CHAPTER III

3. REVIEW RELATING TO STATUTORY CORPORATION

3.1 GENERATION OF THERMAL POWER AND POWER PURCHASE AGREEMENTS BY KERALA STATE ELECTRICITY BOARD

Highlights

Consequent on amendment to the Electricity (Supply) Act, 1948, by the Government of India, allowing private participation in power sector, the Board entered into power purchase agreements (PPAs) with independent power producers (IPPs) for purchase of thermal power. Board also created thermal generating capacity by implementing the Brahmapuram Diesel Power Project (BDPP) and Kozhikode Diesel Power Project (KDPP) during 1997-98 and 1999-2000 respectively. As at the end of 2002-03, the total installed capacity of the Board was 2598.68 mega watt (MW) comprising 1827.5 MW of hydro power, two own thermal projects (234.6 MW), two thermal projects of IPPs (177 MW) and one PPA with National Thermal Power Corporation Limited (359.58 MW).

(Paragraphs 3.1.3, 3.1.4, 3.1.5 and 3.1.53)

Underutilisation of capacity of the two own thermal projects viz., BDPP and KDPP during 1998-2003 and 2000-2003 respectively resulted in extra avoidable cost of Rs.351.28 crore.

(Paragraphs 3.1.12 and 3.1.17)

Failure of the Board to avail of the benefit of the tax holiday pertaining to Kayamkulam unit of NTPC resulted in avoidable payment of income tax of Rs.48.35 crore during April 1999 to June 2003.

(Paragraph 3.1.23)

Failure of the Board to purchase the entire quantity of power available for sale from the plants of Kayamkulam unit of NTPC, BSES Kerala Power Limited (BSES) and Kasargod Power Corporation Limited (KPCL), as per PPAs, during 1999 - 2003 resulted in avoidable payment of deemed generation charges of Rs.395.33 crore on energy units not purchased.

(Paragraphs 3.1.25, 3.1.33 and 3.1.42)

The Board has to incur avoidable recurring liability of Rs.14.23 crore per annum due to inclusion of superfluous provision in the PPA with BSES for securing payment (Rs.11.04 crore) and providing additional security for payment of bills to KPCL (Rs.3.19 crore).

(Paragraphs 3.1.34 and 3.1.40)

Failure to claim the benefit of exemption from payment of excise duty on fuel admissible as per Government of India orders in the case of KPCL resulted in avoidable loss of Rs. 9.99 crore during March 2001 to March 2003.

(Paragraph 3.1.43)

Failure to draw cheaper power from central pool during April 1999 to August 2001 and alternative purchase of high cost thermal power resulted in avoidable additional expenditure of Rs. 16.47 crore.

(Paragraph 3.1.47)

Failure to generate cheaper hydro power and alternative purchase of costly thermal power resulted in loss of Rs.200.41 crore.

(Paragraph 3.1.49)

Introduction

3.1.1 The power requirement of Kerala since 1957 was being catered to by hydel power plants of the Kerala State Electricity Board (Board). In order to augment the power generation in the State, a task force was appointed (1987) by the State Planning Board to conduct a study on generation of power. The task force estimated a peak load demand of 1127 mega watt (MW) in 1987-88, which was expected to rise to 1426 MW in 1989-90 and further to 3880 MW in 1999-2000.

3.1.2 The Board, thereupon, proposed (July 1987) to take up implementation of eleven hydel projects and one thermal project, involving a capacity addition of 1851 MW, in a phased manner, within a period of nine years ending 1999-2000. A further capacity addition of 411.5 MW was also envisaged by implementing mini/micro hydel projects during the same period.

3.1.3 Consequent to amendment (October 1991) to Section 3 of the Electricity (Supply) Act, 1948 by Government of India, allowing private participation and 100 *per cent* equity participation by foreign investors in power sector, Government of Kerala also issued (March 1992) orders allowing private participation in generation of power in the State.

3.1.4 The Board had an installed capacity for hydel power generation of 1476.5 MW in 1993. Without considering the earlier projection of peak load demand of 3880 MW in 1999-2000 by the task force and without considering its suggestion to meet the demand by exploiting hydro generation potential in the State, the Board decided (1992-1995) to implement thermal power projects for a further capacity addition of 5158 MW vide Annexure 21.

For this purpose the Board entered into (March 1995 to March 1996) Memorandum of Understanding (MOU) with ten independent power producers (IPPs) for purchase of 4970 MW of power out of which power purchase agreement (PPA) was signed (March 1995) in respect of only one project of 60 MW viz., Kasaragod Power Corporation Limited (KPCL) against which 20 MW capacity was created in the first phase of the project. The Board also signed PPA under bid route* for 157 MW naphtha based power plant with Bombay Suburban Electric Supplies Limited (BSES).

Simultaneously, the Board signed (January 1995) PPA with National Thermal Power Corporation Limited (NTPC) for purchase of entire generation at a plant load factor (PLF) of 68.5 *per cent*, from their 359.58 MW, naphtha based power plant at Kayamkulam (KYCCPP).

No records were available with the Board to justify the demand projections made for entering into MOUs/PPAs for these thermal projects.

3.1.5 As against the capacity addition of 7420.5 MW (hydel: 1851 MW, thermal: 5158 MW and micro hydel: 411.5 MW) envisaged between 1987 and 1996, the Board created till March 2003 a capacity addition of 1124.08 MW including two own thermal power projects *viz.*, Brahmapuram Diesel Power Project (BDPP) and Kozhikode Diesel Power Project (KDPP) with installed capacity of 106.6 and 128 MW respectively. The total installed capacity as on 31 March 2003 was 2598.68 MW.

Organisational set up

3.1.6 The implementation of own thermal projects at BDPP and KDPP was being supervised by the Principal Project Co-ordinator/Project Manager under the control of Chief Engineer (Thermal) till 1998-99 and thereafter up to 31 May 2002 by the Chief Engineer (Operation and Maintenance-Thermal) under the overall supervision of Member (Technical). From June 2002 onwards the operation of own thermal projects were under the control of Chief Engineer (Generation).

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* Selection of IPPs by inviting quotations through open tenders

Capacity addition through IPPs was supervised by the Investment Promotion and Business Development Cell headed by one Deputy Chief Engineer (IPC) under the control of CE (Electrical) Generation and Systems Operation up to March 1998, the Chief Engineer (Thermal) up to May 2002 and thereafter by the Chief Engineer (Corporate Planning).

