well as the Corporate Office. Audit acknowledges the co-operation and assistance extended by all levels of Management at various stages for timely completion of the Performance Audit.

9.6 Audit findings:

9.6.1 Gas supply agreement

The Corporation entered into agreements with OIL and ONGC/GAIL for supply of gas to AGBPP and AGTP in March 1994 and September 1995 respectively. Audit observed that certain unfavourable terms in the gas supply agreements entered into by the Corporation had an adverse impact on the performance of the two gas based plants as discussed below:

9.6.1.1 Payment on account of Minimum Guaranteed Off take (MGO) and failure to amend terms of the contract

In case of AGTP, gas supply agreements with GAIL/ONGC did not permit waiver of MGO payment due to lower generation arising out of grid failure and no/low grid demand**,** factors over which the Corporation could not exercise any control. As AGTP failed to draw the MGO quantity of gas due to evacuation constraints and low drawal of power by the beneficiary states (refer to para 9.6.3) the project had to incur avoidable expenditure of Rs.3.16 crore (non- consumed MGO quantity being 21770983 SCM) during 2000-01 to 2004-2005. This could have been avoided, if the agreement with GAIL/ONGC had been drawn in line with the agreement of AGBPP with OIL (March 1994) which allowed waiver of MGO clause in the event of non evacuation of gas due to grid restrictions. It was also known to the Management that it was unable to generate power as per the design capacity of AGTP due to low grid demand/power evacuation problem since commissioning of the units, but there was no effort till October 2003 to amend the contract by reducing the contracted quantity of gas / modifying other terms of contract. It was further observed in Audit that while the MOU (March 1994) for supply of gas to AGBPP between OIL and the Corporation provided for such waiver through *force majeure* clause, as per the latest agreement (January 2005) entered into with OIL such provision was not incorporated which could prove to be to the detriment of the Corporation in future. The Management contended (September 2005) that the agreement for supply of gas was more or less a standard one and the gas supplier remained reluctant to deviate from the standard terms. However, the Management on its part made no effort to take up the issue through the Ministry of Power (MOP) explaining the constraints over which it had no control and seek remedy.

9.6.1.2 Fall in calorific value of gas

The average calorific value of gas supplied to AGBPP by OIL fell steadily from 8612 Kcal/SCM to 8307 Kcal/SCM between 1996-97 to 2004-05. While the agreement had a provision for adjustment of price i.e. premium to be paid to the supplier for more calorific value and rebate on gas price for lower calorific value of gas actually supplied, the gas supply agreements with OIL for AGBPP and with GAIL/ONGC for AGTP and subsequent amendments made thereto did not provide for supply of additional quantity of gas (at same price and other terms and conditions) required by the Corporation for fall in calorific value of gas supplied. In case of supply of gas with calorific value at the lower end of the scale, the requirement of gas increased**,** a factor that was to have an adverse impact on generation.

9.6.1.3 Lack of control over flow of gas

Running of the units of AGTP at partial load was due to lack of control over flow of gas as the Flare stack was installed at ONGC/GAIL end who operated the gas valve once a day as per agreement.

9.6.1.4 Failure to arrange for adequate quantities of gas supply

In AGBPP, prior to the introduction of Availability Based Tariff[♣] (ABT) regime in November 2003, gas tie up was restricted to 1.00 MMSCMD[♦] to meet the requirement of gas for operation at design Plant Load Factor (PLF) of 68.49 *per cent*. This was enhanced (January 2005) to 1.4 MMSCMD of gas to attain post-ABT normative availability of 80 *per cent* based on the design heat rate of 2167 Kcal/Kwh and original average net calorific value of 8500 Kcal/ SCM[♥]. It was observed in audit that the quantity of gas supply arranged for under the agreement was deficient *ab initio* as it did not reckon the following factors:

(i) With the implementation of the ABT regime, the gas quantity required for maintaining normative availability of 80 *per cent* was 1.52 MMSCMD[♠]. Further to meet the MOU target of 92 *per cent* availability, 1.75 MMSCMD of gas was required.

(ii) The proposal did not reckon that to run one combined cycle (CC) module at part load or even one Gas Turbine (GT) on open cycle commensurate with the varying schedule given by NERLDC[■], the heat rate would always be higher than the designed heat rate. The plant had also been recording a higher heat rate consistently from 2000-01 to 2004-05 (Refer **Annexure-29**). A higher heat rate implied greater consumption of gas to generate each unit of power at the same calorific value.

