THE CHANGE IN THE ATTITUDE TOWARDS INDEPENDENT POWER PRODUCERS DURING THE 1990s: A CASE STUDY OF THE DABHOL POWER PROJECT

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This is to certify that the dissertation entitled **'THE CHANGE IN THE ATTITUDE TOWARDS INDEPENDENT POWER PRODUCERS DURING THE 1990s: A CASE STUDY OF THE DABHOL POWER PROJECT'** submitted by me in partial fulfillment of the requirements for the award of MASTER OF PHILOSOPHY has not been previously submitted for any other degree of this or any other University and is my original work.

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We recommend that this dissertation be placed before the Examiners for evaluation.

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Dedicated

To

Ma,

Didibhai, Jamaibabu & Sonu

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List of Acronyms.

ABT: Availability Based Tariff

ADB: Asian Development Bank

BEST: Bombay Electricity Supply and Transport

BHEL: Bharat Heavy Electricals Limited

BOO: Build Own and Operate

BSES: Bombay Suburban Electric Supply

BTU: British Thermal Units

CAG: Comptroller and Auditor General

CAGR: Compound Annual Growth Rate

CCGT: Combined Cycle Gas Turbine

CEA: Central Electricity Authority

CERC: Central Electricity Regulatory Authority

DDT: Dividend Distribution Tax

DPC: Dabhol Power Corporation

DSM: Demand Side Management

EDC: Enron Development Corporation

EPS: Electric Power Survey

E & A: Establishment and Administrative Cost

GoI: Government of India

GoM: Government of Maharashtra

GRIDCO: Grid Corporation of Orissa Limited

IPP: Independent Power Producers

IRR: Internal Rate of Return

MAT: Minimum Alternative Tax

MERC: Maharashtra Electricity Regulatory Authority

MoP: Ministry of Power

MoU: Memorandum of Understanding

MPDCL: Maharashtra Power Development Corporation Limited

MSEB: Maharashtra State Electricity Board

NHPC: National Hydro Power Corporation

NPC: Nuclear Power Corporation

NTPC: National thermal Power Corporation

O & M: Operation and Maintenance

OPIC: Overseas Private Investment Corporation

PLF: Plant Load Factor

PPA: Power Purchase Agreement

PSU: Public Sector Undertaking

RoE: Return on Equity

RoR: Rate of Return

SEB: State Electricity Board

T & D: Transmission and Distribution

Tcf: Trillion cubic feet

TEC: Tata Electric Companies

Chapter 1

Introduction

Chapter 1

Introduction

The availability of assured supply of energy is an essential component of economic development and there has been a significant change in the pattern of energy supplies. The dynamics of economic growth can be effectively sustained only through the achievement of adequate and reliable supply of commercial energy, especially of electricity. Commercial energy accounts for 60 per cent of the total energy supplies in India, whereas its share was only 26 per cent at the time of Independence. This has been possible largely due to the massive electrification effort by the state sector, which has been necessitated by economic growth and rapid urbanisation.

Power is on the concurrent list of the Constitution of India, which means that both the Central and the state governments can legislate on matters related to the power sector. The Indian Electricity Act, 1910 and the Electricity Supply Act, 1948 govern the structure of the electricity supply industry. These Acts vest the responsibility of supply of electricity to the ultimate consumers with the State Electricity Boards (SEBs) of the respective state governments. The Ministry of Power (MoP) is primarily responsible for the electricity and energy policy formulation, planning for investment decision and administration of the electricity sector.

The power sector can be largely segregated into four different categories on the basis of type of players:

• **<u>Central Government Corporations</u>:**

This category consists of corporations, like Nuclear Power Corporation, National Hydro Power Corporation (NHPC) and some other small players.

- **State Government Corporations**:

This consists of various SEBs and other corporations that have been promoted by the respective state governments.

- **Private Sector Licensees**:

In the private sector, some companies had been given licenses to carry on generation and distribution activities. While, some of these like the BSES Limited, are generation and distribution companies, others, like Surat Electricity, are just distribution companies.

- **Independent Power Producers**:

The Independent Power Producers (IPPs) have been given the permission to set up generation capacities.

Till the end of 2000, India had a power generating capacity of 96,000 MW. The capacity for Thermal and hydel power was 69,566 MW (72 per cent) and 23,488 MW (24 per cent) respectively. The State government sector (SEBs) accounted for 56,156 MW (58 per cent) of the total capacity. The centrally controlled plants, having a total capacity of 32,860 MW (34 per cent) follow this. The IPPs and the private sector in general started contributing significantly to installed capacity only since 1996.[1] Thus, we see that, despite the entry of the private sector, power generation is still overwhelmingly in the hands of the state sector.

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[1] Dhameja, Nand (2001).

The dissertation deals with the change in the attitude towards Independent Power Producers (IPPs) during the 1990s. Our study is concerned mainly with the question: with the not so sound state of affairs of the SEBs, on the financial front, does giving greater leverage to the private sector amount to a suitable policy for India? For that initially we have looked into some of the developments that have taken place in the power sector during the 1990s, mainly the cost and tariff structure of the State Electricity Boards (SEBs). To illustrate the point how the SEBs has been affected with the onset of the IPPs we have undertaken a case study of the Maharashtra State Electricity Board (MSEB) and its association with the Dabhol Power Project. Though the World Bank constantly presses for the privatisation of the power sector, it must be remembered that the Bank has limited experience as regards the working of the actual socio-economic conditions of the country. The new projects, which are financially designed by the World Bank, are oriented towards assured profits and are not necessarily oriented towards improving the efficiency of the power industry. In fact, the contention of the dissertation is that the effort to give a greater role to the private sector in power generation, as exemplified by the Enron case has been a failure not because of the players involved, but of intrinsic problems for greater private participation in a sector such as this.

In the light of this, our study starts off with a look at the financial position of the SEBs. Here we look at the costs and tariffs of the SEBs over a 10-year period from 1991-92 to 2000-01. We have analysed the reasons behind the sharp increase in the costs, which is one of the main reasons for the deteriorating financial health of the SEBs. We have also looked at the problem of the Transmission and Distribution (T & D) losses, which are attributable to the theft of power and the inefficient transmission system. We have shown in our study that reducing the T & D losses can improve the system considerably. Not only will more power be available, additional funds can be generated, which can be used to improve the condition of the SEBs. We have also looked into the effect of subsidisation on the finances of the SEBs. Cross-subsidisation plays a very important part as it helps to neutralise the losses incurred from supplying power to the agricultural and domestic sector at subsidised prices. But at present the scope for such cross-subsidisation is dwindling because its potential contributors - the industrial and commercial sectors are going for their own captive power generation as it has been proved to be cheaper than obtaining power from the grid. We have then taken a look at the tariff structure of the SEBs. Here we have analysed the consumer category-wise tariff structure over the period 1992-93 to 2000-01. We have analysed in particular the tariff structures of the agricultural and industrial sectors. Finally we have compared the average tariff realised with the average cost of power supply.

In chapter 3, we take a look at a particular SEB, the Maharashtra State Electricity Board (MSEB). Here we analyse whether, there was really the need for more power, as was envisaged by the government in 1991. We have carried out an exercise for Maharashtra on the lines of an exercise done on a national level, which shows that there is in fact more requirement for power. It is true that though India has an electricity infrastructure comparable to those of Britain, France and Germany[2], we do face severe power shortages. This is evident by the frequency of power cuts we experience day in and day out. However, it is also to be noted that the results given by the 16th Electric Power Survey (EPS) were grossly overestimated.

[2] Singh Rajendra (2001)

In chapter 4 we take a look at the controversial Dabhol Power Project. Here we have analysed the Purchase Power Agreement (PPA) signed between the MSEB and the Dabhol Power Company (DPC). In the beginning we have looked at the structure and the costs of the project. Then we have analysed the various inefficiencies in the contract that were undertaken by both the parties. This is followed by the mode of financing of the project and the major contributors of the finances of the project. In the final part of this chapter we have analysed the performance of MSEB in line with the operation of the Dabhol project.

Chapter 5 deals with the impact the Dabhol Power Project had not only on the MSEB but the on the economy of the state of Maharashtra as a whole. The contract itself was flawed which led to all sorts of troubles. It is important to note that before the Dabhol power project came into operation, MSEB was one of the better performing SEBs in India. It is quite intriguing that the state of affairs between the DPC and MSEB has come to such a passe that no matter what amount of power MSEB buys from DPC, it has to pay the full amount of fixed costs. Not only that it has been found that the costs of the project was already quite high, which made matters worse as it led to higher prices of Dabhol power. This was unaffordable for the people of Maharashtra.

Following the controversy over the Dabhol Power Project, the Government of Maharashtra, appointed an Energy Review Committee, under Madhav Godbole as Chairman. The Committee has come up with some surprising facts about the project. In chapter 6, we have put together the facts brought out by the committee. This is followed by some recommendations, which the Committee has suggested for future power projects in India.

There is no denying the fact that we need more power since it is very much essential for all developmental efforts. It really does not matter whether indigenous producers or some foreign power companies provide it, so long as reliable and quality power is provided to the people at affordable prices. However, through our study we have come to note that privatisation of power sector in India still has a long way to go. Merely bringing in foreign investors on the lines of recommendations of the World Bank would not help much. The Dabhol project is a prime example of this. Not only has it led to the deterioration of one of the better performing SEBs in India- MSEB, but also has a severe impact on the economy of the state. Not only that, the situation of the Indian power sector is very critical. The T & D losses have been a long standing problem for this sector. Efforts must be made to improve the T & D as it can generate funds to be used for the betterment of the overall sector. So government policies should be aimed at measures which will reduce the rampant theft of power, regular realisation of bills and installing meters, as it has been noted that the presence of un-metered supplies has led to misuse of enormous amount of power, in the name of the agricultural sector.

Chapter 2

An Overview of the developments in the Power Sector in India during the 1990s

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2.1 Introduction

As in the case of any other product, supply of electricity also involves three distinct functions of production (generation), transportation to market (transmission) and retail supply (distribution). However, electricity utility is unique in that its product is one that cannot be stored for marketing, except to a limited extent through pumped storage and compressed air storage,[3] but must be generated the instant it is to be used. This in turn requires instantaneous co-ordination and integration of the three vertical functions which is technically facilitated by the continuos, instant flow of electricity from the generator to the end-use equipment, by load dispatch centres that keep the supply and demand in balance.[4] Thus an electric utility is distinctly characterised by the technical necessity and significance of vertical integration.

In addition to this technical condition for centralisation is an economic requirement for the integrated functioning of the electric utility. This emanates from its natural monopoly status, granted by its characteristic cost complementarity that occurs in the presence of economies of scale. It is also characterised by asset specificity which refers to the phenomenon investment, for example, in the transmission and distribution sectors, which, once sunk, has little value in alternative uses (i.e., other than the intended one). The large scale transmission (and the associated primary distribution) asset

[3] Reddy, Amulya K. N. (2001)
[4] Ibid

specificity arises in the context of the site specificity of the power plant. The size constraint, in favour of large plants in the generation sector also involves economies. The consequent vertically integrated natural monopoly position of the electric utility thus ensures productive efficiency in the sense that the cost of supply is minimised by having a single firm electricity. Securing such productive efficiency, however, can be disastrous if the monopoly is in the hands of private profiteers with the functional behaviour of setting the output below optimum and the price above marginal cost, causing dead weight loss. While such behaviour can be avoided in principle in a competitive market of many firms, the multiplicity of firms is disadvantageous because it would violate the productive efficiency criterion. Nationalisation of the natural monopoly in the general interests of the society can resolve this dilemma and avoid profiteering behaviour while ensuring productive efficiency and equity. This is the rationale as well as the welfare justification for the electric utility being in the public sector.[5]

The SEBs which own most current generating capacity (about 70 per cent by 1991) also virtually run all the power distribution. They controlled most of the transmission lines within states. Though a small number of private companies continued to provide electricity services to some cities, including Calcutta (now Kolkata) and Bombay (now Mumbai), but they largely purchased power directly from SEBs. The Indian Electricity Supply Act, 1948, clearly mentiones that the SEBs should earn a 3 per cent rate of return on their net fixed assets in service after providing for depreciation and interest charges. This provision was to become operational from the accounting year 1985. However, the SEBs are yet to comply with this statutory stipulation. Currently the

[5] Kannan and Pillai (2002).

finances of the SEBs of India are in complete shambles, with many of them not able to earn the minimum 3 per cent rate of return. The major problem lies in the fact that a substantial portion of cost remains uncovered by the average tariff. Typically, the SEBs' tariffs are equivalent to only 50-60 per cent of the long run marginal costs. They are often supported by heavy subsidies from the state governments to make ends meet. Given the fiscal situation, both the Government of India and the states have been emphasising the need to raise power prices. Nevertheless, notwithstanding the current financial difficulties there is no doubt about the fact the SEBs have performed a yeomen service in the context of building the generation, transmission and distribution capabilities.[6]

Currently, industry and commercial establishments pay higher rates than the actual cost of power, while the domestic and agricultural consumers pay a lower rate. There is a need for an element of cross- subsidy in a country like ours, where a large number of people have very low incomes. According to Prabir Purkayastha, the scheme of allowing the industrial consumers to set up a large amount of captive capacity and to move away from the grid has introduced distortions in the system. Cross-subsidiastion and captive power generation are mutually incompatible. It is thus necessary to either force the industry to take at least half of its electricity from the grid or introduce an electricity surcharge that is used to cross- subsidise the low- end consumers. As far as the domestic consumer is concerned, there is a need to introduce a slab- wise tariff that cross-subsidises the low- end users and generates a surplus from the elite consumers, who have

[6] Rai, Praful (2001).

to be charged suitably for the increase in the consumption of air- conditioners, heaters and geysers.[7]

2.2 Unit Cost of Power Supply of SEBs

The average unit cost of supply of electricity for all the SEBs was 22.5 paise per kwh in 1974-75. It increased to 41.9 paise/kwh in 1980-81(at an annual average compound growth rate of 10.9 per cent) and further to 108.6 paise/kwh in 1990-91(at an annual rate of 10 per cent). In the 1990s, the unit cost of supply of electricity increased more steeply, i.e. from 116.8 paise/kwh in 1991-92 to 225.2 paise/kwh in 1997-98 (at a rate of 11.8 per cent). It further increased to 242.9 Paise/kwh in 1998-99 and 276.3 paise/kwh in 1999-00(RE); it is expected to further rise to 303.8 in 2000-01(AP).

T 2.1: Components of Cost Structure (paise/kwh)

	1992-93 (Actual)	**2000-01(AP)**
Fuel	33.19	50.99
Power Purchase	35.76	138.53
Operation &Maintenance Expenditure	6.00	9.99
Establishment & Administration	19.50	40.89
Miscellaneous Expenditure	1.63	5.02
Depreciation	9.70	19.88
Interest Payments	22.41	38.98
Total	128.19	303.86

Source: *Planning Commission, Annual Report on the Working of SEBs & EDs, June 2001.*

The increase in the total cost of supply is mainly due to the increase in the cost of fuel, E & A cost, interest payments and the cost of power purchase. Increase in the

[7] Purkayastha, Prabir (2001) a.

average unit cost of supply of the various components of the cost structure from 1992-93 to 2000-01 is indicated above in Table, T 2.1.

Table, T 2.2 represents the trends for the different SEBs. The unit cost varied from Rs. 1.60 per unit in Himachal Pradesh to Rs. 4.23 per unit in Assam, in 1997-98.

T 2.2: Unit cost of Power Supply, 1992-93 to 2000-01. (Paise/kwh)

SEBs	**1992-93** (Actual)	**1993-94** (Actual)	**1994-95** (Actual)	**1995-96** (Actual)	**1996-97** (Actual)	**1997-98** (Actual)	**1998-99** (Prov.)	**1999-00** (RE)	**2000-01** (AP)
Andhra Pradesh	100.07	109.00	128.93	156.12	213.63	239.69	287.72	295.50	353.31
Assam	255.22	252.65	299.30	356.07	337.32	457.17	297.48	511.38	541.66
Bihar	185.87	200.05	232.84	252.40	290.55	316.04	299.15	318.54	350.93
Delhi	164.12	NA	NA	329.76	360.87	384.66	458.46	490.12	459.53
Gujarat	146.59	158.40	171.63	181.53	207.41	247.62	276.57	307.66	335.59
Haryana	134.40	165.40	179.53	208.69	240.64	293.40	313.72	343.07	359.98
Himachal Pradesh	114.31	142.60	126.60	111.45	142.96	166.01	193.08	204.19	218.75
Jammu & Kashmir	165.46	209.13	230.80	242.48	286.24	293.01	325.26	347.44	341.01
Karnataka	96.77	112.10	121.11	152.34	187.25	179.37	239.23	255.53	320.65
Kerala	87.30	98.32	108.84	134.46	161.29	196.01	179.24	244.19	275.96
Madhya Pradesh	141.44	157.80	167.18	181.64	216.18	231.46	250.59	260.83	272.38
Maharashtra	138.95	152.24	162.02	185.25	206.87	215.88	223.35	261.24	273.13
Meghalaya	110.09	97.75	139.01	147.35	159.63	179.88	220.65	229.87	267.66
Orissa	98.80	133.46	185.70	227.46	322.60	351.73	350.75	184.19	177.45
Punjab	122.00	145.16	165.06	179.69	187.34	217.18	235.74	247.15	247.17
Rajasthan	138.24	163.80	196.52	213.17	234.55	258.60	287.87	334.58	334.45
Tamil Nadu	124.52	144.72	152.02	170.91	185.02	208.12	229.16	253.09	275.64
Uttar Pradesh	153.42	169.44	177.53	191.98	222.28	253.31	267.71	288.09	293.59
West Bengal	161.90	170.05	185.21	189.39	205.36	252.48	300.36	318.42	342.71
Average	128.15	149.12	163.40	179.60	215.78	240.20	262.93	283.67	303.86

Source: *same as T 2.1.*

Two important factors that cause such wide variation in unit supply cost are:

(i) the source of power, whether hydro or thermal, and

(ii) the coverage of electrification of villages and households

Meghalaya and Himachal Pradesh have lower cost of supply per kwh than other States as these States are totally dependent on hydro-electricity. However, the wide variation is not solely due to source of power; it also due to higher power purchase cost as is evident in the case of Kerala. Though Kerala is still a hydropower dominant system, her unit cost of supply (Rs. 1.92 per unit) exceeds that of Karnataka (Rs. 1.89 per unit), now a thermal power dominant (72 per cent) system, on account of the increased share of imported (thermal) power.

Now we analyse in detail why the cost of supply of electricity has gone up so much in the last ten years. We look at the trends of each component of cost and then try to ascertain the reasons for such increase.

2.3 Components of Cost

The major components of cost of supply of electricity are (i) the revenue expenditure which includes expenditure on fuel, power purchase, O&M, Establishment & Administration and other miscellaneous expenditure, and, (ii) the fixed costs, mainly comprising depreciation and interest payable to institutional creditors and the concerned State Governments. Table, T 2.3 represents the share of each of these components in the unit cost of supply for all the SEBs from 1992-93 to 1999-00.

From the table below, it is clear that power purchase costs is the major factor for the increase in the cost of supply of electricity. Certain components of costs like costs of fuel and interest charges have, in fact shown a decreasing trend, while the other components of cost (except depreciation charges) have more or less remained constant. The depreciation charges increased in the middle of the nineties, but thereafter have shown a downward trend.

T 2.3: Unit Cost of Supply (%)

	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-00
Fuel	25.8	26.1	24.8	24.5	23.4	23.1	20.2	17.2
Power Purchase	27.9	29.3	28.4	32.2	34.1	36.4	38.5	44.5
O & M	4.7	4.9	4.9	4.8	4.2	4.1	3.7	3.4
Estbl./ Admn.	15.2	14.8	14.1	12.9	13.7	13.6	14.8	13.6
Miscellaneous	1.3	1.5	3.2	2.0	2.4	2.2	2.6	1.8
Depreciation	7.6	6.9	9.2	8.8	8.5	7.7	7.2	6.6
Interest	17.5	16.5	15.4	14.8	13.7	12.9	13.0	12.9

Source: *same as T 2.1.*

Now we look at each of the components of cost.

2.4 Expenditure on Fuel

Fuel cost constitutes an important element in the cost structure of SEBs, particularly those that rely substantially on thermal generation. The proportion of expenditure on fuel in the total cost of supply of electricity has declined from about 25.8 per cent in 1992-93 to 17.2 per cent in 1999-00(RE). This may be partly because the states of Andhra Pradesh, Haryana, Orissa, Karnataka and U. P. have restructured their SEBs. Fuel cost is dependent, apart from other things, on the specific consumption of coal and oil and the transportation costs for these fuels.

The specific coal consumption in the thermal plants of the SEBs has been around 0.75 kg to 0.77 kg since 1992-93. There are, however, large inter-State variations. The specific secondary oil consumption in the coal based thermal units incresaed sharply from 7.8 ml/kwh in 1992-93 to 10.8 ml/kwh in 1995-96 and then decreased to 5.4 ml/ kwh in 1998-99 and 4.1 ml/kwh in 1999-00(RE). It is expected to further decrease to 3.5 in 2000-01. The situation is much better compared to what it was in late 1970s and early 1980s when the secondary oil consumption was over 12 ml/Kwh. The average specific oil consumption in Bihar, Hayrana and Assam is higher than that of all-utilities average. On the other hand, Andhra Pradesh, Karnataka Power Corporation, Tamil Nadu, Maharashtra, Rajasthan and Punjab have lower consumption. Madhya Pradesh has achieved a significant reduction in its secondary oil consumption in the last 5 years. The cost of coal per unit of generation of power has increased from 53.4 paise/kwh in 1992-93 to 96.8 paise/kwh in 1999-00(RE). It is likely to increase further to 101 paise/kwh in 2000-01. The States located farther away from coal-fields have to bear a higher cost of coal/Kwh of generation viz. Gujarat, Haryana, Punjab, Rajasthan and Tamil Nadu. The main reason lies in higher transport cost for carrying coal to these States. The cost of secondary oil increased from 3.7 paise/kwh in 1992-93 to 6.8 paise/kwh in 1995-96 and then declined to 4.1 paise/kwh in 2001-02.

2.5 Expenditure on Power Purchase

In the recent years, payments towards purchase of power constitute the largest component in total cost of supply of electricity. The cost of power purchase as a proportion of the average unit cost increased from 27.9 per cent in 1992-93 to nearly 44.5

per cent in 2000-01. The average rate of payment for purchase of power from various sources steadily increased from 76 paise/kwh in 1992-93 to 166 paise/kwh in 1999-00(RE). It was expected to increase to 184 paise/Kwh in 2000-01. The inter-State variations can be seen from the table, T 2.4 below.

T 2.4: Rate of Purchase of Power, 1992-93 to 2000-01.

(Paise/kwh)

SEBs	1992-93 (Actual)	1993-94 (Actual)	1994-95 (Actual)	1995-96 (Actual)	1996-97 (Actual)	1997-98 (Actual)	1998-99 (Prov.)	1999-00 (RE)	2000-01 (AP)
Andhra Pradesh	82.22	90.05	103.00	112.54	123.34	157.99	150.43	141.12	174.08
Assam	58.71	69.64	109.31	130.68	153.37	137.35	125.89	182.56	193.53
Bihar	89.03	99.92	98.29	117.21	150.30	170.40	170.92	184.73	185.40
Delhi	100.21	NA	107.55	134.04	138.03	185.93	190.13	191.29	203.24
Gujarat	78.65	81.93	84.53	108.08	132.55	152.19	199.01	240.02	260.57
Haryana	78.31	100.80	103.64	114.45	128.34	146.88	172.92	194.08	209.16
Himachal Pradesh	35.73	41.67	44.37	60.07	74.84	84.20	85.33	95.51	100.25
Jammu & Kashmir	65.39	81.28	97.72	90.46	123.34	130.65	139.88	144.47	150.07
Karnataka	47.24	58.65	58.48	80.80	96.40	90.76	103.97	111.11	149.80
Kerala	78.82	90.57	96.83	102.81	110.20	128.07	156.56	215.19	244.59
Madhya Pradesh	75.24	87.49	93.08	113.15	142.52	145.08	156.29	172.46	184.54
Maharashtra	96.62	107.34	110.54	155.78	177.18	175.40	182.65	230.03	236.94
Meghalaya	0.00	14.81	32.23	77.34	46.80	59.54	57.77	84.20	92.00
Orissa	64.24	65.75	70.21	104.15	101.82	116.22	108.96	123.21	114.31
Punjab	72.30	66.67	113.58	106.92	123.44	141.05	147.01	153.77	151.44
Rajasthan	80.28	97.68	107.74	108.76	103.90	141.34	141.34	141.84	146.83
Tamil Nadu	72.33	81.97	91.06	99.38	89.03	116.07	135.71	171.78	191.24
Uttar Pradesh	79.39	102.25	106.72	98.95	119.73	134.16	136.98	150.08	157.40
West Bengal	80.13	97.40	104.68	106.66	118.51	155.04	169.42	168.45	183.92
Average	76.17	86.96	94.02	109.86	119.05	140.66	151.86	166.59	184.16

Source: *same as T 2.1.*

Bihar, Delhi, Haryana, Jammu & Kashmir, Madhya Pradesh, Karnataka, Orissa and West Bengal have much higher proportion of power import cost than the all- India average. On an average, 70 per cent of the unit cost of supply was accounted for by power purchase in Delhi, during 1996-97 to 2000-01. This is primarily due to reduction in the share of states' own installed capacity in total capacity of the country and more dependence on the purchase of power from the central utilities and to a certain extent on the Independent Power Producers (IPPs) being set up in few states.

2.6 Expenditure on Operating & Maintenance (O&M) Works

The share of O&M in the average unit cost of supply of electricity in the case of 19 utilities has shown a downward trend from 4.7 per cent in 1992-93 to 4.5 per cent in 1997-98 and further to 3.4 per cent in 1999-00(RE). The States of Himachal Pradesh, and Meghalaya have a fairly high share of O & M (above 10 per cent) in the total cost. On the other hand, the share of O & M expenses in total cost is low in Tamil Nadu, Karnataka, Punjab, Gujarat, Assam and Jammu & Kashmir (about 2 to 3 per cent). The State-wise details are given below in the table, T 2.5.

