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NON-UTILITY POWER GENERATION IN INDIA: POTENTIAL, IMPEDIMENTS, AND POLICY ISSUES

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EXECUTIVE SUMMARY

The power generation capacity in India has increased from 1,712 MW in 1950 to over 42,000 MW in 1986, representing a growth rate of about 9 percent per year. Inspite of this significant growth of capacity, increase in consumption, population growth, agricultural expansion, and industrial growth have caused the demand for electricity exceed the generation capacity. As of 1986, the country is facing a power shortage of over 10 percent of demand while some provinces, such as Kanataka and Haryana, are experiencing deficits of 15 - 40 percent.

Because of the existing socio-economic priorities in India, a large share of this power deficit is borne by the industrial sector. During supply shortages, the agricultural sector will have priority over the industrial sector. Therefore, the power cuts to the industry reaches, at times, 80 percent of their need. The economic loss due to these power cuts are tremendous. A FICCI study[1], for example, estimates that a 10 percent power shortage in the industrial sector can cause an annual production loss of Rs. 7,000 crores ($6 billion). And in fact, these cuts have already affected the Indian economy. It is estimated, for example, that power shortages in recent years have reduced the annual growth rate of the Indian economy by 1-3 percent, thus bringing down the annual growth rate to 3.5 percent.

[1]. As quoted in K.P. Srinivasa Setty, r. Natarajan, "India's Power Scenario - A Case for Captive Power Generation", National Seminar on Captive Power Generation, March 1986.

Financing power sector expansion in the country has become a major burden on the government. In the Seventh Plan (1985-1990), for example, power activities absorb over 20 percent of total development budget, equivalent to over 60 percent of the total energy sector budget. Inspite of this level of budget allocation, the supply is further falling behind the demand. For example, the projected demand for electricity during the 7th Plan is for about 30,000 MW of additional capacity, while because of the shortage of financial resources, only 22,000 MW of new capacity will be added. There is already a short fall of 5,000 MW from the 6th Plan, which in addition to the 7th Plan's anticipated shortage of 8,000 MW adding up to a staggering 13,000 MW shortage, would cause enough dent in the industrial growth rate.

The financial status of State Electricity Boards (SEBs), also, does not allow for any major expansion efforts on their part. Currently, SEBs are losing over $1 billion per year. In addition various technical and managerial inefficiencies have reduced the effectiveness of SEBs in providing power to states.

In light of the financial difficulties of the government and state electricity boards in expanding the country's generation capacity, one answer to the current power problem that immediately comes to mind is to look outside the existing power sector for help. There are many power generation opportunities that can be most efficiently developed by non-utility entities. For example, industries with substantial steam demand can install cogeneration systems and supply their power needs along with their steam needs. Some industries may have access to low cost fuels, such as rice husks, bagasses, and low grade petroleum, which could be efficiently used on site to generate

power. Remote small hydroelectric schemes is another example of power generation opportunities which fall outside the traditional structure of utility operation, and can be efficiently developed by local communities reducing the need for transmission network expansion. In addition, non-utility entities, in particular the private sector, can get involved in development of large scale power plants to reduce the financial burden on the government and the electric utilities.

If such activities are expanded and large non-utility power generation capacity is brought on line, the financial and technical pressure on existing power utilities would be reduced, and the quality of power supply in the country would improve.

STUDY OBJECTIVES

In light of the above background, the objectives of this study are:

(1) Preliminary identification of the technical, economic, and financial potential for non-utility power generation with emphasis on industrial cogeneration and renewable and indigenous energy resources in two states of Gujarat and Maharashtra.

(2) Identification of the technical, economic, financial, and constitutional impediments to the development of non-utility power generation in Gujarat and Maharashtra.

(3) Development of recommendations and an action plan for addressing the impediments to non-utility power generation.

The analysis was carried out in India by a team of consultants of Hagler, Bailly & Company during July 26 - August 23, 1986. The team was assisted by the staff of the National Productivity Council (NPC) in India. The scope of work for this study is presented in Appendix A.

To realize these objectives, the study team collected data in India through a review of the literature and interviews with key representatives of the government, industry, electric utilities, financial institutions and, research organization in New Delhi, as well as the two states of Gujarat and Maharashtra. The list of interviews performed during this study is presented in Appendix B.

STUDY FINDINGS

The study findings are organized in three categories: potential, current environment and major issues.

Potential

The preliminary analyses conducted in this study reveal that the financially attractive non-utility power generation potential in Gujarat and Maharashtra over the next 10 years is about 3,000 MW. By financially attractive potential we refer to the amount of generation capacity that can be developed that will result in lower electricity costs than that supplied by the existing state electricity boards and electric utilities in Gujarat and Maharashtra.

About 2,300 MW of this potential is from industrial cogeneration (see Exhibit 1). The industries with highest potential are fertilizer, basic chemicals,

Exhibit 1

Electricity Generation Costs and Potential for Non-utility Power Options (1986-1996)

Technology	Economic		Financial	
	Generation Costs (Ps/kWh)	Potential (MW)	Generation Costs (Ps/kWh)	Potential (MW)
A. Small Scale				
Cogeneration				
Industrial Topping Systems	Under 85	1,300	Under 130	2,280
Industrial Bottoming Systems	55-77	50	70-120	50
Commercial Systems[1]	Under 80	30	nder 1.60	30
Power Only				
Sugar Cane Residue-Fired Systems	40-49	425	49-66	425
Other Agrowaste-Fired Systems	40-49	neg	49-66	neg
Coal Fired Systems	60-99	(2)	92-169	(2)
Gas Fired Systems	78-117	(2)	120-189	(2)
Municipal Waste-Fired Systems [1]	148	--	195	--
Hydroelectric Systems	N.A.	N.A.	N.A.	N.A.
Dendrothermal Systems	N.A.	N.A.	N.A.	N.A.
B. Large Scale				
Coal-Fired Systems	76-103	(2)	95-145	(2)
Diesel Generators	88	(2)	93-94	(2)

(1) Analysis was done only for Bombay.

(2) The potential is not meaningful since there is no resource limitations for these systems.

Source: Hagler, Bailly & Company

refineries and pharmaceuticals. About one third of the cogeneration potential lies in the existing plants (retrofit or replacement of existing steam generating equipment). Almost all this potential comes from topping cycle cogeneration systems where steam is used first for power generation and then for industrial processes. The potential for bottoming cogeneration is estimated at only 50 MW in refineries, and fertilizer and petrochemical plants.

The study also looked into the cogeneration potential in commercial buildings in Bombay. It found that cogeneration systems are only suitable for large hotels and hospitals, with a continuous demand for hot water for domestic needs and steam for air conditioning. However, only applications in large hotels were found to be financially attractive. In Bombay alone the estimated potential for commercial cogeneration in large hotels over the next 10 years is estimated at about 50 MW.

The potential for power generation from bagasse and cane residue over the next ten years is estimated at about 425 MW -- 75 MW in Gujarat and 350 MW in Maharashtra. This resource represents the least expensive power option among those studied in this report. The potential from other agrowastes is very limited. In Maharashtra, rice husks, groundnut shells, sawdust, and other agrowastes are already being fully used and no excess is available for power generation. In Gujarat, 30 MW are being generated from these resources. Power can be generated from these resources during the dry season, November to April, which is the period of peak agricultural electricity demand and minimum hydroelectric power availability. Therefore,

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their development could reduce the peak generation expansion requirements of utilities.

Power generation options from domestic fossil fuels, i.e., natural gas and coal, are estimated to be only marginally competitive with power from utilities. The cost of power from small-scale (under 50 MW) coal-fired systems, in particular, is expected to be considerably higher than the utilities' generation cost. Natural gas-fired systems, however, could generate power at financially attractive rates in sizes over 20 MW if gas is made available to non-utility generators at concessionary rates. The actual size of the potential for these options would depend on the government's policy on the supply and price of fossil fuels for power generation.

Dendrothermal and other renewable power systems do not represent any considerable generation potential.

Finally, large scale conventional power systems fueled by domestic fossil fuels, e.g. coal and fuel oil, are found to have generation costs competitive with those of the electric utilities. The financial cost of electricity from large coal-fired plants is estimated at 95 to 145 Ps./kWh, and that of electricity from slow-speed diesel generators running on fuel oil at 93 Ps./kWh (compared to the cost of electricity from the utilities at 130 Ps./kWh). At these costs, large scale power plants developed by the private sector would represent a viable solution to power shortages in the country.

Current Environment

The study team found that there are basic differences in the current power sector structure and power supply environment in Gujarat and Maharashtra,

which to a large extent determine the development of non-utility power options in these states. In Gujarat, a severe power shortage causes the utilities to commonly cut the power supplied to industry by 10 to 40 percent, with even higher cuts during the dry season and peak agricultural demand. As a result, industry is experiencing high production losses and is very willing to explore and develop alternative power supply options, as indicated by the fast pace at which they are installing captive power units. In addition, the Gujarat Electricity Board (GEB) has shown extreme interest in encouraging such options. GEB is purchasing power from a number of industries with excess power at prices equivalent to the industries' generation costs. GEB is also purchasing power from a wind farm at prices even higher than its own avoided costs, to verify the feasibility of renewable power sources and to encourage the future development of such resources.

In Mahrashtra, on the other hand, the power shortage is only marginal with roughly 10 percent cut to some industries during the dry season. Otherwise, the power supply is very reliable and steady. Industry is installing some captive power units, but as the supply situation in the past 3 years has improved, and is expected to continue improving at least for the next four years, the momentum for self-generation or captive power generation has slowed down. The Maharashtra State Electricity Board (MSEB) and the private utilities in the state are less enthusiastic about non-utility power options than their Gujarat counterparts. For example, parallel operation with the grid is not allowed in Maharashtra and only a few exceptions have been made. In addition, the Maharashtra utilities tend to believe that non-utility power, even from cogeneration systems, will not be able to compete with power supplied by the grid in reliability and cost. Finally, in large urban

areas, especially in Bombay and Pune, due to government efforts to reduce population growth and air pollution, industrial expansion has been very limited. As a result, utilities are faced with a very slowly growing industrial power demand. Since industries to a large extent subsidize the low electricity tariff to residential and agricultural customers, the utilities in Maharashtra, in general, are very concerned about the impact on their financial status of losing their large industrial customers. This to a large extent has contributed to the utilities' lack of enthusiasm for non-utility power generation.

Gujarat and Maharashtra are very similar in terms of the structure of electricity tariffs and the cost of power to large and medium industries, which happens to be among highest in the country (over 120 Ps./kWh). In addition, the long run marginal electricity generation cost of utilities in Gujarat and Maharashtra is very similar and close to 80 Ps./kWh (this does not include the transmission and distribution costs which could raise the marginal cost of electricity supply to over 100 Ps./kWh).

Major Issues

The major impediments to non-utility power generation development in Gujarat and Maharashtra can be divided into three categories: technical, economic/financial, and institutional.

Technical Issues

In general, information on power generation equipment performance and costs among non-utility entities is scarce. This applies in particular to requirements for interconnecting to the grid. In addition, some industries

have experienced difficulties in operating their generation systems in parallel to the grid. The industrial representatives indicated that their staff need training on operating power equipment and interconnection procedures.

Perspective power generators in general have a perception that the domestic power equipment and systems that are available are of poor quality. This has had an adverse impact on their desire to install power generation equipment. In addition, for some power options, the necessary equipment cannot be found in India, affecting the prospects for developing such options, e.g. small efficient steam turbines for power generation in the sugar industry.

Economic/Financial Issues

The government has traditionally dominated power sector activities in India, and all non-government power activities are highly regulated. Therefore, the private sector is very apprehensive about entering into such activities. Specifically, the private sector is concerned about the allowable rate of return on power projects, which is determined by the government and is currently at 2 percent over the interest rate. At such rates, the private sector would find investments in nonpower projects more attractive than those in power projects. In addition, there is an excise tax on power generated even when generated for self-consumption.

Non-utility power producers are also concerned about the price utilities or state electricity boards (SEBs) would pay for their power while cogenerators are concerned about the rate utilities would charge for providing backup power. No policies currently set the price of such transactions. Finally,

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non-utility power generators, in general, and the private sector in particular are concerned about financing power projects. Most power projects are capital intensive and current government policies require a debt-to-equity ratio of 2:1 or less. The private sector would like to see a less restrictive policy on investments in power projects. In addition, the private sector would like to see more liberal policies on access to foreign exchange for power projects. Finally, the private sector wants the government banks to remove or reduce the markups on supplier's credit to make investment in power projects more attractive.

Institutional Issues

The major institutional issues that concern non-utility power generators are:

- Fuel availability and prices. The government sets the priorities for fuel supply and prices in India. It is not clear, at present, if independent generators will have access to fuel or not, and if they will at what price.

- Import licenses and duties. The current government policy is not clear on conditions under which the importation of power generation equipment will be allowed. Furthermore, there is uncertainty with regard to the amount of duty charged on imported power equipment. Under current regulations, import duty rates could be between 20 percent and 105 percent.

- Sale of power to SEBs. Although various government representatives have implicitly emphasized the need for private sector power generation, there are no explicit policies setting the

terms of interaction between existing electric utilities and independent power generators. The issues of main concern are the purchase price -- the price utilities would pay for non-utility power -- and the requirements for interconnection with the grid.

The existing policy (of not requiring a permit from CEA for plants smaller than 25 MW) has proven to be ineffective since the generators need to obtain licenses for importing equipment, for obtaining their fuel supply, and for financing the project. This process is known to be very time consuming and discouraging.

RECOMMENDATIONS

Based on the findings of this study, in order to increase the participation of non-utility entities in power generation in India, in general, and in Gujarat and Maharashtra, in particular, the following measures are recommended.

1. The government should define and publicize a clear policy on non-utility power generation, covering cogeneration and power-only systems. This policy should:

   (i) Allow independent generators to operate in parallel with, and sell electricity to the grid. In particular, a standard format should explicitly define the technical requirements for interconnection.

   (ii) Define the terms of interaction between SEBs and non-utility generators. These terms should spell out the technical

requirements for interconnection and parallel operation, the purchase price, and the cost of back-up power.

(iii) Define a straightforward procedure for licensing independent generation systems. This procedure should cover obtaining construction and operation permits, import licenses, financing, and fuel supply.

In defining this policy, the government should take into account:

(i) The impact of power shortages on the economic growth and prosperity, especially in the industrial sector

(ii) The inability of SEBs to satisfy the growing demand for electricity

(iii) The positive impact of some non-utility power options on increasing fuel use efficiency and the reliance on domestic fuels.

(2) An important issue for non-utility power generators is the purchase price utilities pay for power. The government should establish guidelines on defining this price. A price policy based on the avoided cost of SEBs presents a fair value for the non-utility-generated power. This will lead to the efficient allocation of resources and expanded generation capacity. In defining the purchase price, the government should take into account such issues as:

(i) The relatively high generation cost of SEBs that will result from future plants

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(ii) The excessive transmission and distribution losses of the grid

(iii) The seasonal, time of day, and regional values of private power to utilities

(iv) The cost of providing power to remote areas and associated premiums that might be considered for power generated in these areas

(v) Special incentives for private businesses that are the first to invest in power generation.

3. The government should provide training in defining purchase price (according to SEBs' avoided costs) to utility personnel. In addition, the government should provide technical assistance to industrial cogenerators and independent power generators in interconnection to and parallel operation with the grid. In light of the extensive experience of U.S. utilities and cogenerators in such activities, the government should explore opportunities for transferring this technical knowhow to India.

4. Since there is a considerable potential for power generation in the sugar industry that is constrained by the shortage of proper equipment (small but very efficient steam turbines), the government should identify and pursue avenues for developing the capability for manufacturing such power systems in the country.

5. The government should publicize local non-utility power generation activities, in particular those projects that involve interaction between SEBs and non-utility generators. The government should undertake demonstration projects to reduce the uncertainty about interconnecting with the grid.

INTRODUCTION

The power generation capacity in India has increased from 1,712 MW in 1950 to over 42,000 MW in 1986, representing a growth rate of about 9 percent per year. In spite of this significant growth of capacity, increase in consumption, population growth, agricultural expansion, and industrial growth have caused the demand for electricity exceed the generation capacity. As of 1986, the country is facing a power shortage of over 10 percent of demand while some provinces, such as Kanataka and Haryana, are experiencing deficits of 15 - 40 percent.

Because of the existing socio-economic priorities in India, a large share of this power deficit is borne by the industrial sector. During supply shortages, the agricultural sector will have priority over the industrial sector. Therefore, the power cuts to the industry reaches, at times, 80 percent of their need. The economic loss due to these power cuts are tremendous. A FICCI study[1], for example, estimates that a 10 percent power shortage in the industrial sector can cause an annual production loss of Rs. 7,000 crores ($6 billion). And in fact, these cuts have already affected the Indian economy. It is estimated, for example, that power shortages in recent years have reduced the annual growth rate of the Indian economy by 1-3%, thus bringing down the annual growth rate to 3.5%[2].

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1. As quoted in K.P. Srinivasa Setty and R. Natarajan, "India's Power Scenario - A Case for Captive Power Generation", National Seminar on Captive Power Generation. March 1986.

2. Ibid

The industry is faced not only with the inadequacy of supply, but also with the unreliability of the entire power system. In most provinces, it is not known when the next power cut will be imposed, and what the amount of cut will be. Thus throwing out of gear all the production schedules.

Furthermore, the power sector being a part of the government, financing the power supply expansion in the country has become a major burden on the government. In the Seventh Plan (1985-1990), for example, power activities absorb over 20 percent of total development budget, equivalent to over 60 percent of the total energy sector budget. In spite of this level of budget allocation, the supply is further falling behind the demand. For example, the projected demand for electricity during the 7th Plan is for about 30,000 MW of additional capacity, while because of the shortage of financial resources, only 22,000 MW of new capacity will be added. There is already a short fall of 5,000 MW from the 6th Plan, which in addition to the 7th Plan's anticipated shortage of 8,000 MW adding up to a staggering 13,000 MW shortage, would cause enough dent in the industrial growth rate.