Scope of Audit

3.1.7 Implementation of BDPP was reviewed and included in the Report of the Comptroller and Auditor General of India for the year ended 31 March 1998. The review was discussed by COPU in March 2003 and the recommendations are awaited (September 2003). The present review conducted between November 2002 and March 2003, deals with generation of thermal power by Board’s own thermal projects (KDPP and BDPP) and purchase of thermal power from NTPC power project (Kayamkulam) and two IPPs (BSES and KPCL) based on PPAs entered into with them.

3.1.8 The draft review was discussed by the Audit Review Committee for State Public Sector Enterprises in the meeting held on 16 September 2003 which was attended by the Principal Secretary to Government, Department of Power and Chairman of the Board.

Performance of Brahmapuram Diesel Power Project (BDPP)

3.1.9 The base load plant (round the clock operation) of BDPP using LSHS or diesel oil as fuel, with an installed capacity of 106.6 MW (five generators of 21.32 MW each) was synchronised to the grid during May 1997 to November 1998. The total cost of the project was Rs. 444 crore at Rs.4.17 crore per MW against the original estimated cost of Rs.281.11 crore at Rs.2.64 crore per MW. The plant was designed for continuous operation for a minimum of 6000 hours per annum corresponding to PLF of 68.5 *per cent*. Capacity utilisation of the plant for the five years up to 2002-03 was as follows:

Particulars	1998-99	1999-2000	2000-01	2001-02	2002-03
Installed capacity (in million KWH)	812.04	936.37*	933.82	933.82	933.82
Total hours available for operation for 5 generators	38088	43920	43800	43800	43800
Actual hours available for operation (excluding loss of hours due to maintenance, break down, etc.)	27746	30652	27172	17693	24154
Plant availability factor (in *per cent*)	72.85	69.79	62.04	40.39	55.15
Units sent out (in million KWH)	241.74	391.78	305.13	120.86	255.20
Capacity utilisation (PLF) *(per cent)*	29.77	41.84	32.68	12.94	27.33

* installed capacity was more on account of leap year

3.1.10 It could be seen from the table that;

- despite fixing a low PLF of 68.5 *per cent*, the actual capacity utilisation was much lower and ranged between 13 and 42 *per cent* during the five years up to 2002-03.

- in 2000-01, 2001-02 and 2002-03 the plant availability factor was less than 68.5 *per cent* due to failure of turbo-chargers of three machines and failure of turbine rotor of one machine. Board took two years and nine months and four years and six months respectively for repairing the machine/replacing the spares, the cost of which amounted to Rs.4.50 crore. Hours lost (39384) on this account during the three years were equivalent to 11.56, 52.97 and 25.37 *per cent* of available hours. Non-productive fixed cost on this account was Rs. 64.19 crore. The Board did not have a system of periodic procurement of essential spares with a view to carrying out timely repairs and replacements.

Failure to conduct timely repair and maintenance resulted in loss of machine hours and consequent non-productive fixed cost of Rs.64.19 crore.

Consumption of fuel

3.1.11 Low sulphur heavy stock (LSHS) and diesel oil (HSD) were the base fuel for the plant. As per design, HSD oil is used as a start up fuel. After attaining 35 *per cent* rated load, the plant automatically switches over to LSHS.

Details of consumption of LSHS and HSD oil, power generated, specific fuel consumption, norms fixed by the manufacturer, excess consumption, cost of power per metric tonne of fuel and total value of excess consumption during the five years up to 2002-03 were as indicated in Annexures 22 and 23. Utilisation of the plant for meeting peak load* demand instead of as base load** plant necessitated frequent stoppage and start up of machines leading to consumption of 9871 MT of LSHS and 2599 kilo litres of HSD oil in excess of norms during the five years up to 2002-03 and resulted in loss of Rs.12.77 crore.

Consumption of fuel in excess of norms resulted in loss of Rs.12.77 crore.

Uneconomic operation of the plant

3.1.12 The Board was operating the plant mainly as peak load plant at a capacity ranging from 13 to 42 *per cent* during the five years up to 2002-03, as against PLF of 68.5 *per cent* equivalent to 6000 hours of operation per annum. At the level of operation of 6000 hours per annum the plant could have sent out 614.016 million KWH of energy per annum. The cost per KWH sent out based on the actual fixed and variable costs for the five years up to 2002-03 was as given in the following table:

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* Operation of plant during peak hour of consumption
** Round the clock operation

Particulars	1998-99	1999-2000	2000-01	2001-02	2002-03
Total fixed cost (Rs. in crore)	76.59	78.75	75.17	72.36	67.64
Fixed cost per KWH (in Rs.) (at 6000 hours of operation for 614.02 million KWH)	1.25	1.28	1.22	1.18	1.10
Variable cost per KWH (in Rs.)	1.80	1.95	2.15	2.35	2.89
Total cost per KWH at 6000 hours of operation (in Rs.)	3.05	3.23	3.37	3.53	3.99
Cost per KWH at the present level of operation (in Rs.)	4.97	3.96	4.62	8.34	5.54
Loss per KWH (in Rs.)	1.92	0.73	1.25	4.81	1.55
Energy sent out (in million KWH)	241.74	391.78	305.13	120.86	255.20
Extra avoidable cost for the year (Rs. in crore)	46.41	28.60	38.14	58.13	39.56

There was extra avoidable cost of Rs.210.84 crore due to underutilisation of the plant.

The operation of the plant at optimum capacity of 68.5 *per cent* PLF would have resulted in reduction in cost per KWH of energy produced, by higher absorption of fixed expenses, reduction in consumption of fuel and minimum stoppage of plant. Extra avoidable cost borne by the Board on account of underutilisation of capacity due to operation of the plant for managing the load requirement of peak periods only instead of continuous generation during the five years up to 2002-03 amounted to Rs. 210.84 crore.