2.7 Expenditure on Establishment and Administration (E & A)

Establishment and Administration charges comprise mainly the wages and salaries of staff. Its share in unit cost of supply of electricity has declined from 15.2 per cent in 1992-93 to 12.8 per cent in 1996-97 and then increased to 14 per cent in 1999-00(RE). The state-wise variation is given in the table, T 2.6.

T 2.5: Share of Operating & Maintenance (O & M) in Total Cost					(%)
SEBs	**1996-97** (Actual)	**1997-98** (Actual)	**1998-99** (Prov.)	**1999-00** (RE)	**2000-01** (AP)
Andhra Pradesh	4.17	3.56	3.00	5.11	5.45
Assam	3.50	2.90	3.39	3.02	2.83
Bihar	5.01	4.57	4.20	3.80	3.30
Delhi	3.43	4.59	4.26	4.85	4.45
Gujarat	2.75	2.91	2.23	2.06	2.03
Haryana	4.61	4.06	3.96	2.25	2.24
Himachal Pradesh	10.87	10.55	10.65	11.64	11.57
Jammu & Kashmir	2.11	1.65	1.63	1.78	1.84
Karnataka	3.73	3.24	3.32	3.08	2.67
Kerala	3.47	2.94	2.94	2.35	1.94
Madhya Pradesh	4.19	4.50	3.85	4.02	3.92
Maharashtra	5.45	6.24	5.43	4.78	4.93
Meghalaya	12.74	12.30	11.65	11.67	11.50
Orissa	2.76	3.15	4.50	2.70	2.77
Punjab	3.33	3.41	3.12	3.49	3.83
Rajasthan	4.55	3.73	2.76	2.48	2.55
Tamil Nadu	2.61	2.33	2.47	2.25	2.09
Uttar Pradesh	4.82	4.90	5.18	5.15	5.36
West Bengal	3.77	2.72	2.67	3.07	3.15
Average	4.10	4.05	3.68	3.39	3.29

Source: *same as T 2.1.*

T 2.6: **Share of Establishment & Administration in Total Cost (%)**

SEBs	1996-97 (Actual)	1997-98 (Actual)	1998-99 (Prov.)	1999-00 (RE)	2000-01 (AP)
Andhra Pradesh	12.15	11.13	10.39	5.54	5.86
Assam	19.33	21.41	18.79	21.16	23.56
Bihar	16.12	15.68	15.10	15.30	24.70
Delhi	10.32	6.93	8.69	8.37	8.05
Gujarat	9.23	8.50	10.07	10.02	10.65
Haryana	15.76	16.79	15.21	15.48	15.03
Himachal Pradesh	27.67	27.09	35.67	29.96	31.27
Jammu & Kashmir	10.40	8.08	9.76	9.87	9.41
Karnataka	17.37	16.37	18.08	16.83	14.62
Kerala	30.34	28.57	26.61	19.67	16.96
Madhya Pradesh	14.23	16.72	16.02	17.68	16.46
Maharashtra	11.85	11.39	12.70	11.85	11.82
Meghalaya	45.92	45.30	43.14	45.02	44.55
Orissa	15.71	15.36	16.16	6.03	6.27
Punjab	17.08	16.53	22.30	19.41	20.31
Rajasthan	8.91	9.50	9.98	9.31	9.56
Tamil Nadu	17.25	18.31	19.39	18.44	17.14
Uttar Pradesh	13.26	13.35	17.45	14.05	13.66
West Bengal	11.57	10.25	11.39	12.13	11.71
Average	13.76	13.61	14.79	13.62	13.46

Source: *same as T 2.1.*

2.8 Fixed Costs

The fixed costs comprise depreciation and interest payments. It is important to note that depreciation is an important item contributing to internal resources generated, while interest charges are a real drain, and hence an increased share of the latter in total cost, signals financial weakness arising from growing dependence on outside funds.

The share of fixed costs in average cost declined from 25 per cent in 1992-93 to 20 per cent in 1999-00(RE). Interest charges have always commanded a bigger share out of this- much more than 10 per cent. While the share of depreciation rose from 7.6 per cent in 1992-93 to 9.2 per cent in 1994-95, it declined to 8.3 per cent in 1997-98 and further to 7.2 per cent in 1999-00(RE). There are, however, considerable inter-State variations in the Share of Depreciation, which are shown in table, T 2.7.

It is evident from the table T 2.7 below, that Maharashtra and Meghalaya have much higher stakes in depreciation, around 10 per cent; Delhi and Himachal Pradesh, on the other hand, have the lowest share, less than 4 per cent.

The interest cost, i.e. interest payable to the financial institutions and the State Governments has also come down to about 13 per cent in 1999-00(RE) from a level of 17.5 per cent in 1992-93. But there are inter-state variations in the interest charges. Very high interest charges are a big problem for many states- Assam, Himachal Pradesh, Kerala, Meghalaya and Uttar Pradesh. These states have a higher share of interest charges in the total cost of supply, more than 20 per cent. Delhi maintains the lowest share position here also- nearly 4 per cent only. This is shown in T 2.8, below.

T 2.7:	Share of Depreciation in Total Cost (%)				
SEBs	**1996-97 (Actual)**	**1997-98 (Actual)**	**1998-99 (Prov.)**	**1999-00 (RE)**	**2000-01 (AP)**
Andhra Pradesh	9.32	7.57	6.33	3.59	3.58
Assam	9.22	9.07	9.97	8.96	8.15
Bihar	8.40	7.65	6.94	6.75	6.27
Delhi	4.07	3.84	3.51	3.72	3.96
Gujarat	8.02	7.77	6.95	6.26	6.45
Haryana	6.71	5.68	5.16	4.46	4.23
Himachal Pradesh	3.87	3.85	3.67	3.54	3.55
Jammu & Kashmir	5.99	5.10	4.67	4.60	4.28
Karnataka	7.12	6.86	6.38	6.23	5.63
Kerala	5.84	5.05	7.32	6.44	5.93
Madhya Pradesh	8.21	7.54	6.26	6.20	6.37
Maharashtra	10.57	10.18	10.07	9.29	8.96
Meghalaya	8.54	13.44	12.54	12.12	11.53
Orissa	8.45	7.68	9.14	4.46	4.70
Punjab	9.05	7.50	6.63	7.01	7.88
Rajasthan	6.97	6.75	6.48	6.65	6.88
Tamil Nadu	6.64	6.75	6.82	6.66	6.78
Uttar Pradesh	1.80	1.77	1.69	1.80	1.90
West Bengal	5.47	4.91	4.35	4.80	4.68
Average	8.01	7.37	6.90	6.71	6.67

Source: *same as T 2.1.*

T 2.8:	Share of Interest Charges in Total Cost (%)				
SEBs	1996-97 (Actual)	1997-98 (Actual)	1998-99 (Prov.)	1999-00 (RE)	2000-01 (AP)
Andhra Pradesh	19.40	17.34	19.52	13.39	13.50
Assam	34.25	29.04	27.36	21.46	21.99
Bihar	7.71	6.66	5.66	4.56	3.64
Delhi	3.89	3.77	3.68	4.01	3.89
Gujarat	11.29	10.77	9.01	8.24	6.49
Haryana	12.59	11.04	8.60	9.29	8.07
Himachal Pradesh	22.08	22.42	21.07	20.19	21.68
Jammu & Kashmir	15.79	13.90	13.01	14.08	13.47
Karnataka	8.56	10.57	9.83	10.11	8.94
Kerala	20.96	19.22	17.94	21.93	17.89
Madhya Pradesh	16.97	14.84	19.69	14.35	13.63
Maharashtra	9.72	8.77	8.15	10.94	12.01
Meghalaya	27.13	24.25	27.89	25.70	24.02
Orissa	6.50	6.82	9.35	14.91	17.02
Punjab	17.88	18.22	19.86	20.66	20.62
Rajasthan	12.43	11.70	11.62	12.71	13.84
Tamil Nadu	8.90	8.30	7.46	8.38	8.41
Uttar Pradesh	24.76	24.30	21.42	25.38	24.99
West Bengal	11.27	10.01	11.24	10.89	11.17
Average	14.05	13.32	13.22	13.37	13.28

Source: *same as T 2.1.*

From the above analysis, it is quite clear that the costs of power purchase has been the major contributory factor for the increase in the costs of supply of electricity. Now let us try to find out what may be the plausible reasons for it. Before that we need to look at the trends and source of power purchase by the SEBs.

The total purchase from Central Sector and other sources, purchase as a percentage of total sales, purchase of power from Central sector as a percentage of total purchase and purchase from Central sector as percentage of total power availability. It can be observed that, states purchase power from Public Sector Undertakings (PSUs) in the Central sector, private generators (wherever such agencies exist) and from neighboring States. The purchase of power as a proportion of total sales of all the utilities taken together was 51 per cent in 1992-93, 62.17 per cent in 1997-98, 66.56 per cent in 1998-99 and 74.73 per cent in 1999-2000 (RE) and is estimated at 74.63 per cent in 2000-01. The results are summarised in T 2.9.

T 2.9: Details of Purchase of Power

Year	Purchase as a % of Availability	Purchase from Central Sector as a % of Total Purchase	
		Total Purchase	Total Availability
1992-93	38.7	77.1	29.5
1996-97	46.2	72.6	33.5
1997-98	46.8	74.4	34.8
1998-99	49.8	70.0	34.7
1999-00 (RE)	56.3	61.2	34.5
2000-01(AP)	56.9	59.6	33.9

Source: *same as T 2.1.*

All the SEBs purchase power from other sources to meet their total requirements. As can be seen from the Table above, the share of power purchased in total availability of power with the SEBs has increased over the years. It can be observed that nearly threefourth of the electricity purchased by the SEBs was from the Central PSUs till 1996-97. However, this trend has changed and since 1997-98 share of Central sector in the total purchases of SEBs has started declining. One of the reasons for this may be increase in generation from their own generating plants, improvement in PLF and, to some extent, the commissioning of private sector projects in few states. The share of purchase in total sales is shown in T 2.10.

T 2.10: Share of Purchase of Power in Total Sale (%)

SEBs	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-00	2000-01
Andhra Pradesh	37.10	38.60	39.53	37.06	40.45	46.72	68.32	148.09	147.08
Assam	65.60	74.50	64.56	63.54	73.08	93.08	74.34	110.46	101.00
Bihar	79.70	81.30	94.99	104.82	106.76	108.79	101.52	106.13	104.19
Delhi	101.10	NA	141.69	163.75	178.72	147.19	174.60	182.22	159.95
Gujarat	29.40	33.70	32.75	39.68	42.16	47.25	52.61	53.68	54.18
Haryana	48.20	59.90	57.09	69.89	69.66	74.95	95.43	118.94	119.80
Himachal Pradesh	60.80	65.50	69.40	63.40	67.38	70.78	65.10	74.12	69.67
Jammu & Kashmir	130.50	141.90	136.21	143.94	153.87	153.87	164.37	166.42	160.41
Karnataka	116.50	116.20	115.53	115.43	116.49	116.49	135.82	136.55	136.33
Kerala	21.10	32.40	31.97	35.58	46.95	55.26	39.37	45.92	51.25
Madhya Pradesh	56.90	55.70	51.49	52.99	54.17	52.38	53.66	54.98	56.02
Maharashtra	28.70	27.90	25.39	31.87	30.12	33.77	33.46	38.34	39.36
Meghalaya	13.50	9.50	23.71	10.91	19.34	14.23	18.25	14.99	24.43
Orissa	38.40	62.90	90.49	121.01	197.91	196.99	193.96	105.83	105.82
Punjab	24.40	26.50	25.82	30.29	28.61	35.34	30.17	28.54	28.31
Rajasthan	60.70	65.40	67.34	72.87	77.57	71.07	71.07	69.13	65.02
Tamil Nadu	37.90	39.70	39.14	35.55	42.86	40.82	46.77	48.20	47.00
Uttar Pradesh	57.50	53.70	51.65	51.77	51.81	53.59	55.23	54.67	54.50
West Bengal	89.80	82.40	85.30	94.50	90.39	92.18	102.06	105.44	105.11
All SEBs	50.40	50.30	52.78	56.28	61.63	61.79	65.98	74.29	74.21

Source: *same as T 2.1.*

The continuos fall in the value of the rupee vis-a- vis the dollar has led to the sharp rise in the costs of electricity. This has led to the private power projects to hike their tariffs, since they are dependent on a large foreign equity component. The burden of the higher import costs will largely be borne by the state electricity boards as the independent power projects (IPP) developers have made sufficient provisions to secure their payments from the state electricity boards (SEBs).[8] But this doesn't seem quite plausible. Exchange risk is unavoidable and perhaps least expensive if we bear it. Suppose a power plant is built domestically, using funds borrowed from international markets, we would have to pay back in dollars and would have to bear the exchange risk too.

2.9 Choice of Fuel

Before setting up the plant, the producer signs a power purchase agreement with the electricity board concerned, which takes complete care of payments for the power supply, including safeguards for exchange fluctuations. The SEBs transmit electricity to a large number of consumers in their respective states. Each category is price sensitive and there is little doubt that the SEBs will face major hurdles in increasing its tariff. In fact, at present rates, from certain sectors it will not even earn half its cost on the power purchase. The power tariff is based on the two components: fixed cost (which includes project cost) and variable cost, including the cost of fuel. The fixed cost will increase due to fluctuation in the foreign exchange. But this is not necessarily the case. It is true only for the new projects and that too for those, which are dependent on imported equipment.

[8] Mallika, S.(1998); http://www.rediff.com/business/1998/feb/13power.htm

The rupee depreciation will make imports of equipment and services for the projects more expensive, thereby leading to a proportionate increase in project costs. The impact on tariff will be greater if the plant is run on imported fuel, which will be the case of most new power plants in the country. Since India has limited liquid fuel resources, the power producers will be forced to import the fuel from overseas, which, in turn, will affect the tariff.[9] For instance in the case of Enron promoted Dabhol Power Project, for every 1000 MW of Gas turbine based power generation, the amount of about 1.5 million tonnes of oil equivalent would have to be imported per annum.

India is the world's third-largest producer of coal, and relies on coal for more than half of its total energy needs. Despite large reserves of coal and renewable energy resources, India is and will continue to be a net importer of energy for the foreseeable future. Indian consumption of natural gas has risen faster than any other fuel in recent years. From only 0.6 trillion cubic feet (Tcf) per year in 1995, natural gas use is projected to reach 1.2 Tcf in 2000 and 1.9 Tcf in 2005. Increased use of natural gas in power generation will account for most of the increase, as the Indian government is encouraging the construction of gas-fired electric power plants in coastal areas where they can be easily supplied with liquefied natural gas (LNG) by sea. Given that domestic gas supply is not likely to keep pace with domestic gas demand, India will have to import most of its gas requirements, either via pipeline or LNG tanker, making it one of the world's largest gas importers.[10] Obviously, the costs of power purchase of electricity have risen alarmingly and continue to do so unabated.

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[9] ibid.

[10] http://www.tcrina.org/conf7.htm

Though, coal-based generation continues to be the mainstay of power generation in India, large scale capacity addition based on oil and / or gas has been preferred in the last decade. Now this shift is further consolidating on liquefied natural gas (LNG)-based capacity addition. The main reasons for this shift are said to be the favorable economics of LNG and the problems related to Indian coal supply and its quality. But little reliable information is available in the public domain about the cost of LNG-based generation, while many experts have expressed concern over viability of LNG-based generation.

In 1991, during the first phase of reforms and liberalization in the Power Sector, Independent Power Producers (IPP) were invited to add generation capacity. This was also accompanied with a liberal attitude towards import of fuels. For example, till 1999, about 2,746 MW of imported oil/gas-based IPP plants have been commissioned and 3,343 MW plants are under construction. Compared to this, only 411 MW IPP plants based on coal are commissioned and another 500 MW are under construction.[11]

The emphasis on LNG is often said to be due to its (expected) economic advantage over coal-based generation and also due to the problems related to availability and quality of India coal. The LNG is also seen as a cleaner fuel. But there are contradictory viewpoints about the economics of LNG as well as the rationality of this fuel shift. Before going any further, we need to look at whether there are really any problems relating to coal being used as a fuel in the power plants.

Coal-based generation is the mainstay of the power sector in India with over 60 per cent of the generation capacity being coal-thermal. Even though India has coal reserves sufficient to last for two centuries (coal reserves as on September 1, 1997 were

[11] MoP (1999); www.powermin.nic.in/nrg75.htm.

estimated at 207 billion tonnes), the problems relating to rate of production, transportation and quality of coal have resulted in substantial difficulties in expanding coal-based generation. In addition to this, even the performance of existing coal- based plants is affected due to shortage of supply and high ash content.

But problems relating to coal are not new. The 'National Power Plan Generation Expansion' prepared by the Central Electricity Authority (CEA) nearly two decades ago also points out problems related to coal, production shortfalls, and transportation bottlenecks. The study reported that the average calorific value of coal supplied to the power plants declined from 5,900 Kcal/Kg in 1960-61 to 4,300 Kcal/Kg in 1981. Presently the average calorific value is in the range of 3,400 - 3,800 Kcal/Kg.[12]

In 1988, the Bureau of Industrial Costs and Prices (BICP), Ministry of Industry (MoI) published a study titled "Towards a New Energy Policy" (BICP, MOI 1988). It was one of the first studies challenging the role of coal as the primary fuel for power generation in the country. It argued that imported oil would be a cheaper option under certain conditions. This study worked out distance of the load center from coal mines and from the sea shore for which power generation based on imported oil would be more economical than use of Indian coal. This study concluded that, for the load centers located near the shore and at a distance of more than 400 to 1,000 km from coal mines, imported oil would be a cheaper option. The paper did not analyze the option of importing coal. It generated substantial debate and led to serious thinking about using imported hydrocarbon fuels for power generation, which earlier was a non-option owing to the restrictions on foreign exchange and the policy of self-reliance. However, the

[12] CEA (1998)

conclusions of the BICP study are no longer valid because the prices and dollar-to-rupee exchange rates have both changed drastically from the values used in the study (oil price was assumed to be in the range $16 to 20 / Barrel, and exchange rate at $1 = Rs 13).

During the mid 1990s, the Government of India (GoI) sanctioned oil import for over 10,000 MW of short gestation power plants, in an attempt to achieve rapid capacity addition. But these projects are now seen as prohibitively costly and only few of these projects have come on line. As mentioned earlier, now the focus has shifted from import of oil (i.e. naphtha) to import of LNG.

But little reliable information is available in the public domain about the key aspect, namely the cost of LNG and the resulting cost of electricity that would justify the use of LNG for power generation. As LNG price is linked to oil price, there is a large element of uncertainty introduced. The fuel policy document by a high-level committee of the Prime Minister's Office, assumes the price of imported LNG at $3 to 4/MMBTu, while arguing that LNG-based capacity addition of 23,000 to 30,000 MW by 2007 would be economical (PMO 1999). On the other hand, Mr. R.V. Shahi, Chairman and Managing Director of the largest private utility in India (Bombay Suburban Electric Supply), claims that LNG price was expected to be $ 4/MMBTu when crude oil price was $18/Barrel. But now the "crude oil price (of) almost $ 28 to 30 per barrel, might mean the fuel cost itself (excluding the customs duty) would be more than Rs. 2 / kWh".[13] This indicates burner tip price of imported gas of around $6/MMBTu. This price is substantially higher than what has been assumed in the earlier study.

[13] Power Line (2000).

T 2.11: Assumptions of Main Power Plant Parameters for LNG (Combined Cycle Gas Turbine (CCGT)) and Coal-based Power Plants.

	LNG CCGT	**Coal Plant**
Plant availability (%)	90	80
Auxillary consumption (%)	3	8.5
Life (years)	30	30
Gross efficiency (%)	46	37
O & M costs (% capital cost/year)	2	2

Source: *Phadke Amol (2001): "Questionable Economics of LNG-based Power Generation"; Economic & Political Weekly, Vol.XXXVI, No.20, May 19.*

Notes:

1. Plant availability and auxiliary consumption as given in Ministry of Power, Government of India (MOP GOI) tariff notifications.[14] It allows an auxiliary consumption of 3 per cent for CCGT (oil /gas-based) power plants and 9 per cent for coal based plants. The auxiliary consumption of coal plants is taken as 8.5 per cent based on the achieved performance of several plants.

2. Efficiency of the power plants: This is a crucial issue, but several sources indicate a wide range of values. The gross efficiency, i.e. at generator bus of CCGT and coal plants are indicated in the range of 43 to 47 and 35 to 38 respectively (MOP tariff guideline.[15] This difference in efficiency for plants using the same fuel can be explained by the variation in plant size, technology, site conditions, and fuel quality.

3. O&M costs are taken at 2 per cent of capital cost, the norm allowed by MOP for tariff notification.[16]

While rejecting the request to support Enron's Dabhol power plant, the World Bank pointed out that the LNG is not the least cost option for capacity addition for a country like India. It said that the LNG- based project as formulated is not economically

[14] MoP (1992); http://powermin.nic.in/nrg47.htm.

[15] ibid.

[16] ibid

viable, and thus could not be financed by the Bank. Local coal and gas are the preferred choices for base load generation. Even when taking into account the fact that India will face increasing difficulties in meeting the growing demand for its local coal and gas and allowing for the differential costs of emission controls, imported coal-not LNG-would appear to be the next best choice for base load generation for MSEB.[17] It needs to be noted that the oil price was very low when this warning was given. Thus there is no unanimity over the economic advantage in use of LNG.

The cost of power from any plant has three major components: (a) capacity cost of plant, (b) the cost of transmission, including the losses in transmission, and (c) the fuel cost. The total of these costs largely determines the resultant cost of electricity. The assumptions of Main Power Plant Parameters for LNG (Combined Cycle Gas Turbine (CCGT)) and Coal-based Power Plants are listed in T 2.11.

Capital cost depends on issues such as site conditions, associated infrastructure development needs (such as roads and ports), financing costs, and construction period. The capital cost of power projects in India is considered to be higher than the international norms. Initial IPPs were negotiated on cost plus basis without incentive for cost reduction. Recently some contracts have been negotiated through competitive bidding for tariff. But their capital costs are not known. Such projects are few and the non-competitively bid projects are expected to dominate in the near future. The capital cost of Enron's Dabhol Power Project is US $ 920/kW (excluding the LNG facility), wheras another CCGT project in Bangladesh is expected to cost only US $ 500/kW.[18]

[17] World Bank (1992).
[18] World Bank (2000).

Three different sources of capital cost of power projects in India are considered. The comparison of these capital costs is summarized in T 2.12.

T 2.12: Capital Cost of Ongoing / Approved Power Plants in India (Rs crores/MW)

	Source 1	Source 2	Source 3
Average cost of CCGT plant	3.36	4.28	3.45
Average cost of coal-based plant	4.47	5.10	4.50
Cost of coal plant as a % of CCGT plant	133%	119%	130%

Source 1: *Ministry of Power (MOP)(1999): 'list of Private projects with techno-economic clearance'. Data for 9,781 MW of gas-based; 16,679 MW of coal-based projects respectively.*

Source 2: *Project Finance Ware (2000):'Database Search and Analysis Conducted by the World Resources Institute, UK. Data for 11,537MW of CCGT and 23,087 MW Of Coal-based power projects proposed in India.*

Source 3: *Central Electricity Authority (CEA)(1998): 'Fuel Map of India'; Ministry of Energy (MoE), Government of India (GoI), New Delhi.*

As seen in the above table, capital cost of coal projects is 20 per cent to 33 per cent higher than that of CCGT project. This analysis considers the capital cost of CCGT and Coal plants in India as Rs. 3.5 Crore/MW and Rs. 4.5 Crore/MW respectively (i.e. Coal plant to cost 30 per cent higher than CCGT plant).

The transmission cost consists of transmission infrastructure cost and the cost associated with technical losses. Both of these costs depend upon the transmission distance as well as the transmission technology (DC or AC and the voltage level). Infrastructure cost consists of costs of transmission lines and towers (which is directly proportional to the distance) and the substation cost (which is not directly linked to transmission distance). A transmission distance of 2,000 km for domestic coal plants and 200 km for plants based on imported coal and CCGT has been considered.

Transmission losses are taken as 4 per cent and 1 per cent for transmission distance of 2000 km and 200 km respectively. For transmission over large distances such as 2000 km the suitable technologies are 765 kV AC or 500 kV DC. For short distances (such as 200km), a 400-kVAC technology is considered appropriate. The total transmission cost including the technical losses is reported to be in the range of Rs. 0.4 to 0.55/kWh for 2,000 km and Rs. 0.08 to 0.12/kWh for 200 km.[19] Here, the transmission costs are considered as Rs. 0.55/kWh for 2000 km and Rs 0.1/kWh for 200 km. A recent study by Power Grid Corporation of India indicates similar costs for HVDC transmission of bulk power for large distances.[20]

Now we take a look at the fuel prices and their trends in the past decade. For imported coal, there exists a spot market and price trends can be found. For Indian coal the price has been de-controlled only recently. The LNG prices are the most difficult to obtain, as most LNG contracts are not available in public domain. Estimate of LNG prices based on the information available in public domain is used here.

LNG Cost

The natural gas price at the power station consists of several components. The cost of LNG, LNG shipping costs, taxes and duties, and regasification cost. LNG contracts are usually long-term contracts, LNG price being either fixed or linked to oil price indices. In case of linkage with the oil price, some-times the possible fluctuations

[19] WCD (1999); TERI (1997); CEA (1998).
[20] Jha, S. (1999).

are limited by adding ceiling and/or floor prices Most contracts also include "take or pay" clauses. Shipping and re-gasification costs are usually fixed. The estimation of LNG price is based on the following information available in the public domain.

a) Some news reports indicate that the companies marketing natural gas (regasified LNG) are quoting a price that is 10-15 per cent lower than price of oil like Naphtha / Distillate. This, at today's cost, amount to $ 5.8/MMBTu.

b) A study by Tata Energy Research Institute (TERI) argues that the LNG cost generally has a 10 to 15 per cent premium compared to price of Brent crude oil (in $/MMBTu). With the oil price range of $ 16 to 18/barrel, the estimated price of LNG is $ 3.1 to 3.6 /MMBTu in India.[21]

c) As per the earlier quoted interview of Mr. R. V. Shahi, LNG price was $ 4/MMBTu when oil price was $ 18/barrel and with present oil price of $ 30/barrel the gas price (including cost of regasification) is expected to be around $6/MMBTu.[22]

d) The USA federal docket shows a LNG sales price of $ 3.47/MMBTu while the crude price was $ 18/barrel.[23]

The above references suggest that burner tip LNG price would be over $ 3.5/MMBTu when the oil price is about $ 18/Barrel and it would be in the range of $ 5.5 to 6 /MMBTu when the oil price is about $ 30/Barrel. The price would also depend upon the nature of the contract as mentioned above.