The financial status of State Electricity Boards (SEBs), also, does not allow for any major expansion efforts on their part. Currently, SEBs are losing over $1 billion per year. In addition various technical and managerial inefficiencies have reduced the effectiveness of SEBs in providing power to states.

NON-UTILITY POWER GENERATION

In light of the financial difficulties of the government and state electricity boards in expanding the country's generation capacity, one answer to the

current power problem that immediately comes to mind is to look outside the existing power sector for help. There are many power generation opportunities that can be most efficiently developed by non-utility entities. For example, industries with substantial steam demand can install cogeneration systems and supply their power needs along with their steam needs. Some industries may have access to low cost fuels, such as rice husks, bagasse, and low grade petroleum, which could be efficiently used on site to generate power. Remote small hydroelectric schemes is an example of other power generation opportunities which fall outside the traditional structure of utility operation, and can be efficiently developed by local communities reducing the need for transmission network expansion. In addition, non-utility entities, in particular the private sector, can get involved in development of large scale power plants to reduce the financial burden on the government and the electric utilities.

In fact many organizations experiencing insufficient and unreliable supply of power have been pursuing various power generation activities. For example, the Bharat Aluminum Co. at Korba is installing 4 units of 67.5 MW capacity. The National Fertilizer Industries is installing 2 units of 15 MW each. A number of industries in Faridabad are jointly commissioning a 100 MW diesel generator. Five major industries in Baroda also are installing a 120 MW coal-fired thermal power plant.

The main purpose of the above projects has so far been to supply their own power needs. There has been very limited sale of power from such independent generators to the grid, but this is mostly an exception. Within an appropriate regulatory and economic environment, some organizations including

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the private sector could supply power for the sole purpose of sale to the grid. The precedents for such activities already exist in India. Tata Electric Company in Bombay for example, is a private utility generating and supply power at high and medium voltage to large customers and Maharashtra State Electricity Board. The Ahmedabad Electric Company, is another private utility, generating and distributing electricity in Gujarat.

If such activities are expanded and large non-utility power generation capacity is brought on line, the financial and technical pressure on existing power utilities would be reduced, and the quality of power supply in the country would improve.

Of particular interest to India is the case of the United States which enacted the Public Utility Regulatory Policies Act (PURPA) in 1978 to promote the development of non-utility power generation options based on national resources and more efficient use of energy. Because of this act, in a five year period between 1980 and 1985 over 15,000 MW of power generation capacity outside the electric utilities wa developed reducing the need for utility expansion.

STUDY OBJECTIVES

The objectives of this study are:

(1) Preliminary identification of the technical, economic, and financial potential for non-utility power generation with emphasis on industrial cogeneration and renewable and indigenous energy resources in two states of Gujarat and Maharashtra.

(2) Identification of the technical, economic, financial, and constitutional impediments to the development of non-utility power generation in Gujarat and Maharashtra.

(3) Development of recommendations and an action plan for addressing the impediments to non-utility power generation.

The analysis was carried out in India by a team of consultants of Hagler, Bailly & Company during July 26 - August 23, 1986. The team was assisted by the staff of the National Productivity Council (NPC) in India. The scope of work for this study is presented in Appendix A.

To realize these objectives, the study team collected data in India through a review of the literature and interviews with key representatives of the government, industry, electric utilities, financial institutions and, research organization in New Delhi, as well as the two states of Gujarat and Maharashtra. The list of interviews performed during this study is presented in Appendix B.

REPORT ORGANIZATION

The study report consists of four chapters:

In Chapter 1, an initial estimate of technical, economic and financial potential of power production from industrial and commercial cogeneration as well as other non-utility power generation options for the two states of Gujarat and Maharashtra is presented.

X 27

In Chapter 2, first, the existing power sector structure in India in general and Gujarat and Maharashtra in particular are described. Then the major issues and impediments associated with the development of non-utility power generation are identified and discussed.

In Chapter 3, first the U.S. experience with the development of non-utility power options as it relates to India will be discussed. Next major technical and financial issues associated with the interconnection between non-utility generators and the utility system will be identified. Finally, some approaches for estimating the value of non-utility power to the existing utilities will be described and typical estimates of this value for utilities in Gujarat and Maharashtra will be made.

Finally, in Chapter 4, the study conclusions and recommendations are presented.

Appendix A through E provide additional information to support the main text of the report. A bibliography follows the appendices.

CHAPTER 1: POTENTIAL FOR NON-UTILITY POWER GENERATION

This chapter evaluates the potential for non-utility power generation in Gujarat and Maharashtra. First, the available non-utility power generation options are identified. Then the existing non-utility generation activities in these two states are reviewed. An finally, the technical, economic and financial potential of each option is estimated.

NON-UTILITY POWER GENERATION OPTIONS

There are two major options for non-utility power generation in India outside the existing structure electric utilities. These are: (1) cogeneration in the industry or in commercial buildings such as hotels and hospitals, and (2) power-only systems.

Cogeneration

Cogeneration refers to the sequential production of electricity and useful thermal energy (usually in the form of hot liquids and gases) as an integral part of an industrial process. Traditionally, industrial thermal energy is produced by boilers and furnaces that typically have efficiencies of 50 to 80 percent. electricity is normally produced by a utility using a boiler and steam turbine with a combined efficiency of 30 to 35 percent. Cogeneration produces both electricity and thermal energy with a combined efficiency of 80 to 90 percent, resulting in greater energy efficiency and lower overall energy costs.

Similarly, cogeneration systems can be used in commercial buildings, such as hospitals and hotels, to simultaneously produce electricity and steam. In this case steam could be used for air conditioning or for domestic heat and hot water needs.

In addition to improving fuel efficiency, cogeneration systems can improve power system reliability and reduce the environmental impact of power generation. By decentralizing sources of power generation, cogeneration increases the availability of reliable power in the event of utility problems. In addition, a reduction in the fuel used to generate a given amount of energy translates directly into a reduction in thermal and other types of pollution.

Power-only Systems

Power-only systems are used to generate electric power with no attempt to use the thermal energy as cogeneration systems do. They can be either small-scale or large-scale systems. In such systems, non-utility organizations or individuals generate power for their own needs, for sale to the grid, or for sale to other customers. Small systems in this study refer to those less than 50 MW in size. Several indigenous renewable resources could be used for such systems, such as bagasse, rice husks, small-scale hydro, wind, and "dendrothermal" plantations on which trees are harvested as fuel for power generation. In addition, these system may use domestic fossil fuels such as coal and natural gas.

The large systems are over 50 MW in size. The technologies that appear most attractive for such systems are thermal power plants fired by coal, gas turbines (simple or combined cycle) fired by natural gas or oil and large

diesel generators. For these systems, investments that would normally be made by state electricity boards or the central government would be made instead by the private sector or other non-utility entities. This option would relieve the financial burden of generation expansion currently faced by the state and central governments.

EXISTING NON-UTILITY POWER GENERATION

Most of the existing non-utility power generation facilities in India are located in the industrial sector. Many industries have their own captive power plants to supplement power purchased form utilities or for emergency use during grid supply interruptions. A survey of 2,751 industrial plants with demand of over 100 kW by NMB indicates that 1,576 industrial units have captive plants.[1] According to the Advisory Board on Energy[2], the total installed non-utility power generation capacity in India in 1984-85 was about 3,500 MW generating 10 billion kWh of electricity. This represents over 6 percent of total electricity generated in the country in that year.

An additional 2,573 MW of generation capacity has been cleared by the Central Electricity Authority (CEA) which is expected to be commissioned in the next 5 years. Out of this 2,573 MW, 1,005 MW will be in the aluminum industry and 786 MW in the steel industry[3].

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[1] NMB, 4,7,1985

[2] Advisory Board on Energy, "Towards a Perspective on Energy Demand and Supply in India in 2004-05", New Delhi, 1985.

[3]. Center for Monitoring Indnian Economy, "Current Energy Scene in India", July 1986.

In 1982-83 over 294 MW of captive power existed in Gujarat, generating over 720 GWh, representing a capacity factor of over 28 percent (see Exhibit 1.1). Similarly, in Maharashtra as of 1982-83, 434 MW of captive generation units were installed generating over 700 GWh of electricity indicating a capacity factor of roughly 19 percent. In both states, about 45% of the installed non-utility generation capacity is from steam plants, mostly cogeneration systems (see Exhibit 1.2). Over 50 percent of the captive capacity comes from diesel generators used primarily for backup purposes during utility supply interruptions. There are very few gas turbines used for power generation. The capacity factor for the steam plants is 40 percent, while that of diesel generators is only 12 percent. This indicates that diesel units are used only for backup, while the steam units are operated rather continuously for process needs. The captive power generation capacity in Gujarat and Maharashtra has increased substantially since 1982 and are estimated at 685 MW and 650 MW in 1986, respectively[4]. The installed cogeneration capacity also has grown substantially. In Gujarat, for example, the cogeneration capacity has grown from 166 MW in 1982 to over 400 MW in 1986. The breakdown of this capacity among industry groups is shown in Exhibit 1.3.

A number of non-utility organizations in India, to cope with the power shortage, are installing their own large generation units and will use the existing grid to transmit the power to their members. For example, five industries in Gujarat -- Gujarat State Fertilizers company (GSFC), Gujarat Narmada Valley Fertilizers Company (GNFC), Petrofils Cooperative Limited,

[4] Center for Monitoring Indian Economy, "Current Energy Scene in India", July 1986.

Exhibit 1.1

Existing Captive Power Capacity and Generation in Gujarat and Maharashtra (1982-1983)

Industry	Gujarat		Maharashtra	
	kW	GWh	kW	GWh
Aluminum	-	-	1,648	5.21
Automobile	-	-	11,646	19.42
Cement	16,795	18.80	1,423	3.06
Chemicals	100,717	294.71	64,640	57.12
Elec. Engineering	2,000	0.88	20,553	15.23
Fertilizers	248	0.02	18,378	63.24
Food Products	537	0.04	4,437	3.28
Heavy Engineering	-	-	8,874	9.62
Iron & Steel	2,142	0.51	6,349	3.34
Light Engineering	2,556	0.99	19,695	16.92
Mineral & Petroleum	24,000	135.27	-	-
Mining	200	0.05	-	-
Miscellaneous	552	-	16,923	19.00
Non Ferrous	1,400	-	48	-
Paper	6,000	27.89	9,524	49.52
Plastic	-	-	1,487	0.20
Rubber	-	-	5,704	16.98
Sugar	36,160	79.35	138,883	292.38
Textile	101,565	169.81	104,109	130.93
Total	294,772	723.00	434,326	705.00

Source: NMB

Exhibit 1.2

Installed Captive Power Capacity in Gujarat and Maharashtra According to System Type (1982-83)

State	Total No. of Industries Having Captive Plants	Installed Capacity (kW)			
		Steam	Diesel	Gas Turbine	Total
Gujarat	134	166,885 (45%)	127,987 (55%)	-	294,872 (100%)
Maharashtra	286	188,152 (43%)	226,174 (52%)	29,000 (5%)	434,32 (100%)

Source: NMB

Exhibit 1.3

Existing Cogeneration Systems in Gujarat

Plant	Capacity (MW)
1. Tata Chemicals	49.90
2. Indian Rayon	9.32
3. Saurashtra Chemicals	15.00
4. Central Pulp Mills	13.50
5. Baroda Rayon	10.00
6. Gujarat Refinery	24.00
7. Atul Products	7.00
8. Dhangadhra Chemical	4.35
9. A.C.C. Savalia	7.00
10. Atic Industries	2.00
11. J.P.C.L.	25.00
12. Anil Starch	2.00
13. Alembic Chemical Works	10.00
14. G.N.F.C.	50.00
15. O.N.G.C. (Hajira)	40.00
16. Reliance Textiles	60.00
17. Other Industries	85.00
Total	415.00

Source: Gujarat Electricity Board

Gujarat Alkalies & Chemicals Limited (GACL) and Heavy Water Project, Baroda (HWP) -- are in the process of installing a 120 MW coal power plant. This plant will supply its power to the Gujarat Electricity Board (GEB) grid and in return the participating industries will receive power from GEB. A similar project is underway in Faridabad, Haryana.

In addition to the conventional captive power systems explained above, there is also a wind power generation plant in Gujarat with a capacity of under 2 MW where the power is supplied to GEB.

Finally, there are three private sector utilities in India which supply power to the electricity boards or directly to consumers. These are: Tata Electric Company in Bombay, Ahmedabad Electric company in Ahmedabad, and Calcutta Electricity Supply Company. We will discuss these private sector utilities in Chapter 2.

POTENTIAL FOR ADDITIONAL NON-UTILITY POWER GENERATION: DEFINITIONS AND ASSUMPTIONS

To determine the relative attractiveness of the various non-utility power generation options, three sets of numbers were developed: the technical potential, economic potential, and financial potential. For each power generation option, the technical potential is that amount of generation that can be developed given the current and expected state of the technology and the availability of the natural resources . This is largely a resource-limited number. The economic potential is that portion of the technical potential that can be developed with resulting electricity costs lower than the marginal production cost of electric utilities or state electricity boards. In determining

the production cost of electricity, this analysis uses only the true economic costs and benefits inputs and factors out of the "transfer payments" such as taxes, duties, and profits that do not represent actual costs but rather shifts of resources from one sector to another. Similarly, the financial potential in the generation capacity that can be developed with costs below the financial cost of power provided by utilities. The financial analysis looks at the project from the viewpoint of the investor. It determines the actual cashflows of a project using market values for capital costs, labor, and materials. It incorporates taxes, duties, profits and other transfer payments explicitly, and determines that actual returns to the investor.

The economic and financial costs (or value) of power from electric utilities, and other key economic and financial assumptions used in these analyses, are summarized in Exhibit 1.4.A and 1.4.B. The derivations of these valves are discussed in more detail in Appendix C.

To allow comparison of systems having major differences in their cash flows, a capital recovery factor (CRF) approach was used. This approach, which is equivalent to a net present value calculation, gives an estimate of the power cost in Rs./kWh or $/kWh.

It should be noted, however, that it is not the purpose of this study to recommend or evaluate the non-economic or "soft" economic factors used to justify such investments. Rather, the study focused on how the Government of India could stimulate investment by the private sector in power systems as a substitute for public-sector investment in electric power generating projects. Consequently, projects requiring significant government assistance in the form of subsidies or soft loans (because of significant non-monetary benefits) have

Exhibit 1.4.A

Key Assumptions for Economic Analysis

- Energy Costs

	Unit Cost	Heat Content	$/mmBtu
Natural Gas	2.2 R/m3	36,850 Btu/m3	4.8
Diesel Oil	1.8 R/lit	36,478 Btu/lit	4.0
Furnace Oil	1.8 R/kg	40,474 Btu/kg	3.5
Coal	260-600 R/ton	19,840 Btu/kg	1.05-2.42
Electricity (to industry)			
Gujarat	0.80 R/kWh	3,412 Btu/kWh	18.76
Maharashtra	0.80 R/kWh	3,412 Btu/kWh	18.76

- Marginal Productivity of Capital: 12 percent

- Standard Conversion Factor (Domestic Cost/Import Cost): 0.80

- Capital Recovery Factors (CRF):

System Life	CRF
10 years	0.177
15 years	0.147
20 years	0.134
25 years	0.127

Source: Hagler, Bailly & Company

Exhibit 1.4.B

Key Assumptions for Financial Analysis

- Required Return on Equity (After Tax, Net of Inflation):

Private Investment	20 percent
Public Investment	15 percent

- Cost of Debt (Net of Inflation): 9 percent
- Debt/Equity Ratio: 2/1
- Marginal Tax Rate: 55 percent
- Depreciation Period: 1 year for cogeneration in existing plants, 10 years for other projects
- Energy Prices:

	Unit Cost	Heat Content	$/mmBtu
Natural Gas	2.2 R/m3	36,850 Btu/m3	4.8
Diesel Oil	3.2 R/lit	36,478 Btu/lit	7.2
Furnace Oil	3.0 R/kg	40,474 Btu/kg	5.9
Coal	260-700 R/ton	19,840 Btu/kg	1.05-2.82
Electricity	1.3 R/kWh	3,412 Btu/kWh	30.48

- Capital Recovery Factors (CRF):

System Life	CRF Private	CRF Public
10 years	0.287	0.231
15 years	0.257	0.198
20 years	0.247	0.185
25 years	0.243	0.179

Source: Hagler, Bailly & Company

been recommended for private investment. In general, such projects would not significantly reduce the need for government financing, but merely change its form (for example, for a single large loan guarantee to many small ones). Therefore, the study team has assumed that a project must be economically and financially viable without significant public subsidies or tax concessions, to ensure private sector support.

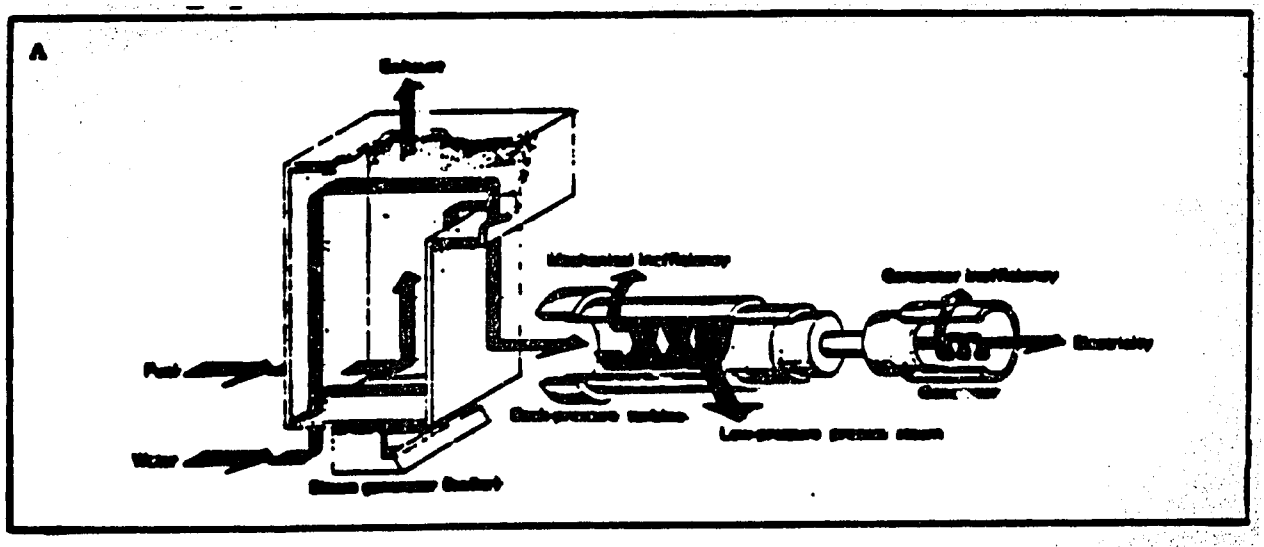
Finally, it is important to recognize that, where a particular technology is deemed only marginally economic or not economic at all, that does not mean the technology is not worth of development. Rather it means that on the basis of the project's most direct and obvious economic costs and benefits, the private sector is not willing to undertake it without significant government subsidies.