Performance of Kozhikode Diesel Power Project (KDPP)

3.1.13 The LSHS/diesel oil based power plant with installed capacity of 128 MW (16 MW x 8) was synchronised to the grid between September and November 1999. The plant was designed to operate as a base load plant (round the clock) at a plant load factor of 80 *per cent* equivalent to 7000 hours of operation. Capacity utilisation of the plant for the three years up to 2002-03 was as follows:

Particulars	2000-01	2001-02	2002-03
Installed capacity (in million KWH)	1121.28	1121.28	1121.28
Total hours available	70080	70080	70080
Hours available for operation (excluding break down and regular maintenance)	47445	44318	52051
Plant availability factor (in *per cent*)	67.7	63.24	74.27
Units sent out (in million KWH)	442.71	282.20	373.75
Capacity utilisation (*per cent)*	39.48	25.17	33.33

Failure to ensure working capital for purchase of fuel and spares led to non-productive fixed cost of Rs.23.38 crore.

3.1.14 Even though the plant was capable of working at 80 *per cent* PLF, the plant availability was only 68, 63 and 74 *per cent* in 2000-01, 2001-02 and 2002-03 respectively. The plant was kept shut down for want of fuel for 2690 hours during 2000-01, for want of spares for 8712 hours in 2001-02 and 9216 hours in 2002-03 which represented about 3.84, 12.43 and 13.15 *per cent* of total available hours in 2000-01, 2001-02 and 2002-03 respectively. Reasons for non-availability of machines for the remaining period were not on record.

Failure of the Board to ensure adequate working capital for procurement of fuel and spares resulted in non-productive fixed cost on 20618 production hours amounting to Rs. 23.38 crore.

Consumption of fuel

Loss due to consumption of fuel in excess of norms amounted to Rs.4.96 crore.

3.1.15 Low sulphur heavy stock (LSHS) or HSD oil was the fuel for the plant. In accordance with the design, HSD oil had to be used as a start-up fuel. As per the specification of the manufacturer, consumption of fuel per KWH at the terminals of the engine was 194.40 gm. During 2001-02 and 2002-03 the consumption of fuel was in excess of norms, resulting in loss of Rs.4.96 crore as per details give below:

Particulars	2001-02	2002-03
Energy generated (in million KWH)	294.50	387.08
LSHS consumed (in MT)	58578	78270
Consumption per KWH (in gms)	198.90	202.21
Consumption as per norms (in gms)	194.40	194.40
Excess consumption per KWH (in gms)	4.50	7.81
Excess consumption (in MT)	1325	3023
Average price of LSHS per MT (in Rs.)	9620	12215
Loss (Rs. in crore)	1.27	3.69

The management attributed (March 2003) the excess consumption to the presence of about 1-2 *per cent* sludge, water, debris and other impurities, low net calorific value of fuel, frequent starts and stops of the plant. The reply is not tenable since the norms fixed by the manufacturer of the plant allowed for 1.25 *per cent* sludge, water, etc., and other factors attributable were controllable.

Uneconomic operation of the plant

3.1.16 The Board was operating the plant mainly as a peak load plant at a capacity (PLF) of 39, 25 and 33 *per cent* respectively during the three years up to 2002-03, as against the PLF of 80 *per cent* fixed as per design, equivalent to 7000 hours of operation per annum. At that level of operation, the plant could have sent out, 869.12 million KWH of energy per annum. The cost per KWH sent out based on the actual fixed and variable cost for the three years up to 2002-03, was as indicated below:

Particulars	2000-01	2001-02	2002-03
Total fixed cost (Rs. in crore)	86.05	81.41	75.77
Fixed cost per KWH at 7000 hours of operation for 869.12 million KWH (in Rupees)	0.99	0.94	0.87
Variable cost per KWH (in Rupees)	2.24	2.09	2.61

Cost per KWH at 7000 hours of operation (869.12 million KWH) (in Rupees)	3.23	3.03	3.48
Cost per KWH at actual level of operation (in Rupees)	4.18	4.98	4.64
Loss per KWH (in Rupees)	0.95	1.95	1.16
Energy sent out in million KWH	442.71	282.20	373.74
Extra avoidable cost (Rs. in crore)	42.06	55.03	43.35

Uneconomic operation of the plant resulted in underutilisation of capacity and extra avoidable cost of Rs. 140.44 crore.

3.1.17 Operation of the plant at optimum capacity of 80 *per cent* PLF would have resulted in reduction in cost per KWH of energy produced by way of increased absorption of fixed expenses, reduction in consumption of fuel, and by minimisation of stoppage of plant. Extra avoidable cost borne by the Board due to underutilisation of capacity by running the plant as a peak load plant during the three years up to 2002-03 amounted to Rs. 140.44 crore.

Purchase of thermal power

3.1.18 In order to meet the gap between energy demand and own generation, the Board resorted to purchase of thermal power from Independent Power Producers and National Thermal Power Corporation at higher rates as discussed below:

National Thermal Power Corporation Limited, Kayamkulam (KYCCPP)

3.1.19 The combined cycle[*] power plant at Kayamkulam, owned by the National Thermal Power Corporation (NTPC) with an installed capacity of 359.58 MW, consisting of two gas turbines (GTs) of 116.6 MW each and one steam turbine (ST) of 126.38 MW was synchronized to grid in November 1998, February and December 1999 respectively. Commercial operation[#] commenced with effect from March 2000. Naphtha was the fuel for the plant and the contracted capacity was 68.5 *per cent* PLF. The table below indicates installed capacity, units purchased and average PLF for the period 1998-99 to 2002-03:

Particulars	1998-99	1999-2000	2000-01	2001-02	2002-03
Installed capacity (in million KWH)	509.31	2388.14	3149.92	3149.92	3149.92
Power purchased (in million KWH)	243.15	1228.88	1904.38	1280.14	2073.73
Percentage of power purchased to installed capacity (PLF)	47.74	51.46	60.46	40.64	65.83

3.1.20 Despite fixing the contracted capacity at 68.5 *per cent* PLF, the actual purchase of power ranged between 41 and 66 *per cent* only during the

[*] Generation using gas turbine and steam turbine in combination
[#] Fixed cost would be payable from the date of declaration of commercial operation

five years, resulting in higher cost per KWH purchased, since as per PPA the entire fixed cost was to be paid by the Board irrespective of the quantity of power purchased.

Power purchase agreement and payment of bills

3.1.21 The power purchase agreement (PPA) provides for a two part tariff comprising variable and fixed cost. A review of PPA signed in January 1995 with NTPC and the payments made for purchase of power by the Board indicated absence of proper evaluation of impact of various provisions of PPA before entering into the agreement and also payments involving financial loss to the Board, as discussed in the succeeding paragraphs.