[21] TERI (1997).
[22] Power Line (2000).
[23] FERC (2000).

Imported Coal Cost

Some state power utilities in India (like Tamil Nadu, Punjab, Gujarat, and Maharashtra) have imported coal in the past. But this is not a regular phenomenon. The price of imported coal at the power station is sum of Free On Board cost (FOB cost, at the producers end), shipping cost, port handling charges, taxes and duties, and land transportation cost (if any).

Over the last decade, the international price of coal has been steadily declining. The US coal price in real $ has declined steadily in the last decade (about 20 per cent in last 10 years) and is estimated to decline further. This trend can be seen in the case of Australian coal also. The FOB cost of Australian coal in 1997 was $34/Ton and the present price is around $24/Ton (a 30 per cent decline in nominal $).

The cost of shipping coal for 5080 knots, using a medium sized vessel, is reported to be around $6.9/ton (Coalportal 2000). For importing coal in India, the freight is expected to of the same order (distance between Newcastle, Australia to Madras, India is 5561Knots). The freight rate from Australia to India will be in the range of $ 7 to 8.5/Ton depending upon the coast. The port handling costs at Indian ports are in the range of $ 5/ ton.[24] All these costs need to be added to arrive at the effective cost of coal. Considering these aspects, the landed cost of imported coal would not be more than US $ 40/ton (i.e. Rs. 1800 / ton). The present cost of imported coal (with a calorific value of more than 6,500 Kcal. /Kg) has been considered at Rs. 1,800/ton. A foreign exchange premium of 15 per cent has been added to this cost, implying an effective cost of 2,070 Rs/Ton.

[24] TERI (1997).

Domestic Coal Cost

Until the end of 1999, the government administered coal prices. The present prices are not much higher. Estimates of long run cost of power-grade coal production from various coal fields, carried out in the study "Energy Modelling for India", indicates a price of around Rs. 800/ton (in 2000 prices).[25] We have taken coal price to be Rs. 800/ton, with the calorific value of 3,800 Kcal/Kg implying a coal cost of Rs. 198/Mkcal ($ 4.4 / Mkcal).

Now we take a base case comparison of LNG, Imported coal and Domestic coal-based base-load power generation. To carry out the comparison, the exchange rate of $1=Rs. 45 has been assumed for all the calculations. The methodology used for the following calculations are shown below.[26]

Capital recovery factor (d)

$$d = c \Big/ (1-c)^{(-b)}$$

Where, 'b' is economic life and 'c' is discount rate.

Annualised capital cost (e)

$$e = d * a * 10^4$$

Where, 'a' denotes Capital cost and 'd' is the Capital recovery factor.

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[25] Ibid.

[26] Phadke, Amol (2001).

***Capacity cost** (i)*

$$i = \frac{(e+f)}{\frac{(g*8760)}{(1-h)}}$$

Where, 'e', 'f', 'g' & 'h' denotes Annualised capital cost, O & M cost, Plant availability and Auxiliary consumption respectively.

***Heat rate net of auxiliary consumption** (o)*

$$o = \frac{860}{m*(1-h)}$$

Where, 'm' denotes Generation efficiency and 'h' denotes Auxiliary consumption.

***Fuel cost** (p)*

$$p = (\frac{n*10^{(-3)}}{l})*o$$

Where, 'l', 'n' & 'o' denotes Calorific value, Fuel cost and Heat rate net of Auxiliary consumption respectively.

***Fuel cost with premium** (r)*

$$r = p*(1+q)$$

Where, 'p' & 'q' are Fuel cost (taking into account the heat rate) and Forex premium respectively.

***Total cost** (s)*

$$s = i + k + r$$

Where, 'i' denotes capacity cost, 'k' denotes transmission cost and 'r' is the Fuel cost with premium.

The results are presented in T 2.13 below.

T 2.13: Base Case Comparison of LNG, Imported Coal and Domestic Coal-Based Base-Load Power Generation

	Domestic Coal	Imported Coal	Imported LNG
Capacity Cost			
a. Capital cost (Rs. Crore/MW)	4.5	4.5	3.5
b. Economic life (Years)	30	30	30
c. Discount rate	15%	15%	15%
d. Capital recovery factor	0.1523	0.1523	0.1523
e. Annualised capital cost (Rs./kW/yr.)	6854	6854	5331
f. O & M cost (Rs./kW/yr.)	900	900	700
g. Plant availability (%)	80%	80%	90%
h. Auxiliary consumption	8.50%	8.50%	3.00%
i. Capacity cost (Rs./kWh)	1.21	1.21	0.79
Transmission Cost			
j. Distance from the load centre (km)	2000	200	200
k. Transmission cost (Rs./kWh)	0.55	0.1	0.1
Fuel Cost			
l. Calorific value (kcal/kg)	3800	6500	NA
m. Generation efficiency	37%	37%	47%
	Rs./ton	Rs./ton	$/MMBTu
n. Fuel cost	800	1800	4.5
o. Heat rate net of auxiliary consumption (Kcal/kWh)	2540	2540	1886
p. Fuel cost (Rs./kWh)	0.53	0.70	1.52
q. Forex premium (%)	0%	15%	15%
r. Fuel cost with premium (Rs./kWh)	0.53	0.81	1.75
Cost of supply at the load centre			
s. Total cost (Rs./unit)	2.29	2.12	2.64

Source: *Phadke Amol (2001) Economic & Political Weekly, Vol.XXXVI, No.20.*

Furthermore, the following conclusions could be drawn:

1) Even at the lowest level of LNG price of \$ 4 /MMBTu and at the prevailing capital costs, both imported coal as well as domestic coal-based generation is cheaper than the LNG-based generation for a wide range of coal prices. At the present coal prices of imported and domestic coal, the loss per year because of choosing a 2,000 MW LNG based plant over an imported coal-based plant or a domestic coal-based plant is about Rs. 500 crores to 300 crores respectively

2) At the prevailing price of LNG (which is in the range of \$ 5 to 6 /MMBTu), the loss per year because of choosing a LNG-based power plant instead of a similar coal-based power plant is colossal. When compared with domestic coal-based power plant it is in the range of Rs. 1,000 to1, 500 Crores per year; while for imported coal, it is in the range of Rs. 1,200 to 1,700 Crores each year.

3) The above figure also considers the possibility that the capital cost of coal-based projects is substantially higher than LNG-based projects. At the prevailing fuel prices, even if we assume that the capital cost of coal-based plant is much higher than the prevailing trend (i.e. the capital cost of coal-based plant is about 60% more than capital cost of LNG-based plant, instead of prevailing value of 30%) the Coal projects are far more economical. The loss because of choosing a 2000 MW of LNG-based power plant instead of coal ranges from Rs. 400 to 900 Crores each year, when compared with a domestic coal base plant.

4) LNG-based generation is economical only in a very unlikely situation when, LNG cost are very low, capital cost of coal-based plants are much higher than the

prevailing costs, and coal prices are much higher than the prevailing prices. In all other situations, the LNG is uneconomical for power generation.

5) As the analysis assumes a transmission distance of 2,000 km for domestic coal-based power plants, for transmission distances less than 2000 km (which could be the case for substantial part of the country) domestic coal-based generation will be more economical than indicated here.

6) Imported coal prices are showing a steady decline for the last decade, this trend is expected to continue, and in that case imported coal-based generation will be more economical than LNG-based generation for almost all-possible prices of LNG.

The above analysis clearly indicates that domestic coal and imported coal based power generation are more economic options than LNG based power generation in most parts of the country, under a wide range of assumptions regarding the capital and fuel costs. The loss due to a single LNG power plant (of 2,000 MW) is in the range of Rs 300 crores per year, in case of low oil price of $ 16-18 /barrel to 1,400 crores per year, in the present case of high oil prices.

- Import of LNG is a bad option even if one decides to import fuel as a short-term measure on account of availability and quality problems related to Indian coal. The option of imported coal turns out to be more economical than import of LNG. It would result in lower cost of generation even if the LNG cost (at burner tip) is as low as $ 4 / MMBTU, and capital cost of coal projects in at high as Rs. 5.8 crores /MW.

Till the establishment of central generating stations under the central government power companies from the early 1980's, the industry was dominated by vertically integrated SEBs and private Licensees. SEBs could purchase electric power from any person under the provisions of section 43 of the E (S) Act on terms as agreed between the contracting parties. However no defining principles were available for tariff setting and tariffs for individual stations were decided on the basis of mutual consent between the generator and the consuming SEBs.[27] Now with the establishment of IPPs, SEBs are bound under the purview of the PPA signed with the IPP developer to buy costly power from it, even if cheaper sources are available. The Enron promoted Dabhol Power Project is a notable example of this.

Another notable example is that of the Grid Corporation of Orissa Limited (GRIDCO) is forced to draw about 770 million units at a steep Rs.2.55 a unit from NTPC stations at Kaniha and Kahalgaon with a combined generation capacity of 2,000 MW. Thirty per cent of the power purchased by GRIDCO comes from the NTPC and this accounts for 42 per cent of GRIDCO's power purchase bill. GRIDCO lacks the network to channel all this power to consumers. Yet it is forced to pay for it, since there are technical problems in disconnecting the seven points through which the power flows.[28]

The generous terms of the two-part tariff guidelines were justified on the ground that they were needed to woo reluctant foreign investors. The policy set no limits on the extent of foreign capital, in fact, the more the better was the general refrain then. The two-part tariff guidelines offer, inter alia, a 16 per cent return on equity, market interest on debt— both domestic and international—and front loaded depreciation rates all of which translate into capacity charge in the tariff. While return on foreign capital is fully repatriable in foreign currency, so is the interest on foreign debt. But the tariff guidelines

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[27] http://www.cercind.org/chapter1_2.htm
[28] Mahalingam, Sudha (1997).

went one step further and made the power purchaser bear the entire exchange risk—a measure that has now come home to haunt hapless utilities like Maharashtra State Electricity Board (MSEB) which went ahead and signed contracts with a huge foreign exchange content.[29]

No wonder the regulator is concerned—it will have to perform the unpleasant task of allowing the escalation to be loaded on to the tariffs. After all, exchange risk, being a pass-through item, is borne by the consumers of electricity and the regulator will have no leeway in this regard. While MSEB could avoid incurring fuel costs by not drawing a single unit of Dabhol power, it has no way of escaping the hefty exchange risk costs which are an integral part of the capacity charge.[30]

The K. P. Rao committee recommended (which the government later implemented) efficiency-enhancing changes were effected in the existing incentive structure. Till 1991, the single part tariff was calculated such that full recovery of fixed costs was assured at a PLF of 62.8 per cent. Generation below this target level penalised the generator on the recovery of fixed cost, since the tariff got proportionately reduced. Conversely, generation above 62.8 per cent resulted in significant excess revenue. The formula adopted post 1991 limited both the incentive and disincentive for recovery of fixed costs. The incentive beyond 68.5 per cent PLF was lower than before while even with nil generation 50 per cent of the fixed cost was recoverable.[31]

The pricing policy according to the IPP policy follows the concept of a two-part tariff. Under the concept, if the power plant operates at a PLF of 68.5 per cent, all

[29] Mahalingam, Sudha (2001); http://www.teriin.org/features/art120.htm
[30] ibid.
[31] http://www.cercind.org/chapter1_2.htm

operating costs including fuel, depreciation, interest, and tax would be recovered fully, besides a return on shareholders funds (excluding retained earnings) of 16 per cent p.a. If the actual PLF falls below 68.5 per cent, there would be an under recovery of costs and a lower return on shareholder's funds. If the actual PLF is higher than 68.5 per cent, the excess power will be priced at the variable fuel costs and an incremental return of 0.7 per cent on the shareholder's funds for every 1 per cent increase in PLF. This is called the second part of the tariff.[32]

In most cases, payment is based on generation, rather than the availability. This results in demand side risk. Revenues of the IPP plants are tied to PLF, rather than the availability factor, which is the more common basis for IPP revenues. In other words, earnings are subject to demand-side constraints. Thus, if the counter-party grid does not require sufficient capacity to dispatch the plant at high levels, the envisioned RoE of 20 per cent -plus may not be attainable. Less likely, but still possible, is that the RoE could fall below the 16 per cent base-case RoE if the grid does not dispatch at the 68.5 per cent base-case plant load factor.[33]

2.10 Transmission & Distribution (T & D) losses

The power sector in India is plagued by the nagging problem of the transmission and distribution (T & D) losses. It is quite large here as compared to many other countries. The energy sent out, net of auxiliary consumption, then fritters away in T & D network to such a substantial extent that by the time it reaches the sales point, it would often be only a smaller fraction of the net generation. Out of total energy generated, only

[32] http://www.webindia.com/equity/power170498.html#ipp
[33] ibid.

55 per cent is billed and only 41 per cent is realised. The loss due to power theft alone costs the sector well over Rs. 20,000 crores annually. Nearly 100 billion kwh of electricity was lost in T & D in various states in 1998-99. The losses increased from 19.8 per cent in 1992-93 to 25 per cent in 1998-99. The revised estimates for 1999-00 indicates these losses as 23.7 per cent and are expected to fall to 23 per cent in 2000-01.[34] These are very high by international standards- compared with less than 10 per cent in most of the developed economies and with less than 15 per cent in many developing countries such as China (7 per cent), Thailand (10 per cent), Argentina (12 per cent) and Chile (11 per cent).[35] A good part of the net generation, itself falling short of demand, thus being lost in transit, power purchase from other states and central sector perforce increases more than is required otherwise. This has led to considerable increase in the costs of purchase of power. In 1997-98, energy import by SEBs ranged from 16.5 per cent of the total energy sales in Meghalaya to as much as 164 per cent in Orissa. Bihar (109 per cent), Karnataka (116 per cent), Delhi (147.5 per cent), Jammu & Kashmir (156.5 per cent), West Bengal (89 per cent) and Assam (79 per cent) were the other major importers. The appalling situation of having to resort to energy purchase much in excess of cent per cent, as in the case of the above five SEBs, means that their auxiliary consumption and other losses of energy far exceeded their own generation to cut down even the costly purchase itself.[36]

There is little doubt that even these high figures of T & D losses are only underestimates that find a suitable cover- up in the overestimates of agricultural

[34] Government of India (2001).
[35] Rao, Shand and Kaliranjan (1998-99).
[36] Kannan and Pillai (2001) b.

consumption. In most of the states, agricultural consumption is largely unmetered, and the SEBs in their eagerness to record reduced transit losses, find this situation a convinient dump for a good part of the unaccounted- for energy.[37]

Not only are the SEBs plagued by technical inefficiency constraints in the form of T & D losses, there are also the institutional and organisational factors. The number of employees per MU of energy sold in India in 1990-91 was about 5 (i.e. labour productivity of 0.2 per employee), while it was 0.2 (or 5 MU per employee, i.e. 25 times higher than that in India) in Chile, Norway and USA. In New Zealand, Argentina and UK it is about 0.6 (or 1.7 MU per employee) and less than 2.5 (or 0.4 MU per employee) in some developing countries such as China, Phillipines and Indonesia.[38] Though the ratio in India, declined marginally to 3.6 in 1996-97, still higher by the standards abroad, wide disparity prevails across the states, from 41.4 in Arunachal Pradesh to 1.9 in Gujarat.

These inefficiencies come out in inflated proportion in the cost of electricity supply. Allowing for some improvements in operational, T & D, and maintaining power planning efficiencies would reduce the unit cost of supply of all SEBs substantially, by 60.77 paise per unit sold, to Rs. 1.67 per unit in from Rs. 2.28 per unit in 1997-98. If we compare this with the average revenue (AR) realised from sales of Rs. 1.85 per unit in the same year. This would yield additional revenue of about Rs. 9,459 crores over and above the total cost of electricity supply- a commercial profit. To this extent then the reported commercial loss of the SEBs, attributed to the so-called unit- cost unrecoverable AR,

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[37] Ibid.
[38] Rao, Shand and Kaliranjan (1998-99).

turns out to be nothing but inefficiency- caused loss. The unit cost savings from efficiency improvement for 1997-98 is shown in the following table, T 2.14.[39]

T 2.14: Unit Cost Savings From Efficiency Improvement for 1997-98 (paise/ unit)

	(paise/ unit)
1. Reported unit cost of power supply in 1997-98	227.89
2. cost savings obtainable	
(I) in power purchase from operational efficiency improvement	49.72
(ii) in establishment & administration, from reduction in over- manning	11.05
(iii) in interest payments, from introduction of 1:1 debt- equity ratio	14.85
3. Total savings possible	75.62
4. Efficient unit cost of power supply	152.27
5. Average revenue realised in 1997-98	184.50
6. Unit commercial profit realisable	32.33
7. Electricity sold in 1997-98 (MU)	293,479
8. Commercial profit realisable (Rs.million)	94,588.25

Source: *Kannan & Pillai (2001); Economic & Political Weekly, January*

The net generation of electricity by all the SEBs in 1997-98 is estimated to be 2,28,020.3 MU. If we assume that the T & D loss could be kept at a minimum of 15 per cent, then the energy that must be available for a sale of 2,93,478.9 MU in that year would be 3,45,269.3 MU, thus necessitating an import of 1,17,248.99 MU (about 40 per cent of the total sales) only, instead of the reported 1,74,373.9 MU (about 60 per cent of the sales), giving a saving in power purchase of 57,124.9 MU, or in power purchase cost of Rs. 7,924 crore at an average power purchase rate of Rs. 1.39 per unit. This would

[39] Kannan and Pillai (2002).

reduce the unit cost of electricity supply, on account of power purchase cost, to Rs. 2.01 per unit sold, against the reported Rs. 2.28 per unit sold. Thus the cost of inefficiency in the T & D system alone comes out to be about 27 paise per unit of electricity sold.[40]

The time overruns of power projects involves manifold and thus heavy costs- besides incurring the cost escalation of the projects and the power purchase costs, the system also is forced to forgo additional sales revenue obtainable. Thus the cost of inefficiency at the planning and execution level is also very high. If we allow for the expenses capitalised, then the total cost in the accounting sense would still decline and commercial profit increase. Yet another factor is the PPA which often contain booby traps of forced purchase provisions. In order to respect the PPA, the SEBs are sometimes compelled to back down their own cheap generators. This is because the PPA is in general designed for a base load plant only, which is permitted to generate at full load whenever possible. This commitment requires backing down of the existing cheaper power stations during off- peak periods and monsoon season, causing uneconomic plant dispatch, i.e. low unit cost power being replaced by high cost power.[41]

In many states, a flat- rate tariff (tariffs based on capacity of the pump rather than on measured consumption) rather than free electricity, is offered, but in either case, existing meters were no longer monitored or were simply removed and returned to the SEBs. Outright opposition due to the high transactional costs of such non- remunerative monitoring and meter installation for new connections drove this.[42] Since the quality of power actually delivered to farmers had for long been extremely poor, it is widely

[40] Kannan and Pillai (2001) c.
[41] Ibid.
[42] Dubash and Rajan (2001).

accepted that most farmers are likely to prefer metered and priced reliable electricity to unmetered free (or low- tariff) unreliable electricity.[43]

In fact, power subsidies have become routine political instruments especially in agricultural states. Moreover, the reliability of consumption estimates has become increasingly suspect. For instance, in Karnataka by the early 1990's, it was estimated that less than half the electricity produced was being metered, the rest being attributed to agriculture and T & D losses. This continued until around 1997. However, in an independent study, the International Energy Initiative showed how the actual losses were likely to be much higher than reported, and the agricultural consumption, correspondingly lower.[44]

Moreover, agriculture consumers in many states are charged on the basis of Horse Power (HP) based tariff. Because of this, it is difficult to assess the consumption of energy by agricultural consumers. HP tariff has led to excessive and unbridled use of energy by the agricultural sector. Also, it provided a possible cover for energy thefts and other commercial losses, which are now disguised as agricultural consumption. Now we have a situation where only about 60 per cent of the energy supplied by the SEBs get billed. Of the energy billed, a large amount is not collected. Mis-classification of consumers (for instance, commercial consumers classified as domestic consumers) results in subsidy being given to undesired consumer class.[45]

Adding to an already over-burdened T& D system, T & D losses merit concern. T & D losses for Indian utilities in aggregate increased from 17.5 percent in 1970/71 to

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[43] Reddy, A. K. N. (2000).
[44] Reddy, A. K. N. and Sumithra, G. (1997).
[45] MoP (1999) a.

21.7 percent in 1985/86, and then levelled off to about 21 percent by 1990/91. As a result, for every GWh of electricity demand about 1.265 GWhs must be generated. Without any doubt the cost of power increase is on the rise.[46]

Apart from technical losses, the incidence of non-technical losses is also quite high. According to a study for the Delhi Vidyut Board total T & D losses of 22 percent comprise about 13 percent technical losses and 9 percent commercial losses. 17. T he reasons for high non-technical losses include electricity theft, faulty meters and un-metered supply. If non-technical losses could be curtailed, T & D operating losses in India would closely match those of most developed countries.[47]

However, due to lack of adequate investments on T & D works, the T & D losses have been consistently on the higher side, and are presently in the range of 22-23 percent. Reduction of these losses by undertaking distribution system improvement works has not been possible for want of adequate funds. Out of the above losses of 19 percent at distribution level, non-technical commercial losses account for about 5 percent. Thus the technical losses of 14 percent are primarily due to inadequate investments for system improvement works, which has resulted in unplanned extensions of the distribution lines, overloading of the system elements like transformers and conductors, and lack of adequate reactive power support.[48]

Let us assume that the remaining 35 per cent is available for sales rather than being lost in transit. We also assume that consumption is satisfied at the given level of 2,93,478.9 MU (in 1997-98), and that the operational efficiency, has already brought

[46] http://www.indianelectricity.com/trans.htm
[47] ibid.
[48] http://www.indianelectricity.com/distri.htm

down the power purchase requirement to 69,187.5 MU, we can have a further reduction in power purchase cost. Using the 35 per cent recovered energy equivalent to 31,073 MU, will generate Rs. 4,310.14 crore or 14.69 paise per unit sold. This will reduce the efficient unit cost of power supply further to Rs. 1.38 per unit, from the reported cost of Rs. 1.28 per unit. Comparing this with the average revenue realised in 1997-98 would yield a commercial profit of Rs. 13,770 crore.[49]

2.11 Losses Due to Subsidised Power Supply

A major factor that determines the level of commercial loss is the differential pricing policy. Loss results if the government subsidy from other sectors are not enough to neutralise the effective subsidies given to agriculture and domestic consumers.[50] Effective (cross) subsidy is defined as the product of the difference between the average cost of power supply and the average revenue realised from a particular sector, and the total power sold to that sector. In other words,

$$\textit{Effective Subsidy} = (AC - AR_i)\, Q_i\,;$$

Where, AC is the average cost of power supply,

AR_i is the average revenue realised from the i^{th} sector, and

Q_i is the total power sold to the i^{th} sector.

[49] ibid.
[50] Kannan and Pillai (2001) c.

Gross Subsidy on agriculture, domestic and inter-state sales has increased from a level of Rs. 7449 crore in 1991-92 to 20209.96 crore in 1996-97 and is likely to increase to Rs. 37712.65 crore in 2000-01 (AP). The gross subsidy per unit (Kwh) of energy sold during 2000-01 works out to 108 paise. While some State Governments partly compensate the SEBs for the subsidized sales of electricity to agricultural and domestic sectors others do not provide any compensation at all. The 2000-01 Annual Plan Proposals indicate the likely subvention from State Governments as Rs. 5792.80 crore. The SEBs make an effort to recover the losses due to the subsidized power supply to agriculture and domestic consumers by way of cross subsidization mainly to the industrial and commercial consumers. It is estimated that the surpluses generated by way of cross subsidization for the year 2000-01 are Rs. 7606 crore.

The subsidy given by the state governments, together with the cross subsidies from other sectors (industry, commercial and railway traction) neutralise only about 60 to 80 per cent of the effective subsidies, with the major portion contributed by cross subsidies. This is because all states do not compensate the SEBs for the subsidised electricity sales to agriculture and domestic consumers. Some of the state governments, on the other hand, write off the interest due to them also in compensation for the subsidised sales. Moreover the tilt in the compensating mechanism has been to tax the other sectors haeavily and tap the maximum cross subsidies. In fact, the sate government subsidy constituted only 17- 20 per cent of the total effective subsidy to agriculture and domestic sectors, while the cross subsidy accounted for about 40 per cent of it.[51]

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[51] Kannan and Pillai (2001) c.