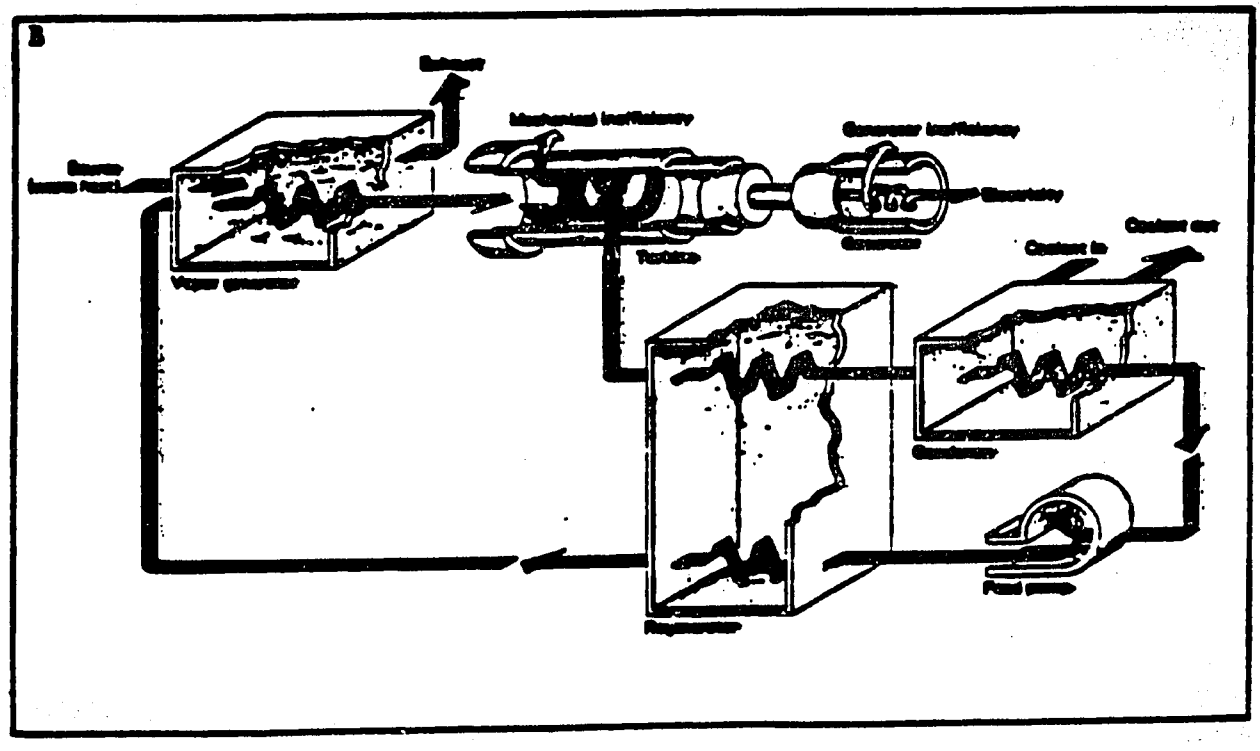
ADDITIONAL INDUSTRIAL COGENERATION

In this section, the potential for additional cogeneration in the industrial sectors of Gujarat and Maharashtra is estimated. Cogeneration systems fall into two categories: topping systems and bottoming systems. In a topping system, thermal energy exhausted in the production of electrical or mechanical energy is used in industrial processes (see Exhibit 1.5A). This thermal energy is usually in the form of low-grade (i.e, low-pressure, low-temperature) steam. Typical applications of this low-grade heat or steam include heating, drying, distillation, and concentration. At any site using low-grade heat and electricity, a topping system is usually an efficient alternative to purchasing power from the grid and generating the heat separately by dedicated system, usually a low-pressure boiler or a heater. The incremental

Exhibit 1.5.A Steam-Turbine Topping System

1.5.B Rankine Bottoming System





investment needed for the cogeneration alternative consists of the cost of the power device (generally a gas or steam turbine or a diesel engine) and the difference in the cost of purchasing and operating a higher pressure boiler than would otherwise be used. The main advantage of a topping cogeneration system is the amount of fuel it saves. In addition, cogeneration systems located in industrial sites may also improve power reliability and quality for that site.

Bottoming cogeneration systems differ from more conventional topping systems in that they use waste heat from industrial processes as the heat source for electricity generation, rather than the heat released from the combustion of commercial fuels. Basically, a bottoming cycle system consists of a waste heat boiler used to vaporize water or organic fluids and a turbine generator with condenser, unless low pressure exhaust steam extracted from the turbine used directly in the process (see Exhibit 1.5B). Such systems are used in processes generating large waste heat streams at temperatures of 300°C and higher. Cement, steel, glass, and some chemical and petroleum refining industries are possible candidates for bottoming systems.

Potential for Topping Cogeneration Systems

To identify the potential for topping cogeneration, we use a computer model developed by Hagler, Bailly which is used in the United States and other countries. A detailed description of this model is presented in Appendix D. This model simulates the market for cogeneration equipment based on industrial steam demand, fuel and electricity costs, technology costs, performance, and availability, and the relevant regulatory and tax environment

in a country or a region. The model computes the life-cycle cost (LCC) for each technology, assesses the market share for each technology, and finally, determines the total market size over the period of analysis. In the following paragraphs we will briefly describe the input data and the market assessment procedure for Gujarat and Maharashtra.

The starting point for assessing the market size or the potential for cogeneration is to determine the demand for industrial process steam. The industry in each state is divided into public and private categories. This is required because of the difference in availability of funds and fuels, the minimum acceptable rate of return on investment, and applicable tax rates for each category. Only industries with steam demand of over 20 tons per hour are considered, as for smaller units the thermal and electrical loads are often too low to justify cogeneration investments. The 1985 steam demand in the industries of Gujarat and Maharashtra is shown in Exhibit 1.6. These figures do not include the steam already produced by cogeneration systems. The size distribution of steam demand is also presented in this exhibit. Exhibits 1.7 and 1.8 show the distribution of steam by fuel type and by electric to thermal load ratio. Exhibit 1.9 shows the expected rate of growth for each industry group. The information presented in Exhibits 1.6 to 1.9 were provided by the National Productivity Council (NPC), based on their experience and the available industry data in Gujarat and Maharashtra as presented in the Seventh Plan Document published by the Planning Commission, various issues of URJA, and the 1985 and 1986 issues of Current Energy Scene in India published by the Center for Monitoring Indian Economy.

Exhibit 1.6

Process Steam Demand and Size Distribution in Gujarat and Maharashtra Industries*

P = Privately Owned Industry
G = Government Owned Industry

Industry	Steam Demand (10^9, Kcal/yr)	Size Distribution (%) 20-50T/h	50-150T/h	150+T/h	Total
Textile					
a. Gujarat (P)	609.70	100.00	-	-	100.00
b. Maha. (P)	605.15	100.00	-	-	100.00
Rayons					
a. Gujarat (P)	377.25	100.00	-	-	100.00
b. Maha. (P)	653.25	-	100.00	-	100.00
Pulp & Paper					
a. Gujarat (P)	392.10	100.00	-	-	100.00
b. Maha. (P)	804.00	26.67	73.33	-	100.00
Refineries					
a. Gujarat (G)	1281.40	-	-	100.00	100.00
b. Maha. (G)	1812.50	-	-	100.00	100.00
Fertilizer					
a. Gujarat (G)	8307.60	1.60	-	98.40	100.00
b. Maha.					
(P)	911.00	17.70	82.30	-	100.00
(G)	4824.00	-	-	100.00	100.00
Basic Chemicals					
a. Gujarat					
(P)	3182.40	20.20	-	79.80	100.00
(G)	2753.20	13.40	-	86.60	100.00
b. Maha					
(P)	1421.40	43.90	-	56.10	100.00
(G)	171.50	100.00	-	-	100.00
Dyes					
a. Gujarat(P)	100.50	100.00	-	-	100.00
b. Maha. (P)	388.60	100.00	-	-	100.00
Pharmaceuticals					
a. Gujarat(P)	743.70	28.00	72.00	-	100.00
b. Maha. (G)	125.60	100.00	-	-	100.00
Tyres					
a. Gujarat	--	--	--	--	--
b. Maha. (P)	214.40	100.00	-	-	100.00
Soaps					
a. Gujarat	--	--	--	--	--
b. Maha. (P)	201.00	100.00	-	-	100.00
Foods					
a. Gujarat(G)	100.50	100.00	-	-	100.00
b. Maha. (P)	388.60	100.00	-	-	100.00

* Only in industries with demand over 20 tonnes per hour.

Source: National Productivity Council

Exhibit 1.7

Steam Distribution by Fuel Type (percent)

Industry	Fuel Type			
	Fuel Oil	Coal	Gas	Waste
Textile				
a. Gujarat	22.10	65.60	12.30	-
b. Maha.	100.00	-	-	-
Rayons				
a. Gujarat	0.00	95.00	-	5.00
b. Maha.	35.00	60.00	-	5.00
Pulp & Paper				
a. Gujarat	6.15	69.24	-	24.61
b. Maha.	21.00	42.53	-	36.47
Refineries				
a. Gujarat	-	-	60.00	40.00
b. Maha.	-	-	71.10	28.90
Fertilizer				
a. Gujarat	14.40	20.50	7.40	57.70
b. Maha. (P)	3.50	-	12.35	84.15
(G)	-	-	33.00	67.00
Basic Chemicals				
a. Gujarat (P)	5.06	94.64	-	0.30
(G)	66.10	-	-	33.90
b. Maha. (P)	72.15	-	-	37.85
(G)	65.00	-	-	35.00
Dyes				
a. Gujarat(P)	50.00	50.00	-	-
b. Maha. (P)	100.00	-	-	-
Pharmaceuticals				
a. Gujarat	16.70	-	75.90	7.40
b. Maha. (G)	100.00	-	-	-
Tyres				
a. Gujarat	-	-	-	-
b. Maha.	100.00	-	-	-
Soaps				
a. Gujarat	-	-	-	-
b. Maha. (P)	100.00	-	-	-
Foods				
a. Gujarat(G)	10.0	-	90.0	-
b. Maha. (P)	54.5	45.5	-	-

Source: National Productivity Council

Exhibit 1.8

Steam Distribution by Electric to Steam Load Ratio (E/T) (percent)

Industry	E/T 0.0-0.20	0.2-0.5t	0.5	Total
Textile				
a. Gujarat	-	100.00	-	100.00
b. Maha.	-	100.00	-	100.00
Rayons				
a. Gujarat	-	100.00	-	100.00
b. Maha.	-	58.70	42.30	100.00
Pulp & Paper				
a. Gujarat	40.00	60.00	-	100.00
b. Maha.	100.00	-	-	100.00
Refineries				
a. Gujarat	100.00	-	-	100.00
b. Maha.	100.00	-	-	100.00
Fertilizer				
a. Gujarat	-	100.00	-	100.00
b. Maha.				
(P)	17.70	82.30	-	100.00
(G)	-	100.00	-	100.00
Basic Chemicals				
a. Gujarat				
(P)	58.70	41.30	-	100.00
(G)	-	100.00	-	100.00
b. Maha.				
(P)	75.3	26.5	-	100.00
(G)	-	100.00	-	100.00
Dyes				
a. Gujarat(P)	-	100.00	-	100.00
b. Maha. (P)	-	100.00	-	100.00
Pharmaceuticals				
a. Gujarat	-	100.00	-	100.00
b. Maha. (G)	-	-	100.00	100.00
Tyres				
a. Gujarat	-	-	-	-
b. Maha.	-	100.00	-	100.00
Soaps				
a. Gujarat	-	-	-	-
b. Maha. (P)	-	100.00	-	100.00
Foods				
a. Gujarat(G)	-	100.00	-	100.00
b. Maha. (P)	-	100.00	-	100.00

Source: National Productivity Council

Exhibit 1.9

Industrial Growth Rate 1985-1995 (percent per year)

Industry	Growth Rate
Textile	3.5
Rayon	2.5
Pulp & Paper	5.2
Refinery	6.0
Fertilizer	5.0
Basic Chemicals	8.0
Dyes	9.0
Pharamaceutical	15.0
Tyres	4.0
Soaps	11.0
Food	5.0

Source: National Productivity Council

An industry will invest in a cogeneration system if the incremental savings from lower electricity costs are higher than the incremental capital, fuel, and operation and maintenance costs. The model calculates the cost and benefits of each system on a life-cycle basis. It assumes that the industry will be allowed to sell its excess electricity to the grid. Therefore, cost of electricity to the industry and the price the utility (or other customers) will pay for the excess power are both taken into account.

Nine cogeneration technologies are taken into account. These are:

- Oil-fired boiler with steam turbine,
- Coal-fired boiler with steam turbine,
- Natural gas-fired boiler with steam turbine,
- Advanced Fluidized bed boiler with steam turbine,
- Oil-fired gas turbine with waste heat recovery boiler,
- Natural gas-fired gas turbine with waste heat recovery boiler,
- Oil-fired combined cycle,
- Natural gas-fired combined cycle, and
- Oil-fired diesel engine with waste heat recovery boiler.

The cogeneration system costs and performance characteristics for each technology are presented in Appendix D. The boiler steam turbine systems using oil, gas, or coal, and diesel engines with waste heat recovery boilers are currently available in India and have been used rather extensively by the

industry. The other technologies are relatively new to the industry, therefore, they will penetrate the market with a slower pace. To reflect this fact, the model assumes different diffusion rates for different technologies. Gas turbines, for example, are assumed to start penetrating the market in late 1980s and the combined cycles in early 1990s, while the conventional boiler steam turbines are already fully diffused.

Based on the above information, the model first determines what technologies and fuels are applicable to each industry, calculates the life-cycle costs and benefits for each technology, and selects the technology with highest net benefit. Based on the input data provided in previous exhibits, the model estimates an economic cogeneration potential of 1,318 MW in Gujarat and Maharashtra industries (see Exhibit 1.10A).

The estimated financial potential for industrial cogeneration in Gujarat and Maharashtra over the next ten years is 280 MW (see Exhibit 1.10B). The industries with the largest potential are fertilizer, basic chemicals and refinery with potentials of 816 MW, 636 MW, and 352 MW respectively. About one third of the potential, roughly 730 MW, lies in the existing industries with the remaining 1,550 MW in new plants coming on line between 1986 and 1996. The availability of natural gas has a very important impact on the size of the potential. Based on the views expressed to the study team on the availability of natural gas for process industries, it was assumed that only fertilizer plants and refineries will have access to natural gas. Assuming that all industries will be able to receive natural gas, the potential could be as high as 3,000 MW. This is primarily due to low capital and O&M costs of gas-fired cogeneration systems.

Exhibit 1.10A

Economic Potential for Industrial Cogeneration in Gujarat and Maharashtra (1986-1996)

	(MW)						
	86-87	88-89	90-91	92-93	94-95	96	Total
Textile	3	2	4	9	15	10	43
Rayon	2	1	3	6	10	7	29
Pulp & Paper	2	1	3	6	10	7	29
Refinery	8	6	12	26	47	33	132
Fertilizer	18	15	30	67	114	70	314
Basic Chemicals	23	18	39	94	180	132	486
Dyes	2	2	4	9	16	12	45
Food	1	1	2	5	8	6	23
Pharamaceutical	5	4	11	31	69	58	178
Tyres	0	0	1	2	3	2	8
Soaps	1	1	2	5	9	7	25
Total	65	52	111	262	483	346	1.318

Source: Hagler, Bailly & Company; based on data from National Productivity Council.

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Exhibit 1.10B

Financial Potential for Industrial Cogeneration in Gujarat and Maharashtra (1986-1996)

	(MW)						
	86-87	88-89	90-91	92-93	94-95	96	Total
Textile	3	2	5	11	19	12	53
Rayon	2	2	4	8	13	8	37
Pulp & Paper	2	2	4	8	15	10	41
Refinery	9	8	37	82	130	86	352
Fertilizer	21	24	115	203	279	174	816
Basic Chemical	25	18	50	127	241	175	636
Dyes	2	2	4	11	21	15	54
Food	1	1	2	6	11	7	29
Pharamaceutical	5	5	14	40	87	74	224
Tyres	1	0	1	2	3	2	9
Soaps	1	1	2	6	11	8	29
Total	72	48	130	339	624	517	2,280

Source: Hagler, Bailly & Company; based on data from National Productivity Council.

The fact that the financial potential is higher than the economic potential indicates the existing distortions in fuel and electricity prices in India.

Potential for Bottoming Cogeneration Systems

Bottoming cogeneration is suitable for industry with exhaust streams at 300°C or more. In general bottoming systems generating less than 500 kW of electrical output (which corresponds to waste heat streams of over 10 mmBtu/hr) are not readily available, and not economically viable. Therefore, in this analysis, we concentrated only on industries with continuous waste heat streams of over 10 mmBtu/hr. The prime candidates for such systems are glass, cement, and steel industries, as well as some fertilizer and petrochemical plants and refineries.