(iii) The impact of steadily falling calorific value of gas over the years (from 8614 Kcal/ SCM in 1997-98 to 8122 Kcal/ SCM in December 2004) was not considered while working out the gas requirement.

Further, the Corporation being a proponent of implementation of ABT in NER since July 2000 should have been able to anticipate the need for enhanced gas commitment to maintain availability at 80 *per cent*. Therefore, it should have taken timely action to enter into a revised agreement with OIL to meet the enhanced requirement but the agreement with OIL was revised only in January 2005.

Due to under assessment of requirement of gas and lack of timely tie-up for supply of gas in requisite quantities, AGBPP could not achieve the target availability and it resulted in under-recovery of fixed charges amounting to Rs.9.94 crore during the post ABT period[♣]. An early initiative to enhance the required quantity of gas based on realistic assessment could have avoided generation loss thereby improving the Corporation's revenue as well as reducing the cost of generation considerably.

[♣] ***Availability Based Tariff (ABT) system , the tariff as fixed by CERC comprised annual fixed charges and variable charges. Full recovery of fixed charges depended upon the declaration of 80 per cent or above plant availability. While each plant was required to declare its generating capacity for the Regional Load Dispatch Center in advance, the beneficiary placed schedule on the plant for purchase of power.***

[♦] ***Million metric standard cubic meter per day***

[♥] ***Standard Cubic Meter***

[♠] ***Calculated on the basis of expected average net calorific value of 8250 Kcal/SCM and the normative heat rate of 2250 Kcal/Kwh***

[■] ***North Eastern Regional Load Dispatch Centre***

[♣] ***November 2003 to March 2005***

The Management, *inter alia,* contended (December 2005) that prediction of trend of calorific value was not possible as gas supplier maintained confidentiality about its source and gas was a mining product. However, the fact of declining calorific value was evident from the monthly gas bills of the Corporation and records revealed that this fact was also known to the Management but it did not take any remedial measures.

The Management further stated that they had taken necessary steps to enhance contracted quantity to 1.4 MMSCMD in April 2003, well in advance of implementation of ABT. However, it was observed that the request for 1.65 MMSCMD gas was made only in December 2004 after 14 months of implementation of ABT and the Ministry of Petroleum & Natural Gas (MOP & NG) intimated (June 2005) the inability of OIL to supply the same.

Recommendations

- Terms of the agreement entered into with GAIL and OIL for supply of gas to AGTP and AGBPP need to be amended to incorporate a clause allowing waiver of MGO payment due to lower generation arising out of grid failure and no/low grid demand over which the Corporation had no control. Accordingly, the issue may be taken up appropriately through the MOP.
- The Management needs to explore the possibility of including a clause in the agreement with AGTP as it was done in the recent agreement with AGBPP (January 2005) to provide for supply of additional quantity of gas (at same price and other terms and conditions) required by the Corporation for fall in calorific value of gas supplied.
- Terms of the gas supply agreement need to be revised if necessary through the concerned Ministry, to make GAIL/ONGC contractually liable to operate the gas valve to suit the varying schedule of generation enforced by grid authorities to meet grid demand and maintain grid discipline. The Possibility of installation of remote control device to control gas flow during odd hours at GAIL/ONGC end also needs to be explored.
- The MOP & NG needs to explore all possible means to supply the additional requirement of gas to AGBPP in the interest of the project and the NER beneficiaries as the project was taken up (1987) to utilise the associated gas flared at that time in upper Assam valley.

9.6.2 Operational Performance

The Installed Capacity, Design Energy, MOU target of generation, Plant Load Factor (PLF) and other performance indicators in respect of AGBPP and AGTP during 2000-01 to 2004-05 given at **Annexure-28** and **29** revealed the following:

9.6.2.1 Non-achievement of Design Energy

AGBPP could not achieve its design energy between 2000 and 2005. The project could not even achieve the MOU generation target agreed with the MOP, which was much lower than the design energy till 2002-03. AGTP also could not achieve the design energy during 2000-01. The Management in its reply (December 2005) stated that it would not be correct to relate actual generation with design energy for arriving at a decision on performance. However, as the installation of a power plant entails huge public investment, the plants are expected to achieve the design energy level as stipulated in the DPR. Audit observed that this could not be done because of various controllable and non-controllable factors which have been discussed in para 9.6.3.