Acceptance of capacity without verification

3.1.22 Standard power purchase agreement prescribed (March 1992) by Government of India, envisaged approval by the bulk power recipient (Board) at each stage of implementation of the project, including testing, commissioning and synchronisation to the grid. The PPA entered into between the Board and NTPC does not contain a specific provision to this effect. Instead, the PPA stipulated that the dates of commercial operation of the generating units shall be as declared by NTPC from time to time. As a result, the Board could not satisfy itself of the capacity and maximum continuous rating of the machines installed, mega volt ampere ratio (MVAR)[*], power factor, etc. Since Board had to pay fixed charges, taxes and duties to NTPC based on capacity of the plant, necessary provision in this regard should have been incorporated in the PPA to protect the financial interests of the Board. In the absence of relevant provisions in the agreement with NTPC the Board had to accept the power irrespective of power factor.

Payment of income tax

3.1.23 According to clause 5.1 of the PPA, tax on income of NTPC as per the provisions of Income Tax Act, applicable from time to time, shall be recovered from the Board, in proportion to the capacity of Kayamkulam power station to the total operating capacity of NTPC on all India basis at the beginning of the financial year. The Kayamkulam combined cycle power plant was eligible for 100 *per cent* tax holiday for the first five years of operation (up to March 2003) and 30 *per cent* for the next five years as per section 80.1A of the Income-Tax Act, 1961, available for enterprises engaged in infrastructure development. Even though no tax was to be paid in respect of the Kayamkulam unit, NTPC had been recovering tax from the Board in proportion to the capacity of the unit to the total generating capacity of NTPC. The amount so claimed by NTPC for the period from April 1999 to June 2003 was Rs.48.35 crore. Failure of the Board to incorporate suitable provisions in the PPA for claiming the benefit of tax holiday for the Kayamkulam unit and also for payment of income tax thereafter with reference to the income of the Kayamkulam plant alone had resulted in avoidable liability of Rs.48.35 crore

Payment of income tax to NTPC despite tax holiday resulted in avoidable expenditure of Rs.48.35 crore.

[*] Reactive power in the cycle

of income tax. It was noticed in audit that in the case of BSES and KPCL, other two IPPs, the payment of income tax was being regulated on the basis of actual liability. The impact of extra payment of income tax on the cost per KWH during April 1999 to June 2003 ranged between 6.34 and 17.96 paise.

Unnecessary payment of cost of 'Hitech Oil'

Payment for hitech oil outside the provisions of PPA resulted in avoidable expenditure of Rs.4.19 crore.

3.1.24 Government of India notification issued in March 1992 prescribed two part tariff consisting of 'fixed charges' and 'variable charges' for the Combined cycle plant. The variable energy charges claimed by NTPC included, in addition to cost of naphtha, cost of 'Hitech Oil' a specific ingredient for improving operational efficiency of GEC (General Electric Company) make machines, installed at the plant. As per clarification offered (December 2000) by Central Electricity Authority 'Hitech Oil' was a fuel conditioner and not a fuel and was not contributing to calorific output during combustion. NTPC had included weighted average price of 'Hitech Oil' along with the price of Naphtha in their bills. As per guidelines issued (March 1992) by Government of India, cost of naphtha alone was prescribed as the variable cost component in respect of Naphtha based power stations. The adviser to Government of Kerala also advised (January 2001) that, the use of 'Hitech Oil' in power generation shall be at the cost of NTPC, as no improvement in heat rate was involved on mixing 'Hitech Oil' with Naphtha. As the cost of 'Hitech Oil' is a part of operation, reimbursement of cost of 'Hitech Oil' as variable energy charges was not obligatory. Despite the above, the Board had admitted the cost of 'Hitech Oil' in computing the variable charges. Avoidable additional expenditure on this account for the period from December 1998 to March 2003 amounted to Rs. 4.19 crore.

Wasteful expenditure on deemed generation

3.1.25 As against the installed capacity of 3149.92 million KWH per annum of the plant, the contracted capacity was only 2157.70 million KWH per annum at a PLF of 68.5 *per cent*. As per the provisions of PPA, fixed cost incurred by NTPC for operating the plant was to be reimbursed irrespective of the power purchased by the Board.

Loss due to deemed generation charges paid on under-drawn power amounted to Rs.248.54 crore.

The Board was forced to order the station to back down generation frequently during monsoon months to avoid spillage of water from the hydro generation reservoirs, for absorbing power available from the central pool at cheaper rates and to save variable cost of power purchased from the Kayamkulam Power Station. For the generation capacity not utilised, the Board had to pay deemed generation charges equivalent to the fixed cost of units not purchased. Deemed generation charges paid during 1999-2000 for 1669.03 million KWH of energy not generated and purchased, amounted to Rs. 248.54 crore. This resulted in increase in cost per KWH by 14 paise in 1999-2000, 40 paise in 2000-01, 83 paise in 2001-02 and 24 paise in 2002-03.

Avoidable payment of incentive

3.1.26 Government of India notification (March 1992), stipulated that for generation of power above 68.5 *per cent* PLF, incentive not exceeding 0.7 *per cent* of equity capital for every percentage point of increase in PLF would be payable to the generating company and in respect of naphtha based thermal power plants, the extent of backing down ordered by State Electricity Boards beyond PLF of 6000 hours operation (68.5 *per cent)* in a year should not be reckoned as generation achieved for incentive purpose.

There was avoidable payment of incentive of Rs.16.08 crore in violation of Government of India guidelines.

Contrary to the above condition, the PPA with NTPC in respect of KYCCPP, a naphtha based plant, envisaged payment of incentive for generation of power above 68.5 *per cent* PLF, at rates ranging between 0.35 and 8.2 *per cent* of equity capital, reckoning extent of units backed down above 68.5 *per cent* PLF also as generation achieved. It was noticed in audit that the actual generation by KYCCPP during 2000-01 was only 62.11 *per cent*, which was below the PLF of 68.5 *per cent* prescribed in the PPA. Against this NTPC declared 81.61 *per cent* capacity as available for generation and the Board paid incentive for the 13.11 *per cent* deemed generation in excess of the PLF of 68.5 *per cent* as well. Thus, inclusion of a provision in the agreement for reckoning backed down generation as actual generation for purpose of payment of incentive, in violation of the Government of India guidelines, resulted in avoidable payment of Rs.16.08 crore on 597.79 million KWH of backed down production.