According to NPC, all glass melting furnaces in Gujarat and Maharashtra have a fuel consumption of between 3,500 and 15,000 kl per year, corresponding to waste heat streams of 1.0 to 5.0 mmBtu/hr. Therefore, none of these plants are viable candidates for bottoming cogeneration applications.

Most cement plants in Gujarat and Maharashtra use wet process kilns. In addition, most large plants are very old and inefficient and do not represent opportunities for cogeneration. The steel plants do not represent any potential for cogeneration either, as they are too small and use batch processes not allowing for continuous operatior

Refineries, petrochemical plants and fertilizer plants are the only industries in Gujarat and Maharashtra where there is any viable bottoming cogeneration potential. According to NPC, 10 installations in Gujarat and Maharashtra fit

the minimum requirement of 300°C exhaust temperature and 10 mmBtu/hr waste stream. The total waste heat available at these plants is estimated at 600 mmBtu/hr. Assuming an average thermal to electricity conversion efficiency of 15 percent the total cogeneration potential in these industries will be about 25 MW. Assuming an average growth of 7 percent per year between 1986 and 1996, the accumulative technical potential for bottoming cogeneration in these industries in 1996 is estimated at 50 MW.

Using U.S. capital costs and annual O&M costs that are 5 percent of capital costs, economic levelized cost of electricity from bottoming cogeneration systems range from 55.4 to 77.0 Ps./kWh and the financial levelized costs between and 69.8 to 119.9 Ps./kWh (see Exhibit 1.11). These costs are lower than the estimated economic and financial marginal cost of electricity from utilities, 0.8 and 1.3 Rs/kWh respectively. Therefore, the entire technical potential is both economically and financially attractive.

Potential for Cogeneration in Commercial Buildings

In recent years attention has been turned to the possibility of putting cogeneration systems (based primarily on diesel generators with waste heat recovery boilers) in large commercial buildings such as hotels, hospitals, and office buildings. In these systems, a diesel generator supplies most or all the power needed by the building or by a complex of buildings. Waste heat in the form of hot water (typically at 90 to 95 degrees C) or low pressure steam (typically 15 psi) is recovered from the diesel's jacket water, lubricating oil, and exhaust gas. This waste heat recovery gives the system an overall efficiency much greater than power generation alone. Typical

Exhibit 1.11

Economic and Financial Costs of Producing Power From Bottoming Cycle Cogeneration Systems

System Size (MW)	Capital Cost (1986 US$/kW)	Levelized Cost of Electricity (Ps/kWh)		
			Financial	
		Economic	Private	Public
4.0+	1,800	55.4	86.3	69.8
2.0	2,100	64.8	100.1	81.4
1.0	2,500	77.0	119.9	96.9

Assumptions:

System Life = 15 years
Economic CRF = 0.147
Financial CRF = 0.257 (Private investment)
= 0.198 (Public investment)
Annual O&M = 5 percent of capital cost

Source: Hagler, Bailly & Company.

diesel cogeneration systems can have a power output between 31 and 35 percent of the fuel input, and can at the same time recover useful thermal energy representing between 35 and 45 percent of the fuel input. This results in an overall system efficiency between 70 and 80 percent.

While it is possible to use a boiler/steam turbine or a gas turbine/waste heat recovery boiler in a commercial cogeneration application, these alternative systems generally do not appear as financially attractive as the diesel system for three reasons. First, commercial buildings typically have a high electric-to-thermal demand ratio (E/T) which a diesel system can match more easily than the others. For example, typical E/T's for commercial buildings in India and in other countries are between 1 and 10 and in some cases even higher, since most commercial buildings require electric power for lights, air conditioning, lifts, and equipment, while thermal power is needed only for hot water. There is of course in Bombay little or no space heating requirement. Diesel cogeneration systems normally have E/T ratios of 0.8 to 1.1, while boilers with steam turbines have E/T's from 0.1 to 0.3, and gas turbines with waste heat recovery boilers have E/T's from .3 to 0.5. Thus the diesel systems give a better match of supply to demand[5].

Second, many buildings already have diesel generators for emergency purposes. These can be retrofitted with waste heat recovery boilers at a comparatively low incremental cost. On the other hand, boilers in commercial buildings are generally low pressure (150 psi or less) and thus are unsuitable for cogeneration which requires high pressure boilers (300 psig

[5] It should be noted that part or all of the electrical demand for airconditioning can be satisfied using steam in an absorption chiller. This has the net effect of reducing the electric-to-thermal demand ratio.

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or more) without replacement or expensive modifications. Gas turbines are not generally used for standby in buildings because of their costs, relatively sophisticated operating requirements and noise.

Third, building operators are generally familiar with diesel systems and have little concern about operating them continuously rather than just a few hours per month for test purposes as is currently done. In fact, many diesels in India are operated at high duty factors for 12 hours per day or more due to the unreliability of grid power in some areas.

There are however several problems with the use of diesel engines. First, diesels have substantial noise and vibration associated with their operation. While this in not usually a major problem with systems operating only as standby, it has been a serious problem for systems operated continuously in densely populated areas. In many cases a separate building was constructed to house the diesel system to keep the noise and vibration away from the building(s) being served. A mitigating factor for cogeneration system operations is that the waste heat boilers are effective mufflers for the system.

Second, diesels can contribute significantly to air pollution primarily in the form of nitrogen oxides (NOx). These can add to already serious air quality problems in the densely populated areas large buildings are usually sited in. Large diesels with good operating practices will emit approximately 1.6 kg of NOx, 0.03 kg of particulates, and 0.4 kg of CO per 100 kWh generated. In comparison, a large central coal-fired power plant with good controls will emit 0.3 kg NOx, 0.14 kg of particulates, and 0.02 kg of CO per 100 kWh. While emission control technologies are available for diesels, these must be

monitored closely and it is very easy for them to go out of adjustment as the diesel output changes to meet the load variations. In that case, the emissions indicated above can easily be exceeded. This problem is exacerbated because diesel engine exhausts are usually located relatively close to ground level, which can result in serious concentrations of pollutants near the cogeneration site. In contrast, central power stations usually have high exhaust stacks which give the pollutants time to disperse before they reach ground level. Several organizations in the Bombay area interviewed in the course of this study indicated that environmental problems were of serious concern in the Bombay area, as evidenced by restriction on coal use by industry. While no specific regulations applied to diesel emissions, they may be instituted if significant numbers of diesels were operated on a continuing basis rather than only sporadically as is now the case.

A final problem with installing a diesel cogeneration system is space for the diesel generators, waste heat boilers, and absorption chillers. All of the potential cogeneration facilities visited in the course of this study indicated that finding room for these systems would be a problem. Generally, space now devoted to other uses such as parking or storage would need to be used. The problem is particularly acute in the urban areas where many of the larger buidings are located and where land is very expensive or simply not available.

To determine if commercial building cogeneration systems have significant potential in India, we looked at its potential in Bombay. In the following sections, we examine the technical, economic, and financial potential of these systems.

Technical Potential

Cogeneration systems based on diesel generating systems can in principle be used in any type of building having both an electric and thermal demand. The total commercial building electrical consumption for Bombay Electric Supply and Transport (BEST) which provides electrical service to most of Bombay proper was in 1984/85 684 million kWh, or 37.5% of its total sales of 1703 million kWh. If we assume a 40% overall load factor for the commercial buildings (BEST never estimated this figure; this value is approximately equal to that realized in the United States), this gives a total commercial building sector demand of approximately 182 MVA, out of a total BEST peak maximum demand of 404 MVA. In principle, all of this demand could be supplied by diesel systems, although realistically only a small portion of this potential is likely to be realized.

Experience in the United States and Europe indicate that the best opportunities for cogeneration systems generally lie in large buildings, particularly hotels, hospitals, and colleges. While there is some potential in large office buildings and retail centers, these generally have too low a thermal demand to make such use economic. This is true even for buildings in colder climates than India's which may have some heating demand, because usually these large buildings will have such large internal gains from people, lights, and equipment that they require cooling almost year-around, with space heating needed only for a few hours in the winter mornings.

After discussions with building owners and operators and consultants, in Bombay the study team focused its efforts on large hotels and hospitals as being the most attractive for congeneration opportunities. Office buildings

were felt to have a very low potential because as discussed previously they have little thermal load. The two building types which appeared to have significant thermal loads are large hotels and hospitals. One hotel guide lists 42 hotels in Bombay having 20 rooms or more, with a total of 4,585 rooms. Of these, 6 have more than 200 rooms each (with a total population of 2,432 rooms, soon to be expanded to 2,782 rooms), 5 have betwwen 100 and 200 rooms (with a total of 641 rooms), and 31 have less than 100 rooms (with a total population of 1,512 rooms). While this guide probably does not list all of the hotels, it does appear to include all the larger ones of 100 rooms or more.

The three larger hotels visited as part of this study (with a total of 1528 rooms, or 1/3 of the estimated total) had peak demands of approximately 5.3 kW per room, and annual consumptions of approximately 27,000 kWh/room/year. If these are representative of the remaining hotels (and they do appear reasonably close to consumptions in other countries), and if the hotel population grows at 3.6% per year (the expected Indian urban population growth rate between now and 1996), this sector will have 7,043 rooms by 1996, with a resulting technical potential for cogeneration systems to generate 37 MW.

The study team was unable to find detailed information on the number and size of hospitals in the Bombay area. Three of the largest hospitals were visited to obtain information on energy use to determine if there was significant potential for cogeneration systems. These three together had a total peak demand of 3.0 MW. Discussions with personnel at these hospitals indicated that the greater Bombay area had approximately 20% of the total

hospital beds in Maharashtra, or approximately 16,340 beds. By 1996, the total number of beds is projected to grow at a 2.6% per annum, for a total of 24,000 hospital beds in the greater Bombay metropolis. These three hospitals together had a total of 1100 beds, with a specific power demand of about 2.7kW/bed. This implies the total greater Bombay hospital power demand in 1996 will be approximately 65 MW, which can potentially be displaced by cogeneration systems.

No other type of commercial buildings in Bombay were identified by the study team to provide opportunities for cogeneration.

Economic Potential

The economic costs of diesel generators, waste heat boilers and absorption chillers were estimated using information provided by Indian manufacturers using the following procedures. Diesel generator sets and waste heat boilers for gensets having individual outputs of 1 MW or less are manufactured in India at present. Manufacturers estimate the foreign exchange portion of the gensets and waste heat boilers is equal to 10% of the installed cost, and for absorption chillers is equal to 40% of the installed cost. Transfer payments such as taxes, duties, and profits are equal to approximately 15% of the installed costs for gensets and boilers and 20% for absorption chillers. Using a Standard Conversion Factor of 0.8 gives a ratio of economic capital cost to selling price of 0.875 for gensets and boilers and 0.90 for absorption chillers.

The economic potential of commercial building cogeneration is estimated for a large hotel, a mediuem size hotel and for a large hospital in Exhibits 1.12A, 1.13A and 1.14A. These indicate that commercial cogeneration does not appear

Exhibit 1.12A

Estimate of Economic Costs for Medium Size Hotel Cogeneration System

	Conventional System	Cogeneration System
Installed Diesel Generator Capacity	2 x 550 kW	3 x 550 kW
Chillers:		
Electric	2 x 200T, 1 x 80T	2 x 200T, 1 x 80T
Absorption	-	1 x 100T
Incremental Capital Costs:		
Diesel Generators (10^6Rs)	-	2.5
Waste Heat Boilers (10^6Rs)	-	0.5
Chiller	-	2.0
Total Incremental Capital Cost (10^6Rs)		**5.0**
Incremental Operating Costs:		
Fuel Oil (@ Rs 2.0/l, 10^6Rs)	0.7	4.4
Purchased Power (@ 0.80 Rs/kWh, 10^6Rs)	5.0	-
Operating and Maintenance	-	0.9
	5.7	5.3
Net Operating Cost Savings (Loss) (10^6Rs/yr)	-	**0.4**
Annualized Incremental Capital Cost (10^6Rs)		**0.7**
Net Annual Savings (Loss) (10^6Rs)		**(0.3)**

Source: Hagler, Bailly & Company

Exhibit 1.13A

Estimate of Economic Costs for Large Size Hotel Cogeneration System

	Conventional System	Cogeneration System
Installed Diesel Generator Capacity	2 x 1,100 kW	4 x 1,100 kW
Chillers:		
Electric	2 x 900T	2 x 900T
Absorption	1 x 500T	1 x 500T
Incremental Capital Costs:		
Diesel Generators[1] (10^6Rs)	-	9.6
Waste Heat Boilers[2] (10^6Rs)	-	1.6
Chiller[3]	-	-
Total Incremental Capital Cost (10^6Rs)	-	**11.2**
Additional Operating Costs:		
Fuel Oil[4] (@ Rs 2.0/l, 10^6Rs)	2.5	12.9
Purchased Power[5] (@ Rs 0.80/kWh, 10^6Rs)	14.2	-
Operating and Maintenance[6]	-	3.1
	16.7	16.0
Total Operating Cost Savings (10^6Rs/yr)		**(1.3)**
Annualized Incremental Capital Cost (10^6Rs)[7]		**4.03**
Net Savings (10^6Rs)		**2.5**

[1] Includes diesel, synchronous generator, civil works, design and construction costs, and power conditioning equipment, with an installed cost of Rs 4,375/kW.

[2] Economic Cost of waste heat boilers = Rs 300/kW of diesel output.

[3] No additional chillers are needed for this site.

[4] Fuel Oil Requirements: absorption chiller = 154,000l/yr; hot water = 1,080,000l/yr.

[5] Current electric consumption = 17.75 x 10^6 kWh/yr.

[6] Diesel/gen sets O&M = 0.15 Rs/operating hour - kW (at 20 x 10^6 kW - operating hrs/yr); absorption chiller at O&M = 3% of capital cost additional (capital cost = 2.2 x 10^6 Rs).

[7] Capital Recovery Factory (at 12% for 20 years) = 0.134.

Source: Hagler, Bailly & Company

Exhibit 1.14A

Estimate of Economic Costs for Large Hospital Cogeneration System

	Conventional System	Cogeneration System
Installed Diesel Generator Capacity	1 x 210 kVA	3 x 1,000, 1 x 210 KVA
Chillers:		
Electric	2 x 350T, 1 x 300T	2 x 350T, 1 x 300
Absorption	-	x 200
Incremental Capital Costs:		
Diesel Generators (10^6Rs)	-	13.1
Waste Heat Boilers (10^6Rs)	-	1.0
Chiller	-	4.0
Total Incremental Capital Cost (10^6Rs)		**18.1**
Incremental Operating Costs:		
Fuel Oil (@ Rs 2.0/1, 10^6Rs)	0.6	2.3
Purchased Power (@ 0.8 Rs/kWh, 10^6Rs)	3.1	-
Operating and Maintenance	-	0.8
	3.7	3.1
Net Operating Cost Savings (Rs10^6)		**0.6**
Annualized Incremental Capital Cost (Rs10^6)		**2.4**
Net Annual Savings (Loss), (10^6Rs)		**(1.8)**

Source: Hagler, Bailly & Company

to be economically viable in these buildings. This economic unattractiveness is due to the relatively high cost of oil imports needed to fuel these systems and the relatively low economic costs of electricity from the grid which rely on domestic coal and hydropower. It should be noted that this does not mean these systems will never be economic. An increase in the avoided electricity cost of between 10 and 20 percent will make the hotel systems economically viable, and an increase in avoided electricity costs of 60 percent will make the hospital system economically viable. However the present economic potential based on present estimates of economic costs is 0.

Financial Potential

The financial performance of commercial building cogeneration systems is summarized in Exhibits 1.12B, 1.13B, and 1.14B. These indicate that cogeneration systems appear attractive for the hotels, but not for the hospital. The reason they appear attractive is the high cost of electric power, Rs. 1.6/kWh. Thus, it is possible over the next few years that cogeneration systems may be installed in large hotels. It should be noted that at least one major Indian hotel chain has installed a diesel cogeneration system at a hotel in Calcutta. The primary reason for this was the poor reliability of electricity supply in that city. Thus they have no plans at present to make a similar installation in their Bombay sites which at least for the past 5 years have had very reliable electricity supplies, even if the cogeneration systems did make financial sense. However, if the Bombay electrical supply situation deteriorates in the future to the point where the hotel sites require several hours of operation of standby diesel generators every day, they will look more closely at a cogeneration system.

Exhibit 1.12B

Estimate of Financial Costs for Medium Size Hotel Cogeneration System

	Conventional System	Cogeneration System
Installed Diesel Generator Capacity	2 x 550 kW	3 x 550 kW
Chillers:		
Electric	2 x 200T, 1 x 80T	2 x 200T, 1 x 80T
Absorption	-	1 x 100T
Incremental Capital Costs:		
Diesel Generators (10^6Rs)	-	2.5
Waste Heat Boilers (10^6Rs)	-	0.5
Chiller	-	2.0
Total Incremental Capital Cost (10^6Rs)		**5.0**
Incremental Operating Costs:		
Fuel Oil (@ Rs 3.6/l, 10^6Rs)	1.2	4.4
Purchased Power (@ 1.6 Rs/kWh, 10^6Rs)	-	-
Operating and Maintenance	-	0.9
	11.0	8.7
Net Operating Cost Savings (Loss) (10^6Rs/yr)	-	**0.4**
Annualized Incremental Capital Cost (10^6Rs)		**0.7**
Net Annual Savings (Loss) (10^6Rs)		**(0.3)**

Source: Hagler, Bailly & Company

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Estimate of Financial Costs for Large Size Hotel Cogeneration System

	Conventional System	Cogeneration System
Installed Diesel Generator Capacity	2 x 1,100 kW	4 x 1,100 kW
Chillers:		
Electric	2 x 900T	2 x 900T
Absorption	1 x 500T	1 x 500T
Incremental Capital Costs:		
Diesel Genertors[1] (10^6Rs)	-	11.0
Waste Heat Boilers[2] (10^6Rs)	-	1.8
Chiller[3]	-	-
Total Incremental Capital Cost (10^6Rs)	-	**12.8**
Additional Operating Costs:		
Fuel Oil[4] (@ Rs 3.6/l, 10^6Rs)	4.5	23.3
Purchased Power[5] (@ 1.6/kWh, 10^6Rs)	28.4	-
Operating and Maintenance[6]	-	3.1
	32.9	26.4
Net Operating Cost Savings (10^6Rs/yr)		**6.5**
Annualized Incremental Capital Cost (10^6Rs)		**4.03**
Net Savings (10^6Rs)		**2.5**

[1] Includes diesel, synchronous generator, civil works, design and construction costs, and power conditioning equipment, with a cost of Rs 5,000/kW.