T 2.15 indicates the extent of cross subsidization from these sectors. The cross subsidy from commercial and industrial sectors (as a percentage of effective subsidy to domestic and agricultural consumers), which was 41.7 per cent in 1992-93, declined to 25.3 per cent by 1999-2000 (RE). It is expected to further decline to 21 per cent in 2000-01. This reflects that share of domestic and agricultural consumers, who get power supplies at subsidized rates, has been progressively increasing over the years as compared to decline in the share of industrial sector consumption. The high cost of power imposed on the industry, the mainstay of the SEBs, which is now deserting the grid in taking the captive route, and thus worsening the crisis of the SEBs. It can be computed that the alternate means of generation using the captive route is about Rs.2.50 to Rs.3.00. on the other hand, the tariffs proposed by the World Bank experts are in the range of Rs.6.00 for industry and Rs.3.50 for agriculture. This has encouraged industrial and commercial sectors to set up their own captive generation.[52]

"Net subsidy" on account of sale of electricity to agricultural and domestic consumers was Rs. 5404 crore in 1991-92 which works out to 46 per cent of Central Plan Assistance paid to states and UTs (Rs. 11749 crore) to States in that year and it is likely to increase to Rs. 31244.31 crore in 2000-01 (AP), which works out to 84.8 per cent of Central Plan Assistance (Rs. 36824.40 crore) to States in that year. Even if we consider Rs. 7606 crore surplus generated by the SEBs by way of cross-subsidization from other sectors, the uncovered subsidy will be of the level of Rs. 23638.35 crore for the year 2000-01. Introduction of the national minimum agricultural tariff of 50 paise/Kwh would generate additional revenue of Rs. 2260 crore during the year 2000-01. It is, therefore, suggested that State Government should take policy initiatives to reduce the gap between

[52] The Crisis of the State Electricity Boards: Real Issues"(2001); www.indiainfoline.com

the cost of supply and average tariff. Government may also look into the possibility of levying the excise duty and other local taxes and evolve a suitable mechanism to plough back the amount to meet the subsidy fully.

T 2.15:	**Surplus Generated/ Cross Subsidy from Other Sectors**		(Rs. crore)
Year	**Subsidy to Agriculture and Domestic sectors**	**Cross Subsidy**	**Subsidy to Agriculture and Domestic sectors**
1992-93	9,369.90	3,911.00	41.7
1993-94	11,096.40	4,522.50	40.8
1994-95	13,477.80	5,379.20	39.9
1995-96	16,830.40	6,333.70	37.6
1996-97	19,971.20	7,778.90	39.0
1997-98	22,965.10	9,010.90	39.2
1998-99	27,118.50	7,641.40	28.2
1999-00	32,644.90	8,247.30	25.3
2000-01	36,549.80	7,605.96	20.8

Source: *same as T 2.1.*

However, the reported loss due to subsidised power sales to agriculture in India is a substantially overestimated one. It has been found out that about 30 to 40 per cent of what is usually reported as agricultural power consumption in fact represents unaccounted- for energy. Now assuming, quite reasonably, that the actual agricultural consumption is only 65 per cent of the reported one, we can estimate the commercial loss, due to subsidised sales of 57,707 MU of electricity (instead of the reported 88,780 MU) to agriculture at a unit cost- revenue margin of 197.47 paise/ unit in 1997-98, to be Rs. 11,395.4 crore, instead of the given Rs. 17,531.3 crore. The total effective subsidy provided to both agriculture and domestic sector would then be Rs. 16,080.4 crore, and accounting for cross subsidy and subsidy from the state government, the loss due to subsidised power sale would turn out to be only Rs. 1,084.3 crore, instead of the reported Rs. 7,220.6 crore. Thus a good part of the huge amount of subsidy claimed to be provided to agriculture, does in fact represent the cost of inefficiency in not operating and maintaining the T & D system properly.[53]

According to some experts, like Prabir Purkayastha, of the Delhi Science Forum, vehemently opposes the blame put on the agriculture and domestic sectors for the poor financial position of the SEBs. According to him, the agricultural sector receives unmetered supplies; therefore the amount of electricity it receives is not known. This allows for large scale manipulation of figures as a large part of the theft of electricity is put in the agricultural account.

The problem with the SEBs is not one of low agricultural tariff alone. The agricultural tariff should be lower as it is given power mostly at night and this helps in flattening the load curve. While agricultural subsidies do account for a part of the financial problems of some of the SEBs, they are not the sole reasons of their impending collapse. The T&D losses including commercial losses of electricity are increasing rapidly and while the revenue realised is not. An exercise has been done by Paul & Purkayastha (1997) to examine the finances of the SEBs with T&D loss also as a consumer. The computations show that the amounts due to T&D losses (Rs.16,168,00 crore) as a proportion of the losses of the Boards are very high and are comparable to that incurred due to subsidised power to agriculture (Rs. 17,491.2 crore) . This makes the economics of power generation completely lopsided. The malaise is more generalised as

[53] Kannan and Pillai (2001) c.

can be seen from the case of Delhi and Orissa, which have low agricultural loads but T&D losses to the tune of 54 per cent and 47 per cent respectively.[54]

2.12 Average Tariff and Revenue Realisation

In general, increasing block rate tariff that penalises higher consumption levels because of capacity shortage is in practice in India. Hence, the average tariff at the aggregate level cannot be the price confronting the customer in his decision making options; rather it can only be a supply price to the utilities.[55] The overall average tariff for sale of electricity by the SEBs was 18.8 paise/kwh in 1974-75, 32.4 paise/kwh in 1980-81. It increased to 105.4 paise/kwh in 1992-93 and to 199 paise/kwh in 1997-98 (RE). It is likely to be 212 paise in 2000-01(AP). There are large inter-State variations in the average tariff from 1992-93 to 2000-01(AP) as is evident from T 2.16, below.

2.13 Consumer Category-wise Average Tariff

Table, T 2.17 below gives the consumer category-wise average tariff for electricity sale from 1992-93 to 2000-01. Average unit revenue realised from agricultural sector and domestic lighting is significantly lower compared to the overall average unit revenue realised, while Electricity for commercial users, industry and railway traction is charged at significantly higher rates than the average tariff.

[54] The Crisis of the State Electricity Boards: Real Issues"(2001); www.indiainfoline.com
[55] Kannan and Pillai (2001) c.

T 2.16: Average Tariff for the Sale of Electricity, 1992-93 to 2000-01. (Paise/kwh

SEBs	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-00	2000-01
Andhra Pradesh	94.30	98.60	92.90	97.10	156.00	166.65	165.54	177.00	182.00
Assam	121.00	121.30	121.50	203.31	205.61	215.81	245.72	312.09	353.16
Bihar	118.40	147.40	155.00	178.76	185.20	200.80	200.14	200.14	200.14
Delhi	134.00	NA	NA	232.70	248.56	323.97	264.33	283.76	320.00
Gujarat	100.30	121.00	128.00	132.00	163.00	184.00	190.00	206.00	225.00
Haryana	72.50	83.30	110.00	132.80	155.28	187.36	199.55	214.74	214.91
Himachal Pradesh	101.10	106.80	116.30	121.40	143.45	162.32	173.62	192.06	203.04
Jammu & Kashmir	35.30	35.10	36.70	35.60	34.02	34.35	66.67	156.36	194.16
Karnataka	93.40	106.80	105.10	114.40	140.55	152.20	192.20	204.89	252.88
Kerala	74.00	82.10	86.70	92.80	95.61	124.60	130.63	187.50	236.66
Madhya Pradesh	118.90	118.90	129.60	139.40	176.48	170.36	156.34	159.94	166.74
Maharashtra	136.90	150.50	161.10	169.00	199.83	208.81	215.61	229.73	231.18
Meghalaya	89.50	91.40	98.90	107.20	127.74	129.14	129.16	131.40	174.18
Orissa	77.20	95.10	149.80	175.36	235.02	259.04	255.59	138.73	157.87
Punjab	70.30	89.30	108.30	124.90	136.07	147.79	157.60	171.59	176.42
Rajasthan	105.10	115.30	133.30	142.30	165.53	187.89	187.89	194.38	195.79
Tamil Nadu	107.10	128.30	150.20	165.90	172.88	194.63	198.51	209.10	233.49
Uttar Pradesh	108.40	111.80	122.40	140.80	142.98	171.56	180.61	182.02	183.35
West Bengal	115.70	135.40	143.00	147.90	151.60	182.02	183.81	223.36	240.72
Average	105.40	116.70	128.00	139.00	165.74	180.85	185.75	199.13	212.00

Source: *same as T 2.1.*

Though the SEBs are empowered by the Electricity Supply Act to determine prices, with the state governments expected to have only a advisory role, it si the latter that effectively take decisions. The socio- political compulsions of distributional solicitude of the governments have resulted in significant distortions in setting tariffs for various consumer categories in line with the cost involved in supplying each group. Thus the cost of providing electricity to low voltage (LV) consumers (domestic, agriculture etc.) is much higher on account of the additional cost of extensive distribution network, and more importantly, of higher distribution loss of energy, than the high voltage (HV) and extra high voltage (EHV) industries. However, the agricultural and domestic consumers enjoy a privilege of heavily subsidised supply of electricity at the cost of others.

T 2.17: Consumer Category Wise Average Tariff (Paise/ Kwh)

	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-00	2000-01
Domestic	77.3	84.3	92.8	85.0	105.7	136.2	140.1	157.8	173.4
Commercial	165.3	186.3	208.0	172.8	239.1	293.6	322.4	354.9	340.4
Agriculture/ Irrigation	16.1	17.9	18.8	19.0	21.2	20.2	20.6	21.1	28.5
Industry	171.5	198.2	221.1	219.5	275.5	312.7	320.5	344.5	359.9
Traction	206.8	216.4	261.4	282.5	346.8	382.2	405.9	414.7	420.8
Outside State	91.0	84.5	111.8	93.5	151.4	138.1	163.6	181.6	193.8
Overall	105.4	116.7	128.0	139.0	165.3	180.3	185.5	199.0	212.0

Source: *same as T 2.1.*

The unit average revenue realisation for all the consumer categories (including the tariff charged from agricultural consumers) has increased, though at varying rates. The increase has been small for agricultural sector and fairly substantial for commercial and industrial consumers. The state- wise details for agricultural sector are given in T 2.18.

T 2.18: **Average Tariff for Agriculture, 1992-93 to 2000-01.** **(Paise/kwh)**

SEBs	1992-93 (Actual)	1993-94 (Actual)	1994-95 (Actual)	1995-96 (Actual)	1996-97 (Actual)	1997-98 (Actual)	1998-99 (Prov.)	1999-00 (RE)	2000-01 (AP)
Andhra Pradesh	8.60	6.40	5.30	2.80	13.35	16.12	15.35	15.00	14.00
Assam	179.00	93.30	88.00	158.90	181.44	476.70	183.73	232.71	233.24
Bihar	10.50	14.80	15.20	16.20	14.02	12.15	12.23	12.23	12.23
Delhi	38.00	NA	NA	NA	NA	372.36	50.00	50.00	276.00
Gujarat	11.00	19.00	22.00	19.00	20.00	18.00	17.00	17.00	17.00
Haryana	25.50	29.00	45.50	51.90	52.41	61.06	50.00	29.45	29.47
Himachal Pradesh	33.00	33.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Jammu & Kashmir	11.80	9.10	9.30	10.30	10.00	12.50	50.00	220.00	250.00
Karnataka	4.20	2.80	1.80	1.70	5.73	11.55	23.57	21.23	108.66
Kerala	25.10	29.40	23.90	23.70	26.99	54.63	59.55	59.55	59.55
Madhya Pradesh	24.50	19.70	3.70	4.20	6.82	5.30	4.73	11.07	11.07
Maharashtra	15.20	22.70	18.20	16.50	22.55	21.46	30.00	24.61	24.61
Meghalaya	42.70	50.00	53.30	47.00	49.65	49.30	40.00	40.00	52.00
Orissa	30.90	21.20	53.10	54.20	70.94	84.95	93.26	NA	NA
Punjab	10.80	19.50	34.50	38.50	28.46	FREE SUPPLY			
Rajasthan	31.00	30.80	30.10	27.20	31.22	34.58	34.58	36.52	34.85
Tamil Nadu	0.00	0.00	0.00	0.00	1.52	1.60	1.12	1.12	1.20
Uttar Pradesh	31.60	31.90	43.10	49.50	42.48	49.65	49.50	48.95	49.97
West Bengal	19.20	25.30	19.90	21.80	17.39	23.27	26.36	50.40	53.80
Average	16.10	17.90	19.40	19.00	21.20	20.22	20.59	21.02	28.42

Source: *same as T 2.1.*

The uneconomic pricing of electricity is to a great extent responsible for the poor state of affairs of the SEBs. The depressed average tariffs are due to subsidised prices charged to the domestic and agricultural segments. Almost all the states are supplying electricity to the agricultural sector at levels well below the so- called prescribed minimum of 50 paise per unit. In some states like Tamil Nadu, farmers are supplied free power. As a result, the average revenue realised from this sector is obviously very low, as low as 6 paise per unit, in states like Karnataka. However, in states like Assam and Himachal Pradesh, the average revenue is well over Re. 1 per unit. But in these states, the share of the agricultural sector in total sales is negligible. The agriculture sector accounts for nearly one-third of the SEBs' sales volumes. But the revenue realised from this sector has been only 3.5 per cent of the total revenue. The domestic and the agriculture sector taken together account for 50 per cent of the total sales of SEBs. But their share in the total revenue is only 16 per cent.

Unlike the agricultural sector, which is supplied power at almost zero charge, industrial customers are asked to pay well over Rs. 3.50 per unit in most of the states. The state- wise details for the industrial sector are given in T 2.19 below.

The industrial sector together with the commercial sector, is in fact, the biggest contributor to the sales revenue in most of the states, accounting for 80 per cent of the revenue, when sales to these sectors have been in the range of 34-35 per cent only In Gujarat, Madhya Pradesh, Karnataka and Maharashtra, this sector contributes over 60 per cent of the sales revenue. In these states, the average revenue from this sector is also well over Rs. 3.00 per unit. The state- wise details for the year 1999-00 is shown in T 2.20.

T 2.19. **Average Tariff for Industry, 1992-93 to 2000-01.** (Paise/kwh)

SEBs	1992-93 (Actual)	1993-94 (Actual)	1994-95 (Actual)	1995-96 (Actual)	1996-97 (Actual)	1997-98 (Actual)	1998-99 (Prov.)	1999-00 (RE)	2000-01 (AP)
Andhra Pradesh	177.50	214.70	221.80	236.00	309.24	340.00	354.73	397.08	399.19
Assam	99.10	132.80	129.70	195.30	209.13	192.56	317.52	366.43	361.40
Bihar	174.60	205.00	220.50	247.40	246.77	275.99	275.33	275.33	275.39
Delhi	190.10	NA	NA	NA	NA	492.12	384.56	403.33	367.37
Gujarat	188.00	220.20	220.00	235.00	287.87	338.70	367.70	398.70	434.72
Haryana	171.00	195.70	222.30	266.60	319.87	372.20	397.92	445.06	445.11
Himachal Pradesh	97.00	105.00	125.00	135.00	161.23	198.00	218.95	222.58	232.54
Jammu & Kashmir	46.60	39.60	40.30	41.00	40.00	46.00	70.00	135.00	200.00
Karnataka	185.40	221.60	231.00	262.20	329.88	415.05	425.00	432.21	438.10
Kerala	82.50	92.80	101.10	104.20	126.79	163.20	174.60	278.23	278.23
Madhya Pradesh	183.90	211.00	238.00	268.30	363.00	377.48	382.86	408.16	410.57
Maharashtra	211.10	232.90	270.50	271.60	330.38	354.44	396.61	368.00	202.23
Meghalaya	106.10	144.00	146.90	130.00	130.47	158.17	110.80	154.71	202.23
Orissa	89.10	111.30	170.80	193.60	302.97	322.27	292.82	NA	NA
Punjab	125.80	153.50	165.10	187.10	219.22	241.75	268.42	282.76	283.19
Rajasthan	158.90	178.00	204.10	234.60	271.56	323.60	323.60	318.91	321.89
Tamil Nadu	157.20	202.40	245.10	270.50	253.42	295.15	314.17	341.65	365.23
Uttar Pradesh	210.90	225.20	240.80	272.10	275.95	383.45	422.76	418.42	423.36
West Bengal	125.90	149.50	183.00	209.30	237.07	280.52	276.54	319.99	346.97
Average	171.50	198.20	219.90	245.50	276.89	314.63	322.01	346.08	360.23

Source: *same as T 2.1.*

T 2.20: Contribution of Different Sectors to Revenue of the SEBs- 1999-2000. (%)

	Domestic	Agriculture	Industry	Commercial
Andhra Pradesh	23.00	3.20	57.00	8.80
Assam	-	-	-	-
Bihar	6.20	1.20	66.80	6.20
Delhi	-	-	-	-
Gujarat	9.50	3.20	64.80	4.80
Haryana	25.60	10.60	42.80	6.40
Himachal Pradesh	6.50	0.10	54.00	6.60
Jammu & Kashmir	-	-	-	-
Karnataka	19.10	4.00	60.70	10.20
Kerala	21.20	1.30	36.10	15.20
Madhya Pradesh	8.60	1.50	45.00	6.50
Maharashtra	8.50	3.70	28.30	5.70
Meghalaya	-	-	-	-
Orissa	17.60	1.00	63.60	6.60
Punjab	18.80	0.00	63.50	7.40
Rajasthan	11.40	5.80	61.30	8.80
Tamil Nadu	11.80	0.00	68.30	13.70
Uttar Pradesh	17.00	8.10	47.90	13.30
West Bengal	10.20	2.10	40.50	9.90

Source: *indiapoweronline.com*

According to Hemant Joshi, Executive Director, CRISIL, the crux of the problem is the tariff structure. Agricultural consumption is almost free, while domestic consumption is subsidised to some extent. In order to recover the deficit, industrial and commercial consumers as well as the railway traction are overcharged. This cross subsidy, however, has a limit. Rising tariffs mean that, after a point, it is cheaper to generate electricity rather than buy from the SEBs. The SEBs could manage in the past because of cross subsidisation. Now the cross-subsidisation opportunity has also been exhausted, because tariffs for the industrial users have reached such levels where they cannot afford new hikes and would rather shift to captive generation.

As the industrial tariffs are kept very high to cross- subsidise the low agricultural and domestic tariffs, increasingly large industrial units are setting up their own power generation plants. This is not only less expensive but more reliable than the power from the grid. The alarming decrease in the contribution of industrial consumers to the total revenue of the SEBs bears enough testimony to the fact; it has come down to about 35-40 per cent from 60 per cent in the 1960s. With the proportion of agricultural supply increasing from 10 to 25 per cent during the same period, the financial viability of the SEBs has been impacted as less number of industrial units are taking electricity from the grid. For instance, half a decade back almost all cement plants bought electricity from the SEBs. But, in 1997-98, captive plants powered 28 per cent of the cement produced. The figure rose to over 33 per cent in 1998-99. Since industrial consumers are in the highest tariff bracket, the SEBs' revenue generation is bound to suffer.

2.14 Unit cost-revenue comparison

The percentage of sales revenue realised to cost incurred has declined in the last few years, from 82.2 per cent in 1992-93 to 70.2 per cent in 1999-00(RE). The recovery of cost through tariff is likely to be about 70 per cent of the total cost of supply during 2000-01. The average tariff has not increased proportionately with the increase of the cost of supply and resultantly, the gap between the cost of supply and the average tariff has increased considerably, from 11 paise/ kwh in 1984-85 to 92 paise/ kwh in 2000-01.

Though the number of consumers has increased during this period, the increase has mainly been in the category of agricultural and domestic consumers, who are getting power at subsidised rates. T 2.21 indicates the average recovery of cost through tariff, over the period from 1992-93 to 2000-01.

T 2.21: Recovery of Cost through Tariff

	Average Cost (Paise/ Kwh)	Average Revenue (Paise/ Kwh)	Revenue as a % of Cost
1992-93	128.2	105.4	82.2
1993-94	149.1	116.7	78.3
1994-95	163.4	128.0	78.3
1995-96	179.6	139.0	77.4
1996-97	215.6	165.3	76.7
1997-98	239.7	180.3	75.2
1998-99	262.5	185.5	70.7
1999-00	283.6	199.0	70.2
2000-01	303.8	212.0	69.8

Source: *same as T 2.1.*

There are wide inter-State variations in the ratio of average revenue realised to the average cost of supply as can be seen from T 2.22. Among the 19 states considered, Maharashtra has had always the highest cost recovery ratio- greater than 90 per cent. In fact, from 1992-93 to 1996-97, except for the year 1995-96, it was nearly 100 per cent. Himachal Pradesh and Tamil Nadu also had a ratio greater than 90 per cent from 1994-95 to 1997-98. It was and below average in a number of other States, namely Andhra Pradesh, Assam, Bihar, Delhi, Haryana, Punjab and Madhya Pradesh in 1999-00(RE) and

2000-01(AP). It was particularly low for Jammu & Kashmir, where the figure was less than 20 per cent.

T 2.22: **Sales Revenue as a Ratio of Cost, 1992-93 to 2000-01.** (%)

SEBs	1992-93 (Actual)	1993-94 (Actual)	1994-95 (Actual)	1995-96 (Actual)	1996-97 (Actual)	1997-98 (Actual)	1998-99 (Prov.)	1999-00 (RE)	2000-01 (AP)
Andhra Pradesh	94.20	90.50	72.10	62.20	73.07	69.53	57.44	59.95	51.45
Assam	47.40	49.70	53.90	57.10	60.95	47.21	56.99	61.03	65.20
Bihar	63.70	73.50	66.40	70.8	63.74	63.45	66.90	62.83	57.03
Delhi	81.70	NA	NA	70.60	71.97	72.61	63.69	65.55	69.64
Gujarat	68.40	76.60	74.80	72.90	75.44	74.32	68.73	66.81	67.18
Haryana	54.00	50.40	61.50	63.60	64.50	63.66	63.59	62.59	59.70
Himachal Pradesh	88.50	74.80	91.90	98.80	91.83	89.93	82.61	86.88	86.12
Jammu & Kashmir	21.30	16.70	10.30	13.20	10.67	12.49	10.70	19.70	25.85
Karnataka	96.50	95.30	86.80	74.90	75.06	83.98	73.37	80.18	78.86
Kerala	84.70	83.50	79.60	69.00	59.28	63.57	72.99	76.78	85.76
Madhya Pradesh	84.00	80.70	77.50	79.50	81.64	73.60	62.39	61.32	61.22
Maharashtra	98.50	98.80	99.40	91.20	98.21	96.86	96.56	88.70	85.51
Meghalaya	81.30	93.60	71.20	72.70	78.64	71.79	58.54	57.16	65.13
Orissa	78.10	71.20	80.70	77.10	72.84	73.64	72.87	74.23	88.97
Punjab	57.60	61.80	66.70	69.70	73.16	68.09	67.19	69.43	71.38
Rajasthan	76.00	70.40	67.80	67.80	71.93	74.53	66.40	64.03	69.21
Tamil Nadu	66.00	66.70	98.80	97.10	93.44	93.52	66.62	62.62	84.71
Uttar Pradesh	70.60	66.00	69.00	70.70	64.32	67.73	67.47	63.19	62.45
West Bengal	71.50	78.40	73.70	78.50	72.07	73.17	61.20	70.15	70.24
Average	82.20	78.30	78.30	76.10	76.81	75.95	70.87	70.35	69.95

Source: *same as T 2.1.*

2.15 Restructuring of the Power Sector

However, it is now being advocated by the World Bank that the economies of scale have already been exhausted, and vertical integration can safely be unbundled and that (at least) in generation, the monopoly structure can be struck down effectively, and instead competition be commissioned. But it must be remembered that competition is not a goal but a means to an end. Economists extol competition because it will deliver economic efficiency. The average person in contrast, desires competition firstly to get a lower price for the product and second, out of a belief that equity, fairness and prevention of exploitation by a monopolist or a olipolist, results from competition. However, the standard theory of competition fails in industries where the product sold is an undifferentiated commodity, and separately where the product requires large fixed investment or overhead costs. Electric power possesses both these characteristics. Hence, price discrimination is certain to occur in electric power markets.[56] The cost structure of electric power is heavily weighted towards overhead costs. Large investment is required before sales can take place, and the annual charges related to the investment must be covered whether sales occur or not. Depreciation, capital cost and even fuels bought under long-term contracts are costs that continue whether sales are made or not. Fixed costs put pressure on the owners to operate the plant at high capacity factors, so that the annual costs can be spread over a high volume. With high volume, the per unit share of the overhead costs is low, and electricity can be priced low enough to attract sales that will result in a high capacity factor.[57]

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[56] Coyle, Eugene P. (2002).
[57] Baumol, Joskow, and Kahn (1994)

The problem is to attract the high sales volume without pricing below the average cost (AC) of production, i.e. without pricing at a loss. Thus, to earn profits, electric power companies turn to price discrimination, setting different prices among different sets of consumers. This is because large fixed costs need to be spread over a large volume of sales, but achieving high volume through uniformly low prices leaves total costs not covered. The solution, therefore, is to charge some customers more than AC, while reaching the necessary volume by selling to others at less than AC.[58]

Unbundling of the system into separate generation, transmission and distribution entities raises the problem of the integrated operation of the whole system. If all the units resulting from unbundling are driven by profit maximisation (all players pursuing their self- interest), there must be an authority that will co-ordinate their operation for supply - demand matching. The absence of such an authority aggravates the problem of grid discipline and management. This has been the case with California. Here, a new marketplace in which prices fluctuated violently replaced a monopoly in which government set stable rates. The increased revenues, which resulted from the price hikes, flowed to out- of- state energy firms - the IPPs.[59]

According to a World Bank study report, it has been pointed out that subsidising the price of electricity is both economically and environmentally inefficient. Low prices give rise to excessive demand and, by undermining the revenue base, reduce the ability of power utilities to provide and maintain supplies. Underpricing electricity also discourages investment in new, cleaner technologies and more energy efficient processes. Thus, there is increasing pressure from these multilateral agencies to go for deregualtion of the power

[58] Coyle, Eugene P. (2002).
[59] Reddy, Amulya K. N. (2001).

sector. So after the failure of the policies of inviting foreign capital on concessional terms, the MoP, in conjunction with the World Bank, has introduced another new policy. The scheme is to restructure the SEBs by breaking them up and selling them to the private sector. According to the government, once generation, transmission and distribution are separated, the generators will compete among themselves and bring down the power costs. Though the process has already been undertaken in India, in the state of Orissa, the experience has not been a happy one. It belies the beliefs that unbundling improves efficiencies or leads to lower tariffs. Not only that, the process of deregulation in California bears strong similarity to the World Bank approach particularly with regard to unbundling the electricity sector and privatising its components. Hence, it is important to draw crucial lessons from the California energy crisis to safeguard the Indian power sector.