Failure to sell surplus power to other states

3.1.27 Kayamkulam project was originally envisaged as a regional project. The infrastructure facilities were designed for a large project and location was identified on consideration of evacuation system suitable for sharing with other states. Later, when it was decided to utilise the station exclusively for Kerala, the increased capital investment and high transmission costs have added to the high cost of power from the station. Based on directions from Government of India, NTPC proposed (March 1997) to amend the PPA to the effect that in the event of Board's inability to draw 100 *per cent* power generated by the station, NTPC may divert such quantum of surplus power to other states for which charges were to be paid by beneficiary states. The State Government was averse to such an amendment as it did not anticipate a situation at that point of time where the State will not be able to absorb the entire power from the power station. When the unit started (March 2000) commercial operation, the Board could not draw the entire power generated by KYCCPP. Even then the Government of India suggested (October 2000) for surrender of excess power from the station to other states in the region and for billing of the entire power generated on pooled regional tariff. This suggestion was also not accepted by the State Government/Board on the ground that surrender of excess power could result in load shedding and power cut during summer months. Had the Government/Board accepted the proposal of the Government of India, the payment of deemed generation charges of

Rs. 248.54 crore mentioned under paragraph 3.1.25 *supra* could have been avoided.

BSES Kerala Power Limited

3.1.28 Under the bid route the Board signed (December 1996) PPAs with BSES Kerala Power Limited (BSES) for implementation of two open cycle* power plants of 40 MW each at Thiruvananthapuram and Kochi. A third power plant of 40 MW proposed to be implemented at Kochi was also entrusted (December 1996), without bidding, to BSES for implementation. All the three projects were combined and converted as a single combined cycle# power plant of 157 MW for implementation at the site in Kochi. Provisional PPA for combined cycle plant was signed on 23 April 1998 and final PPA on 3 May 1999.

3.1.29 The 157 MW naphtha based combined cycle power plant consisting of three gas turbines (GTs) of 40.5 MW each and one steam turbine (ST) of 35.5 MW were synchronized to grid on 6 June, 2 August, 4 December 1999 and 23 November 2000 respectively. As per the PPA (May 1999) the Board had agreed to purchase power generated by the plant at 80 *per cent* PLF. Despite the synchronisation of the generators to the grid in 1999-2000 and 2000-01, the Board had declared the commercial operation of the plant under open cycle mode with effect from 15 June 2001 only. Commercial operation of the plant under combined cycle mode was kept in abeyance by the Board (July 2001) on the ground that the generators were not delivering at inter connection point MVAR corresponding to 157 MW at 0.8 power factor (PF) in accordance with Article 4 of the PPA read with Schedule 4. Installed capacity, power purchased and percentage of utilisation by the Board during 1999-2003 were as given below:

Particulars	1999-2000	2000-01	2001-02	2002-03
Installed capacity (in million KWH)	643.46	1064.34	1064.34	1372.32
Power purchased (in million KWH)	6.00	120.71	208.44	295.96
Percentage of utilisation by the Board	0.93	11.34	19.58	21.52

3.1.30 The utilisation of capacity by the Board ranged between 0.93 and 21.52 *per cent* only during 1999-2003 indicating that the PPA for additional capacity of 157 MW was not based on demand and resulted in avoidable payment of deemed generation charges as discussed in paragraph 3.1.33 *infra*. As a result of under drawal, average cost of purchase of power per unit varied between Rs.5.25 and Rs.7.79 during the four years ended 2002-03.

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* generation by using gas turbine

generation using gas turbine and steam turbine in combination

Impact of detrimental provisions of PPA

Schedule of implementation

3.1.31 PPA signed with BSES on 3 May 1999 prescribed that the PPA for the combined cycle plant would supersede the earlier two PPAs signed on 24 December 1996 and the third PPA signed on 23 April 1998, which had the effect of changing the schedule of implementation of the project. The Board had complied with all the conditions to be fulfilled as per PPAs signed in December 1996, viz, arranging State Government guarantee for liquidation of Board's liabilities to BSES, opening of letter of credit for ensuring timely payment of invoices and opening of escrow account for securing the payment to BSES, etc., by 10 July 1998 and the date of completion of the project was 5 April 2000. As against this, the third gas turbine was synchronized to grid only on 23 November 2000, after a delay of seven months. However, in the fourth PPA signed on 3 May 1999, the inclusion of provision for supercession of all earlier PPAs resulted in depriving the Board of compensation of Rs.2.24 crore, payable by BSES for belated completion of the project under open cycle. The Board had not yet (September 2003) opened the escrow account and letter of credit as per the final PPA (May 1999). Thus, the signing of new PPA had the effect of postponing the date of commissioning till the allied conditions were again satisfied by the Board even though these conditions were fulfilled as per the open cycle agreements signed earlier.

Power factor of energy supplied

3.1.32 Articles 1 and 5 of the PPA for the combined cycle power plant stipulated that the four generators (40.5 MW x 3 and 35.5 MW x 1) would deliver 157 MW at inter connection point at a load factor not less than 0.8 lagging. However, lack of penal provisions in the PPA for supply at lesser power factor, MVA, etc., rendered it impossible for the Board to claim damages for variation in power factor.

Deemed generation charges

Deemed generation charges on energy not actually purchased amounted to Rs.144.17 crore.

3.1.33 Despite the inability of BSES to deliver power at 0.8 power factor, the Board had declared the commercial operation of the project with effect from 15 June, 2001 under open cycle mode and purchased 631.11 million KWH of power during the four years up to 2002-03. As per Article 5.1 of the PPA the Board had to purchase entire electricity generated by BSES at 80 *per cent* PLF at the tariff fixed as per Article 7. Thus, the Board had to pay deemed generation charges to BSES, for short drawal of power with effect from 15 June 2001, based on availability declaration filed by BSES. During 15 June 2001 to 31 December 2002, deemed generation charges payable by the Board for failure to purchase power declared by BSES as available, amounted to Rs.144.17 crore. The claim has not been settled (September 2003).