[2] Cost of waste heat boilers = Rs 400/kW of diesel output.

[3] No additional chillers are needed.

[4] Absorption chiller = 154,000/yr; hot water = 1,080,000/yr.

[5] Current electric consumption = 17.75 x 10^6 kWh/yr.

[6] Diesel/gen sets O&M = 0.15 Rs/operating hour - kW (at 20 x 10^6 kW - operating hrs/yr); absorption chiller at 3% of capital cost additional (capital cost = 2.2 x 10^6 Rs).

Source: Hagler, Bailly & Company

Exhibit 1.14B

Estimate of Financial Costs for Large Hospital Cogeneration System

	Conventional System	Cogeneration System
Installed Diesel Generator Capacity	1 x 210 kVA	3 x 1,000, 1 x 210 KVA
Chillers:		
Electric	2 x 350T, 1 x 300T	2 x 350T, 1 x 300
Absorption	-	1 x 200
Incremental Capital Costs:		
Diesel Generators (10^6Rs)	-	15.0
Waste Heat Boilers (10^6Rs)	-	1.2
Chiller	-	4.4
Total Incremental Capital Cost (10^6Rs)		**20.6**
Incremental Operating Costs:		
Fuel Oil (@ Rs 3.6/l, 10^6Rs)	1.0	4.2
Purchased Power (@ 156 Rs/kWh, 10^6Rs)	6.1	-
Operating and Maintenance	-	0.8
	7.1	5.0
Net Operating Cost Savings (Rs10^6)	-	**2.1**
Annualized Incremental Capital Cost (Rs10^6)		**2.8**
Net Annual Savings (Loss), 10^6Rs		**(0.7)**

Source: Hagler, Bailly & Company

SMALL-SCALE POWER GENERATION FOR SALE TO THE GRID

In this section the potential for non-utility power generation from small scale facilities will be discussed. In contrast to cogeneration systems discussed in the previous section, these systems will be built solely for generation of electricity for sale to utilities or to other customers. These systems include:

- Sugar cane residue-fired systems
- Other agro waste-fired systems
- Fossil-fueled systems
- Municipal waste-fired systems
- Small-scale hydropower systems
- Other renewable systems, i.e. wind, solar, dendrothermal

In the following sections, the technical, economic, and financial potential for each system is evaluated, and other factors that affect the potential of these resources are discussed.

Potential for Sugar Cane Residue-Fired Systems

In the cane sugar industry, electric power can be generated from bagasse, the fiber residue from crushing available at the mill, or from leftovers at the field, such as cane tops and leaves. Whereas generating power from bagasse has been traditionally done for decades in medium and large scale sugar mills, burning cane field residues in boilers to generate high pressure steam and then electricity, is a new technology. In the following paragraphs the

characteristics of the cane sugar industry in India, and more specifically in Maharashtra and Gujarat are reviewed and a preliminary assessment of the technical, economic and financial power potential is presented.

India is the world's largest producer of sugarcane, producing on the order of 190 million tonnes per year. Out of this as much as 33 percent is consumed by the vacuum pan sugar factories for producing crystal sugar and 55 percent is consumed by gur & khandsari manufacturers (traditional small scale operation) and the balance of 12 percent is used for seed and chewing purposes. There are as many as 366 sugar factories now working in 18 different states and union territories of India. The breakup of these 366 sugar factories in the private sector, public sector and cooperative sector is shown in Exhibit 1.15.

Several specific features of the Indian Sugar industry are important to stress:

1. As mentioned above, only 33 percent of the total cane produced is used in conventional sugar mills to produce (white) sugar.

2. Most sugar mills are privately owned, generally through cooperatives (see Exhibit 1.15)

3. Sugar mill capacity is standardized with a basic unit being sized at 1250 tonnes of cane per day (tpd) in crushing capacity - only 3 mills have a daily capacity greater than 5,000 tpd (see Exhibit 1.16).

Exhibit 1.15

Total Number of Installed Sugar Factories

State/Union Territory	Private	Public Sector/ State Owned	Coop.	Tota
1. Uttar Pradesh	55	18	28	101
2. Bihar	21	9	-	30
3. Punjab	2	2	6	10
4. Haryana	1	-	7	8
5. West Bengal	1	1	-	2
6. Assam	-	1	1	2
7. Nagaland	-	1	-	1
8. Rajasthan	1	1	1	3
9. Madhya Pradesh	5	-	3	8
10. Orissa	1	-	2	3
11. Maharashtra	11	-	80	91
12. Gujarat	-	-	16	16
13. Goa	-	-	1	1
14. Tamil Nadu	12	2	11	25
15. Karnataka	8	3	16	27
16. Pondicherry	1	-	1	2
17. Andhra Pradesh	10	5	18	33
18. Kerala	1	-	2	3
ALL INDIA	130	43	193	366

Sources: National Federation of Cooperative Sugar Factories

Exhibit 1.16

Number of Sugar Factories According to Their Cane Crushing Capacity (Tonnes of Cane Crushed Per Day)

State/Union Territory	1250& Below	1251 2001	2001-3000	3001-5000	Above 5001	Total
1. Ulter Pradesh	58	27	10	6	-	101
2. Bihar	22	8	-	-	-	30
3. Punjab	9	-	1	-	-	10
4. Haryana	5	2	-	-	1	8
5. West Bengal	2	-	-	-	-	2
6. Assam	-	-	-	-	-	-
7. Nagaland	1	-	-	-	-	-
8. Rajasthan	2	1	-	-	-	3
9. Madhya Pradesh	6	2	-	-	-	8
10. Orissa	3	-	-	-	-	3
11. Maharashtra	57	16	12	6	-	91
12. Gujarat	9	3	-	3	1	16
13. Goa	1	-	-	-	-	1
14. Tamil Nadu	12	7	3	3	-	25
15. Karnataka	15	5	5	2	-	27
16. Pondicherry	1	1	-	-	-	2
17. Andhra Pradesl	25	4	2	1	1	33
18. Kerala	3	-	-	-	-	3
TOTAL INDIA	233	76	33	21	3	366

Source: National Federation of Cooperative Sugar Factories

4. Most sugar mills are self-sufficient in electricity produced from bagasse. A typical mill has 2 or 3 boilers. The Government of India has been prescribing standard specifications for the plant and machinery required in the new sugar factories. The specifications of steam and power generation equipment for a typical 1,250 tpd factory are described in Exhibit 1.17.

Technical Potential

A Committee constituted by the Delhi Productivity Council for energy conservation and surplus power generation in the Indian sugar industry, submitted its report in November, 1982. According to this report, all the existing sugar factories in India would be able to produce surplus electric power to the extent of 1,800 MW by installing high pressure boilers and special types of power generators in their factories The conditions for and potential of power generation from cane field residue has not been analyzed.

To estimate the power generation potential from excess bagasse and cane field residues in Gujarat and Maharashtra, detailed production and mill-specific statistics were reviewed (see Exhibit 1.18). Based on these statistics, it was possible to build up a table showing the amount of excess bagasse and cane field residues (CFR) available in each state and estimate the technical potential for excess power generation, using the following assumptions:

- 70 kWh of excess power can be generated from bagasse for each tonne of cane crushed (this is discussed in more detail below)

Exhibit 1.17

Characteristics of Steam and Power Generating Systems in a Typical Sugar Mill

Steam Generating Plant (Boilers)

For 1,250 tonnes per day	Two boilers
For 2,000 tonnes per day	Three boilers
Minimum continuous load	20 tonnes per hour
Pressure at superheated outlet	21 kg/cm^2
Temperature at superheater outlet	Minimum 300°C and Maximum 340°C with 15° at MCR
Feed water temperature	85°C
Fuel	Bagasse with 50 percent moisture or low viscosity furnace oil
Efficiency	65 percent + 2.5 points G.C.V with bagasse at 50 percent moisture or 80 percent + 2.5 points with furnace oil

Power Generating Plant (Turbo-Alternator Set)

For 1,250 tonnes	One turbo-alternator
For 2,000 tonnes	Two turbo-alternators
Turbine type	Backpressure, multistage
Speed	900-1,000 rpm
Steam input condition	Pressure: 12-21 kg/cm^2 Temperature: 300°C-350°C
Steam consumption	Less than 13 kg/kW
Back pressure	0.95 kg/cm^2
Alternator	1,875 kVA, generating 3 phase, 50 cycle, 500-440 volts, AC, with 0.80 power factor

Sources: National Federation of Cooperative Sugar Factories

- There are 4 net tonnes of CFR available for each acre of cane cultivation or 10 tonnes/hectare

- Only individual sugar mills sized at 1250 tpd or higher can generated power

- Crushing season duration averages 158 days or 5.25 months in Maharshtra and 137 days in Gujarat (4.6 months). For this preliminary estimate we have used an average of 150 days for both states.

Results show that about 350 MW of excess power could technically be produced in Maharashtra for 10-11 consecutive months and about 75 MW in Gujarat (see Exhibit 1.18).

According to Indian industry specialists, this potential can technically be realized by: (1) increasing boiler pressure from 30 psig to 600-900 psig; (2) using adequate and efficient turbo generators (extraction condensing); and, (3) implementing general energy conservation measures in the mill, such as improved mills, bagasse drying, improved evaporators, use of thermo- and/or turbo-compression and general steam conservation actions.

Economic and Financial Potential

According to Indian sources, the cost of the above mentioned modifications would be about 200 Rs. Lakhs (US $1.6 million) for new factories (incremental capital cost only) sized at 1,250 tpd and 500 Rs. Lakhs electric (US $4 million) for retrofitting existing mills (see Exhibits 1.19 and 1.20). Both capital costs are for 5 MW installed electric capacity. These numbers

Exhibit 1.18

Sugarcane Statistics (1984/85)

	Maharashtra	Gujarat
Number of Mills[1]	78	12
Planted area (ha)[1]	294,000	103,000
Total surgarcane produced (tonnes, million)[2]	26.55	7.75
Of which, crushed in mills for white sugar (tonnes, million)	17.90	3.74
Sugar production (tonnes, million)	1.99	0.39
Quantity of bagasse produced at at 50% moisture (tonnes, million)	5.10	1.06
Quality of trash (leaves only) available for power production (tonnes, million)	1.98	0.49
Potential for Surplus Power Generation		
- From bagasse at 70 kWh/tonne crushed for 5 months, GWh	1,253	262
MW	348	73
- From Trash at 3,000 kcal/kg, 20% efficiency, 5 extra months (MW)	383	80

1) Source: "Cooperative Sugar" Vol. #17, June 1986.

2) (On the bans of 4 tonnes/acre - Source: Federation for White Sugar Mills over.)

Exhibit 1.19

Additional Cost for Modification and Equipment to be Incorporated in New Factories for Surplus Power Generation (Rs. lakhs)

1.	Cane preparation - splitting of cane carrier and installation of fibriser.	15.00
2.	Mills - providing under-feed rollers on all the mills and recirculation of imbibition liquid.	15.00
3.	One Boiler - 40 tonnes per hr. capacity at 600 psig (incremental cost)	40.00
4.	Power house - one 2.5 MW back pressure governed turbo-set and one 2.5 MW condensing turbo-set (incremental cost)	100.00
5.	Step-up transformer and protection system for supplying power to grid.	15.00
6.	Others	15.00
	Total	200.00

Sources: National Federation of Cooperative Sugar Factories

Exhibit 1.20

Equipment Required for Surplus Power Generation in Factories of 1,250 TPD and Above

Equipment	Cost (Rs.Lakhs)	Remarks
One 70 T/hr. boiler operating at 600 psig (at super heated outlet and 780°F)	200.0	Complete with water treatmen plant, condensate storage tank, etc.
One 5 MW back-pressure governed turbo generating set and one 5 MW condensing set	250.0	Including foundation, buildings, electrical control distribution, etc.
Step-up transformer and protection systems for supplying power to the grid	30.0	
Miscellaneous	20.0	
TOTAL	**500.0**	

Source: National Federation of Cooperative Sugar Factories

are in line with a more recent World Bank study which estimates the specific investment cost at US $480/kW for similar situations[6].

Economic and financial fuel and O&M costs have been considered identical in this preliminary analysis, and the opportunity cost of bagasse and CFR assumed equal to their best market alternatives, i.e., paper feedstock for bagasse and cattle feed for cane leaves (cane crops are already entirely used for cattle feed and are not accounted for in the resource base estimate). Both fuels have been assumed to have the same market value of Rs. 150/tonne. Based on the above assumptions, power can be generated at mill gate for an economic cots of Ps. 40-49 and for a financial cost of Ps. 49-Ps. 66 (see Exhibit 1.21). These numbers being below both the economic and financial marginal cost of power, 0.80 Rs/kWh and 1.30 Rs/kWh, respectively, it is concluded that all the technical potential is economically and financially attractive. Therefore the economics and financial market for power from cane residue is estimated at 350 MW in Maharashtra and 75 MW in Gujarat.

Potential for Other Agro Waste-Fired Systems

In addition to the cane sugar industry, a number of other agroindustries also produce significant amounts of residues that could be used to generate power. The major agro wastes available in Maharashtra are rice husks, paddy straw, ground nut shells, cotton sticks, sawdust, and animal dung. For Maharashtra, all the above resources combined represent a total of 11.5 million tonnes representing a theoretical potential of about 1,800 MW of power (see Exhibit

[6]. World Bank, Identifying the Basic Conditions for Economic Generation of Public Electricity from Surplus Bagasse in Sugar Mills, October 1983.

Exhibit 1.21

Economic and Financial Cost of Electricity From Cane-Waste-Fueled Systems (Ps./kWh)

Days of Operation Per Year	Non Fuel Costs		Fuel Cost	Total Cost	
	Economic	Financial		Economic	Financial
150	25	42	24	49	66
250	16	25	24	40	49

Assumptions:

Capital Cost	= $480/kW
Capital Recovery	= 0.150 for Economic Cost
	= 0.250 for Financial Cost
Fuel Cost	= Rs.150 per tonne of waste

Source: Hagler, Bailly & Company

1.22). However, none of these wastes are available in sufficient quantities in a small number of places to warrant further investigation (see Exhibit 1.23). All wastes are currently being used as cattle feed, fuel, construction materials, etc., and are heavily traded. Given the existence of numerous other options for power generation, it was not considered worthwhile to pursue the analysis further.

In Gujarat, the same characteristics exist, but two by-products, ground nuts and cotton seeds appear to have some potential for power generation. According to a 1984 NPC study,[7] almost 500,000 tonnes of groundnut shells and 535,000 tonnes of various oil seeds would be available annually. Another study[8], however, finds smaller quantities, i.e., 115,000 tonnes and 140,000 tonnes.

Using a mid-point of 300,000 tonnes for groundnut shells and 350,000 tonnes of cotton and other oil seeds and waste, and assuming that only 50% of these quantities correspond to locations where these wastes can be collected, we arrive at a technical potential of around 20 MW for each resource. The small size of this potential does not warrant any further economic and financial analysis.

Potential for Small Fossil-Fueled Systems

These systems include diesel engines, gas turbines, and boilers with condensing steam turbines, running on imported diesel oil, domestic natural gas, or

[7] National Productivity Council, 1984.

[8] Utilisation of Agricultural Residues," by Gujarat Individual and Technical Consultancy Organization, 1983.

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Exhibit 1.22

Agrowastes Production and Availability for Power Generation (in thousands tonnes, 1984)

Agrowaste	Maharashtra		Gujarat	
	Production	Available	Production	Available
Rice Husks	151	0[1]	381	100 - (30)[4]
Groundnut Shells	328	0[2]	1,500	500 - (115)
Cotton and Other Oil Seeds and Waste	882	0[3]	787	535 - (140)
Sawdust and Chips	10,158	0[3]	negl.	
Total (rounded)	**11,500**	**0**	**2,700**	**1,135**
Power Generation Potential (MW)	1,800	-	350	147

1) All used onsite (power) or sold at an average RS 60/Tonne (P 177)
2) All used onsite or sold as fuel (P 178)
3) All sold
4) GEDA study

Source: National Productivity Council

Exhibit 1.23

Overall Utilization Pattern of All Types of Agro-Industrial By-Products in Maharashtra (in percent)

	Used	Sold	Disposed of
Rice Husk	17.05	82.95	-
Bagasse	100.006*	-	-
Molasses	101.89*	-	-
Groundnut Shells	28.05	71.95	-
Cotton Gin Waste	-	94.60	5.40
Saw Dust & Wood Chips	-	100.00	-

* Includes quantities purchased.

Source: National Productivity Council

domestic coal. In this analysis we will concentrate only on systems fueled by domestic fuels, i.e., coal and natural gas. As a practical matter these schemes would not normally be cost competitive with power from utility's large central power stations. However, because of current power shortages many industrial plants are seriously considering such "captive" generating options to allow continuous operation of their prosuction systems.

Technical Potential

Well-developed systems exist that can produce as much power as desired from fossil fuels. Thus, there is no technical limit to the use of small fossil-fueled systems and the "technical potential" is not a meaningful number and will not be estimated here.

Economic Potential

The estimated production cost for an economic delivered natural gas cost between 1,500 and 2,200 Rs./000M^3 is Rs.0.60/kWh to Rs.0.99/kW (see Exhibit 1.24). These costs appear to be competitive with power from the existing utilities (i.e., competitive with their long-range marginal costs of about 0.80 Rs/kWh) at large systems or at low gas prices.