9.6.2.2 Lower Declared Capacity

During monsoon in the NER which was generally from May to October every year, hydel generation was utilised to the fullest extent and planned maintenance was carried out in thermal units. During the non-monsoon period (November to April) maximum availability from thermal units of AGBPP/AGTP was required to ensure optimum benefit for NER. In fact, maximum output from NER thermal units during non-monsoon period would have ensured minimum Unschedule Interchange (UI)[♣] import from Eastern Region (ER) thereby reducing financial burden on NER States. However, since commencement of ABT in NER, average Declared Capacity (DC) of AGBPP during non-monsoon period (November 2003 to April 2004) was around 225 MW only (against installed capacity of 291 MW). During non-monsoon period of 2004-05, although DC marginally improved (226 MW to 231 MW), it was still far less than the installed capacity. Less DC, due to lack of appropriate gas tie-up at times resulted in UI/contracted import from ER, putting additional burden on NER States.

9.6.3 It was observed in audit that a number of factors resulted in low generation of power, some of which like lower industrialisation and consequential low demand and lower generation schedules given by beneficiaries were not in the control of the Corporation. However, the following factors that contributed to lower generation could have been controlled, if not completely avoided, by taking appropriate action at the level of the Corporation or the other agencies working in the power sector through proper co-ordination.

9.6.3.1 Transformation and transmission constraints

There were transformation and transmission limitations in the NER power evacuation system as connectivity among the major load centres within NER system was far from adequate. There were constraints in state-owned 132 KV transmission system leading to overloading of lines and Inter-Connecting Transformer (ICTs). Evacuation constraints also existed in the inter-regional transfer of power beyond NER.

Further, though simultaneous setting up of AGBPP and inter- regional transmission line from Kathalguri to Malda was approved by the GOI in November 1987, Kathalguri to Malda transmission line was commissioned only in October 1999. However, power could not be exported to Eastern Region prior to November 2000 due to delayed approval (August 2000) from Northern Eastern Regional Electricity Board. Though the plant at Agartala was commissioned in July 1998, the associated transmission system was commissioned only in November 2000. Prior to that, the only transmission line available for evacuation of power from AGTP was a 132KV D/C Line (Line I and II) of the Power Department, Government of Tripura which was more than 30 years old at the time of commissioning of the units (1998-99). This restricted flow of power to 20-25MW only. With the commissioning of Line-III by Power Grid Corporation of India Ltd (PGCIL) in November 2000 the scenario improved. However, even after that evacuation was

♣ UI for generating station shall be equal to its actual generation minus its scheduled generation. UI for beneficiary shall be equal to its total actual drawal minus its total scheduled drawal

restricted upto 50 to 60 MW for a considerable period of time because of frequent outage of line due to tower collapses, conductor snapping and pilferage of tower members. Only from September 2004, PGCIL allowed AGTP to evacuate upto 70 MW through Line- III.

Although the Inter-Disciplinary Group of Ministry of Power in their report (March 2001) stressed upon quick establishment of transmission links on priority basis for inter-regional flow to ensure that all under-utilised capacities in any region were utilised to meet power demand in other regions, there was absence of time bound concerted efforts by the Central and State level organisations to overcome the evacuation constraints and facilitate export of surplus power in NER. Early action by the Corporation, PGCIL and Assam State Electricity Board (ASEB) to make the 220 KV Samaguri-Balipara line operational, which was done as late as in May 2004, although AGBPP and AGTP were operational from July 1998, would have helped in improving the system redundancy, provided stronger connectivity with ER system and allowed additional export of power.

9.6.3.2 High cost of AGBPP power

There was net import of power in NER from ER during 1999-00 to 2002-03 (ranging from 292.978 MU to 752.898 MU in a year) when there was surplus capacity available in NER. Net export from NER to ER commenced only in 2003-04 (191.20 MU) onwards with the implementation of ABT in NER. Import of power to the extent of 752.898 MU from NTPC units of ER was resorted to by ASEB for meeting its power requirement, as NTPC power was cheaper compared to that of AGBPP and transmission charges for NTPC power were nil as against 35 paisa per unit for AGBPP power. Non-drawal of major portion of allocated power by the beneficiary states was due to high cost of AGBPP power compared to the cost of power of other NEEPCO projects**.** ASEB resorted to merit order scheduling preferring drawal of cheaper power from the available sources. Accordingly, the tariff being the highest, AGBPP power got the lowest priority in the order of receiving schedule from ASEB. High cost of AGBPP power was primarily because of abnormally high capital cost, which was Rs.5.20 crore per MW compared to Rs.2.70 crore to Rs.3.63 crore per MW in respect of gas / Naphtha based combined cycle power projects cleared by CEA around 2000-01. High capital cost of the project was stated (December 2005) to be due to adverse law and order situation prevailing in the region, geographical remoteness of the project etc.