It is not enough to point out the specific shortcomings of the regulated electricity system. Such shortcomings do not mean that a market-driven system will be successful and will be beneficial to the society. The establishment of a market-driven system is associated with transaction costs and gestation periods. Hence, a careful comparison of the costs and benefits of the old regulated system and the new deregulated system is essential before dismantling the old and ushering in the new. Even if it is decided that a cost-plus price regime must be replaced with market-driven prices, it must be realised that a market alone is not sufficient. Demand for electricity is relatively inelastic; it does not fall with the increase in prices. Also as electricity cannot be stored, creating an artificial shortage is simple. This creates an ideal situation to rig the market. Once a scarcity is created, competition fails. Competition will only work if there is a surplus over demand for electricity. Hence, the extent of competition must be monitored and it must be shown that there is indeed effective competition.

The GoI, however, initiated the policy of private investment in the form of IPPs, who were given a set of incentives to set up power plants in India. The drive to increase the country's generating capacity, together with the general trend towards economic liberalisation in India, led to much interest among foreign investors in setting up IPPs in India. Enron was one of the first IPPs to set up a private power plant at Dabhol in Maharashtra, with the help of foreign equity. In the light of this, in the following chapters, we take a look at the power situation in Maharashtra as a case study and then study the developments that have taken place as the Dabhol project was set up.

Chapter 3

Demand - Supply of Power in Maharashtra

Chapter 3

Demand - Supply of Power in Maharashtra

3.1 Introduction

Energy is one of the crucial inputs in the process of economic development and the adequate availability of power is the sine-qua-non for future progress. The performance of all-important sectors in the economy ranging from agriculture to commerce and industry depends vitally on the availability, cost and quality of power. Fortunately, Maharashtra is favourably placed in this respect than most other States in India. Maharashtra has been enjoying a relatively comfortable position with regard to power availability vis-a-vis the other States. However, in recent years, the rising demand from the agricultural, industrial and commercial sectors has placed a great strain on the power situation in the State.[60]

3.2 Demand for power in Maharashtra

At the outset, it can be stated that demand growth has been much lower than forecast and, more importantly, it has been quite uneven across different categories. In particular, the growth in the metered HT Industrial category, which is the largest high-tariff group, has been very limited. On the other hand, agriculture, one of the low-tariff categories, has grown steadily. This growth however represents an exaggeration, since a large proportion of unauthorised drawing of power is invariably shown as agricultural consumption. So, to get a true picture, the MSEB Annual Statement of Accounts now

[60] India Investment Centre (IIC) (2000); http://iic.nic.in.

gives Adjusted Agricultural consumption figures along with the agricultural consumption. Domestic and commercial consumption has grown the most and this has implications on the load profile of the State. An examination of the load curve for Maharashtra reveals around 8000 MW of base load, about 2250 MW of intermediate load that persists for about 15 hours and another 2000 MW of evening peak load that lasts for about five hours during a particular summer day. This may change as the share of peaking consumers such as domestic and commercial consumption increase over time.[61]

The demand for power in Maharashtra, in fact, varies seasonally, as well as over any given day. Power demand peaks in summers and over a few hours every morning and evening. The maximum (peak) demand for power in Maharashtra is about 11,500 MW in 1999- 2000.[62] The peak shortfall in summer months is at most 2000 MW. Off peak demand is approximately 7500 MW. During winter, the peak demand for power is about 10391 Mw and so power supply was sufficient to meet even this peak demand. During the summer, on the other hand, the peak demand is often as high as 11,600 MW during the same period.

The gross energy requirement for Maharashtra has increased at a Compound Annual Growth Rate (CAGR) of about 5 per cent p.a. during the period 1995-2000. If we take a look at the consumer category-wise analysis for MSEB, we will see that in (FY) 1999-00, industrial HT consumers form the biggest segment, consuming 39 per cent of the total energy. Adjusted Agriculture is the next biggest segment with a consumption of 24.5 per cent (in 2000, agriculture and adjusted agriculture are the same). The other major categories are domestic (15.4 per cent), bulk supply to licensees (8.5 per cent) and

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[61] (2001): Report of the Energy Review (Godbole) Committee; April.
[62] http://www.msebindia.com/consumer/sysposn.phtml

commercial (3.3 per cent). During the period 1995-2000, while domestic consumption rose by 9.9 per cent per year and (adjusted) agriculture rose steadily by 4.4 per cent, HT industrial rose only by about 2.9 per cent p.a., and that too mostly in 1999-2000. Commercial consumption did grow significantly but it still forms only a small share. In addition to the demand from MSEB, there is substantial demand from the licensees in Maharashtra, who serve its major urban centres.[63] The consumer category - wise analysis is shown in the following table, T 3.1.

T 3.1: Consumption of Energy - Details by Consumer Category (MU)

	1996	1997	1998	1999	2000	CAGR (%) (1995-2000)
Domestic	4,424	4,897	5,341	5,915	6,455	9.9
Agriculture	13,332	13,867	15,382	15,968	10,293	-6.2
Adjusted Agriculture	8,673	8,935	9,242	9,461	10,293	4.4
Commercial	979	1,129	1,139	1,243	1,382	9.0
Industrial	14,585	14,711	144,667	14,930	16,393	1.9
Bulk Supply	5,354	4,824	4,271	4,165	3,581	-9.5
Others	2,945	3,269	3,093	4,106	3,878	7.1
Total Consumption	41,619	42,698	43,894	46,328	41,982	0.2
Gross Energy (MU)	49,642	50,815	53,353	56,598	60,460	5.0

Source: *MSEB Annual Statement of Accounts, 2000-01.*

It is useful to contrast this trend with the past projections of MSEB, which had estimated that the demand of electricity would grow at 8 per cent and the peak load

[63] (2001): Report of the Energy Review (Godbole) Committee; April.

demand by 1.000 MW every year. Even the CEA (15th Electric Power Survey) had estimated the peak load demand for Maharashtra at the end of 9th Five-year Plan, i.e. 2001-02 to be about 13,147 MW and 18.300 MW by 2006-07. Subsequently the 16th EPS revised it to 12,472 MW by 2001-02 and 14.906 MW by 2006-07.[64]

Nevertheless, Maharashtra needs more power. Since the amount of power generated by the state utilities in the state is insufficient to meet the demand, it has to depend on power produced by the private power companies as well as from other states. Since some power is imported from outside the state, energy pumped into the grid is a better measure of consumption. The power situation in Maharashtra is presented in the following table, T 3.2.

T 3.2. Electricity Generation and Generating Capacity of Utilities in Maharashtra

Year	Energy Pumped in the Grid (Billion kWh)	Generating Capacity ('000 MW)	Load Factor of Thermal Plants (per cent)
1992-93	44.87	10.68	59.71
1999-00	72.72	13.83	71.77
Growth rate annual (per cent)	7.14	3.76	2.66

Source: *Parikh, Kirit S (2001);Economic & Political Weekly, April 28.*

From the above table it can be observed that electricity pumped into the grid has grown at 7.13 per year since 1992-93, whereas the generating capacity has increased only

[64] Ibid.

by 3.76 per cent per year. So to make sure that generating capacity is increased, the state should undertake measures to ensure that drawing power from the grid does not hinder the power plants to expand their generating capacity. But whether that should be met by developing private power plants using foreign investment or domestic ones is a different policy matter altogether.

However, it is important to note that we can lower the need for generating capacity if we reduce waste, follow energy conservation measures and increase efficiency of energy use. Various studies has been undertaken by experts about the saving potential of energy from Demand Side Management (DSM). Experts like Jyoti Parikh have estimated a saving potential over a period of 15 years of 2,500 MW of peak demand for Maharashtra. Another option is to expand generating capacity is through repair and renovation of old power plants as envisaged by Sudhakar B. Reddy.

Now we present an analytical exercise to show whether there is really any need for additional generating capacity in Maharashtra.[65] We consider a period spanning the 10 years, 1999-2000 to 2009-10. The installed capacity (IP) for Maharashtra in 1999-2000 was 14672 MW. The annual rate of increase in demand for power in the last decade has been around 4 - 5 per cent per year. Taking the same rate of demand, the IP required in 2009-10 will be calculated as follows:

$$IP_{2009\text{-}10} = IP_{1999\text{-}2000} * (1 + 5/100)^{10}$$

The installed capacity required in 2009-10, as calculated above is 23,899 MW. Taking the estimate of Jyoti Parikh, we take the saving potential over a period of 10 years

[65] Kirit S. Parikh has estimated the saving potential from energy conservation measures and increase in efficiency for All – India level. Here we have estimated the same using the above estimates and figure from MSEB Annual Statement of Accounts for Maharashtra.

as 1,700 MW. Further, we make a generous estimate that another 1,700 MW of capacity can be generated from the repair and renovation of old power plants. But even after assuming that DSM and renovation potentials are fully realised, we still need additional generating capacity from new power plants. The results are tabulated as follows in T 3.3.

T 3.3. Meeting Generating Capacity Need over the Next 10 Years in Maharashtra

(figures in MW)

(1) Installed capacity (1999-2000)	14,672
(2) Required in 2009-10 (at a growth rate of 5 per cent per year)	23,899
(3) Additional capacity required [2-1]	9,227
(4) Less	
(4a) Full DSM potential	1,700
(4b) Repair, renovation and maintenance	1,700
(5) Additional new generating capacity required [3-4a-4b]	5,827

Thus from the above analytical exercise, we find that there is in fact a need for more power in Maharashtra. Over the next 10 years, it needs to augment generating capacity at least by 5,800 MW from new plants.

There is hardly any doubt that MSEB is the biggest SEB in the country, in terms of its generation capacity, transmission network, sale of power and revenue.[66] Though power in Maharashtra is supplied by various agencies, MSEB plays the most significant role in the generation and distribution of power in the State. It accounts for 67 per cent of the total installed capacity, including state's share in the Nuclear Power Corporation (NPC) and National Hydro Power Corporation (NHPC), as on 31st March, 1999. Apart from the MSEB, there are a) independent power projects like Enron's Dabhol

[66] Abraham, P. (2001); http://www.indiapoweronline.com/Scripts/GNT004C1.ASP?SecID=2&CatID=6.

power project and b) licensees like Tata Electric Companies (TEC) and the Bombay Suburban Electric Supply (BSES) (accounting for 14 per cent and 4 per cent respectively) which distribute electricity in the permitted area. Besides, the State also has a share in the Central Government power projects.[67]

3.3 Supply of Power in Maharashtra

Power supply to the city and the southern suburbs are handled largely by the Bombay Electric Supply and Transport (BEST). The western suburbs, north of Bandra, are served by BSES. The Maharashtra State Electricity Board (MSEB) services the rest of the Bombay Metropolitan Region. These two companies supply Bombay with its current demand of about 2 GWatts of power. Of this, between 1 and 1.5 GWatts is obtained from the TEC. The rest comes from the MSEB. TEC purchases 300 to 400 MW per day from the MSEB. Statewide, there is a difference of 2 GWatts in demand between peak and off-peak hours.[68]

The power supply system in Bombay is linked to the Maharashtra State grid, which in turn is part of the western grid; connecting Maharashtra, Gujarat, Madhya Pradesh and Goa. Mainly generators belonging to the Central Government undertakings--the National Thermal Power Corporation (NTPC) and the NPC feed the grid. The MSEB currently has a quota of 31 per cent of the power generated for this grid.[69]

Maharashtra planned to increase the installed capacity in the state (including licensees), which was 11.582 MW in 1994-95 to 17,050 MW by 2002 and 21,161 MW

[67] India Investment Centre (IIC) (2000); http://iic.nic.in.
[68] http://theory.tifr.res.in/bombay/amenities/power/
[69] ibid

by 2005, an increase of over 9000 MW. As against this, actual capacity today stands at 14,672 MW. Supply is then insufficient at peak hours, and MSEB resorts to load shedding. Due to shortfalls in supply, the MSEB also plans to buy power from privately owned power projects. However, even if Maharashtra does suffer from power shortages, it is only during certain seasons, and only for a few hours a day. These shortages are best met by peak load plant - one that can be switched on and off at short notice and thus used during peak hours alone. The DPC plant on the other hand is a base load plant; one which needs to be operated continuously over twenty four hours. Further MSEB has guaranteed 90 percent purchase (of Phase II) throughout the year. So, in order to tide over shortages for a few hours a day in some seasons, MSEB is forced to purchase DPC power, at an exorbitant rate, for 22 hours a day, all around the year. Indeed, at the time of signing the contract, several agencies including the World Bank had observed that DPC was inappropriate for overcoming Maharashtra's power shortage.[70]

One of the problems of planning in the power sector has been inflating the demand for grid power. On the one hand, captive generation for the industry is encouraged, on the other, the demand of the industry on the grid is predicted on the basis of earlier growth rates. The growth rate of electricity is not autonomous but depends on the cost of power, purchasing power of the people and the rate of economic growth. The annual rate of increase in power demand for the last decade has been of the order of 4-5 per cent and not 7-8 per cent as predicted by the 14th, 15th and now the 16th Electricity Power Surveys (EPS). This has created a false sense of panic and short - term measures such as expensive IPP power and the liquid fuel route. One of the reasons for introducing

[70] www.altindia.net/enron/Home_files/myths.html

the Dabhol Power Project, promoted by Enron, in Maharashtra was the alleged future shortages that were predicted which are now shown to be fictitious.[71]

The GoM's submission at the start of the project regarding the need for power was flawed to the extent that it failed to distinguish between different types of load. This led to an inappropriately high PLF of 90 per cent being taken for purposes of calculating per unit tariff. In 1993, however, based on the past growth of consumption and load, it was possible to argue that a 695 MW plant could be absorbed into the system. This, however, completely omitted any consideration as to whether there was a demand for power at the price charged by DPC in the future. The growth of relatively high-tariff consumers and the prevailing electricity tariffs and the scope for their increase to absorb the increased cost of DPC power was not analysed even though the World Bank did point out the possible fallacies in the demand forecasts. The World Bank in its assessment of the project, in 1993, pointed out that dispatching the plant as a base load unit at 80-85 per cent minimum plant factor would prevent the operational flexibility of a combined cycle plant. It also stated that the project would add more capacity than needed to meet the projected load growth in 1998 and would also result in uneconomic plant dispatch.

In fact, the MSEB demand projections for justifying the requirement of Dabhol was on the basis of the 15th EPS. The actual consumption in 1998 was higher than the estimate in the 15th EPS by 4.4 per cent. MSEB therefore replaced the base year EPS estimate with the higher actual consumption and applied the EPS growth rates to this higher base. The actual growth in demand in the MSEB system in the years immediately before 1998 was in fact much lower than the 15th EPS estimates. Indeed, there is a sharp

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[71] Purkayastha, Prabir (2001) a.

slowdown in growth in 1996. This slowdown was completely ignored. While the actual consumption in 1998 was indeed about 4.6 per cent higher than estimated by 15th EPS, the trend growth rate was actually much lower (2 per cent in 1997 and 5 per cent in 1998) than estimated by the 15th EPS (8 per cent in 1997 and 1998). As compared to the growth of 2 per cent and 5 per cent in the previous two years, MSEB estimated an immediate return to earlier growth rates of 8-9 per cent per annum. The actual increase in consumption in 1997 and 1998 were only 1173 MU and 2538 MU respectively, while the projections assumed additional consumption in the range of 5000 MU to 6000 MU per year, over double the recent growth.

With this background of demand and supply in Maharashtra, we now take a look at the Dabhol Power Project, which was set up to meet the need for power of the people of this state. Whether it was successful or not, we try to find out in the subsequent chapters.

Chapter 4

The Dabhol Power Project

Chapter 4

The Dabhol Power Project

4.1 Introduction

The Government of India (GoI), without paying any heed to the warnings from various quarters, gave the go ahead to private investment in the power sector. The Ministry of power wanted a large, ambitious project that would not only serve as a flagship for its new power policy, but would also supply enough fuel to a new generation of clean, efficient and modern generating plants. Following a visit of a high level (GoI) delegation to Houston, USA, the Enron Corporation agreed to visit India to investigate power plant development opportunities. In June, 1992, they identified a potential site for a gas- fired power plant on the western coast of India, in the port town of Dabhol, 180 miles south of Bombay (now Mumbai) in the state of Maharashtra.[72]

Enron entered a memorandum of understanding (MoU) with the Maharashtra State Electricity Board (MSEB) to build a Power Project, on a Build Own and Operate (BOO) basis. The operating entity was the Dabhol Power Company (DPC), which is a joint venture. During most of the project development period, Enron owned 80 per cent of the project, while General Electric and Bechtel each owned 10 per cent. The turnkey contract had been awarded to Enbech, a consortium of Enron International and Bechtel Enterprises. In late 1998, MSEB purchased part of Enron's equity stake, which reduced Enron's share to 65 per cent.[73] The proposed project would be the largest plant Enron Development Corporation (EDC) had ever built, the largest of its kind in the world, and

[72]Report of the Prayas Energy Group (2000); http://www.prayaspune.org/energy/eng_pub_sel.htm.
[73] Human Rights Watch (1999).

at \$2.83 billion, the largest foreign investment project in India. According to the Godbole Committee, the DPC is not just a power project, but a complex intermeshing of power, LNG supply, shipping and port projects put together.

After extended negotiations, a Power Purchase Agreement (PPA) was signed between Dabhol Power Corporation (DPC), a subsidiary set up by the Enron Corporation and its affiliates, Bechtel and General Electric of USA, and the Maharashtra State Electricity Board (MSEB). Now we present a brief discussion about some of the key characteristics and provisions of the PPA.

4.2 The Power Purchase Agreement (PPA)

In infrastructure, private companies invariably seek to ensure that investments are recouped with a profit margin. In power generation projects, private investors often will not invest without a power purchase agreement (PPA) in place, under which the publicly owned utility agrees to purchase all the output of the plant at a price fixed in foreign exchange for a period of 20 to 30 years.[74] On the 8th of December 1993, the Maharashtra State Electricity Board (MSEB) signed a Power Purchase Agreement (PPA) with Dabhol Power Corporation (DPC), a subsidiary of the multinational corporation Enron (which was later amended on 2nd February 1995). This agreement was later re-negotiated on the 19th of November 1995.

[74] Bayliss, Kate (2002).

4.3 Structure of the Dabhol Project

Initially it was planned to establish a combined cycle gas/ naphtha/ distillate fired power plant of capacity 2550 MW, but subsequently it was scaled down tc 2184 MW. Thereafter it was planed for a 2,015MW project and the Maharashtra government decided to break the project into two phases. Phase I would be a 695MW plant with nominal peak capacity of 70 MW, using distillate fuel instead of natural gas and and Phase II stipulate a nominal base load of 2150 MW and nominal peak of 34 MW, essentially a gas-fired plant.

A substantial element of the Dabhol project was construction of a modern port facility that could unload large tankers of the imported liquified natural gas (LNG) from Oman.[75] The project would run in base load, on natural gas, and the LNG unloaded at Dabhol port will then be re- gasified for use at the Re- gasification facility, all of which was to be built by DPC.[76]

According to clause 2.5 (b) of the Agreement, either party by giving a notice of 21 days may terminate the contract regarding Phase II due to non-fulfillment of condition precedent to Phase II. In case such termination occurs the Power plant will remain unconverted and hence continue to be run on distillate fuel oil, which is a costlier fuel. As a result the country will inherit a costlier fuel run power plant.

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[75] Report of the Minority Staff Committee on Government Reform, U.S., (2002); http//:www.house.gov/reform/min/pdfs/pdf_inves/pdf_admin_enron_dabhol_fact_sheet.pdf

[76] Paul, Priti (2000); http://research.gsd.harvard.edu/new_cdiweb/publication/case-detail.cfm

4.4 Capital Costs of the Plant

The capital cost for Phase I would be $920 million, with an estimated turnkey construction cost of $527 million. The second phase would cost about $1.9 billion. Dabhol was broken into two phases because EDC had been unable to finalize its gas contracts and because the government had become concerned about the mounting criticism of the project. The shift from gas to distillate was done because distillate could be sourced from local refineries, helping deflect the criticism that gas imports would be a persistent drain on India's foreign exchange. Furthermore, using distillate instead of gas eliminated the need to build a port facility for Phase I.[77]

In the final agreement, DPC undertook to build and operate a 2184 MW electricity-generating unit at Dabhol in Maharashtra. MSEB, on its part, committed itself to making certain recurring payments to DPC over a twenty-year period, commencing with the commissioning of the plant. According to this estimate, at 90 percent off-take, MSEB will pay DPC a sum of approximately Rs. 4 lakh crores over the life of the project. The payments MSEB must make to DPC consist of fixed payments and variable payments. The PPA does not contain a breakdown of project costs, either fixed or variable. The only mention is of a budgeted, cost for Phase II of $1,087,000,000 (excluding LNG facility construction costs, $734/kW for 1480 MW). Usually the costs for gas-fired combined cycle plants, including fuel infrastructure costs, is $500-$600/kW. Note that this cost is not binding, rather it is stated as a budget estimate. DPC will prepare a statement of actual total costs after completion of Phase II and any difference between the Budgeted cost and the Total cost will be credited back to the MSEB with some

[77] Inkpen Andrew (1997); http://www.t-bird.edu/pdf/about_us/a07970004.pdf

adjustments. Fixed payment may be thought of as an `interest' or return on capital investment. The amount of fixed cost MSEB must pay DPC every month is independent of the amount of power drawn by MSEB from DPC. As per agreement, MSEB will have to pay separately for Capacity Charges and Energy Charges. As per Schedule 9 of the Agreement, the Capacity Payment will include capital recovery, return on equity, debt servicing (principal and interest), fixed operation, maintenance cost, and, annual insurance premium. Although the Capacity Payment appears to be fixed, it actually is not, as the payment is price linked to price escalation and exchange rate fluctuation. Capacity Payment will be on the Rated Capacity of the power plant, which will be tested annually. If the available Capacity is reduced, MSEB will still be liable for payment based on the full Rated Capacity. The MSEB will have to also pay capacity charges based on Rated Capacity in the event of under-utilization of the plant capacity (i.e. in case of lower load factor).[78]

As per Schedule 10 of the Agreement, the Energy Payment will include delivered energy payments in terms of BTU, "take or pay" fuel adjustments, various fees, such as, testing fees, fuel management fees, commissioning fees and variable operating and maintenance charges. The Energy Payment will be a "pass-through" and vary depending on price of the fuel i.e. distillate or LNG as the case may be. For Phase II, energy payments will be calculated on the basis of an assumed minimum gas dispatch regardless of how much the plant actually generates. According to the agreement the DPC will recover every single amount that it will spend in the form of Capacity Charges and Energy Charges. However, the MSEB will not have any say on the cost of plant and

[78] Acharya, Anurag (2001).

machinery and the fuel that will be imported by DPC through Enron Development Corporation appointed by it as Fuel Manager.

The DPC plant is being built in two phases. Phase one (740 MW) is already operational; fixed payments on Phase I amount to Rs. 1020 crores a year. Once Phase II is commissioned, fixed payments will triple, and so amount to at least Rs. 3000 crore a year at current prices. The variable payment, on the other hand, is supposed to cover the actual costs of power generation and so is in direct proportion to the amount of power drawn. The variable rate was Rs. 3.72 per unit in November 2000. The net amount payment to DPC (sum of fixed and variable payment) averaged to Rs. 7.80 per unit that month. According to the PPA, subject to certain penalties, MSEB is free to choose to purchase as much power as it desires from Phase I. However, MSEB is obliged to purchase a minimum of 90 percent of the power generated in Phase II, failing which, it is obliged to pay for that amount anyway. The capital charge and the operating charge, according to the terms of the PPA, has to be paid 86 per cent of the time in a year whether MSEB purchased any power from DPC or not. The net payment (at 90 per cent capacity purchase) by MSEB after phase II is operational is estimated to be of the order of Rs. 7000 crores in the very first year. Over twenty years, this is Rs. 140,000 crores at current prices.[79]

The generation of power does not have any meaning unless it is transmitted through the transmission line. According to the PPA, the power generated by DPC shall be transmitted through the transmission lines of MSEB and to receive power from the power plant the MSEB will have to build infrastructure by spending an amount of about

[79] Acharya, Anurag (2001).

Rs. 323 crores. The DPC will avail of the infrastructure built by the MSEB and also avail of the existing transmission line to sell the power generated by it but will not make any payment or any adjustment either in the fuel cost or in the capacity charge. Neither will it bear any transmission loss though the power generated by it would be transmitted through MSEB's transmission lines. In the US and most other countries, a transmission "extension cord" of this nature is always paid for by the developer of the power plant, since their choice of project location determines the cost of the transmission line connecting the power plant to the grid. Though DPC is neither bearing any cost for construction of transmission line nor paying any service charges for using MSEB's transmission line, MSEB will have to pay liquidated damages for delay in entry into commercial service of Phase I or either block of Phase II because of MSEB's delay in construction of transmission lines.[80]

If MSEB cannot pay Enron, the Maharashtra state government has signed a guarantee that makes it liable for all MSEB's dues to Enron. If the Government of Maharashtra cannot make these payments, the Government of India has staked all its assets (including those abroad, save diplomatic and military) as surety for the payments of the MSEB to Enron. The MoU with Enron states that Enron would be paid the same amount whether the MSEB consumes 50, 75 or 90 per cent of the plant's capacity. This blatantly violates Indian law, which states that a power company can enter into a contract only to sell the electricity that it actually generates and not its generating capacity.[81]

The PPA between MSEB and DPC could be termed as the most controversial document in the history of Indian power sector. It was kept as a "zealously guarded

[80] Audit Note on the PPA from the office of the Accountant General (1995)
[81] http://www.altindia.net/enron/navpane2.htm

secret". Though it had already achieved a kind of notoriety, when PPA was finally released it virtually opened the Pandora's Box. Some of the salient findings of the analysis are as follows:

The internal rate of return (IRR), an indicator of profitability, for DPC is exorbitantly high, to the tune of 28 per cent (post-tax, real). This is equivalent to 30 per cent before tax in dollar terms on equity which was to be 30 per cent of the total cost. In short, this means that we will be borrowing capital from Enron at exorbitant rate of about 38 per cent in rupee terms. According to the recommendations of Vanguard Capital, the consultant appointed by Government of India, IRR of 17 per cent to 21 per cent (post tax, real) is adequate to attract foreign investment in power sector even after considering perceived high-risk.