For small coal-fired boilers and steam turbines (less than 50 MW), the economic costs are higher than for gas turbines, from Rs.0.78/kWh to Rs.1.17/kWh. These are higher due primarily to the much higher capital cost of small coal-fired systems (see Exhibit 1.25). Only at coal costs below 450 Rs/tonne, the cost of power from small-coal fired systems would be

Exhibit 1.24

Economic Cost of Electricity from Small Natural Gas-Fired Simple Cycle Gas Turbines (Rs/kWh)

	Natural Gas Cost (Delivered Rs/100 M^3)		
System Size	1500	1800	2000
50 MW	0.60	0.69	0.82
20 MW	0.66	0.75	0.88
5 MW	0.78	0.87	0.99

Assumptions:

System Size (MW)	Capital Cost ($/kW)	Annual O&M (% of Capital Cost)
5	350	3
20	500	4
5	800	5

- Capacity factor = 0.60
- Overall efficiency = 30% (Heat rate = 3,240 kWh/1,000 M^3)
- System operating life = 20 years
- Capital recovery factor = 0.134
- Natural Gas = 9,300 kCal/1,000 M-

Source: Hagler, Bailly & Company

Exhibit 1.25

Economic Cost of Small Coal-fired Boiler/Steam Turbine System (Rs/kWh)

Coal Cost/ (Rs/tonne)	Electricity Cost (Rs/kWh)
300	0.78-0.89
450	0.86-0.97
600	0.95-1.17

Assumptions:

- Total installed capital cost = $1,500/kW
- Annual O&M cost = 1 cent/kWh (=OV08 Rs/kWh)
- Capital recovery factor = 0.134
- Annual capacity factor = 0.60
- Overall plant efficiency = 25% (Heat Rate = 3,440/kCal/kWh)
- Coal heat value = 3,500-4,000 kCal/kg
- System generating life = 20 years

Source: Hagler, Bailly & Company

competitive with the marginal cost of electricity generation by utilities (0.80 Rs/kWh).

Financial Potential

The Financial Costs for power from these systems (that is, the price the investor needs to obtain to meet his normal investment requirements) are estimated in Exhibit 1.26 and 1.27. The larger gas turbines (20 MW to 50 MW) appear attractive with power costs ranging from Rs.0.92/kWh to Rs.1.39/kWh, particularly if they were justified primarily to provide a reliable alternative to utility power (These numbers are compared with the cost of eelctricity from the grid that is about 1.3 Rs/kWh). Coal-systems in these relatively small sizes do not appear competitive with the utlitity supplied power as the unit cost of electricity for these systems is higher than the grid supplied power (1.3 Rs/kWh)(see Exhibit 1.27).

The important issue with regard to the attractiveness of fossil-fueled systems is the availability and price of natural gas and coal. The government sets priorities in distributing the limited available coal and natural gas in the country. Currently, the natural gas consumption is limited for feed stock in fertilizer and petrochemical industry and a few power plants. The coal supply is nont as tight as that of natural gas, but the utilities and large industries have priority in receiving coal. Furthermore, price of both fuels is strongly administred by the government. Therefore, the possibility of power generation from small fossil-fueled systems is directly linked to the governemnt's policy on supply of these fuels. We will discuss this matter further in the next chapter.

Exhibit 1.26

Financial Cost of Electricity from Small Natural Gas-fired Simple Cycle Gas Turbines (Rs/kWh)

System Size	Natural Gas Cost (Delivered Rs/1000 M^3)			
	2200		3000	
	Public	Private	Public	Private
50 MW	0.92	1.00	1.17	1.24
20 MW	1.03	1.14	1.28	1.39
5 MW	1.26	1.44	1.51	1.69

Assumptions

System Size (MW)	Capital Cost ($/kW)	Annual O&M (% of Capital Cost)
50	350	3
20	500	4
5	800	5

- Capital Factor = 0.60
- Overall Efficiency = 30%
- Capital Recovery Factor = 0.351 for Private, 0.257 for Public
- Marginal Tax Rate = 55%
- Depreciation = Straight Line, 10 years
- System Operating Life = 20 years
- Net Heat Rate = 3,240 kWh/1,000 M^3

Source: Hagler, Bailly & Company

Exhibit 1.27

Financial Cost of Small Coal-fired Bioler/Steam Turbine System (Rs/kWh)

Coal Cost Delivered (Rs/tonne)	Public Sector Electricity Cost (Rs/kWh)	Private Sector Electricity Cost (Rs/kWh)
300	1.21-1.30	1.55-1.64
450	1.30-1.43	1.64-1.77
600	1.38-1.55	1.72-1.89
700	1.44-1.61	1.76-1.96

Assumptions:

- Total installed capital cost = $1,500/kW
- Annual O&M cost = 1¢/kWh (0.125 Rs/kWh)
- Capital recovery factor = 0.351 for private, 0.25% for public
- Annual capacity factor = 0.60
- Overall plant efficiency = 25% (heat rate = 3,440 kCal/kg)
- Coal heat value = 4,000-6,000 kCal/kg
- Marginal tax rate = 55%
- Depreciation = straight line, 10 years

Source: Hagler, Bailly & Company

Potential for Municipal Waste-Fired Systems

The study team also evaluated the potential for burning municipal wastes in Bombay to generate electricity for sale to the grid. The average daily waste generation of Bombay is 3,000 tonnes per day, which are delivered to six landfills. A study by the the National Environmental Engineering Research Institute characterized the waste composition[9] (see exhibit 1.28). This indicated an average calorific value for the waste of 2,028 kcal/kg. The energy content of various waste samples ranged from 900 to 4300 kcal/kg.

The performance of the waste-to-energy plant is based on a design using proven U. S. technology which was provided by Mr. A. Michaels, a consultant for the U. S. Government who was in India at the time of this study looking at the potential for waste-to-energy plants in Calcutta. A single plant having a 400 US ton per day capacity costs $9,000,000.

Of this, $6,000,000 represents the boiler cost (which is imported), $1,000,000 represents turbine/generator and material handling systems which are available from Indian manufacturers, and the remainder is for site preparation and installation. The output of this system depends on the heating value of the waste supplying it. The maximum output is 5.0 MW with a waste calorific value of 2,800 kcal/kg. With waste calorific values less than 1,300 kcal/kg, the waste will not support combustion. Accordingly, the total technical potential for electric power from the 3,000 tonnes per day of municipal waste in greater Bombay is estimated ar 33 MW, based on a 400 ton per day plant having a peak output of 4 MW.

9. National Environmental Engineering Research Institute, "Characteristics of Bombay City Refuse", Nagpur, September 1985.

Exhibit 1.28

Composition of Bombay Municipal Solid Wastes

Average Higher Calorific Value	:	2,500 kCal/kg
Average Moisture Content	:	52.0%
Average Lower Calorific Value[1]	:	2,028 kCal/kg

Source: "Characterization of Bombay City Refuse", National Environmental Engineering Research Institute; Nagpur; September, 1985.

Lower Calorific Value Include a 6% reduction for Hydrogen content

Economic Potential

The economic potential for a Bombay waste to energy project is estimated in Exhibit 1.29A. The economic capital cost of the system is Rs 131,250,000, based on a foreign exchange requirement of $6,000,000 and local currency requirements of $3,000,000. The annual operating expenses are estimated to be Rs 12,400,000. With an annual output of 20,246 MWh, the net power cost is Rs 1.48/kWh. This is not competitive with our estimated avoided cost of Rs 0.8/kWh. However, this does not allow any credits for reducing the amount of waste that must be disposed of in landfills. Our discussions with the Bombay Municipal Corporation (BMC) indicate that these landfill preparation costs are approximately 20 Rs/ton with no charge for the land itself. if a credit of 18 Rs per ton is given to the waste-to-energy project because it reduces the was which must be landfilled by approximately 90%, the economic cost is reduced to Rs 1.37/kWh, which is still much higher than the avoided electricity costs. Thus the estimated economic potential for these systems is nil.

Financial Potential

The financial cost of electric power for a private investor interested in investing in a municipal waste-to-energy system is estimated in Exhibit 1.29B. This indicates that a private investor would require Rs 1.95/kWh to achieve his desired return on investment. This is substantially above the marginal cost of electricity supplied by utilities in Maharashtra (1.3 Rs/kWh). Thus there is no financial potential for these systems.

Exhibit 1.29A

Economic Cost of Power from Bombay Municipal Wastes

Average Daily Wastes Delivered	: 3,000 tonnes/day (to six landfills)	
Capital Cost, 400 ton/day Plant	: Foreign Exchange = $6,000,000 = RS 93,750,000	
	Local Currency = $3,000,000 = RS 37,500,000	
TOTAL	:	**131,250,000**
Annual Operating Costs	: $8/ton = RS 12,400,000	
Annual Days of Operation	: 310	
Annual Output	: 50% - 4.0 MW	(= 14,886 MWh)
	: 36% - 2.0 MW	(= 5,360 MWh)
	: 14% - No output power	
TOTAL		**20,246, MWh**
Analyzed Capital Cost[1]	: Rs 17,587,500	
Total Annual Cost	: Rs 29,987,500	
Net Power Cost	: Rs 1.48/kWh	

[1]Capital Recovery Factor (20 years, 12%) = 0.134

Source: Hagler, Bailly & Company

Exhibit 1.29B

Financial Cost of Power from Bombay Municipal Wastes

Average Daily Wastes Delivered	:	3,000 tonnes/day (to six landfills)
Capital Cost, 400 ton/day Plant	:	$9,000,000 = Rs 109,800,000
Annual Operating Costs	:	$8/ton, - Rs 12,400,000 per year
Annual Days of Operation	:	310
Annual Output	:	50% - 4.0 MW (=14,886 MWh) 36% - 2.0 MW (= 5,360 MWh) 14% - No output power
TOTAL	:	**20,246 MWh/year**
Total Annualized Capital Cost[1]	:	Rs 27,120,600
Total Annual Costs	:	Rs 39,120,600
Net Power Cost	:	Rs 1.95

[1]Capital Recovery Factor (20 years, 20%, 55% tax rate, 1 year depreciation) = 0.247.

Source: Hagler, Bailly & Company

Potential for Small Hydroelectric Systems

Many developing countries are interested in developing small and large hydropower systems to either supply power to the electricity grid or to provide power to remote areas. This study tried to identify the potential for small hydropower systems in India with a size less than 25 MW having a capital investment cost of less than Rs 1,000,000,000 ($80,000,000). Based on experience in other developing countries this is a reasonable upper limit on the size of project which might be developed by private investors. Unfortunately, the study team was unable to find detailed information on small hydropower which would provide estimates of capital and operating costs of potential hydropower sites and estimates of annual outputs, so no realistic estimates of economic and financial potential could be developed. Exhibit 1.30 gives information provided to the sudy team on small hydro electric sites in Maharashtra. This indicates that 127 MW of small hydropower is being developed at 14 sites, and another 124 projects with a total capacity of 101 MW is under investigation.

Potential for Dendrothermal Systems

Dendrothermal systems are wood-fired power generating systems in which wood is burned in a boiler which generates power using a conventional steam turbine. The wood is grown on nearby "plantaions" which are managed and selectively harvested to provide a continually renewing fuel supply. This concept has been under study in India for a number of years by organizations such as DNES and members of the Bio-Energy Society of India. Most of these efforts have focused on the use of species of Eucalyptus, which are

Exhibit 1.30

Potential for Small Hydro Electric Power in Maharashtra

	Name of the Project	Name of District	Total Installed Capacity
A)	**Completed**		
	1) Radhanagari	Kolhapur	4.8 MW
	2) Vir	Poona	9.0 MW
	3) Yeldari	Parbhani	22.5 MW
	4) Paithan	Aurangabad	12 MW
		Total	48.3 MW
B)	**Under Construction**		
	1) Warna	Sangali	16 MW
	2) Khadakwasla	Pune	16 MW
	3) Dudhganga	Kolhapur	24 MW
	4) Ujjani	Solapur	12 MW
	5) Manikdoh	Pune	6 MW
	6) Surya	Thane	6.0 MW
	7) Dimbhe	Pune	5 MW
	8) Vaitarna Toe of dam	Nasik	1.5 MW
	9) Dhom	Satara	2 MW
	10) Yeoteshwar	Santara	0.057 MW
	11) Kanher	Satara	4 MW
	12) Bhatsa	Thane	15 MW
	13) Bhandaradara	Ahmadnagar	10 MW
	14) Pawna	Pune	10 MW
		Total	127.575 MW

C) **Under Investigation**

A total number of 124 project with a total capacity of 101.21 MW are under investigation.

fast growing, can in many cases be grown on marginal lands unsuited for foood crops, and have a relatively high heat content. Much of the work reported in research papers has focused on developing fuelwood for use in cooking by rural families, rather than on growing the wood on large plantations for use in electric power generation by a relatively large (up to 50 MW) central plant.

The use of land for dendrothermal plants must compete with other uses such as cash crops. Normally, these other uses are economically more attractive than raising fuelwood. This restricts the availability of land fro energy plantations to degraded land, culturable wasteland, barren land, permanent forest and grazing land, and perimeter land on private farms. The amount of these types of land available in Maharashtra and Gujarat is estimated at 11.78 million hectares, which have a potential annual yield of 34 million tonnes per year. Assuming a plant load factor of 60% and a heat rate of 129 kWh/tonne, the technical potential of dendrothermal plants is 840 MW.

LARGE SCALE POWER GENERATION FOR SALE TO THE GRID

It is also possible for Non-Utility entities to finance large-scale power plants (over 50 MW). The objective of this type of investment is to displace the funds needed by SEBs or the central government to finance new power projects. Well developed systems exist that can produce as much power as desired from local or imported fuels. Therefore, there are no technical limitations to the development of large scale power generatin capacity.

The main issues associated with the development of large scale power projects by the private sector are associated with the government's policy

with regard to allowable rate of return on investment, availability and price of fuels, access to imported equipment, and tax rates. These issues will be discussed in detail in the next chapter.

In Gujarat and Maharashtra, there are already two private sector utilities, Ahmedabad Electric Company and Tata Electric Company, which have been generating elelctricity and selling their supply to SEBs and also directly to consumers. One more private utility in Maharashtra, Bombay Suburban Electricity Supply (BSES) which has been a distribution utility is planning to install a generation plant. The fact that these utilities are planning to expand their generation capacity indicates that large scale power production for sale is a financially attractive activity. However, these utilies have access to foreign concessionary financing, i.e. World Bank and other internaltional development bank loans, and have priority in receiving fuels.

Recently, because of the existing power shortages in the country, a number of industries have decided to build large power plants to supply their needs. A number of industries in Gujarat, for example, have formed the Gujarat Industries Power Company (GIPC), and are planning to install a 120 MW coal-fired power plant in Baroda. A number of industries in Faridabad, Haryana, similarly, are in the process of installing a 100 MW power plants consisting of 8 diesel sets. The first plant, GIPC, is based on all Indian equipment, while the diesel generators for the Faridabad plant are to be imported.

Using the capital and O&M costs of these plants, we estimated the economic and financial cost of power from these units, using the fuel costs and other assumptions used for calculating electricity costs in this study. It is found

that the economic cost of electricity from the 120 MW coal plant is between 76.3 adn 89.5 Ps./kWh (see Exhibit 1.31) depending on the cost of coal (between 300 and 500 Rs/tonne). These cos.s are competitive with the economic marginal cost of electricity from SEBs especially at lower coal costs. Similarly, the finacial cost of electricity from a 120 MW coal-fired plant is between 1.16 and 1.40 Rs/kWh, which is competitive with the marginal cost of power from SEBs (at 1.3 Rs/kWh), especially for lower coal prices (see Exhibit 1.31).

Similar elelctricity cost calculations were done for a 100 MW diesel plant. It was found that the economic cost of elelctricity from such a plant is abou 87.7 Ps./kWh which is very close to the economic marginal cost of electricity generated by SEBs (see Exhibit 1.32). The financial cost of power from a 100 MW diesel plant is estimated at 93.1 to 99.4 Ps./kWh which is very competitive with the marginal cost of power supplied by SEBs or exisintg utilities, at roughly 1.3 Rs/kWh (see Exhibit 1.32).

The exact cost of power from such units, and the feasibility of their development, however, depends on the governments policy on such projects. These issues will be discussed in detail in the next chapter. This priminilary cost calculation indicates that such units could generate elelctricity at costs lower than the cost of power supplied by SEBs. The economic and financial potential for power generation from such systems is not resource limited. Therefore, no estimates of the potential is made.

Exhibit 1.31

Estimated Cost of Electricity from 120 MW Coal-Fired Plant

Coal Cost (Rs/tonne)	Electricity Cost (Ps/kWh)		
		Financial	
	Economic	Private	Public
300	76.3	95.5	119.1
400	82.9	102.1	125.7
500	89.5	108.7	132.3
600	96.1	115.3	138.9
700	102.6	121.9	145.5

Assumptions:

Capital Cost	= $1,400/kW[1]
O&M	= 8.05 Ps/kWh[1]
Plant Life	= 25 years
Capital Recovery Factor	= 0.127 (Economic)
	= 0.243 (Financial, Private Investment)
	= 0.179 (Financial, Public Investment)
Capacity Factor	= 67 percent

[1] Based on cost of the plant at Faridabad.

Source: Hagler, Bailly & Company

Exhibit 1.32

Estimates Cost of Electricity from 100 MW Diesel Generator Plant

Plant	Capital Cost (1986 US $/kWh)	O&M Cost (Ps/kWh)	Fuel Cost (Ps/kWh)	Levelized Cost of Electricity (Ps/kWh)		
				Economic	Financial	
					Private	Public
Diesel	640[1]	8.0[2]	64.0[2]	87.7	99.4	93.1

Assumptions:

System Life = 15 years

Economic CRF = 0.147

Financial CRF = 0.257 (Private investment)

= 0.198 (Public investment)

(1) Based on the capital and O&M cost of Faridabad plant and 7,500 hours of operation per year.