9.6.3.3 Commissioning of new generating units by Government of Tripura

Baramura Gas Based Thermal Power Project (21MW) was sanctioned by the Government of India in October 2000 under Northern Eastern Council funding when there was already substantial under-utilization of the capacity of AGTP due to lack of demand and evacuation facilities. The project was scheduled to be completed in two years. The power station was commissioned in November 2002. The available power was to be shared among the states of Assam, Tripura and Mizoram in the ratio of 2:1:1. Further, one 21 MW unit was commissioned in Rokhia Gas Based Power Plant of Tripura Government in July 2002. Consequent to commissioning of these units, the drawal of power by the Government of Tripura from Central sector generating units fell drastically from 344.29 MU (2002-03) to 146.12 MU (2003-04). This indicated poor planning in development of generating capacity by the authorities concerned. The Corporation had also not taken up the issue appropriately with the concerned authorities.

Recommendations

- One of the two Double Circuit (D/C) 132 KV line proposed for construction by NEEPCO from the proposed Tripura Gas Based Power Project (280 MW), Monarchak, to Agartala Sub-Station may be considered for looping in and looping out at AGTP which will provide additional facility for evacuation of power from AGTP and avoid hindrance in the existing system.
- The Corporation should vigorously pursue to ensure that PGCIL takes adequate steps to remove evacuation constraints and take up with NER states (through NEREB/NEC) for strengthening their transmission network.
- The Corporation along with beneficiaries of NER should vigorously pursue with CERC/MOP so that transmission tariff is brought down to the level of other regions to make export of surplus NER power commercially viable.
- To avoid mismatch between the construction of generation system and evacuation and distribution as happened in case of AGBPP, AGTP and RHEP[♣], it was imperative to share the information on monitoring and progress of generation as well as matching transmission projects by both the generation and transmission utilities with active participation/intervention of the Ministry concerned in the appraisal process. Further, closer co-ordination and interaction among concerned authorities like MOP, MOP&NG, CEA, CPSUs (NEEPCO, PGCIL, NTPC[♦], GAIL[1], OIL, ONGC) North Eastern Regional Electricity Board (NEREB), State Governments/State Electricity Boards etc. was required with constant follow up at the planning, implementation and operational stages to ensure optimum operational efficiency of power projects.

9.6.4 Auxiliary Consumption

Both AGTP and AGBPP failed to restrict the auxiliary consumption[♥] within the norm[•] of one and three *per cent* respectively during 2000-01 to 2004-05. Loss due to excess auxiliary consumption during the said period worked out to Rs.10.24 crore for AGBPP and Rs.3.43 crore for AGTP. Reasons for such excess auxiliary consumption were not on record. In reply (December 2005) the Management stated that excess auxiliary consumption was due to operation of the units at partial loads/ Full Speed No Load (FSNL) at times because of restriction in demand from the beneficiaries. However, the Corporation did not explain the link between partial load/FSNL and higher auxiliary consumption. No analysis in this regard was also made by the Corporation.

♣ Ranganadi Hydro-Electric Power Project owned by NEEPCO

♦ National Thermal Power Corporation

1 GAIL (India) Limited

♥ in relation to any period, means the ratio, expressed as a percentage, of energy in Kwh generated at Generator terminals minus energy in Kwh delivered at the Generation Station switchyard to gross energy in Kwh generated at the Generator terminals.

• Fixed by CERC

9.6.5 Gross Station Heat Rate

Gross station Heat Rate ‣(GSHR) for both the plants was much higher (ranged between 236 to 1036 Kcal/Kwh) than the norm* fixed by CERC and resulted in excess consumption of heat in AGBPP (4963021 million Kcal) and AGTP (1163762 million Kcal) during the period covered under audit implying excess gas consumption. In case of AGBPP, the higher GSHR was stated (September 2005) to be due to part load and open cycle operation of the units while in case of AGTP, higher GSHR was because of the part load operation of the machines and running of the machines at FSNL conditions under compelling circumstances in pre-ABT period when the beneficiaries did not draw their allocated shares for various reasons. The Management contended (December 2005) that the situation improved with implementation of ABT with effect from November 2003. However, even with the introduction of ABT, the heat rate was still higher (ranged between 442 to 556 Kcal/Kwh) than the norms.