Guidelines subsequently issued by the central government suggested a rate of return of 16 per cent on equity for a PLF of 68.5 per cent and a bonus of 0.7 percentage point for every one percentage point increase in availability. Thus, the 95 per cent availability of Dabhol power plant would qualify for *16+ 0.7(95-68.5)=34.5 per cent* return. The 30 per cent IRR implicit in the PPA with DPC was below this norm.

In these scenarios, the price of electricity from Enron varies from Rs. 2.55 (8 cents) /kWh (1997) to about Rs. 12 (12 cents) /kWh (2016). Thus, the oft-quoted rate of Enron's electricity, Rs.2.40/kWh is quite deceptive. If required for comparison, the most realistic and representative price of Enron's electricity is Rs. 4.18 (about 13 cents)/ kWh at busbar i.e. at the doorstep of the Enron plant and about Rs. 5.5 (17 cents) /kWh at the doorstep of an average consumer. This is the levelised tariff for 70 per cent PLF and 4 per cent rupee depreciation. The PPA does not specify capital cost of the project. Change in capital cost (either decrease or increase) will not be passed on to MSEB. But change in costs due to change in customs duty and other taxes will be passed on to MSEB. [82]

According to Kirit S Parikh, agreeing to a capital charge based on a rate of return without any control over total plant cost provides all incentives to overstate the capital cost of the plant. According to him, the capital cost of DPC plant was some 20 per cent too high. This was based on the capital costs of the Chandrapur power plant based on coal. The Chandrapur coal based plant, with a capacity of 500 MW bid a price of Rs. 22,500 ($700) per exportable kW of power. If we add 20 per cent for contigency and 27 per cent for interest during construction, the cost of the plant comes to Rs. 32,700 ($1,029) per kW. Since Chandrapur is an expansion, some costs are saved. So to bring the costs of this plant on a comparable basis, another 15 per cent have to be added to its cost. On account of its lower availability of 68.5 per cent, 10 per cent more are added. This is because a 10 per cent extra capacity of 68.5 per cent availability plants give the same loss of load probability as a 90 per cent plant availability (as DPC). This will bring the cost of the Chandrapur plant to Rs. 32,700 x 1.15 x 1.1 ≅ Rs. 41,400 per exportable kW of power, i.e. $1,290 per exportable kW of power. While this may look comparable to the initially bid Dabhol project cost of $1,300 per kW, it should be noted that gas/oil-based plants are usually 20 per cent cheaper than coal-based plants. Thus, the cost of the Dabhol project was high and must have provided not only cushion tc insure the promoters against all kinds of uncertainties but also for possible escalation.[83]

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[82] Sant, Dixit and Wagle (1995).
[83] Parikh, Kirit S (2001).

While there was no compulsion on MSEB to buy power from DPC, the fact that capacity charges had to be paid 86 per cent of the time meant that if MSEB did not buy power for that much time the unit cost of power actually purchased would go up. Suppose MSEB bought power only for 60 per cent of the time. Then the effective capital and operating charge would not be Rs. 1.24 as laid down in the PPA, but will be equal to Rs.1.24 x (0.86/0.60) = Rs. 1.78. The fuel charges are Rs. 1.16; thus the cost of power would be Rs. 2.94 per kW. If on the other hand MSEB actually bought power 86 per cent of the time, its cost of power would be Rs. 2.40 per kW. MSEB's demand varies over the day, and at night time off-peak hours when the demand is often less than half the peak demand, some power plants have to be backed down. Providing a high load factor of 86 per cent to DPC would imply that during off-peak hours (at night) MSEB would be backing down its own power plants. In other words, it would be purchasing power at Rs. 2.40 per kW from DPC when it could be generating it from its own coal-based plants at a marginal cost of Rs. 0.60 per kW (which is one-fourth the cost of power of DPC). This would mean that MSEB would incur some Rs. 180-270 crores ($ 56-84 million) per year of avoidable cost.[84]

4.5 Analysis of DPC's Performance Guarantees and Related Penalties

One of the main planks of the pro-Enron argument is a set of various performance guarantees from the DPC and the related penalties that it has agreed to pay in case of default. As per the PPA, DPC will pay penalties for the late completion of plant, shortfall in capacity, and efficiency lower than the agreed value. Additional penalties are

[84] Ibid.

applicable in case the plant availability falls below 90 per cent. It must be noted that the agreed parameters, when these penalties become applicable are different for DPC and it's contractors. The following table, T 4.1 shows the payment by DPC to MSEB and by DPC's contractors to DPC in case of failure to give specified performance.[85]

T 4.1. Penalties for DPC and Contractors for failure to meet agreed parameters

Parameter	DPC pays MSEB	Contractors pay DPC
1) Delay in construction		
a) Upto six months	$ 14,000/day	$ 250,000/day
b) After six months	$ 110,000/day	$ 340,000/day
2) Shortfall in capacity	$ 100/kW	$ 1,892/kW

Source: *Parikh, Kirit S (2001); Economic & Political Weekly, April 28.*

DPC assures plant construction within 33 months. If the plant construction is delayed beyond 33 months, for first 6 months of delay, DPC will pay $14,000 /day (Rs 0.64/kW/day) to MSEB. After first 6 months, the penalty will be increased to $ 110,000 /day (Rs 5/kW/day). This is on the lower side of the range (Rs 5 to 7 /kW/day) prescribed by Vanguard Capital, the consultant to Government of India (GOI).[86] On the other hand, as per the construction contract signed by DPC with Bechtel and General Electric (called contractor), DPC will receive much larger penalties from the contractor. The contractor assures construction in 33 months, and for the delay up to 6 months, contractor will pay $250,000 /day to DPC and there after $340,000 /day.[87] In effect, DPC will retain nearly, $230,000 per day after paying penalty to MSEB. This sum, of $230,000 is sufficient for DPC to meet the daily interest payment on all debt and allows an additional margin of Rs.

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[85] Ibid.
[86] Vangurad Capital Limited (1994).
[87] IDBI (1994).

13 lakh per day for other expenditures. In effect, in case of delay, DPC pays nothing from its pocket, neither as interest on loans nor as the much talked about penalties to MSEB. Contractor's willingness to assure such heavy penalties to DPC also indicates that guarantee for constructing such plant in 33 months does not involve a big risk. In other words, the said commendable performance being assured by DPC needs to be viewed critically because: (a) In many cases, DPC assures a performance (plant capacity and efficiency for example) that is lower than what is achievable in the worst case. Thus, even if plant performs as expected, DPC automatically gets a bonus for "good" performance; (b) Further, the so-called "stiff penalties" that DPC is said to have promised to MSEB are negligible compared to those it is getting from its contractor. Thus, DPC has thoroughly sheltered itself from any risk burden. Rather, it has manoeuvred itself in such an enviable position that, in many cases, it stands to gain even if it fails to attain the performance standards.[88]

According to the counter guarantees, in the event of MSEB defaulting on payments to DPC due under the PPA, the Government of <u>Maharashtra has irrevocably and unconditionally guaranteed payment</u>. Moreover, this guarantee indemnifies DPC "against any loss sustained or incurred by the Company by reason of the invalidity, illegality or unenforceablity of any of this Guarantee." Further, the <u>Republic of India has counter guaranteed</u> the payments due to DPC in the event of a Government of Maharashtra default. These guarantees are legally binding under international law. The Republic of India has put all its assets, past, present and future, save diplomatic and military, as collateral in this guarantee.[89] These agreements have proved crippling for

[88] Sant, Dixit and Wagle (1995).
[89] Acharya, Anurag (2001).

governments. In the case of the Enron-owned Dabhol power project in India, the terms of the PPA have been so onerous for the MSEB - due to currency devaluation and the high cost of fuel used - that it has defaulted on payments. Enron has called in its sovereign guarantee and the Government of India has met payments but on the basis that it will be compensated by withholding funds from the Maharashtra state budget.[90]

4.6 Financing of the project

When financing for Phase I of the project was planned, the involvement of the multilateral development banks, primarily the World Bank, was considered crucial to the project's success. On being requested, in 1993, to provide financing for the (then proposed) Enron project, the World Bank conducted a detailed study of its feasibility. Its report categorically states that the project was "*not economically viable, and thus could not be financed by the Bank.*" Specifically, the World Bank did not oppose the privatisation of the Indian power sector or the participation of multinationals in power generation, but its experts felt that this particular project was not viable. It went on to say that it "*would place a heavy financial burden on the MSEB.*" because it was "*too large for base load operation in the Maharashtra State Electricity Board (MSEB) system.*" A letter from Heinz Vergin, the country director for India, to Montek Singh Ahluwalia, the secretary of the Department of Economic Affairs for the Indian Ministry of Finance, states:

"Our analysis based on the parameters provided to us indicated that the LNG- Based project as presently formulated is not economically viable, and thus could not be financed by the Bank. We have reached the conclusion on the two following grounds:

[90] Bayliss, Kate (2002).

a) the proposed 2015 MW project is too large for base load operation in the Maharashtra State Electricity Board (MSEB) system. Project design is inflexible and would result in uneconomic plant dispatch (lower variable cost coal power would be replaced by much higher cost LNG power) in order to utilize the full amount of LNG to be contracted. This adversely affects the economic viability of the project and would place a heavy financial burden on the MSEB ; and

b) the project is not part of the least Cost sequence for Maharashtra power development. Local coal and gas are the preferred choices for base load generation".[91]

The World Bank's institutional and operating mandate has been to support, expand and, if necessary, force the entry of foreign private capital into countries that are averse to such an entry. In this case, however, the brutal analysis of the World Bank is damming. To any unbiased observer of the project, the World Bank's irrefutable critique should have sounded the death knell for the project.[92] Even the Central Electricity Board had serious concerns about the project's capital cost and rates, finding that Enron's proposed price, "electricity from the Dabhol project was more than twice as expensive as what the CEA found to be acceptable or competitive."[93]

It has been assumed that 5 per cent of DPC equity is brought in the initial year and loan equivalent to 95 per cent of equity (with 12 per cent interest in US $) is brought in the next year. This loan is later replaced by real equity before commissioning. The financing package of DPC is shown as follows in T 4.2; the interest indicated is the effective interest rate, and the term indicates repayment period after construction.[94]

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[91] World Bank (1992); http://www.altindia.net/enron/Home_files/WBreport.htm.
[92] Mehta, Abhay (2001); http://www.india-seminar.com/2001/503/503%20abhay%20mehta.htm
[93] Enron in India (2002); http://rwor.org/a/v23/1140-49/1140/enron-india.htm
[94] Sant, Dixit and Wagle (1995).

T 4.2. Financing Package of DPC.

	Million $	Interest % (p.a.)	Term (Yr.)
Total Cost	910.0	—	—
Equity Capital	266.2	—	—
Indian Loan	95.6	17.5%	9.5
US Exim Loan	298.2	8.4%	8.5
OPIC	100.0	10.0%	12.0
Other $ loans	150.0	11.0%	7.5

Source: *Sant, Dixit and Wagle (1995); Economic and Political Weekly, June 17.*

Enron was undeterred by the World Bank's refusal to fund the project or negative reports appearing in the Indian media. So powerful was Enron's campaign that even the World Bank's worries about cost of power were ignored. Enron also scored a couple of other firsts, which are turning into serious problem areas. Firstly, it was a negotiated project at a time when the new power rules required competitive bidding. The reason: since nobody wanted to invest in India there was no question of bidding. This claim has never been verified, but it clearly ignores the fact that domestic public sector companies such as Bharat Heavy Electricals Limited (BHEL) were setting up world class projects at a fraction of Enron's cost and without demanding any guarantees. Secondly, the tariff negotiated by Enron, was far beyond what was permitted by the government under the power reform measures. Under these the government hiked returns to power generation companies from 12 per cent to 16 per cent on a plant load factor of 68.5 with a in-built bonus for higher generation. Enron's rate of return remains a mystery and is variously estimated at anywhere over 24 per cent to 30 per cent. Power experts say some charges such as high heat rates, higher specific fuel consumption, 90 per cent deemed generation, a fixed capacity charge and high auxiliary power consumption costs which were built into the tariff were incongruous with the modern technology of Combined Cycle Gas Turbine installations. The result: Enron's power costs Rs 7.80 a unit when private power generators such as Tata Electric Companies continue to be paid just around Rs 2 per unit.[95] On March 2, 1995, EDC completed the financing for Phase I of the Dabhol project. Phase I financing would come from the following sources:

* a 12-bank syndication led by the Bank of America and ABN-Amro (loans of $150 million). (Others included Credit Suisse First Boston (CSFB), ANZ Investment Bank, Citibank, Development Bank of Singapore and Credit Lyonnais)[96]
* U.S. Export-Import Bank ($300 million; arranged by GE and Bechtel)
* The U.S.-based Overseas Private Investment Corporation (OPIC). ($298 million)
* Industrial Development Bank of India (IDBI)($98 million)[97]

With an estimated cost of $1.5 billion and a capacity of 1,440 MW, Phase II of the project is slated to be almost twice the size of the $920 million, 740 MW Phase I. Initially U.S. government's Export- Import (Ex- Im) Bank and OPIC as well as private investors, were expected to finance Phase II. Ex- Im Bank, for example, could have extended up to $500 million for the second phase of the project. However, the involvement of Ex- Im Bank and OPIC was suspended in May 1998 because of the underground nuclear tests conducted by India. The absence of Ex- Im Bank and OPIC financing created serious problems for Phase II planning. Nevertheless, Enron scrambled to handle the setback. It secured $1 billion in financing from international commercial

[95] Dalal Sucheta (2000); http://www.rediff.com/money/2000/dec/20dalal.htm
[96] Sectoral Updates- Power Sector (1999); http://www.indianembassy.org/enews/econews(may99).pdf
[97] Case Study: Enron India, www.stanford.edu

banks. The company obtained a $200 million loan guarantee from the Export- Import Bank of Belgium and $50 million from the Export- Import Bank of Japan (J-Exim) as part of the $1 billion financing package. The company also announced that rupee loans equivalent to $300 million would be obtained from Indian banks, led by Indian government's Industrial Development Bank of India (IDBI). The State Bank of India (SBI) announced as "in principle" agreement to loan $150 million for Phase II of the project. Furthermore, the Indian government's Industrial Finance Corporation provided an $83 million loan for Phase II. The Indian government however, did not extend a counter-guarantee for Phase II.[98]

4.7 Performance of the MSEB

Till only recently, MSEB was one of the few SEBs which never failed to earn a minimum rate of return (RoR) of 3 per cent, which many SEBs struggled to reach. It also enjoyed the luxury of being an excellent paymaster and never defaulted in payments of even government loans, not to talk about defaults in payments to international bodies.[99]

MSEB has been one of the better performing boards in the country and has, even with the indifferent performance on the T&D front, managed till 1997-98 to consistently earn net revenue surpluses. However, problems started to appear once the Phase I of the Dabhol project came into operation. It should be noted that MSEB's problems lie more in the distribution side of the business. Even though tariffs have been increased regularly, the increase has been unbalanced.[100] According to a planning commission report, MSEB's

[98] Human Rights Watch (1999); http://www.hrw.org/reports1999/enron/enron8-3htm
[99] Abraham, P. (2001); http://www.indiapoweronline.com/Scripts/GNT004C1.ASP?SecID=2&CatID=6.
[100] Report of the Energy Review (Godbole) Committee.

average tariff in 1990-91 was 103.1 paise per unit, as compared to the national average of 81.8 paise per unit. This has increased to 231.18 paise per unit in 2000-01, while the national average is 212 paise per unit.[101]

T 4.3. Consumer Category- wise Average Tariff (1996-97 to 2000-01).

	1996-97		1997-98		1998-99	
	Maharashtra	**National Average**	**Maharashtra**	**National Average**	**Maharashtra**	**National Average**
Domestic	129.20	106.24	151.80	137.23	164.70	140.86
Commercial	343.65	240.30	430.33	295.42	459.00	324.32
Agriculture/ Irrigation	22.50	21.20	21.46	20.22	30.00	20.59
Industrial	330.38	276.89	354.44	314.63	396.61	322.01
Railway Traction	307.13	346.82	338.83	382.17	390.00	405.94
Outside State	222.97	151.39	200.98	138.53	230.00	164.84
Overall Average	199.03	165.74	208.81	180.85	215.61	185.75

	1999-00		2000-01	
	Maharashtra	**National Average**	**Maharashtra**	**National Average**
Domestic	174.50	158.66	176.00	171.16
Commercial	414.26	356.60	417.76	341.20
Agriculture/ Irrigation	24.61	21.02	24.61	26.42
Industrial	368.00	346.08	202.23	360.23
Railway Traction	368.00	414.72	371.50	420.76
Outside State	225.00	182.81	250.00	194.79
Overall Average	229.73	199.13	231.18	212.00

Source: same sa T *2.1.*

[101] Annual Report of the Working of the SEBs and EDs, Planning Commission, New Delhi; June 2001.

The consumer category- wise average tariff in Maharashtra vis- a- vis the national average for the years 1996-97 to 2000-01 is shown in the following table, T 4.3. The sector- wise evaluation suggests that there is a great deal of divergence between the figures in Maharashtra, as against the national average. The domestic tariff in Maharshtra has always been higher than the national average, though in 2000-01 the divergence is much less. Agricultural tariff, on the other hand, had a lower rate. The industry in Maharashtra is worst placed. Industrial tariff in 1998-99 was 351.2 paise per unit in the State while the national average was 297.53 paise per unit. This factor highlights the need for distributing the cost of power more equitably amongst the consumers in the State.

This result in certain consumer categories, with excessive tariffs has begun to reduce consumption or go off the grid. Concomitantly, consumers with subsidised tariffs have not tempered their use of power. Consequently, the average tariff realisation has not increased commensurately with the rise in cost of supply. The unit cost of power supply was 107.44 paise per unit in Maharashtra and the national average was 108.59 per unit in 1990-91, while in 2000-01 the corresponding figures were 273.13 and 303.86 paise per unit.

MSEB runs several power generating plants itself, in which it manufactures about 74 percent of all the power it supplies. It purchases the deficit from private power manufacturers including DPC. Between April 1999 and January 2000, MSEB purchased 12,300 million units of power from private power manufacturers, for a net payment of Rs. 2600 crores at the average rate of Rs. 2.11 per unit. 3040 million units of this power were purchased from DPC at a cost of Rs. 1206 crores, at the average rate of Rs. 3.97 per unit. It is striking that DPC supplied MSEB with only 25 per cent of its power purchase, and yet received 46 per cent of the payment. Between April and October 2000, MSEB purchased power from DPC at an effective rate of approximately Rs 6.13 per unit. (In October 2000, the variable cost of power was 3.72 per unit. The rest is from fixed costs.). It is useful to keep in mind that even a difference of one paise in the tariff per unit for the power from DPC phase I costs the state Rs. 4 crores per year at the levels of purchase in 2000.[102] T 4.4 below shows the power purchased by MSEB from private manufacturers.

T 4.4. Power Purchased by MSEB from private manufacturers

	Power Purchase (%)	Payments (%)
National Thermal Power Corporation (NTPC)	61	39
National Power Corporation (NPC)	12	11
Tata Electric Corporation (TEC)	2	2
Dabhol Power Company (DPC)	25	48

Source: *www.altindia.net/enron*

During 1999-2000, MSEB's purchase from DPC was 3,870 MU at a per unit cost of Rs. 4.12, involving Rs. 1,595 crores. Its purchase from NTPC was 9,257 MU at a per unit cost of Rs. 1.41, involving Rs. 1,304 crores, while from NPC, the MSEB purchased 1,868 MU, at a per unit cost of Rs. 1.82, involving Rs. 340 crores.

Between April 1999 and January 2000, payments to Enron was almost same as that to all other providers combined, while Enron produced only one-third of the power produced by the other providers. Table, T 4.5 gives the details of the power purchase by MSEB from DPC between April 2000 and October 2000.

[102] Acharya, Anurag (2001).

T 4.5. **Power Purchase by MSEB from DPC (between April '00 and October '00)**

Month	**Total Units purchased (MU)**	**Total Cost (Rs. Crores)**	**Net Cost (Rs/unit)**	**Variable Cost (Rs/unit)**	**Fixed Cost (Rs/unit)**
Apr-00	447.50	190.60	4.26	2.36	1.90
May-00	381.70	187.00	4.90	2.67	2.23
Jun-00	39.70	99.00	24.94	3.51	21.43
Jul-00	179.50	140.00	7.80	3.07	4.73
Aug-00	231.20	157.00	6.79	3.13	3.66
Sep-00	257.80	175.60	6.81	3.51	3.30
Oct-00	267.30	186.00	6.96	3.72	3.24

Source: *same as T 4.4.*

Note: Net Cost = Fixed Cost + Variable cost.

The fixed cost component of the price is the (approximately fixed) amount MSEB must pay DPC every month. This can be obtained from the above table as the product of the fixed cost per unit in a given month, and the number of units purchased (MU) in that month. This amounts to approximately Rs. 85 crore per month. In a month, such as June '00, when MSEB did not purchase much DPC power (presumably because of reduced demand in monsoon period), this fixed cost sent the net cost per unit shooting up to an amazing Rs.24.94 per unit.

It is also clear from this table that the variable cost of power from DPC, i.e. the other component of the price coming from fuel costs etc., is itself more than the net price per unit at which MSEB could purchase from other suppliers. During this period, the price of DPC power (Rs. 3.97 per unit on the average) was already more than twice the average rate paid to all other suppliers (NTPC, TEC and NPC). DPC's power has become even more expensive since then (Rs 7.81 per unit in November 2000). This is shown in the following table, T 4.6.

T 4.6. Average rate of Power Purchased by MSEB from the private manufacturers.

(price per unit in Rs.)

National Thermal Power Corporation (NTPC) (Apr. '99 - Jan. '00)	1.42
National Power Corporation (NPC) (Apr. '99 - Jan. '00)	1.80
Tata Electric Corporation (TEC) (Apr. '99 - Jan. '00)	1.97
Dabhol Power Company (DPC) (Apr. '99 - Jan. '00)	3.97
Dabhol Power Company (DPC) (Apr. '00 - Oct. '00)	6.13
Dabhol Power Company (DPC) (Nov. '00)	7.81

Source: *same as T 4.4.*

DPC power was more than twice as expensive power from any other sources in April 99. Over the last two years, the subsequent escalation of this already exorbitant cost has been alarming. In 1998-99, the year just prior to DPC's commissioning, MSEB's net revenue from the sale of power amounted to Rs. 11,650 crore. After subtracting all expenditures, MSEB claimed a surplus of Rs. 376 crores that year.

As mentioned above, when Phase II goes on line, MSEB would end up paying DPC about Rs. 7000 crores (60 percent of its 1998-99 revenue), in return for about 28 percent of its net energy supply. For comparison, the current net annual budget of the Government of Maharashtra is approximately Rs. 24,000 crores. Thus it would appear that the Enron deal is set to bankrupt MSEB.[103]

[103] Acharya, Anurag (2001).

As the *variable cost* for DPC power was higher than the *total cost* of power purchased from almost any other source, it was contended that in order to minimize costs, MSEB should draw no power from DPC. MERC, in partial concurrence with this view, ordered MSEB (in May 2000) to reduce its projected purchase of DPC power from 4200 MU to 3050 MU for the year 2000-01. More recently, in January 2001, MSEB suspended all purchase of power from DPC, appearing, thereby, to officially endorse the petitioners' claims. Even as MSEB currently `minimizes its losses' by drawing no power from DPC, it is contractually obliged to pay DPC Rs. 1140 crores a year, in return for exactly nothing. This loss to the nation will at least triple once phase II goes on line. Over a 20 year period this amounts to an overpayment of at least Rs 60, 000 crores, or 13 billion dollars (at current exchange rate). For comparison, the Maharashtra GDP is approximately 50 billion dollars a year. This is despite the fact that Maharashtra faces a power shortage for only a few hours a day. However, MSEB will be obliged to buy DPC power 21 hours a day, even at night and other times when cheaper sources of power are available.[104]

Hence, it is quite clear that the Dabhol project is by no means providing any benefit for the people of Maharashtra. It is cutting into the revenues of the state exchequer, thereby leaving very little for the sate government to spend on the social sectors like, health and education.

[104] Ibid.

Chapter 5

Impact of the Dabhol Power Project

Chapter 5

Impact of the Dabhol Power Project

5.1 Introduction

The terms of the Power Purchase Agreement proved crippling for the MSEB. The financial state of the electricity board declined drastically. By 2001, Maharashtra's tariff payments had more than doubled since 1993. Electricity from Dabhol cost more than three times as much as other power in the system, according to state officials. A number of factors have driven up the price. The first phase of the project was fuelled by naphtha, which had become much more expensive because of rising oil prices. The bills were calculated in rupees, but tied to the dollar, so as the rupee lost value, the price in domestic currency increased. In December 2000, Dabhol was selling power to MSEB at Rs. 8 per unit and MSEB was selling it at Rs. 2 per unit.[105]

5.2 Increase in the cost of Supply

The increase in the cost of supply is reflected in the major change in the composition of the MSEB's expenditure over 1995-2000. The share of power purchase costs as a percentage of total expenditure has increased from 30 per cent to 38 per cent, and the share of fuel expenses, incurred due to generation by MSEB plants, has declined from 34 per cent to 29 per cent. The power purchase cost, which had gradually risen from Rs. 2050 crore in 1995-96 to Rs. 2834 crore in 1998-99. jumped sharply in 1999-2000 by Rs. 1543 crore to Rs. 4377 crore. The billing by DPC, after the commissioning of Phase

[105] Bayliss & Hall (2001).

I, was Rs. 1617 crore. In addition, in order to absorb this power, MSEB reduced the purchase of lower cost power from TEC, NTPC and other sources. These costs will go up steeply with the commissioning of Phase II.

The other main increase in expenses has been on account of interest on borrowings, though its share of expenditure has not changed. Borrowings have increased from Rs. 3247 crore in 1995-96 to Rs. 6493 crore in 1999-2000. Other costs have so far contributed little to MSEB's precarious financial position. Salary and wages, and Operation and Maintenance (O&M) expenses actually grew more slowly than the growth of overall expenditure, at 11.2 per cent and 9.5 per cent per year respectively as compared to 15.12 per cent per year for overall expenditure.