(2) Based on fuel oil costs of 3.0 Rs/k

Source: Hagler, Bailly & Company

SUMMARY

The electricity generation potential and cost of various Non-Utility power generation options are summarized in Exhibit 1.33. Among the small scale power generation options, industrial cogeneration and agro waste-fired systems represent the least cost options. The economic cost of power from industrial cogeneration is under 80 Ps/kWh and the economic potential between 1986-1996 is 1,300 MW. The financial cost of elelctricity from industrial cogeneration systems is under 1.3 Rs/kWh and at these costs 2,280 MW of capacity could be developed between 1986 and 1996.

The economic cost of elelctricity from cane residue-fired systems is between 40 and 49 Ps./kWh compared to the marginal generation cost of utilities at 80 Ps./kWh. About 425 MW of generation capacity can be developed from this resource in the next 10 years. This potential is also financially very attractive. Although other agrowaste-fired systems could generate electricity at financially attractive costs, the potential from such resources is limited by their availbility; in Maharashtra the potential is nil and in Gujarat only 30 MW.

The analysis of feasibility of power generation from cogeneration systems in commercial buildings in Bombay indicated that only large hotels represent an economically and financially attractive opportunity. Cogeneration in hospitals and and other commerical buildings results in electricity costs beyond the cost of power from the grid.

The cost of elelctricity from small scale fossil-fueled systems depends on the price of coal and natural gas and varies between 60 Ps./kWh and 117

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Exhibit 1.33

Electricity Generation Costs and Potential for Non-utility Power Options (1986-1996)

Technology	Economic: Generation Costs (Ps/kWh)	Economic: Potential (MW)	Financial: Generation Costs (Ps/kWh)	Financial: Potential (MW)
A. Small Scale				
Cogeneration				
Industrial Topping Systems	Under 85	1,300	Under 130	2,280
Industrial Bottoming Systems	55-77	50	70-120	50
Commercial Systems[1]	Under 80	30	Under 1.60	30
Power Only				
Sugar Cane Residue-Fired Systems	40-49	425	49-66	425
Other Agrowaste-Fired Systems	40-49	neg	49-66	neg
Coal Fired Systems	60-99	(2)	92-169	(2)
Gas Fired Systems	78-117	(2)	120-189	(2)
Municipal Waste-Fired Systems [1]	148	--	195	--
Hydroelectric Systems	N.A.	N.A.	N.A.	N.A.
Dendrothermal Systems	N.A.	N.A.	N.A.	N.A.
B. Large Scale				
Coal-Fired Systems	76-103	(2)	95-145	(2)
Diesel Generators	88	(2)	93-94	(2)

[1] Analysis was done only for Bombay.

[2] The potential is not meaningful since there is no resource limitations for these systems.

Source: Hagler, Bailly & Company

Ps./kWh for economic, and 92 Ps./kWh and 189 Ps./kWh for financial anlysis (see Exhibit 1.33). At low fuel prices and relatively large unit sizes, these systems could compete with the power supply from the grid.

Municipal waste-fired systems do not represent any economically or financially attractive potential for power generation, as the cost of electricity from such systems is much higher than the cost of supply from the grid.

Because of the lack of data, no estimates of power generation costs and potential of small hydroelectric and dendrothermal systems were made.

Finally, large scale power systems, fueled by domestically availale fuel oil and coal could produce elelctricity at costs competitive to the cost of power from utilities.

The financial cost of electricity from large coal-fired plants is estimated at 95 to 145 Ps./kWh, and that of electricity from slow speed diesel generators running on fuel oil at 93 Ps./kWh. At these costs large scale power plants developed by the private sector present a significant opportunity to reduce power shortages in India.

CHAPTER 2: IMPEDIMENTS TO NON-UTILITY POWER GENERATION

In this chapter, major institutional, financial and technical issues associated to the development of non-utility power generation in India will be identified and discussed. As before, the emphasis of the analysis will be on Gujarat and Maharashtra. The chapter starts with a description of the power sector structure in India in general, and in Gujarat and Maharashtra, in particular.

As part of this analysis the study team conducted a number of interviews with key representatives of electric utilities, state electricity boards, private sector entities, financial institutions, power equipment manufacturers and government agencies involved in power sector planning. This chapter addresses the issues raised during the course of the interviews.

Finally, the chapter reviews the structure of the capital market in India, analyzes the availability of private capital for investment in power systems, and identifies means of mobilizing private capital for such projects.

POWER SECTOR STRUCTURE

At the time of independence in 1947, there were scattered generating facilities in India supplying surrounding towns and industries. The scattered generators were generally run by state governments, or by local authorities and private companies. The industrial generators were a part of industrial plants, which also often sold electricity to surrounding townships. The central government played only a regulatory role. Under the Indian Electricity Act of 1910, the

central government licensed the electricity generation undertakings and defined the safety requirements. The administration of the Act was left to the state governments.

Soon after the independence, the central government decided to make the states responsible for the management of power systems, and for this purpose passed the Electricity Supply Act of 1948. Under this act, subsequently, the State Electricity Boards (SEBs) were formed as government-owned autonomous corporations responsible for generation, transmission, and distribution of electricity on the state level. Although SEBs are supposed to be autonomous in managing their day-to-day operations, in practice they are under the control of state governments in such matters as capital investment, tariffs, borrowing, pay, and personnel policies. SEBs own and operate over 70 percent of the power system in the country.

In 1964, as a first step towards power system integration in the country, the government created the Regional Electricity Boards (REBs), responsible for coordinating the operation of SEBs on a regional level. The REBs have advisory functions and are, in effect, associations of SEBs. There are five REBs in India. The responsibilities of REBs include preparation of coordinated maintenance schedules, development of integrated operations and efficient generation schedules, and formulation of pricing policy for inter-state transfer of power.

The Central Electricity Authority (CEA) was also instituted under the 1948 Act and was created in 1950 to develop national power policy and to coordinate the various agencies involved in supplying electricity. It is formally responsible for approving investment proposals, providing consulting

support to SEBs, assisting in the integration of supply systems, training of personnel, and research and development. CEA is administered by the Department of Power within the Ministry of Energy.

In 1969, the government established the Rural Electrification Corporation to coordinate rural electrification efforts in the country and to provide financial and a technical expertise for SEB schemes. Currently, REC finances over 70 percent of total rural electrification investment in the country.

In 1975, the government created the National Thermal Power corporation (NTPC) and the National Hydropower Corporation (NHPC) to construct and operate large power stations and associated transmission facilities. These two organizations are intended to achieve higher operation efficiencies than SEBs. The NTPC has already established a number of large pithead thermal stations. The NHPC is also engaged in setting up a few hydro-electric stations. However, since the states control water rights and are reluctant to relinquish their rights to the central government, the NHPC has not been very successful at accomplishing its mandate.

In Gujarat, in addition to the Gujarat Electricity Board (GEB), there is one private utility, Ahmedabad Electric Company (AEC), generating and distributing electricity in and around Ahmedabad. AEC has been in operation since 1912, and is one of the few remaining private generation companies in the country.

In Maharashtra, in addition to the Maharashtra State Electricity Board (MSEB), there are three private utilities. The Tata Electric Company generates electricity in Bombay and sells its power to MSEB and to a number of large industries. The Bombay Electricity Supply and Transport (BEST)

and the Bombay Suburban Electricity Supply (BSES) are two distribution companies operating in and around Bombay, respectively. These two utilities purchase their power from MSEB and Tata Electric Company. Private utilities have to renew their operating licenses periodically with MSEB. In addition, Atomic Power Authority of India operates a nuclear plant in Maharashtra.

Generation Capacity

The power generation capacity in India has grown from 1,712 MW in 1950 to over 42,000 MW in 1985. Between 1979 and 1985 alone the generation capacity was expanding at an annual rate of over 8 percent. Almost 60 percent of India's electricity is generated from coal, 34 percent from hydro, and the rest from oil, nuclear energy, and natural gas. Although a number of thermal projects are planned for the short term, the shares of hydro and nuclear are likely to increase in the long run.

As projected in the Seventh Plan, by 1990 the generation capacity in India is expected to reach over 64,700 MW, 31 percent from hydro, 67 percent from thermal, and 3 percent from nuclear power (see Exhibit 2.1). During the Sixth Plan, the actual generation capacity installed was 5,000 MW less than the projected figure. For the Seventh Plan, it is expected that the actual installation will be about 8,000 MW less than planned.

The total generation capacity in Gujarat, as of March 1986, is 3,280 MW for which 300 MW is from a hydro plant and the rest from thermal units (see Exhibit 2.2). The Ahmedabad Electric Company owns and operates two units of 161 MW and 220 MW capacity. The remaining plants are operated by

Exhibit 2.1

Composition of Installed Generation Capacity in India (1985-1990)

	Hydro	Thermal	Nuclear	Total
1985	14,314(35%)	27,082(64%)	1,095(3%)	42,491(100%)
1989-90	19,855(31%)	43,081(67%)	1,800(3%)	64,736(100%)

Source: Center for Monitoring Indian Economy, "Current Energy Scene in India" July 1986.

Exhibit 2.2

Power Generation Capacity in Gujarat (March 1986)

Plant	Location	Capacity (MW)
(a) Thermal		
GEB		
Ukai 1-5	Surat	850.0
Wanakbori 1-4	Kheda	840.0
Dhuvaran	Kheda	534.0
Gandhinagar	Gandhinagar	240.0
Utran	Surat	61.0
Others		77.0
AEC		
Sabramati	Ahmedabad	220.0
Ahmedabad Elec. Co.	Ahmedabad	161.0
Subtotal		2,983.0
(b) Hydel		
Ukai	Surat	300.0
Total		3,283.0

Source: Center for Monitoring Indian Economy, "Current Energy Scene in India", July 1986.

GEB. The primary fuel for thermal plants in Gujarat is coal with oil used only as a support fuel. Only one unit at Dhuvaran (280 MW) runs entirely on oil. There is also a 54 MW gas turbine unit at Dhuvaran which is not being used because of lack of natural gas. Currently, only the Utran plant has access to limited amount of natural gas (sufficient for 32 MW). The availability factor for GEB plants varies between 42 percent and over 97 percent (during 1984-85), with an average of 72.32 percent. The load factor for GEB plants is between 30 percent and 76 percent with an average of 53.24 percent. In contrast, the availability factor for AEC plants is over 80 percent and the plant load factor over 70 percent. According to GEB, the average variable generation cost in Gujarat (fuel and O+M). In contrast, the average cost of supplying power to industry (including T&D costs and losses), is 70-80 Ps./kWh, and to agriculture is more than 80 Ps./kWh.

The total installed generation capacity in Maharashtra, as of March 1986, is 7,200 MW. 4,883 MW from thermal plants, 672 MW from gas turbines, 320 MW from a nuclear plant, and the remaining 1,325 MW from hydroelectric plants (see Exhibit 2.3). MSEB owns and operates 4,053 MW of thermal capacity, 1,049 MW of hydro, and 672 MW of gas turbines. The Tata Electric Company operates about 830 MW of thermal and 276 MW of hydroelectric capacity. There is one nuclear plant in Maharashtra at Tarapur, close to Bombay, with a capacity of 320 MW, operated by the Atomic Power Authority. During 1984-1985, 68.5 percent of electricity generated in Maharashtra was from steam thermal power plants, 22.8 percent from hydroelectric plants, 3.5 percent from nuclear plants, and the remaining 5.1 percent from gas turbines.

Exhibit 2.3

Power Generation Capacity in Maharashtra (March 1986)

Plant	Location	Capacity (MW)
(a) Thermal		
Koradi 1-7	Nagpur	1,100.0
Nasik 1-5	Nasik	910.0
Chandrapur 1-4	Chandrapur	840.0
Trombay 1-5	Greater B'bay	830.0
Uran 1-8	Raigad	672.0
Bhusawali 1-3	Jalgaon	482.0
Parli 1-4	Bid	480.0
Tarapur (Nuclear)	Thane	320.0
Paras	Akola	92.5
Khaperkheda	Nagpur	90.0
Chola	Thane	40.0
Ballarshah	Chandrapur	18.0
Subtotal		**5,785.0**
(b) Hydel		
Koyna	Koyna	920.0
Tata	Raigad	276.0
Vaitarna	Nasik	60.0
Paithab	Aurangabad	12.0
Others		57.5
Total		**7,200.5**

Source: Center for Monitoring Indian Economy, "Current Energy Scene in India", July 1986.

The availability factor for MSEB's thermal units varies between 29.80 percent and 94.86 percent with an average of about 67 percent. The plant load factor for MSEB plants is between 45 and 51 percent (during 1984-1985). In contrast, for Tata Electric Company plants the availability factor is between 74 percent and 97.8 percent with an average of 86.6 percent, and the plant load factor is between 51 percent and 71 percent with an average of about 65 percent.

All steam thermal plants in Maharashtra are primarily coal-fired with oil or natural gas as support fuel. As a matter of policy, the government requires all thermal units to run on coal.

During the Seventh Plan 960 MW of thermal and 125 MW of hydro capacity is to be added to Gujarat grid. Similarly 1,480 MW of thermal and 365 MW of hydro additional capacity is planned in Maharashtra (see Exhibit 2.4).

Electricity Demand

Over the past two decades, the consumption of electricity in India has grown approximately twice as fast as total commercial energy consumption and now accounts for more than 30 percent of the latter. Even though the power subsector received 20-25 percent of total public investment, electricity supply has not kept pace with demand and shortages have been prevalent throughout the country. During the last five years, shortages have been estimated at, an average, about 13 percent of electricity requirements. Exhibit 2.5 indicates the extent of power shortages in various states in India during March 1986.

Exhibit 2.4

Capacity Additions During Seventh Plan

Plant	(MW)
Gujarat	
A. Thermal	
Wanakori Extension, Kheda	630
Sikka, Jamnagar	120
Gandhinaga Extension, Gandhinagar	210
Total	**960.0**
B. Hydel	
Ukai Left Bank Canal, Surat	5
Kadana Pumped Storage, Panch Mandi	120
Total	**125**
Maharashtra	
A. Thermal	
Chadrapur Extension, Chandrapur	420
Urban Gas Extension, Raigad	324
Khaperkheda Extension, Nagpur	420
Parli Extension, Bid	210
Urban Gas Turbine, Unit-8, Raigad	108
Total	**1,482.0**
B. Hydel	
Bhira Tail Race, Raigad	80
Tillari, Kolhapur	60
Pandana, Pune	10
Bhandardara, Ahmednagar	10
Khadakunsala, Pune	16
Bhatsa, Thane	15
Ujjanai Paniped Storage, Solapur	12
Vaitarana, Nasik	15
Pench, Nagpur	
Total	**364.5**

Source: Center for Monitoring Indian Economy, "Current Energy Scene In India," July 1986.

Exhibit 2.5
Power Cuts/Restrictions in Force during March 1986

	Cuts	
	Demand	Energy
Delhi	Peak period restriction on industries	10%
Haryana	2 off days/week upto 3.3.86 on industries with 8 hrs./day supply and no cut thereafter with 100% demand cut for continuous process industries between 1800-2100 hrs. Agricultural consumers were supplied power for 6-21 hrs./day.	50%
Himachal Pradesh	Peak period restrictions on industries	
Jammu & Kashmir	15 hrs./day supply in Jammu and Srinagar for general industrial commercial, domestic and agricultural consumers.	
Punjab	50% demand cut between 1800 hrs-2200 hrs. with peak hour restrictions for industries getting supply from independent feeders including continuous process indurtries. Agricultural consumers were supplied power for 8¾ hrs.-24 hrs./day depending upon day-to-day availability.	
Rajasthan	Peak period restrictions on industries Agricultural consumers were supplied power for 8-10 hrs./day.	0-50%
Uttar Pradesh	Restricted supply for certain categories of industries. 1 day/week closure for general industsial consumers with peak period restrictions. Agricultural consumers were supplied power for 10 hrs./day.	
Gujarat	25-35% demand cut on general industries Agricultural consumers were supplied power for 10-24 hrs./day.	
Madhya Pradesh	10% demand cut to H.T. consumers having contract demand more than 1000 KVA. Rural areas consumers were supplied power for 17 hrs./day 3 phase and 7 hrs./day single phase.	
Maharashtra	0% - 15% 24 hrs. power supply to rural areas	
Karnataka	0% - 20% Peak period restrictions on industries	0 - 70%
Tamil Nadu	15% - 40% All A.T. essential, commercial, agricultural & industries with demand of 130 KVA and less were exempted. Agricultural consumers were supplied power as per the grouping of rural feeders	15 - 40%
Pondicherry	15% - 40% All H.T. essential commercial, agricultural and industries with demand of 130 KVA & less were exempted. Agricultural consumers were supplied power as per the grouping of rural feeders.	15 - 40%
West Bengal	15% cut on H.T. industries and also peak period restrictions on industries	5 - 30%
Orissa	75% power cut on heavy and power intensive industries. However, these were permitted to draw power purchased from outside sources by OSEB (being available at present) to meet their requirement.	

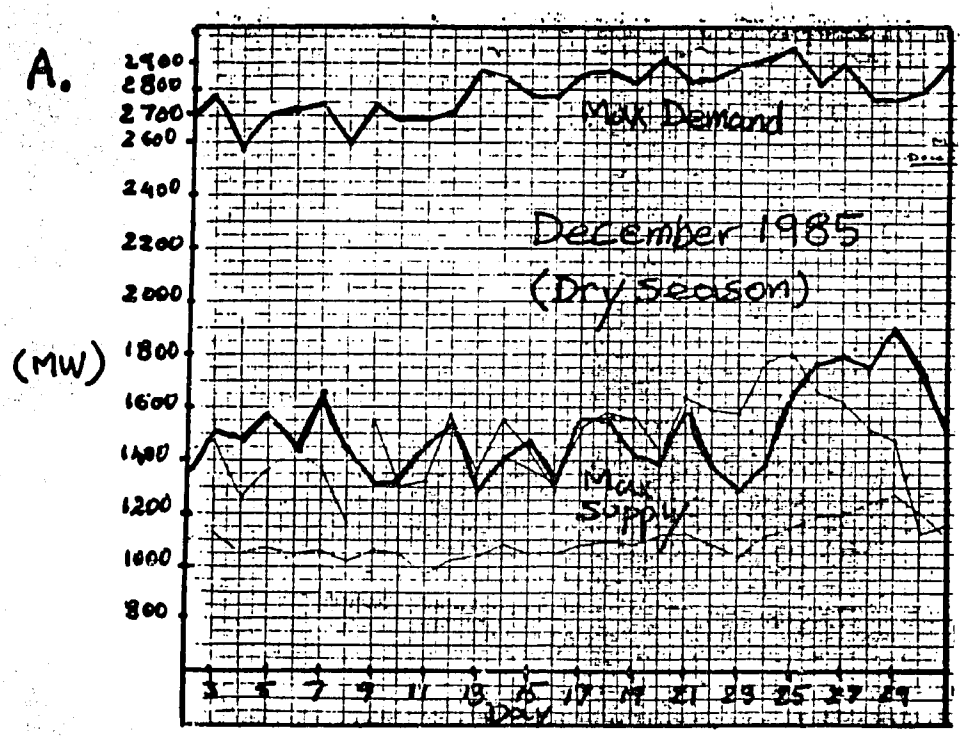
Source: Central Electricity Authority, Bulletin on "Power Supply Position in the Country, New Delhi March 1986.