9.6.6 Energy Audit

Despite the gas-based stations not achieving the normative auxiliary consumption as well as GSHR, the Corporation did not conduct any energy audit since commissioning of the plants (July 1998). In fact, comprehensive energy audit from time to time to identify potential areas of savings and to evolve and implement appropriate action could lead to significant savings in the cost of generation. Accordingly, the Inter-Disciplinary Group (IDG) (March 2001) of the Ministry of Power, advised the power stations to create internal Energy Audit Group and also expose their working from time to time to outside experts, to critically analyse and evaluate various actions. However, the Corporation neither created Energy Audit Group nor conducted energy audit through outside agency/experts (December 2005).

9.6.7 Man/MW Ratio

Although both the projects were commissioned in July 1998, the sanctioned manpower as fixed during the construction stage was not revised to correspond to the requirement of the power plants in Operation and Maintenance (O&M) stage. Even after seven years, the Corporation was unable to firm up manpower requirement at O & M stage power plants. In the absence of any sanctioned strength, the deployment of manpower at various projects exceeded the limits set by National Power Plan (1985-2000) wherein the norm for Man/MW ratio for gas based power plants was fixed at 0.61. The Man/MW ratio was consistently higher varying from 1.20 to 1.33 in case of AGBPP and from 1.69 to 2.0 in case of AGTP as shown in **Annexure-29**. In reply (December 2005) the Management stated that the reason for such high Man/MW ratio was smaller unit size of the machines which increased the number of machines compared to projects in other parts of the country. However, this contention was not tenable in view of the norm fixed by CERC for recovery of O & M expenditure for small gas based plants.

‣***The head produced in Kcal input required to generate one KWh of electric energy at Generator Terminals.***

* ***2250 Kcal/Kwh for AGBPP and 3580 Kcal/kwh for AGTP***

Recommendations

- The Corporation should immediately assess the requirement of manpower in different categories for its O & M projects and get the same formally approved.
- The Corporation should also take effective steps to bring down the Man/MW ratio in both the gas based power plants to conform to the manpower norm set in the National Power Plan (1985-2000).

9.6.8 Operation and Maintenance (O & M) Expenditure

Expenditure incurred on O&M of both the gas based generating stations was substantially higher than the normative O&M expenses recoverable as a component of Annual Fixed Charge in the tariff. Of the total O&M expenditure, Corporate Office expenses constituted 21 to 31 *per cent* in case of AGBPP and 17 to 35 *per cent* in case of AGTP. These alongwith increased repair and maintenance cost for AGBPP led to under-recovery of O & M expenses. In case of AGBPP, the inventory (spares) level in terms of months of consumption ranged from 50 months (2003-04) to an abnormally high level of 385 months (2001-02) leading to blocking up of working capital. While CEA had indicated inventory level for each power plant at around 2.5 *per cent* of capital cost, it ranged from 3.7 to 5.5 *per cent* in AGBPP.

Recommendations

- Both the power stations may initiate steps for limiting the O&M expenses within the level set by CERC to avoid under-recovery on this count.
- The Corporation should take steps to bring down inventory levels within 2.5 *per cent* of capital cost.

9.7 Maintenance of Gas based power plants

9.7.1 Maintenance Policy

The inspection routines for maintenance of gas turbines of different make were laid down by the Original Equipment Manufacturers (OEMs) in their maintenance manuals which emphasised the importance of developing a schedule of inspection intervals and maintenance procedures based on the utilization of the equipment and the experience accumulated during its operation. The CEA also highlighted that maintenance management function was as important as generation and stressed upon the power plants the necessity of having a written down Maintenance Policy. Though both the gas based power plants were commissioned seven years back, the Corporation had not developed any documented maintenance policy incorporating its own inspection schedules and associated procedures as well as defining the responsibility of various functions e.g. Operations, Maintenance, Stores etc.

9.7.2 Non-adherence to scheduled inspections

9.7.2.1 As per recommendations of the OEM the scheduled inspections were required to be carried out for AGTP machines for first Combustion Inspection after 8000 hours, Hot Parts Inspection after 24000 hours, second Combustion cum Baroscopic Inspection after 36000 hours and Major Inspection after 48000 hours. In most of the cases, the scheduled maintenance could not be conducted as per the recommended time schedule and were actually conducted after 8388 to 10179 hour, 24192 to 29300 hours, 38148 to 40422 hours and 54233 to 54240 hours respectively. As such, the units at AGTP had to be operated over a considerable period of time on 'risk hours'. This increased the probability of malfunctioning and under-performance of the machines. The machines were also subjected to faster wear and tear due to excess use without proper maintenance.