Security for ensuring payments to BSES

Inclusion of superfluous provisions in the PPA for securing payment resulted in avoidable recurring liability of Rs.11.04 crore per annum.

3.1.34 Article 9 of PPA requires opening of letter of credit for ensuring monthly payments of tariff invoices, and opening of escrow account as security for an amount equal to 1.25 months' aggregate projected payments (fixed and variable) at 80 *per cent* PLF, in addition to Government guarantee for securing the entire obligations of the Board to BSES. Opening of the escrow account would result in blocking of funds amounting to Rs.23.18 crore on which Board would sustain a recurring loss by way of interest amounting to Rs. 3.48 crore per annum @ 15 *per cent* in addition to letter of credit charges of Rs. 7.56 crore per annum. Thus, the inclusion of additional security provisions when the payments were already guaranteed by Government would result in financial loss to the Board.

Station heat rate

Failure to purchase power at the agreed quantity resulted in avoidable liability for payment of Rs.14.84 crore towards adjustment of heat rate.

3.1.35 Schedule 5 of PPA stipulated that operation of the plant below 75 *per cent* capacity as per requirements of Board allowed correction of station heat rate and fuel consumption factor. Increase in heat rate results in increase in fuel consumption. During June 1999 to March 2001, BSES had raised bills for Rs.62.33 crore towards variable charges on 126.72 million KWH. During this period the plant was operated at less than 75 *per cent* PLF and station heat rate varied from 2700 to 3700 Kilo calories (kc) per unit. The Board had admitted and paid Rs. 47.49 crore on account of fixed cost based on agreed station heat rate of 2398 kc/KW for 80 *per cent* PLF as per PPA. As per the provisions of the PPA, the balance amount of Rs.14.84 crore would also be payable, since the drawal of power by the Board was below 75 *per cent* capacity. The Board would be liable to pay variable charges at higher rates for underutilisation of contracted capacity in future also. The matter was referred (June 2003) to the Central Electricity Authority for decision.

The PPA did not contain a provision for passing on to the Board any savings due to reduction in station heat rate.

Delay in declaration of commercial operation

3.1.36 Article 7 of the PPA read with tariff tables A to D specifies the fixed and variable charges for purchase of power under open and combined cycle mode separately. As per this condition, variable charges (fuel cost) was payable, based on station heat rate and gross calorific value of fuel at the price of naphtha prevailing during the billing month. As per table A to D variable charges payable was Rs.1.33 per KWH under open cycle and Rs.1.08 per KWH under combined cycle, based on the price of naphtha of Rs.6100 per MT prevailing in January 1995, involving a saving of Rupee 0.25 per KWH on changing over to combined cycle mode.

3.1.37 Eventhough, BSES synchronised the steam turbine of 35.5 MW to the KSEB grid on 23 November 2000 declaration of commercial operation of

Delay in declaring the commercial operation under combined cycle resulted in loss of Rs.20.39 crore.

the plant has been kept in abeyance by the Board till date (September 2003) on the ground that the generators were not delivering MVAR at inter connection point corresponding to 157 MW at 0.8 power factor as per requirements of Article 4 of PPA. Despite the above, the Board had purchased 328.16 million KWH of power from BSES during November 2000 to May 2002 paying variable charges applicable for open cycle, ignoring the savings in variable charges under combined cycle. Savings lost by the Board due to delay in declaration of commercial operation under combined cycle mode amounted to Rs.20.39 crore (September 2003).

Kasargod Power Corporation Limited

3.1.38 A Memorandum of Understanding (MOU) was signed (May 1994) between the Government of Kerala and RPG Enterprises, Bombay, for setting up a diesel power project in Kasargod district. PPA was signed (March 1995) by the Board with Kasargod Power Corporation Limited (KPCL), a separate company formed for setting up an LSHS based power plant with capacity of 60 MW. Subsequently (March 1996), the implementation of the project was divided into two phases, the first being a 20 MW plant. Revised PPA was signed in August 1998. The three generators of 7 MW each were synchronised to the grid on 3 March 2001. As per the PPA, the Board had agreed to purchase power generated by the plant at 80 *per cent* PLF. Installed capacity, power purchased and percentage of purchase to installed capacity for the period from March 2001 to March 2003 were as given below:

Particulars	2000-01	2001-02	2002-03
Installed capacity (in million KWH)	13.92*	175.20	175.20
Power purchased (in million KWH)	0.06	111.54	146.94
Percentage of purchase to installed capacity	0.43	63.66	83.87

3.1.39 Despite creation of additional capacity of 20 MW, utilisation of capacity by the Board was very low during 2000-01 to 2002-03 resulting in payment of deemed generation charges as discussed in paragraph 3.1.42 *infra*.

Impact of detrimental provisions of the PPA

Security for ensuring payments to KPCL

Avoidable additional security for payment of bills necessitated recurring interest loss of Rs.3.19 crore per annum.

3.1.40 Article 9 of PPA requires opening of letter of credit for ensuring monthly payments of tariff invoices and opening of separate bank account *viz.*, 'Escrow Account' as security for an amount equal to 1.25 months' aggregate projected payments (fixed and variable) at 80 *per cent* PLF, in addition to Government guarantee for securing the entire obligation of the Board to KPCL. Opening of Escrow Account would result in blocking of funds amounting to Rs. 5.72 crore based on March 2002 bills on which the Board would sustain a recurring loss by way of interest amounting to Rs. 0.86 crore per annum @ 15 *per cent* in addition to letter of credit charges of

* For 29 days only

Rs. 2.33 crore per annum. Inclusion of more than one safety clause for prompt discharge of payment lacked justification.

Rebate for prompt payment of power charges

Omission to include in the PPA the usual provision for rebate would result in recurring loss of Rs.1.37 crore per annum.

3.1.41 Government of India guidelines (March 1992) on PPA, envisaged a rebate of 2.5 *per cent* for payment of bills through letter of credit and one *per cent* rebate for payment, otherwise than through letter of credit within a period of one month of presentation of bills. The PPA with KPCL does not provide for the benefit of rebate for payment through letter of credit or otherwise. The omission to include such a provision would result in recurring loss of Rs.1.37 crore per annum on monthly bills of Rs. 4.58 crore payable at 80 *per cent* contracted capacity.