5.3 Impact of the Project

The impact of DPC on the increase in the overall costs incurred by MSEB is self-evident. The increase in the subsidy claim by Rs. 1729 crore, from Rs. 355 crore to Rs. 2084 crore is substantially due to the increase in the gap between the average cost of supply and the average tariff, was principally due to the increase in power purchase costs. The expenditure on power purchased from DPC, i.e., 3,871 MU. was Rs. 1,617 crore. If this had been purchased at the average cost of-non-DPC supply of Rs. 1.90 per unit, the expenditure would have been Rs. 736 crore. In addition, apart from the increase in power purchase costs due to the purchase of DPC power, a portion of the increase in interest costs is also on account of DPC as a result of debt incurred by MSEB in order to invest in DPC through Maharashtra Power Development Corporation Limited (MPDCL) over 1998-99 and 1999-2000.

Subsequent to the commissioning of DPC Phase I, the financial deterioration of MSEB has been rapid. While MSEB was in profit in 1998-99, it plunged into huge losses (excluding subsidy) of Rs.1681 crore in 1999-2000. In 2001-02. the uncovered gap, at existing tariff, is estimated to be as large as Rs.3761 crore. Given the rapidly growing cost of power purchase, slowdown in HT consumption, which actually declined over 1999-2000 to 2000-01 and increasing levels of receivables, the cash available to MSEB to pay its creditors and suppliers has been affected. The Board is now under a severe cash crunch and has defaulted on several of its creditors including DPC during the past year. The dues payable on the revenue account, which were Rs. 2088 crore in 1995-96 have increased to Rs. 4245 crore in 1999-2000.

There were three major mistakes in the Enron contract. The first was to peg the cost of power against the dollar. If Coca Cola or Pepsi can sell colas in India in rupees, so can Enron. The second was to accept the hydrocarbon route – naphtha LNG as the fuels for Dabhol and link our energy prices to the volatile international prices of oil. The third was to guarantee minimum off-take for paying fixed costs. These three factors taken together have ensured that Enron power at present is three times MSEB's average cost of power generation and more than twice of any other power producer in the state. Worse, it is likely to rise every year as the rupee continues to depreciate against the dollar. In other words, even if Maharashtra government can survive the steep hike in tariff required to pay Enron this year, their situation will worsen continuously as Enron's price rises every year.[106]

[106] Purkayastha, Prabir (2000) a.

The Enron issue shows clearly the difference between textbook capitalism and the real thing. In economic texts, the capitalists take "risks" and earn profits as compensation for their risk taking. In the real world, they look for guaranteed profits and take no risks whatever. In the Enron case, the foreign exchange risk, the fuel price increase risk was assumed by MSEB.[107] The Government of Maharashtra and the Union Government are to underwrite all the risks of the project, provide an average return over 40 per cent, guarantee a 90 per cent off-take by shutting down their much cheaper generation and provide various other facilities under threat of penalties. Enron will bring in Rs. 30 crore, own the plant and have very little liabilities. If they renege, the assets (or the lack of them) that may be available at that time are all they are accountable for. For this dubious privilege, MSEB will have to shell out about Rs. 1200 crore in the first year of its operation, this cost rising every year by 4 per cent on capital servicing account, inflation, foreign exchange rate variation and increased fuel costs.[108] Even the off-take was guaranteed. If Enron was not taking any risk, why were they being paid prices that included internal rate of return of more than 28 per cent? Enron received sovereign guarantees from the Government of India, which made it possible for them to raise finances from the market. If the government had raised the same loans itself, the cost of the project would have been much lower, the domestic industry would have received orders for equipment and the subsequent tariffs much lower. This was the real alternative that the government had before it. If private capital wants to come in to the power sector, it has to take the normal risks of the market. Instead, the government decided to take all

[107] Ibid.
[108] Purkayastha, Prabir (2000) b.

the risks and award Enron all the profits. It is this logic of carpet bagging capitalism that is driving MSEB and the Maharashtra government to bankruptcy.[109]

The price of the power from Dabhol is far beyond what consumers in the area will pay or the state can afford. The financial problems began to appear in the winter of 2000. Phase I of the project runs on naphtha (a derivative of crude petroleum), but oil prices have apparently been higher than projected, and demand has been substantially lower. In addition, the deal was structured to peg the costs of power to the dollar, so the state bore the risk of currency fluctuations. The state was contracted to buy the full output of the plant, but was purchasing only 10-20 per cent of the plant's output from Phase I. The state was obligated nonetheless to pay the plant's full fixed costs, which further increased the rates. In 2001, power from Dabhol was four times more expensive than that from domestic power producers. The payments due for the power from Dabhol alone would be more than Maharashtra's entire budget for primary and secondary education. These financial problems were expected to worsen dramatically after Phase II came on line, as it would add an additional 1,444 megawatts of power and the entire project would be converted to run off imported liquid natural gas.[110]

Based on the analysis by the Prayas Energy Group of the renegotiations committee report in 1995 and the present financing structure of the project, it could be concluded that the fair cost of equity of the foreign promoters is not more than $ 320 million (Rs. 1,500 crores). This too is based on the condition that DPC completes the project to make it ready for power generation in the next six months, without burdening

[109] Purkayastha, Prabir (2000) a.
[110] Report of the Minority Staff Committee on Government Reform, U.S., (2002); http//:www.house.gov/reform/min/pdfs/pdf_inves/pdf_admin_enron_dabhol_fact_sheet.pdf

the project with any additional loans. As is known by now, by 1999, DPC had already borrowed a total loan (from Indian and foreign institutions) of nearly $ 2,050 million for the project. This implies that the total equity component of the project is only $ 450 million ($ 2,500 million minus $ 2,050 million). Out of this equity, the MSEB has already put in $ 130 million as its own equity. So, the total equity that is needed to be put in by the foreign promoters is barely $ 320 million. As the project stands today, it is no different from the project that was renegotiated. Enron, DPC and government of Maharashtra all have agreed in writing for this capital cost. In other words, purchase of entire equity of all foreign promoters for a price more than $ 320 million (Rs. 1,500 crores) would amount to paying a premium to Enron and not discount. On this background, Enron's demand for $ 800 million while claiming to offer a discount of 30 per cent, is nothing but a gross exaggeration.[111]

The Negotiation Group has claimed that given the manner, in which DPC's tariff is structured, a reduction in capital costs per se has no effect on the tariff and therefore affords no benefit to MSEB. However, this is not really the case. A higher capital cost increases the comparable GoI tariff since their costs are calculated on a cost-plus basis. A higher GoI tariff makes it easier to show that the DPC tariff is lower, and therefore makes it easier to satisfy deviation from the GoI guidelines.

For purposes of comparison, it has often been argued that the actual cost per MW was not high and it should exclude the cost of harbour and other facilities. But if one eally did take these costs away from the project, the tariff would no longer be lower than the GoI tariff, even without any change in the assumptions on heat rate, O&M costs, PLF

[111] Report of the Prayas Energy Group (2001).

and exchange rate depreciation. The high capital cost biased the results in favour of DPC, by increasing the Gol tariff. In calculating the Gol tariff, MSEB assumed that fixed O&M costs would escalate at 10 per cent per year, i.e., the domestic inflation rate. The indexation is limited to actual inflation, but it is debatable whether 10 per cent was an appropriate estimate for that time. Combined with a fixed exchange rate and a lower escalation rate in the DPC tariff, this resulted in a high capacity charge for the Got tariff, and helped to show that the Gol tariff was higher than the DPC tariff. The comparison of Phase I tariff submissions by DPC and GoI, as calculated by the Godbole Committee is shown below in T 5.1.

T 5.1. Comparison of Phase I tariff submission (Rs. per unit)

	Original Submission by MSEB	**Heat Rate assumed as per the PPA**	**Exchange Rate Depreciation of 5 per cent**	**Plus Change in PLF to 68.5 per cent**	**Change in PLF only**
DPC Tariff	2.98	2.98	3.69	4.37	3.44
Gol Tariff	3.2	3.06	3.37	3.34	3.26

Source: *Godbole Committee's Calculations.*

As per the first PPA, the DPC tariff was escalating at 4 per cent per year. However, since the tariff submission did not consider any depreciation in the exchange rate, the effect of this increase in dollar cost did not find full reflection in the tariff calculation. It is curious that this assumption of fixed exchange rates was maintained even though a domestic inflation rate of 10 per cent was assumed. It is elementary economics that excess domestic inflation leads to depreciation of the exchange rate. This is all the more surprising since the exchange rate had depreciated sharply during the negotiation period. While the GoI levelised tariff increases to Rs. 3.37 per unit. the DPC tariff rises from Rs. 2.98 lo Rs. 3.69 per unit. Also. the DPC tariff is higher than the GoI tariff from 2000 onwards. The assumption of a fixed exchange rate played a key role in showing that the DPC tariff was lower than the GoI tariff.

The base case assumption for calculating the GoI tariff assumes a PLF of 90 per cent. A higher PLF reduces the per unit tariff for DPC since it spreads the fixed charges over a larger base. At the same time, it increases the GoI tariff since a higher return on equity (RoE) is assumed for the GOI tariff due to incentives, i.e., the assumption of PLF at 90 per cent makes the DPC tariff analogous to a two-part tariff where the RoE is 31.05 per cent. As mentioned earlier in this report, the assumption of a PLF of 90 per cent was gratuitous, but it was very convenient, since it permitted MSEB to show that the DPC tariff was lower than the GoI tariff. If a PL.F of 68.5 per cent is assumed, along with an exchange rate depreciation of 5 per cent, then the levelised DPC tariff rises to Rs. 4.37 as compared to Rs. 3.34 for the GoI tariff. Indeed, even if no other change except a PLF of 68.5 per cent, was made, i.e., even if the exchange rate is fixed, and a heat rate of 2000 kcal/kWh was assumed for the GoI plant, even then the levelised DPC tariff at Rs. 3.44 is higher as compared to Rs. 3.26 for the GoI tariff.

Thus, it is seen that even without changing the unfavourable assumptions on capital cost and indexation of O&M expenditure, the demonstration that the DPC tariff for Phase I was indeed lower than the GoI tariff is seen to be based on very convenient assumptions of a fixed exchange rate and a heat rate of 2000 kcal/kWh, a PLF of 90 per cent and of course, the high capital cost and indexation of O&M expenditure. Instead of trying to determine whether MSEB was actually receiving value for money, the effort seemed to be to find assumptions so as to demonstrate that the DPC tariff was lower than the GoI tariff.

But, the story does not end here, and Enron (as usual) wants more and more. A few months before the suspension of work, it was claimed that over 90 per cent of the project work was complete. But due to just a few months suspension of the work, now Enron is claiming the additional cost of US $ 360 million, i.e., 14 per cent additional cost overrun for completion of the project. So, now Enron is claiming a project cost of $ 3,690 million instead of $ 2,500 million; a difference of $ 1,190 million (or a cost increase of Rs. 5,500 crores). Thus, it is yet to be decided, as to who will bear the burden of the excess cost of this deal. Enron, the prospective buyer (i.e., their shareholders), the consumers, the Indian financial institutions (i.e., the investors), or the government (i.e., the tax-payers).[112]

5.4 Current Situation of the Dabhol Power Project.

At a time when the nation is facing an acute shortage of power, it is a tragedy that the state-of-the-art Dabhol power plant in Maharashtra has been lying idle. An early recommissioning of the plant is ruled out because of the troubles Enron Corporation is facing in the US. After all, the bankrupt US energy trader has a 65 per cent stake in the DPC. The troubles facing Dabhol preceded Enron's bankruptcy as is borne out by the fact

[112] Report of the Prayas Energy Group (2001).

that the plant has been closed since June last. In fact, proceedings for sale of the 2,184-megawatt gas-fired plant and an adjacent LNG facility are already on.[113]

Even if a company or a consortium of companies makes bold to buy DPC, there is no certainty it will find a buyer for the power Dabhol produces. In fact, all the problems DPC faces today began when MSEB failed to pay for the power purchased from it. This forced DPC to serve an asset transfer notice on the MSEB as a step towards termination of their power purchase agreement. This halted the construction on the 1444-megawatt second phase of the project. MSEB finds the power supplied by DPC too costly and uneconomic to distribute. Small wonder that finding a buyer for DPC power will be more difficult than finding a buyer for DPC. This, again, may put off some of the companies which have shown interest in bidding for DPC. The French energy major, Totalfinaelf, which was one of the potential bidders, has already excused itself out of the deal finding the project unviable.[114]

For some time now, Enron's 65 per cent equity in the DPC has been up for sale. So is the 20 per cent equity that belongs to General Electric and Bechtel. Although Tata Power and BSES Ltd. showed interest in picking up a majority stake, it soon became clear that the tainted project had no takers.[115] The preliminary termination notice issued by DPC in May 2001 expires on 19th November 2001, signaling the end of the "negotiating period". In this context, the most significant issue being debated is the fair cost of DPC's equity held by the foreign promoters. Press reports indicate that Enron and the other foreign promoters are in a "benevolent mood" and are willing to forgo all

[113] (2001) Indian Express.
[114] ibid.
[115] Katakam, Anupama (2002).

profits, if they get back only what they have invested. In fact, they are talking about discounting their equity by 30 per cent, and claim that the fair price for their equity is $ 800 million. As against this, the prospective buyers (such as Tata and BSES) feel that this cost is too high and want the price tag to be lowered. If Enron is not prepared to accept this, the Indian financial institutions (FIs) may come under pressure to absorb the difference. This is evident in the proposals being discussed, which envisage that the FIs would buy the equity and act as the "Ware-house" for the equity, which they will sell later, absorbing the loss. The central government might also consider the option of giving tax and other concessions by declaring Dabhol as a "Mega Project". Thus, it needs to be remembered that, apart from the paying to foreign promoters, governments or FIs will have to bear the remaining losses necessary in order to make the project viable through the other means such as the tax losses, interest cuts, or loan write-offs.[116]

[116] Report of the Prayas Energy Group (2001).

Chapter 6

The Godbole Committee Report

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6.1 Introduction

Enron is responsible for the biggest and most controversial foreign investment project in India. The project is on the brink of collapse. The Dabhol project was highly controversial in India from the start, and it was associated with allegations of malfeasance and corruption at the highest levels.[117] While controversy has been ongoing throughout the life of the project, there are several key areas of dispute including the process and content of the original agreement as well as of the revised agreement. Since a lot of different constituents were affected by the project including the other small IPPs, it was not surprising that the project found itself in the midst of many controversies. Many small IPPs who were against such "mega projects" complained that the package of customs duty exemptions for equipment available to larger projects were not available to them, putting them at a comparative disadvantage. According to media accounts, India's Planning Commission originally opposed the project on grounds that the plant's annual requirement of 3-million tons of gas would drain at least $250-million from India's foreign exchange reserves.[118] Moreover, since liabilities under PPAs typically executed with IPPs are expected to persist over periods as long as 20 years, a general review of the power situation as well as a specific review of particular IPPs, their financial implications and effect on power supply situation has become necessary. Concomitantly, there is considerable concern regarding the financial health of the MSEB. As a matter of prudent

[117] (2001); The Guardian.
[118] Independent Power Report (1993).

governance it is incumbent to evolve a course of action that would be in the larger public interest of the state. Accordingly, the Government of Maharashtra (GoM) constituted an Energy Review Committee, under the chairmanship of Mr. Madhav Godbole to examine some of these issues.[119]

6.2 Findings of the Committee

The committee was entrusted with the task of an in-depth scrutiny of the Enron Deal. The committee, which submitted its report in April 2001, came out with some shocking revelations and bold recommendations. At the outset, it should be noted that the Dabhol project was a negotiated project at a time when the new power rules required competitive bidding. The reason given was that since nobody wanted to invest in India, there was no question of bidding. This claim has never been verified, but it clearly ignores the fact that domestic public sector companies such as the BHEL were setting up world class projects at a fraction of Enron's cost and without demanding any guarantees.

The most contentious issue regarding the project has been the cost of the project. The PPA shows that the cost of the main plant equipment is Rs. 610 crores, while the project costs are about five times this amount. The cost for the main plant equipment is comparable to indigenous power equipment costs; the significant difference being that in Indian plants main equipment costs are roughly 60 per cent of the total project costs. Even if we take into account the additional financial costs in going the private sector route, other costs should have been at the most equal to the main equipment costs. In

[119] Report of the Energy Review (Godbole) Committee (2001).

other words, the total cost of the project based on the above, should not have exceeded Rs. 1200-1300 crores. However, the total costs of the project, in reality, are much higher.

The reasons for this are not far to seek. The total contract value for the construction of the project is Rs. 1872 crores, i.e., three times the value of the main plant equipment. The rest of the costs was obviously nothing but the reflection of a desire to show higher project costs to take advantage of the fixed guaranteed return on capital which would translate into even higher profits. It is striking to note that Enron is leveraging its equity, while putting in a measly amount; it is bringing in only 1.5 per cent of the total project cost by way of equity, while owning 80 per cent of the total equity. Enron brought in only Rs. 30 crores in cash, while the rest was brought in through loans. Not only that, they were allowed to sell off 30 per cent of their equity before the project was commissioned.

According to the Godbole Committee report (hereafter mentioned as report), signing the deal had many extremely disastrous financial implications. The contract included payments to Enron for shipping LNG, which was higher than a comparable contract. It has been also pointed out by the committee that the designed capacities of the components of the project, other than the power project such as the LNG Re-gasification facility, Marine facilities, Shipping charter, Gas-supply Agreement were in excess of the need of the power project.

The report has clearly opined that power from the project was priced way beyond what was reasonable and the decision-making process was neither reasonable nor rational. The report has given detailed computations of how MSEB according to the PPA, agreed to <u>excessive payments to Enron, to the tune of Rs. 930 cores per year</u>. It is important to note that the government had committed for a 90 per cent PLF, which is highly advantageous for Enron, as the load factor in Maharashtra is only 61 per cent. According to the Maharashtra Electricity Regulatory Commission's merit-order dispatch, power sources with lower variable costs have to be used before costlier power can be purchased by MSEB. So as the unit variable cost of power from Dabhol is quite high, MSEB can lift it only when all other sources are exhausted. This is why MSEB is lifting only 40 per cent of Dabhol's power, as it is cheaper for MSEB not to lift the entire power, and to pay Enron the capacity charges of Rs. 95 crores per month. Not only that, Enron has passed the entire cost of re-gasification facility to MSEB, thus charging it by about Rs. 253 cores even though it uses only 40 per cent of the re-gasification facility.

MSEB has been one of the better performing SEBs in the country, and has even with the indifferent performance on the T & D front, managed till 1997-98 to consistently earn net revenue surpluses on an accrual basis. Even though tariffs have been increased regularly, the increase has been unbalanced, with the result that certain consumer categories, with excessive tariffs, have begun to reduce consumption or go off the grid. Consequently, the average realisation has not increased commensurately with the rise in the cost of supply, though in the few years before Enron came online, the gap between the average revenue realisation and the average cost of supply was limited. In fact, there was a reduction in subsidy claims (from GoM to MSEB to get over the shortfall in MSEB accounts) from Rs. 630 crores in 1995-96 to Rs. 355 crores in 1998-99. However due to the sudden rise in the gap from 15 paise to 41 paise (an increase of 173 per cent) per unit, there was a sudden five-fold increase in subsidy claim to Rs. 2084 crores in 1999-2000. This was partly due to the fall in average realisation (3 paise) but mainly due to the sharp increase in the average cost of supply by 23 paise per unit (from Rs. 1.84/kWh in 1998-99 to Rs. 2.12/kWh in 1999-2000).

According to the committee, the sudden increase in the average cost of supply in one year is mainly due to the sharp increase in the power purchase cost, which increased from 14,429 MU in 1998-99 to 18,687 MU in 1999-00. The corresponding expenditure n power purchase was Rs. 2843 crores in 1998-99 to Rs. 4377 crores in 1999-2000 (increase by Rs. 1543 crores in one year). The committee further points out that the total payments to DPC, after commissioning of Phase I, was Rs. 1617 crores. Not only that, MSEB reduced its purchases from the other cheap sources (reduction by about 900 MU) viz. TEC, NTPC etc. to accommodate the electricity from Enron.

At the time the Enron deal was originally agreed upon, Enron and its defenders claimed a tariff of RS. 2.40 per unit. This certainly did not seem as frightening as the current figure, Rs. 7.20 per unit. MSEB is paying Enron 15 per cent of its revenue for a miniscule 5 per cent of its requirement. But this is only for Phase I. Once Phase II comes into operation it will have grave consequences not only for MSEB, but also for the Maharashtra government. According to studies done by the Prayas Energy Group, once Phase II becomes operational, MSEB will have to pay Enron 52 per cent of its current revenue for meeeting less than 20 per cent of its electricity needs. This means a net loss of more than Rs. 3,000 crores per year.

6.3 The Renegotiation Group

At the outset it can be stated that the claims put forward by the Renegotiation Group are not accurate. According to the Renegotiation Group the original cost of the project (both Phase I & Phase II) as indicated to the Renegotiation Group was $ 2.83 billion. The Group considered the cost of Phase I to the tune of $ 919.8 million to be high. Since the equipment cost had since declined, it recommended a reduction in the cost by $ 330 million. This was supposed to reduce overall cost to $ 2.5 billion. Also the increase in the capacity (169 MW) was mostly due to a design change in the gas turbine. The additional output did not lead to any significant additional cost to the DPC. However, the Group considered this to be a benefit as a saving in additional capital investment for additional capacity which was valued at $ 223 million (at the rate of Phase I cost of $ 918 million for 695 MW). An additional cost of $ 35 million could be saved which was incurred on account of converting the plant to a multi-fuel plant. This is very surprising, as the appropriate interpretation is surely that the initial cost was excessively high and therefore overstated. Thus, according to the Renegotiation Group, the total savings in capital costs obtained was to the tune of $ 588 million (330 + $ 223 + 35)[120], a savings of around 22.5 per cent. So if these savings were in fact possible, then surely the fixed charges should have been scaled down.

However, the reported savings of 22.5 per cent were actually not made on Phase I at all. The reduction was based on the projected costs of Phase II. In other words, the Shiv Sena-BJP government signed an agreement to build Phase II when the previous government's agreement with the DPC made Phase II optional. Then the Shiv Sena government reported it had saved 22.5 percent on Phase II, thereby reducing costs. It failed to mention that the former agreement had no obligation to have Phase II at all.

[120] Figures are in million $.

Costs for Phase I are the same as the old agreement, and all the savings are on Phase II. In other words, the new terms recommended by the six-member Negotiating Group set up by the Maharashtra Government to revive the Dabhol Power Project were unacceptably advantageous to Enron and clearly disadvantageous to Maharashtra and India.

The Group also recommended a removal of 4 per cent escalation in the capital recovery charge from the date of commissioning of Phase II. Based on this, the DPC agreed to a levelised tariff of Rs. 1.89 per unit at Rs. 32 to the dollar, at a fuel price (FOB) of \$ 1.95 per million BTU (British Thermal Units), which is equivalent to a price of \$ 13 per barell of oil at a PLF of 90 per cent. In other words, what was agreed was a fixed tariff in dollar terms by way of capacity charge. This levelised tariff was compared to the pre-re-negotiated tariff and the levelised two-part tariff, under the GoI notification at a discount rate of 17 per cent per annum which was equal to Rs. 2.60 per unit and Rs. 2.05 per unit respectively. The Group found that the pre-re-negotiated tariff was higher than the GoI tariff, even though in the earlier documents it was shown to be lower. This was after the Group neglected the impact of two very important changes in regard to the levelised tariff viz., the depreciation of the rupee and the change in fuel prices. However, the committee points out that the rate of electricity of DPC (during May 1999 to December 2000) was Rs. 4.67 per unit, a far cry from Rs. 1.89 per unit, as claimed by the Group.

The tariff negotiated by Enron was far beyond what was permitted by the government under the power reform measures. Under these, the government hiked returns to power generation companies from 12 per cent to 16 per cent on a PLF of 68.5 per cent, with an in-built bonus for higher generation. Enron's rate of return remains a mystery and according to various estimates is anywhere between 24 per cent to 30 per cent. Enron's power costs Rs. 7.80 per unit when other domestic power generators like TEC continue to be paid just around Rs. 2.00 per unit. With the rupee continuing to lose value against the dollar and the price of LNG and naphtha rising as they have done over the years, the price of power of DPC will be on a rising trend.

The Annual Report prepared by the Comptroller & Auditor General (CAG) of India, states that the GoM could have renegotiated with the DPC to reduce the tariff per unit of power by leveraging the profits accruing to the DPC due to the increased additional capacity. By reinstating the deal, the CAG report points out that it cost the exchequer a whopping $ 175 million over and above the Rs. 4.47 per kWh cost of power that will have to be paid to the DPC. According to the CAG report, the tariff per unit of power would have been reduced had the then GoM renegotiated the earlier PPA, instead of scrapping the project and then renegotiating it. The report further points out that MSEB went out of its way to provide power supply to DPC during the construction phase for a meagre sum of Rs. 3 million. MSEB could have easily collected Rs. 46.4 million from DPC had it supplied power at its regular rates instead of concessional rates.

The littany of improprieties committed by Enron in collaboration with MSEB is very long. Regarding the basis for the reduction in tariff, the capital cost was reduced to $ 1.5 billion, as was mentioned in a letter from DPC to MSEB dated April 8, 1996. However, the subsequent tariff submission from MSEB and CEA to the GoI continued to mention the project cost as the original cost of $ 2.83 billion. If we take a look at the Enron contract, we can identify at least three major clauses, which had led the whole project to such as a sorry state of affairs. The first was to peg the cost of power against the dollar, thereby entailing the risk of exchange rate fluctuation. The second was accepting the hydrocarbon route - naphtha and LNG as fuels for Dabhol, which meant linking our energy prices to the volatile international prices of oil. If the above two were not enough, a third flawed agreement was that MSEB promised to a fixed capacity charge. This all led to the power produced by Enron to be too expensive, with the price likely to rise every year, as the rupee depreciates against the dollar, from Rs. 32 a dollar in 1993 to Rs. 48 at present. Though the cost of electricity will be lower once the Dabhol project shifts to LNG (a cheaper fuel than naphtha) in Phase II, still the cost of power from DPC will be quite high relative to the domestic private power producers like BSES and TEC.