9.7.2.2 Maintenance of the Units in AGBPP

As per recommendations of the OEM, the first and second Hot Parts Inspection (HPI) of the gas turbines of Units I to IV of AGBPP were required to be carried out after the machines completed 9000 and 28000 running hours respectively. Against the recommended HPI to be carried out after 9000 hours, the first such inspection in respect of all the four units was delayed by 3347 to 7529 hours. Further, major inspection for these machines was carried out during non-monsoon period when gas turbines were expected to be utilised to the fullest extent to meet the power requirement of the NER/other regions.

Similarly the Combustion Inspection of the gas turbines in Units V and VI were to be carried out after 8000 fired hours as per the manufacture's recommendation. However, it was carried out after 21465 and 14879 hours respectively. Hence, in AGBPP too the units operated on 'risk hours' for a considerable period of time.

9.7.3 Inspection of 'Generators' and 'Exciters'

The 'Generators' and 'Exciters' of Mitsubishi make Gas Turbines were to be inspected after one year from initial start up or when operation exceeded 300 starts. Similarly, the 'Generators' and 'Exciters' of BHEL make Gas Turbines were to be inspected after one year of commissioning or on completion of 8000 running hours. The said inspections had, however, not been carried out, with attendant risk of high restoration cost and loss of generation in case of any forced breakdown of the machines.

Thus, recommended periodicity of preventive maintenance of the machines was not adhered to strictly in conformity with the respective OEM's guidelines. There was no justification for non-adherence to the prudent maintenance practice recommended by the manufacturers as there was no pressing demand for continuous operation of plants in the NER in view of the low demand.

The Management stated (September 2005) that delays in maintenance of the machines beyond OEM's recommended periodicity was due to high lead-time in procurement of imported spares, requirement of unforeseen spares and necessity for approval of NERLDC/NEREB for shutdown programme etc. The reply is not tenable as forwarding of indents for planned outage jobs to the material management department well in advance (say 24 months as recommended by CEA), commencement of outage planning 12-18 months in advance (as also recommended by CEA) could have avoided delays in carrying out recommended maintenance inspections.

Recommendations

- The Corporation should strictly follow the prudent maintenance practice recommended by OEMs.
- The Corporation may consider manualising the 'Maintenance Policy' of each plant defining responsibilities of various functional wings e.g. Operations,

Maintenance, Stores etc to ensure accountability and to further improve productivity, plant availability and safety.

9.8 Ecology and Environment

Non-compliance of statutory stipulations

The Ministry of Environment and Forest (MOE&F) accorded provisional clearance for AGTP in January 1992 and Tripura State Pollution Control Board (TSPCB) issued (December 1991) No Objection Certificate (NOC) to the project, subject to fulfilment of some stipulations which included, *inter-alia*, installation of Fire Protection System (FPS) and commissioning of DM water plant for controlling NOX emission level. However, even after seven years of commissioning of the project the FPS for the plant and DM plant could not be commissioned due to selection of non-performing vendors. Besides, the project was yet (August 2005) to comply with the requirements in regard to the off-site Emergency Plan called for (1992) by the MOE&F. The issue had, however, been taken up with the State Government.

Recommendations

Compliance with environmental requirements as stipulated by various statutory authorities should be given high priority.

9.9 Conclusion

Although the machine availability of both the power stations in the pre-ABT period was enough to meet the power requirements of NER, comparatively high cost of generation alongwith transmission and transformation constraints in the region limited the generation of power from these stations and its drawal by the beneficiary states. In the post-ABT period, AGBPP was unable to generate upto its installed capacity, as demanded by the beneficiaries, due to lack of adequate gas tie-up with Oil India Ltd which, in turn, increased cost of power drawn by them from AGBPP. Though at the time of conceptualisation and approval of the projects, the need for parallel development of evacuation infrastructure was planned, the same was not implemented simultaneously resulting in bottlenecks. Further, the Management failed to time its maintenance activities in the monsoon period so as to generate maximum power during the non-monsoon period to optimise its operations. There was an absence of a well planned and time bound effort by all the multilateral agencies involved in the sector for removal/minimisation of constraints in generation and evacuation of power in the NER. Such concerted efforts will also minimise wastage of scarce and exhaustible natural gas and under utilisation of gas based power plants in the NER constructed at considerable cost.

The review was issued to the Ministry in December 2005; its reply was awaited.