Deemed generation charges

Deemed generation charges paid on power not purchased during April 2001 to August 2002 amounted to Rs 2.62 crore.

3.1.42 The Board had agreed (Article 5 of PPA) to purchase entire power generated by KPCL at 80 *per cent* PLF at the tariff fixed as per Article 7. As per this condition the Board was liable to pay fixed charges as deemed generation charges on units not purchased, limited to 80 *per cent* PLF, in the event of inability of the Board to purchase power from KPCL. The Board had given backing down instructions to KPCL on several occasions, either to avoid spillage of its hydel reservoirs during monsoon months or for absorbing cheaper power available from central power stations, in order to save variable cost of generation by KPCL. Deemed generation charges paid on 37.13 million KWH of power not purchased during April 2001 to August 2002 amounted to Rs 2.62 crore.

Payment of excise duty on fuel

Failure to claim the benefit of exemption from excise duty resulted in loss of Rs.9.99 crore.

3.1.43 As per Government of India notification (March 2001), KPCL was eligible for exemption from payment of excise duty on LSHS used for generation of electricity subject to sanction of the State Government obtained by the IPP under Section 28 of Indian Electricity Act, 1910 to the effect that KPCL was a licensee under Part II of Indian Electricity Act, 1910 (9 of 1910) to supply electrical energy and to engage in the business of supplying electrical energy. KSEB being engaged in generation and supply of electricity was availing this concession in the generating station at BDPP and KDPP on LSHS consumed. However, the matter was not taken up by the Board with KPCL and the failure of the KPCL in obtaining necessary exemption from payment of duty and passing on the benefit of reduction in cost to the Board, resulted in loss of Rs.9.99 crore during March 2001 to March 2003.

Payment of exchange rate variation

3.1.44 The proposed means of financing of the KPCL power project as per PPA and actual expenditure on implementation of the project were as indicated below:

Particulars	As per PPA		Actual	
	Rs. in crore	**Percentage to total**	**Rs. in crore**	**Percentage to total**
Debt:				
i. In Indian rupees ii. In Netherlands guilders	10.49 35.00	15.37 51.30	47.00 NIL	66.41 NIL
Promoters' contribution:				
i. In Indian rupees ii. In US dollar (equity)	22.74 NIL	33.33 NIL	12.12 11.65	17.13 16.46
Total	**68.23**	**100**	**70.77**	**100**

3.1.45 As per Schedule 8 of PPA, borrowings included foreign currency loan in Netherland guilders amounting to Rs.35 crore, repayable to KPCL in Indian rupees, along with exchange rate variation prevalent on the billing date, as monthly foreign debt service charges (MFDSC) forming part of fixed charges. On actual implementation of the project, there was no foreign exchange component in the borrowings as originally envisaged and the entire borrowings was in Indian rupees only.

Undue benefit passed on due to unnecessary payment of exchange rate variation was Rs.1.26 crore.

In the absence of any borrowings in foreign currency there was no necessity for payment of MFDSC in terms of Netherlands guilders every month on the basis of original financing pattern. The undue benefit passed on to KPCL by way of payment of exchange rate variation during May 2001 to March 2003 amounted to Rs.1.26 crore.

Purchase of power from central power stations

3.1.46 The power requirements of the State was being met out of own generation from hydel power stations, purchase from central power stations and independent power producers. The power allocation from central power stations was being made by the Ministry of Power at pre-determined percentages. The average cost per unit (KWH) purchased from central pool ranged between Rs. 1.42 and Rs. 1.91 during 1998-2003.

Failure to draw cheaper power from central pool and alternative purchase of high cost thermal power resulted in additional expenditure of Rs.16.47 crore.

3.1.47 Eventhough the cost per KWH of power purchased from central pool was cheaper as compared to the cost per KWH of power from own thermal power stations and IPPs, the Board did not draw power from central power stations to the full extent and alternatively purchased power from other costlier sources during April 1999 to August 2001. Avoidable additional expenditure incurred on under-drawn power of 109.06 million KWH from central pool when compared to the variable cost of power purchased from KYCCPP for the period during April 1999 to August 2001 amounted to Rs.16.47 crore.

Underutilisation of cheaper hydel capacity and procurement of costlier thermal power

3.1.48 The total installed capacity of 19 (including captive capacity created by two private entrepreneurs) hydel power stations in the state as at the end of 31 March 2003 was 1825.5 MW. The installed capacity, plant load factor fixed, power generated, capacity utilisation and actual average plant load factor of the 17 projects owned by the Board for the five years up to 2002-03 were as given in Annexure 24.

It could be seen from the Annexure that the average capacity utilisation (PLF) of the 17 projects during the five years up to 31 March 2003 ranged between 31 and 47 *per cent* only, indicating that substantial portion of the hydro-generation capacity created by the Board by investing huge funds was not utilised fully.

Failure to generate cheap hydro power and alternative purchase of costly thermal power resulted in loss of Rs.200.41crore.

3.1.49 Out of 17 hydel projects having a total capacity of 1792.5 MW, 9 generating stations (sl.no. 1,2,3,4,5,7,9,10 & 11 of the Annexure 24) having a total installed capacity of 519.5 MW and having lesser water storage facility had to spill excess water during monsoon season. The Board was to continuously monitor and manage the water availability of these nine stations in such a way that the shutdown of the generators for maintenance and repairs was planned efficiently and the generators kept ready so as to utilise the machines to the maximum extent to avoid spillage of water without producing power. Failure of the Board to effectively manage the available water for hydro generation necessitated purchase of costlier thermal power and resultant loss of Rs.200.41 crore, as discussed below:

3.1.50 The Pallivasal hydro power station of the Board had a capacity of 37.5 MW with six generators (three each with 5 and 7.5 MW respectively) and the power station with capacity of 48 MW (4x12 MW) was also constructed by the Board at Sengulam with the sole intention of using the tail race waters of the Pallivasal project. It was noticed in audit that the maintenance of machines at Pallivasal station was not being carried out in time, and there was undue delay in renovating and repairing the generators during April 1998 to July 2002 ranging from one month to four years.