Though Enron's $ 2.83 billion project is hailed as the largest Foreign Direct Investment (FDI) in India, more than half the funds of the project (nearly $ 1.88 billion or Rs. 60 billion) have either come from the Indian financial institutions or have been guaranteed by them. The Godbole Committee report points out that the Indian lenders and financial institutions failed to do a proper project appraisal before committing the money.

6.4 Sustainability of the Dabhol Power Project

The DPC claimed that it was willing to work out a solution so as to ensure stability of MSEB and the project in the long term. It suggested solutions such as off-take of power by GoI/NTPC for sale to other states, reduction in LNG 'Take or Pay' by selling LNG on spot basis. It also sought several tax concessions such as 10-year tax holiday (applicable to mega power projects), import duty exemption, exemption from

Minimum Alternative Tax (MAT) and Dividend Distribution Tax. This implies that DPC was not willing to negotiate with the Committee, in defiance of government's resolution to ask the Committee to carry out negotiations with the DPC. Further the likely solutions suggested by DPC are aimed at finding ways to ensure that its revenues and profitability remain unchanged while the payments are ensured. This needs to be seen in light of the possibility of over 50 per cent reduction in fixed costs recommended by the Committee.

It has now come to our notice that the Central Electricity Authority (CEA) has placed a precondition on Phase II of the project which states that the MSEB must ensure that all the power would be absorbed before commencing Phase II. this condition cannot be met by MSEB at present, as the MSEB does not have the capacity to purchase the entire output, and that too at five to six times the cost of alternative sources.

If Enron does ultimately pull out, the costs will be quite heavy for Maharashtra. Even if the MSEB takes over the project, running it will be a challenge, considering the high costs of operation. The already inflated project cost includes the LNG project as well. DPC has set up a 5 million tonnes LNG plant in Maharashtra, whereas the project requires only 2.1 million tonnes. Considering the feasibility of marketing gas to other users and spot sale of LNG, as well the large investments planned by several companies in India for LNG terminals, the Committee has recommended separation of LNG and associated facilities from the power plant. This will substantially reduce the cost of the power project. Even if the project cost is brought down, the operating cost is already on the higher side.

By the end of 1999, DPC had already borrowed $ 2.05 billion from the financial institutions. At a 70:30 debt-equity ratio, the real project cost is obviously much higher than was claimed by Enron during the renegotiation. The Prayas Energy Group has claimed that on the basis of the $ 2.5 billion project and with an exposure of $ 2.05 billion from the Indian financial institutions, Enron cannot claim more than $ 320 million for its share of the equity. This figure sharply contrasts with the estimate of $ 800 million reported to be under consideration by Indian financial institutions. The evaluation of the project's worth was done following reports about DPC selling the stake of its three MNC promoters, for about $ 800 million, after a 30 per cent discounting. Based on DPC's cumulative loans from Indian financial institutions, the total equity component comes to only $ 450 million. Of this, the equity of MSEB is $ 130 million. This brings the total equity put in by foreign promoters to about $ 320 million. Thus, buying the foreign promoter's stake for a price more than $ 320 million would amount to paying a premium to Enron rather than a discount.

Restructuring the project on the lines suggested by the Committee, it would be feasible to reduce the fixed capacity charge by over 50 per cent. This together with the recommended move from 'Take-or-Pay' nature of LNG to 'Pay-as-Use' and desirable PLF of only 30 per cent in the initial year would result in reducing the total liability on MSEB to less than half. Thus, the Committee clearly brings out the real extent of excessive profitability of DPC equity holders (even without considering the issues of inflated capital costs) which results in very high and unaffordable tariff.

It is now obvious that the Enron promoted DPC was an enormous blunder. Not only has the MSEB been driven to near-bankruptcy, but a shadow hangs over the completion of Phase II of the project. MSEB's inability to pay stems primarily from the fact that the revenue it earns from the sale of power of DPC is far less than what it pays out to DPC.

An initiative that was launched as part of the ideology of reform has ended by defeating the grounds on which the reform process is commonly advocated. It is known that among the major creditors who have lent to Enron huge amounts of money on the strength of the government's guarantee are a host of Indian banks and financial institutions. If a similar credible guarantee had been provided to an Indian firm, it would have assessed the same sources to earn similar profits, which may not have been repatriated abroad in equal measure. What benefit the policy has offered in terms of attracting foreign investors who could deliver more than the Indian corporates is by no means clear. The fact that the policy has worsened the crisis in the power sector and elsewhere in the economy has even begun to affect the credibility of the sovereign guarantee that the government had offered. Under the prevailing terms and conditions, if the government opts to pull back its commitment to backing Phase II of the project and purchasing all power it generates, it would have to pay a compensation to the tune of Rs. 35,000 crores.

The Committee suggested that all the partners in DPC should write off 50-75 per cent of their equity stake. Currently, the entire equity held by the partners in Phase I amounts to $ 435 million; for Phase II $ 452 million. According to the Committee, restructuring of the project costs will bring down the tariffs to Rs. 2.40 per kWh, which is the ideal price. But Enron wants a zero-loss exit, sighting the fact a cut in equity is unrealistic for DPC's offshore sponsors. With no takers for the project apart from the

GoI, the only option now seems to wait until the judicial probe is over and the court cases are settled.

6.5 Recommendations of the Godbole Committee

Before the Godbole Committee came up with its recommendations, both the MSEB as well as DPC submitted their proposals to the committee. The MSEB proposed that at a minimum, MSEB's purchase obligations should be restricted to an amount equivalent to the Phase I capacity. It also claimed that no liability for gas take or pay and for the re-gasification plant should fall on MSEB, and no escrow cover should be required of MSEB. Furthermore during negotiations, efforts may be made to reduce the capacity charges. Finally, even to service the power purchase obligations of Phase I, support from GoM will have to continue until MSEB's revenues build up through suitable tariff revision and reforms.

On the other hand, DPC specifically offered to work with GoM for off-take of power by GoI or any of its agencies for optimal utilisation of existing installed capacity to bridge demand-supply gap in other parts of the country. It also offered to assist MSEB to sell power to other States on marginal cost basis and also to reduce MSEB's LNG take or pay obligation, by sale of LNG on spot basis. In the last case, MSEB would need to bear the differential cost, if any, of such sales. DPC expressed the hope that GoI or any of its agencies, preferably NTPC, would purchase DPC power equivalent to at least 1 block (740 MW). since GoI under the counter guarantee, is, in any case, obliged to make payments for 740 MW. According to DPC, this will permit GoI to pool DPC power with NTPC power and enable reduction of average tariff, and provide NTPC with significant capacity addition with no up-front investment. DPC believes that this will also potentially give NTPC access to re-gasified LNG for its gas based power projects on the Western coast. DPC was also prepared to offer 15 per cent equity to NTPC as part of its ongoing effort to reduce equity so as to avert consolidating DPC's accounts with those of Enron, as required under US law. The other suggestion from DPC was that it should be accorded the mega project status so that it derive the benefits accruing as a result, i.e., 100 per cent tax holiday for 10 years and import duty exemption on capital goods. The DPC proposed that it should be allowed to set off these benefits against import duty payable on fuel imports, in which case these benefits can be passed on to MSEB. DPC has also proposed that it be given exemption from applicability of Minimum Alternative Tax (MAT) and Dividend Distribution Tax (DDT). DPC, at the same time, underlined that all project contracts (including PPA) have stringent provisions for non-performance by way of default provisions, liquidated damages, termination provisions, etc. DPC has emphasised that an effective solution lies in operating DPC at 90 per cent dispatch level to minimise unit tariff. It also suggested that MSEB should undertake reforms in a time-bound manner and reducing MSEB's obligations to DPC over a 3-4 year term to enable MSEB to undertake reforms.

The Committee has carefully considered the points made by MSEB and the DPC. The question of restructuring of MSEB and initiating a time-bound reforms programme is certainly crucial to any long term and durable solution to the problem. In so far as the other points made by MSEB and the DPC are concerned, however, the Committee believes that it will not be possible to deal with the relevant issues by merely bringing in the GoI in the matter and expecting any of its agencies such as the NTPC to purchase a part of the DPC power. If DPC power is expensive for Maharashtra consumers, so will it be for consumers- in all other parts of the country. The main point is that even if MSEB was in the best of financial health it should not have purchased DPC power. DPC power is not the least cost option, whether looked at from the point of view of a consumer in Maharashtra or elsewhere in the country.

It must also be noted that any such change in the arrangements for sale of power will have to be approved by the Central Electricity Regulatory Commission by following the procedure prescribed under the relevant Act and calling for objections from the consumers and so on. It is therefore imperative that the basic issues involved in this project are addressed up-front. These would call for financial re-engineering and restructuring of DPC so as to reduce the cost of its power substantially. Only such a package of measures will open up possibilities for greater off-take of DPC power not only in Maharashtra but also elsewhere in the country.

The Committee examined the possibility of sales outside the MSEB system.. Given the current price of DPC power, and the demand supply situation in the neighbouring states, and indeed the finances of all SEBs in general, which lose more money with every extra unit sold as their additional revenue realisation is below the cost of supply, the Committee found the option to be impractical. The Committee therefore arrived at the conclusion that there is no buyer for the existing power, as currently priced and according to the existing terms of the PPA.

However, the Committee has recommended a radical restructuring of the project. Within the terms of this restructuring, however, the restructured fixed charge continues to be the responsibility of MSEB. This is being distributed over a low off-take in the initial years, and is resulting in a higher tariff. Sale of power outside MSEB will allow this fixed charge to be distributed over a larger base and thereby reduce the per unit tariff. While MSEB itself may be able to locate creditworthy buyers for such power, DPC may prove to be more successful in marketing than MSEB. The Committee therefore recommends that DPC be allowed to sell such power subject to the condition that: DPC designates a certain capacity for sale outside the MSEB system and the fixed charges on account of MSEB are reduced in proportion to this designated capacity.

Essentially, negotiations would have therefore to be held to alter the terms of the PPA. With the project as it is currently structured, DPC is eminently profitable and carries relatively high interest debt. There is substantial scope for altering the terms and still retaining a reasonably profitable project. Such a renegotiation is not anathema to DPC. Indeed, according to them, they made concessions in 1995 and expect to make them again in the near future.

Under the present tariff structure, DPC has almost no variable charge until the PLF reaches 73 per cent, i.e., 14,000 MU. Even if MSEB were to buy no power from DPC, it would have to pay around $ 1140 million per year, or about Rs. 5360 crore per year. Under the current tariff structure it is financially sensible to draw as much power as possible from DPC, since even if one does not draw the power, one would have to pay anyway. This would imply replacing 73 per cent of MSEB's entire power purchase of approximately 18,000 MU in 2001-02 and replacing it with power from DPC, which would increase the cost of power purchase substantially.

The Capital recovery charge is the critical item that distinguishes DPC from the tariff structures of other IPP. In the GoI two-part tariff structures, the equity charge is specified separately, as a specified rate of return on equity invested and a separate debt service charge that reflects the interest paid, while repayment of principal is made from depreciation provisions. In such a structure, as the debt is paid off, the tariff comes down over time, unlike the DPC case, where it remains constant in dollar terms, and increases in rupee terms due to depreciation.

The Committee has suggested for the renegotiation of the Heat Rate to Match the EPC Guaranteed Heat Rate. This is because IPPs make considerable profit from the difference in these heat rates. Renegotiation will therefore lead to a reduction in the overall tariff by reducing the fuel charge. Fuel arbitrage refers to the profit earned by the IPP as a result of differences in actual payment made for fuel consumption by the SEB and the actual expenditure incurred by the IPP on fuel. This difference occurs because the heat rate specified in the PPA is higher (which implies a higher fuel consumption) than the heat rate attained during actual operations. While the SEB is billed on the notional and higher fuel consumption based on the PPA heat rate, the IPP actually incurs only for the lower and actual fuel consumption.

It is evident that if DPC is to be made sustainable, the tariff will have to be reduced considerably. At the current levels of tariff, there is no demand for power from DPC and as such, the low PLF implies that tariffs will continue to remain high. A lower tariff will induce demand, increase PLF and thereby allow the fixed costs to be distributed over a wider base. A lower tariff can only be obtained by lowering the fixed costs associated with the project.

A conversion of all dollar-denominated equity into Rupee equity (which is equivalent to denominating the equity return in Rupee terms instead of, dollar) brings a further reduction in the tariff. However, the first year tariff including fuel charge is still too high to be absorbed into the system. It is necessary to reduce per unit fixed cost component of tariff in initial years when PLF is expected to be low.

According to the Committee, reduction in tariffs in the initial years can only be achieved through changing the financial structure of DPC substantially. Three such changes are explored, viz., conversion of all debt into Rupee debt, introduction of a moratorium with an extended repayment period and reduction in the interest rate. Part of the equity could be converted into preference capital, with the same redemption period as the debt apart from a write down of equity. These options involve significant financial sacrifices for the debt and equity holders.

Conversion of equity into rupees reduces the equity return by removing dollar indexation, and conversion of all debt into Rupee debt (same repayment profile as the existing loans) reduces the debt service charge. The subsequent restructuring, write down of equity and reduction of interest reduce capital recovery charge and debt service respectively. A moratorium on debt service increases the levelised cost (due to a higher burden of interest cost), but reduces the payout in initial years, when PLF is expected to be low. Finally, conversion of equity to preference capital at 8 per cent, with the same redemption profile as the loan moratorium reduces the equity return.

The actual tariff so obtained will depend on the extent of restructuring and the off take of power. The rise in PLF can be accelerated by selling the power to other distributors or to creditworthy buyers in Maharashtra or other states, who also lack sufficient intermediate load facilities and who can take advantage of higher time of day (ToD) tariffs, now being permitted by regulators, e.g., if BSES starts buying this power, then one can achieve lower tariffs. However, if the full extent of restructuring as described above is undertaken, even if the PLF rises slowly over time, for example reaching 67.5 per cent by 2007 (a higher PLF cannot be assumed for a plant that is expected to serve intermediate load), the ultimate tariff could still prove affordable.

The Committee has recommended the separation of the power plant and the LNG fuel facility as there are significant alternative uses for the LNG facility. The Re-Gasification facility, which is much larger than what the power plant needs, could be marketed to other gas marketers and importers of LNG, such as Petronet LNG Limited. Similarly, the harbour facility can also be used as a common facility, by such importers of LNG, as its capacity is again well above what can be used by the power plant. With respect to the LNG purchase contract itself, the Committee noted that other buyers for the LNG can be found, perhaps with some additional investment in pipelines. Besides, the current market conditions for spot LNG make it quite attractive to trade LNG on the spot market. Finally, the Committee observed that if total deliveries including additional buyers are less than what is required for the shipping charter, it could be used for transportation of LNG in the spot market.

Even though there are such 'take or pay' provisions in most LNG supply contracts, the advantage of a separate fuel venture is that such demand risks are distributed more widely across various consumers, so that no individual buyer is exposed to the risk of take or pay. In this case DPC has transferred the entire risk to MSEB. One of the advantages of the separation of the fuel venture would be the ability to distribute these risks in a more equitable manner.

The Committee has not examined the viability of this separate LNG project in detail. However, it is known that large volume of new investment are being planned by Petronet LNG, as well as other private parties, which include large business houses such as Tata and Reliance. Thus, the committee noted that it would be reasonable to assume that there is a business case for an existing facility, such as the one at Dabhol, with already well developed port and re-gasification facilities to be utilised by the other parties. If there is no such case, the Committee suggests that the Ministry of Petroleum and Natural Gas (MoP&NG) as well as the financiers and investors in projects such as Petronet re-examine their business plans intensively, lest similar expensive follies such as DPC are committed elsewhere.

The most contentious issue with respect to DPC is the tariff and its non-transparent nature. It is essential to remove this capacity, which can be done by converting the tariff structure into a two-part tariff based on the GoI guidelines and the ABT (Availability Based Tariff) Order of the CERC. The Committee therefore recommends that the DPC tariff be redefined using the principles contained in GoI guidelines and the ABT Order of CERC to convert it into a two-part tariff but limit equity return substantially.

Dollar linkage in the project increases the rate of growth of tariff since the effective equity return is the base return plus depreciation. Since the rate of future depreciation is contentious and uncertain, this adds unnecessary volatility to the tariff, in a situaon where it has become necessary to define a predictable tariff in order to evolve a long-term restructuring plan. The debt component of the fixed charge also has the same unpredictability, though in this case the difference in interest rates between domestic and foreign funds provides a cushion against a certain level of- depreciation. Indeed for certain levels of depreciation, it would be less expensive to have foreign debt. The Committee therefore recommends that the equity return for the redefined DPC tariff be defined in rupee terms rather than in dollar terms.

In the initial years, the off-take of power from DPC is likely to be low, given the lack of creditworthy buyers for the power, until such time as the distribution system can be reformed within Maharashtra and outside, where the process has begun in states like Andhra Pradesh and Karnataka. If the fixed charge is distributed over this low off-take, it will increase the per unit tariff to unaffordable levels. The finances of DPC therefore need to be restructured so as to defer the payment obligations to the later years, when the off-take would be higher and the higher fixed cost can be distributed over this higher off-take, which will keep tariff at acceptable levels.

In view of the non-sustainability of the Dabhol, the promoter company i.e. DPC should forego a portion of the return on its equity so that the project may become viable. The Committee therefore recommends that the maturity of the debt of DPC be increased, preferably to 15 years, with an initial moratorium of 5 years. An indicative interest rate for such debt could be 12 per cent (in rupee terms, which would be around 6 per cent in dollar terms). In case such maturity is not possible for foreign loans, the foreign debt should be converted to rupee debt and restructured accordingly. Concomitantly the equity may also be restructured into deferred preference capital, so that the impact on tariff is felt only in later years.

The Escrow Agreement with DPC, as currently structured, requires fresh regions to be added when there is a shortfall in revenue requirements. This will soon give rise to a situation where virtually all of MSEB's revenues will be required to be escrowed to meet DPC's payments, leaving little for wages and fuel, let alone additional power purchase. The escrow arrangement is not even in the interest of DPC, since it would retard reform of distribution, which is critical to raise revenue collection. The Committee therefore recommends that as part of the negotiations, the current Escrow Agreement with DPC be cancelled. The security of future payments to DPC under the restructured tariff (and the security of payments to other IPPs) will be based on increased cash flows from a reformed distribution system.

This extent of financial restructuring will not be possible without the active co-operation, involvement and possibly financial support from GoM and GoI. The debt of DPC can be serviced only if MSEB makes timely payments as per the restructured tariff, which again will depend on timely payment of subsidies by GoM to MSEB. Similarly, given prudential guidelines, it may not be possible for existing domestic lenders to increase their exposure to DPC to the extent envisaged in case of a conversion to rupee debt.

All the restructuring is designed to yield a tariff that will translate into a cost of supply that is affordable to the consumer. Therefore, the final tariff stream that emerges from the process, at realistic levels of PLF that may be as low as 30 per cent in the initial years, is a critical determinant of the efficacy of the restructuring. It is important to subject this tariff to a full range of sensitivity analysis with respect to variables such as the exchange rate, fuel price, PLF, etc. The Committee recommends that this tariff be benchmarked to the lowest cost of supply of power from gas-based projects elsewhere and also to the willingness of other buyers such as other states to pay for the power. Such benchmarking is necessary to ensure that Dabhol power becomes saleable within and outside Maharashtra in a sustainable manner. This aspect is central to the whole process of negotiation with DPC. Without such benchmarking, any negotiation with DPC would prove futile.

Chapter 7

Conclusion

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There has been a major change in the approach on the part of the GoI towards privatisation in the 1990s. Private capital was invited to extend its participation in the economy, even in sectors like power that were inaccessible a decade back. In fact, the power sector was chosen to be at the forefront of the new liberalising regime in India. Private companies were allowed to develop and operate power plants and to sell their power to the SEBs. Such a change in attitude towards the Independent Power Producers (IPPs) was guided mainly by two major factors. One was the model of privatisation envisaged by the World Bank under which IPPs were to be allowed to set up power plants in India. In return the government had to offer concessions such as full foreign ownership, which has been exemplified in the case of Dabhol Power Project. This was fully foreign-owned and was controlled by the Enron Corporation. The government also had to provide tax holidays as well as an assurance of a return on investment. Not only that, the IPPS were not required to go through a process of competitive bidding; the contracts were negotiated.

The other factor, which led to the change in the attitude of the government, was the deteriorating financial health of the SEBs. The government thought it to be prudent to invite foreign investment so as to improve the situation confronting the power sector in the beginning of the 1990s. As the SEBs were not able to provide power to the people it was up to the IPPs to generate more power.

In order to boost private investment in the power sector, the government had diverted many projects originally identified for NTPC, to the private sector. These included the Cogentrix project in Andhra Pradesh (now being developed by China Light & Power and TEC), Hirma project in Orissa (being developed by Southern Electric and Reliance).

However, even after a decade of the experience of the IPPs, results are far from satisfactory. In fact with the experience of the Dabhol project, the process of privatisation as envisaged by the World Bank has suffered a serious setback. Many IPPs are already withdrawing their investments in the power plants in the country. The fact that the IPPs are presented as a new source of finance in electricity generation is quite misleading. Investors in an IPP will not construct a power plant unless they are assured of a certain level of returns on their investments.

Along with the policy of IPPs, the World Bank had also propounded a model of restructuring with increased competition. According to the World Bank, the economies of scale in the state run power sector have already been exhausted and thus vertical integration can be safely unbundled and that (at least) in generation, the monopoly situation can be struck down effectively, and instead competition be commissioned.

However, unbundling the system into separate generation, transmission and distribution entities raises the problem of the integrated operation of the whole system. If all the units resulting from unbundling are driven by profit maximisation, there must be some authority to keep a watch over their operation. Such a process of restructuring has already taken place in California. In California, the electric power industry has been operating as a natural monopoly just like our own SEBs. In exchange, the average consumer and business received steady service at affordable rates. Once a competitive market replaced the monopoly structure, electricity prices in California started to rise rather than reducing the rates for consumers. The increased revenues, resulting from the price hikes went to the IPPs.

Moreover, any restructuring and privatisation will mean that either the assets will have to be transferred to the new companies at their book value or at their market value. If it is transferred at the book value, it will imply selling the assets of the people at throwaway prices to the investors. As this is politically difficult, these will have to be re-valued at market prices or what it will cost today to set up such a plant to run for the rest of its useful life span. Though the consumer had already paid for the capital costs of the plant through their electricity bills, they will have to pay for them again after such revaluation. Though it is true that there are cash reserves set aside for the provision of depreciation, but they do not prove to be enough to cover the revalued price.

The process of restructuring should also look at one of the major problems confronting the power sector in India, the problem of T & D loss. According to the MoP T & D losses at present is 21 per cent. Reduction of T & D loss is one of the major tasks ahead for the government. In fact, the SEBs can only be revived, by setting up an independent regulatory framework for the power sector. The increase in realisation through reduction in T & D losses from the national average of 21 per cent to 15 per cent and by monitoring diversion of agricultural load will result in additional revenue being generated. These funds can then be used to upgrade the existing power stations, which are quite outdated. The money generated through billing will mean financing the cost of modernisation for generation, transmission and distribution. These measures are absolutely vital whether or not the SEBs are unbundled and restructured.

However, there is no denying the fact that more power is needed in India as it is very much essential for all developmental efforts. But linking the rate of return on investment in a power plant to the dollar entails big problems on the Balance of Payments (BoP) front. This is because as the rupee continues to depreciate, the volatility of the foreign exchange market will then have a serious bearing on these power projects. This did happen in the case of DPC. It is advisable that reliable and quality power is provided to the people at affordable prices. But whether indigenous producers or some foreign power companies provide it depends upon the policy adopted by the government. However, before signing agreements with the foreign investors, it should be borne in mind that under no circumstances there should be a compromise on the national interest. The government should simply do away with contracts, which incur financial drain on the economy.

Since we have already experienced such shortcomings in the case of DPC, it is very important that in future such mistakes are not repeated. The Dabhol project, which was set up mainly to increase the generating capacity of power in the state, the outcome was far from what was hoped for. The price of power available from DPC was too expensive to be affordable to the consumers in the state. Project costs have increased alarmingly over the last decade. Due to lobbying by the foreign investors, like Enron, the system of competitive bidding failed miserably. Once it was obvious that MSEB was not able to meet its payment obligations towards DPC, the plant was closed down in June 2001. As the plant was lying idle, offers were made to buy DPC. But even if some company, quite bold enough, decides to buy DPC, there is no guarantee that it will find a buyer for the power it produces. On the one side are those who see no merit in purchasing power from DPC and thus want the project to be scrapped while on the other side are those who want it to be renegotiated once again.

The Godbole Committee was thus set up to review the power situtaion in Maharashtra, in general and entrusted with the task of an in-depth scrutiny of the Enron deal, in particular. The committee has maintained throughout that under no circumstances was the DPC feasible and so has come up with various recommendations. Among the various structural changes recommended by the committee, the most significant one was the separation of the LNG facility and harbour from the project. It also recommended that in view of the non-sustainability of the project, DPC should go for a drastic reduction in the profitability of the promoters as well as in the interest rates of the loans extended by financial institutions supporting the project so as to reduce the tariff and make the project viable. Hence, the government should take serious note of the recommendations put forward by the committee, and ensure that renegotiation takes place along those lines.

Despite some attempts made by the GoM in the last two to three years, regarding the restructuring of the power sector in Maharashtra, the developments are much different than many other reforming states. The severe financial impact of the Dabhol project has forced MSEB/GoM to look for ways of avoiding incurring the liabilities. At the same time, measures should be undertaken by the government to relieve the people of Maharashtra and other states too (as there are efforts to sell power produced by DPC to other states) from the unwarranted and high-cost power of DPC. The Enron experience has also resulted in rethinking about other IPPs in the state. Therefore all new power projects and new investments must necessarily take into consideration the existing power set-up in the country rather than going into piecemeal contracts as in the case of DPC.

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