Failure of the Board to repair and make available the generators at Pallivasal power station within the normal/targeted time during the monsoon season for the three years up to 31 March 2002 resulted in spillage of 313.31 MCM[*] of water out of which 395.61 million units of energy could have been produced @ 0.792 MCM per million units (mu). Since the Sengulam power station was working on the tail race water of Pallivasal, the above spillage of water also contributed to non-generation of 246.68 mu (@1.27 MCM per mu) of power at Sengulam involving a total loss of generation of 642.29 million units of energy. By carrying out the repair and renovation of generators in time the

[*] Million cubic metres

Board could have avoided the additional variable cost of Rs.186.40 crore on the alternative purchase of 642.29 million KWH of thermal power.

3.1.51 In respect of four hydro-generating stations (Sholayar, Poringalkuthu, Panniyar and Neriyamangalam) the machines were not ready for operation during the monsoon season of 1999-2000 to 2001-02 due to, shutdown of the generators for planned maintenance resulting in a loss of Rs. 14.01 crore on alternative purchase of costlier thermal power.

Impact of thermal generation and power purchases on Board's revenue

Under utilisation of capacity

3.1.52 The Board started using thermal power from May 1997 onwards and the total installed capacity as on 31 March 1998 was 1775.78 MW comprising 1690.50 MW hydro power and 85.28 MW thermal power (equivalent to 14808.78 MKWH and 747.05 MKWH respectively). Additional capacity of 822.90 MW consisting of 137 MW hydel power and 685.9 MW thermal power was created during the five years up to 2002-03.

3.1.53 Gross installed capacity (source-wise), maximum demand for peak load consumption, available total thermal capacity, thermal power purchased/ generated and capacity utilisation for the five years up to 2002-03 are given below:

Particulars	**1998-99**	**1999-2000**	**2000-01**	**2001-02**	**2002-03**
Installed capacity (in MW)					
Hydel	1706.50	1756.50	1806.50	1827.50	1827.50
Thermal :					
Own	106.60	234.60	234.60	234.60	234.60
IPPs/NTPC	233.20	481.08	481.08	501.08	536.58
Central pool allocation	416.00	619.00	500.00	500.00	500.00
Gross capacity (in MW)	2462.30	3091.18	3022.18	3063.18	3098.68
Maximum demand for peak load consumption (in MW)	1918	2182	2316	2333	2347
Available total thermal capacity (in million KWH)	1321.66	4532.83	6283.28	6444.56	6755.54
Thermal power purchased/generated (in million KWH)	484.89	1801.31	2772.99	2023.18	3145.58
Capacity utilisation (in *per cent*)	36.69	39.74	44.13	31.39	46.56

It could be seen from the above that;

- as against the gross installed capacity of 2462.30 to 3098.68 MW during the five years 1998-2003, the maximum demand during peak hour, in these years ranged between 1918 and 2372 MW.

- despite creating additional capacity of 771.18 MW of costlier thermal power, the actual utilisation of thermal capacity ranged between 31 and 47 *per cent* only during the five years from 1998-2003.

This indicated that creation of additional thermal capacity of 536.58 MW by way of PPAs with KYCCPP, BSES and KPCL was avoidable and contributed to losses by way of purchase of power at exorbitant cost and payment of huge amount by way of deemed generation charges as discussed in paragraphs 3.1.25, 3.1.33 and 3.1.42 *supra*.

3.1.54 Based on the total installed capacity (own generation, PPAs and central pool allocation) the units (KWH) that could have been generated during the four years from 1998-99 to 2001-02 ranged between 21569.75 and 26833.46 million. The actual units produced/purchased ranged between 11164.61 and 12554.06 million representing 44 to 52 *per cent* against which the sales recorded was between 8667.91 and 10319 MU only. The transmission and distribution loss ranged between 17 and 31 *per cent.* Thus, the thermal capacity created since May 1999 by way of own projects and PPAs representing generation of 6444.56 MKWH was grossly underutilised which could have been avoided by better utilisation of available water resources, utilising central pool allocation to the full extent and by reducing the transmission and distribution loss which represented the all time high of 31 *per cent* during 2001-02.

Impact on cost of units sold

3.1.55 Annexure 25 provides for the details of thermal and hydro power available for sale, cost of power purchased/generated and sold, sales realisation thereof, net profit/loss on sale of hydro power/thermal power, etc., during the five years ended 2001-02.

There was aggregate net loss of Rs.2506.33 crore during the four years up to 2001-02 due to thermal power generation and purchase of power from IPPs.

3.1.56 The details in the Annexure indicate that during the year 1997-98 when there was only hydro-power generation and purchase of allocated power from central pool, there was a net profit of Rs.257.09 crore from sale of power. Ever since own generation and purchase of thermal power from IPPs/NTPC started in 1998-99 the Board incurred loss on sale of power ranging between Rs.239.11 crore and Rs.1022.06 crore per annum up to 2001-02 resulting in an aggregate net loss of Rs.2506.33 crore during 1998-2003, despite the fact that the per unit sales realisation registered an increase of 133 *per cent*. Even the peak load management would have been possible with the effective utilisation of available capacity during the period. The loss was compensated by State Government by way of subsidy and the percentage of subsidy to gross revenue from sale of power (excluding electricity duty) ranged between 17 and 56.

The above matters were reported to Government/Board in May 2003. Their replies are awaited (September 2003).

Conclusion

The Board decided to create own thermal generation capacity and also entered into power purchase agreements with independent power producers without properly assessing the energy requirement and peak load demand. The demand projections made by the task force appointed (1987) by the State Government and its suggestions for meeting the demand by exploiting the hydro generation potential in the State were not given due consideration at the time of creating thermal capacity. After implementing the Brahmapuram Diesel Power Project and Kozhikode Diesel Power Project the Board did not operate the plants as base load plants and used these facilities mainly for peak load management leading to low capacity utilisation. The additional capacity created through PPAs was not fully utilised leading to payment of heavy deemed generation charges. The creation of additional thermal capacity could have been avoided by better utilisation of available water resources, power available from central pool and by reducing the transmission and distribution losses. Various provisions of the PPA were detrimental to the financial interests of the Board. The injudicious decision of the Board to generate/purchase thermal power without proper demand study, planning and evaluation of future financial implications resulted in huge losses.

The Board ought to properly balance the thermal and hydro generation and the possibility of selling surplus thermal power to other States has also to be considered so as to avoid payment of deemed generation charges. Efforts to reduce the variable costs of thermal power purchased from IPPs by using cost efficient fuel need to be explored.