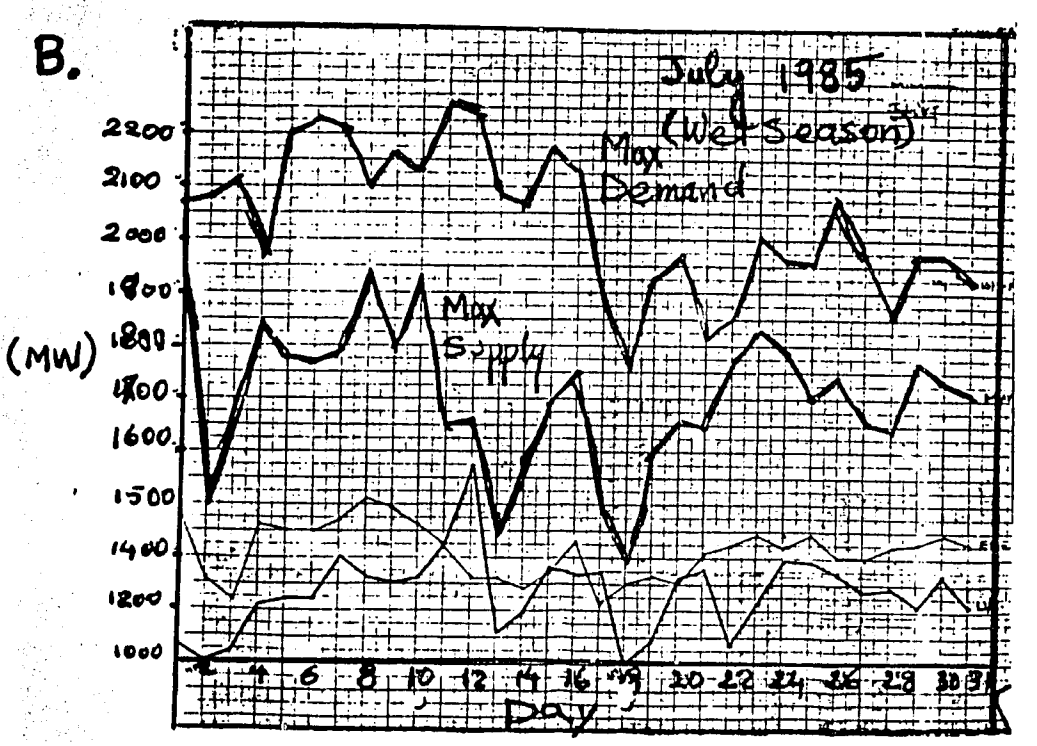
The principal sectoral shares of total electricity consumption are: industrial, 60 percent; agricultural 16 percent; and the rest for residential and commercial sectors. Agriculture's share has grown steadily owing to increased electrical irrigation pumping made possible by rural electrification and encouraged by heavy subsidies. Total consumption has grown at an average annual rate of 8 percent during the past two decades although the increasing severity of power shortages suggests that potential demand has grown more rapidly. The Central Electricity Authority (CEA) has forecast demand growth in the rang 10-11 percent per year between 1984/85 and 1994/95. However, actual growth will continue to be supply constrained.

In Gujarat, the maximum demand for electricity during the dry season (November to April)in 1985 was 2,967 MW while the maximum generation capacity available at the time of peak demand was 2,017 MW (see Exhibit 2.6.A). During the wet season (May to October), because of reduced agricultural load, the peak demand is about 500 MW lower than that of the dry season. In 1985, in Gujarat, even during the wet season there was a shortage of about 450 MW (see Exhibit 2.6.B). Therefore, GEB reduced the demand by direct load shedding to rural and industrial customers, and by holiday load staggering (see Exhibit 2.7). According to GEB, this deficit is expected is expected to continue through the Seventh Development Plan. The capacity deficit in 1985-86 is estimated at 798.5 MW and is projected to grow to 1,226 MW by 1990 (see Exhibit 2.8).

Over 49 percent of demand for electricity in Maharashtra (measured in kWh) comes from the industrial sector, followed by agriculture 16.8 percent, domestic 13.3 percent, and commercial 6.4 percent. The public lighting,

Exhibit 2.6
Maximum Demand and Generation Capacity in Gujarat (MW)
A. Dry Season, December 1985
B. Wet Season, July 1985





Source: Gujarat Electricity Board

Exhibit 2.7

Peak Load and Restrictions During the Year 1985-1986 in Gujarat System

A.	Gujarat system estimated peak unrestricted demand	2,967 MW on 25-12-85
B.	Generation availability at the time of peak demand	2,017 MW
C.	Restrictions required to bridge the gap between supply and demand	950 MW
	1) Load shedding in rural areas	560 MW
	2) Holiday stagg to HT/LT NCP Industry with restrictions of additional weekly off	120 MW
	3) 50% demand cut to HT Industry	200 MW
	4) Loss due to low system frequency (49.3 C/S)	70 MW
	Total	950 MW

Source: Gujarat Electricity Board

Exhibit 2.8

Peak Demand, Installed Capacity Required, Installed Capacity Available and Net Shortage in Capacity in Gujarat, 1985-1990 (MW)

	1985-86	1986-87	1987-88	1988-89	1989-90
Maximum demand	2,811	3,083	3,381	3,700	4,038
Installed capacity required	4,392	4,817	5,283	5,781	6,309
Installed capacity as on 31.3.85	3,383.5	3,383.5	3,383.5	3,383.5	3,383.5
Addition from approved and on-going schemes	210	425	875	1,335	1,337
Addition from Central Sector Schemes	-	-	-	100	491
Additions from New/un-approved schemes (Central Secto Schemes)	-	-	-	-	90
Total addition	210	425	875	1,435	1,918
Lost (-) Retirement (MW)	-	-	25	145	218.5
Net installed capacity	3,593.5	3,808.5	4,233.5	4,673.5	5,083
Anticipated deficit (-)	798.5	1,008.5	1,049.5	1,107.5	1,226

Source: Gujarat Electricity Board

interstate and other categories consume represent the remaining 15 percent of demand. Power shortage in Maharashtra has been very limited in recent years. There are no energy cuts to domestic and commercial customers and textile industries. The general industries and continuous process industries receive energy cuts on the order of 10 percent and 5 percent respectively. The demand cut to essential customers and service industries has been removed. However, general industries, continuous process industries and textile industries received power cuts of 15, 10, and 10 percent respectively (see Exhibit 2.9).

CURRENT POLICIES ON NON-UTILITY POWER GENERATION

During the last thirty years, the role of the private sector in India's power generation and distribution activities has been dramatically reduced. There were 316 privately owned power generation and distribution entities in 1951, but because of the specific provisions of the 1948 Electricity Supply Act, state electricity boards took over these private licensees reducing them to a mere five in 1986. The Act, basically, brings the responsibility of power generation and distribution to the state electricity boards and the Central Electricity Authority and bans private utility companies and major captive generation except in individual cases and on special merits.

Faced with the growing inability of state electricity boards to supply sufficient amount of electricity to satisfy the growing demand in the country and realizing the loss of production in the industrial sector because of power cuts, the government in recent years has allowed captive power generation in

Exhibit 2.9

Demand and Energy Restrictions in Maharashtra (1984-1985)

Category of Consumers	Power Cut %
Energy Cut:	
Domestic	0
Commercial	0
General Industries	10
Continuous Process Industries	5
Textile Industries	0
Essential Consumers	0
Service Industries	0
Seasonal Consumers	0
Demand Cut:	
General Industries	15
Continuus Process Industries	10
Textile Industries	10
Essential Consumers	0
Service Industries	0

Note: 1) There is no power cut for the Industrial units outside BMR & PMR having their sanctioned M. D. up to 250C KVA.

2) Agricultural consumers have no restriction on use of power.

Source: Maharashtra State Electricity Board

large industries. The current government policy regarding captive power generation is as follows[1]:

- Industries may be allowed to install indigenous diesel generating sets without any hindrance to provide stand-by and emergency power supply. Import of diesel generating sets should however require to be processed with normal procedure.

- In industries where process steam is required or where waste heat is available, captive generating capacity should be encouraged in accordance with "total energy concept" [industrial cogeneration].

- In all other cases, captive power plants would not normally be allowed to be installed by any industry. However, each case will be considered on its merits.

To streamline the installation of captive power generation, new units do not need to receive permission from CEA as long as their capacity is under 25 MW. However, if the total investment for the project exceeds Rs 5.0 million or it requires import of equipment, it should be approved by the central government.

Recently, There are indications that the government is considering possibility of private sector investment in power generation activities. In particular, the Minister of Energy on a number of occasions has pointed to the need for an active role by the private sector in power generation activities. According to the Minister of Energy, the government realizes that there will be a gap of

1. Central Electricity Authority, "National Power Plan",, 1983.

about 10,000 MW in power generating capacity and demand during the Seventh Plan period, which can not be filled by the government alone, and is considering a role for the private sector to close this gap. However, according to the Minister, it has been decided that the role of private sector will be limited to power generation and distribution activities will remain in the domain of government. The prime consideration for approval of private sector power projects seems to be the source of financing. The government is especially interested in tapping new sources of funds such as non-resident Indian investment or resource mobilization from the public[2]. So far, however, no clear policy has been announced on the subject of private power generation indicating the acceptable rate of return on investment, government attitude on fuel supply, or purchase price for the power. The Minister of Energy has indicated that the private sector generation of power does not require amendments of the existing Electricity Generation Act or the Industrial Policy Resolution. The import of equipment, if necessary, according to the Minister, would be permitted, subject to the fact that indigenous capacity is not adversely affected[3].

The indications are, however, that at least the existing private sector utilities have been allowed by the government to expand. A recent proposal from the Bombay Suburban Electricity Supply Ltd for a 500 MW station in Bassein, Bombay, for example, has been approved by the government[4]

2. Financial Express, Bombay, 12 February 1986
3. Ibid.
4. Business Standard, Calcutta, 25 May 1986.

VIEWS OF POWER AUTHORITIES ON NON-UTILITY POWER GENERATION

During the course of this study, we interviewed a number of representatives from the Central Electricity Authority, state electricity boards, and utilities. In this section the views of these organizations as relayed to us during our interviews are summarized.

Central Electricity Authority

CEA recognizes the importance of captive power generation in the country. In order to facilitate the development of such projects, no longer permission from CEA is required to install captive units as long as their capacity is below 25 MW. For larger units, every attempt is made to speed up the licensing process. To improve fuel use efficiency in the country, CEA requests that cogeneration systems be installed in industries with large steam demand who are interested in captive power generation.

On the subject of power generation for sale to state electricity boards or other customers, CEA has not taken any explicit stand. We were told by some CEA officials that since the power will be purchased by SEBs, policies defining the terms of interaction between private generators and SEBs should be developed by state governments. We were told that currently there are no restrictions keeping state electricity boards from purchasing power from private sector power generators at mutually agreed terms. If an independent power generation entity can generate power at costs lower than SEBs marginal generation costs, it would be in the best interest of SEBs to acquire this power, and very likely they will do so. Therefore, we were told. there

is no sense in setting policies on purchase price of power or cost of backup power provided by SEBs.

State Electricity Boards and Utilities

The Gujarat Electricity Board is perhaps the most progressive utility in India with respect to its attitude towards non-utility power generation. GEB has been encouraging non-utility generation by providing technical assistance to cogenerators, commissioning a study evaluating the industrial cogeneration potential in the Gujarat, and allowing generation from diesel sets (captive units) by its industrial customers. GEB is already purchasing power from a number non-utility generators. Gujarat Refinery, Krishak Bharati Cooperative (a fertilizer plant), and Tata Chemicals already are selling power to GEB. However, the purchase price is based on the variable generation costs, i.e. fuel and O&M costs, to the non-utility generator and not based on the marginal generation cost of the utility. In an effort to promote unconventional power sources in the state, GEB has also been purchasing power from a 2 MW wind farm with relatively high rates (1.40 Rs/kWh). This rate is based on rough estimates of Geb's expected long run marginal generation cost of about one Rupee/kWh, and is intended to encourage development of renewable power sources in Gujarat.

According to GEB management, purchasing electricity from independent generators at prices equal to utility's marginal cost of generation (the avoided cost concept) is financially justified and could lead to increased supply of power in the state. However, as long as the electricity tariffs, which are controlled by the state government, are not allowed to increase as the cost of

production increases, GEB will not be in a position to pay independent suppliers according to relatively high avoided costs. In terms of financial balance of accounts, GEB would be better off enforcing power cuts than buying electricity at high costs and selling it at lower prices.

We were also told by GEB representatives, that the main cause of SEBs inability to expand their generation capacity to match demand is their inability to raise income through higher tariffs. As long as tariffs do not represent the marginal cost of generation, there will be a negative cash balance hampering expansion efforts of SEBs. In addition, GEB representatives indicated that the low availability factor of existing plants is not necessarily the fault of SEBs since the only fuel available to them is low quality coal which greatly complicates operation of thermal plants and causes frequent failure of boilers. Furthermore, we were told that SEBs are required to purchase domestic power equipment with often inferior quality resulting in frequent breakdown of units.

GEB representatives also pointed to the inherent operational efficiencies in SEBs stemming from their existing management and operational structure. Finally, we were told by GEB management that they are already convinced that there is need for private sector entry in power activities in the India, and that they are interested in learning how such schemes should materialize.

Representatives of AEC, the private utility in Gujarat, also were open to the idea of purchasing power from non-utility generators at their own marginal costs. AEC representatives, however, believe that the private sector will find it extremely difficult to raise capital for power projects. In their view, as long as the electricity tariffs are controlled by the government, the return on

investment in power projects would be very modest keeping most investors away. For small projects (15-20 MW) the private sector may be able to raise capital from private sources. For large projects, on the other hand, private sector would have to compete with SEBs for public funds. The prospects for access to the limited funds available are very poor.

In Maharashtra, since the utilities have sufficient supply capacity with very little power cuts, especially compared to other states, their attitude towards independent generators is very different from that of GEB. MSEB representatives, for example, feel that there is no need for non-utility power generation for sale to the grid and therefore, such activities are not encouraged and sale of power to the grid is not allowed. As a matter of policy, MSEB does not allow parallel operation with the grid except in very special cases.

According to the representatives of Tata Electric Company in Bombay, because of the regulated nature of power industry, where the allowable profit is limited to 2 percent over the interest rates, the private sector would not be attracted in investing in power project when they can achieve higher returns on their investment in nonpower activities. However, Tata, a private company itself, has found power investments so far attractive enough to continue staying in business. In addition, we were told that the electricity generated from captive units will cost more than the power from Tata, therefore, independent generators would not find it beneficial to generate power. Furthermore, fuel supply will be a major problem for small independent generators. To guarantee fuel supply, Tata representatives indicated, the independent generators would need to have a full time team

tracking the supply of coal. Coal is distributed by the government with supply priority given to SEBs and large government industries. In their view the rate of return on cogeneration systems using oil will be about 15 percent, therefore only subsidized capital will make them attractive to investors.

More importantly, according to Tata representatives, the industry will have technical problems operating captive power units. Finally because of the reliability of power supply in Maharashtra, no one will want to invest in its own power generation units. In their view, the regulations on purchase price and interactions between utilities and independent generators, if any, should be defined by the state authorities and not the central government.

BEST, the private distribution company in Bombay, is not too keen on purchasing power from independent generators in general and cogenerators in particular. Because of the existing government restrictions on industrial expansion in Bombay, the share of industry's demand for electricity as a fraction of total demand on BEST has been declining in recent years. During 1972-84, for example, the industrial demand was growing with an annual rate of only 0.3 percent, while the residential demand grew with an annual rate of over 4.7 percent. Since the industry pays relatively high rates for its power needs, compared to other classes of consumers, BEST is reluctant to allow power generation in the industrial sector.

VIEWS OF INDUSTRIAL AND FINANCIAL ORGANIZATIONS ON NON-UTILITY POWER GENERATION

As part of this effort the study team held discussions with over 50 representatives of Indian industry and financial organizations. These

individuals offered their candid views of the problems and potential of non-utility power generation. There was a surprising degree of consensus in there views. In the following section we summarize their comments on non-utility power generation in general, government policies, financing, and utility scale generating plants.

Attitude on Non-utility Power Generation

Overall, the industry representative, both public and private, preferred not to go into the power generation business. This preference was based on three factors. First, they preferred to invest their available capital in their normal business endeavor, rather than use a significant portion for a much less productive power system investment. In particular they cited the government policy or restricting the return on power system investments to two percentage points above the current "bank rate", or currently about 12 percent. Private companies, particularly those having publicly traded stocks, were looking for returns of 20 percent or more.

Second, the firms felt the power generation business to be highly risky because politics play such an important part. The government controls every aspect of power generation. Supply and cost of domestic power equipment and spare parts, capital and foreign exchange availability and costs, fuel availability and price, tariffs for sale of power to public and private entities, and despatching of units. Because of the complex web of subsidies and controls a determination by a government ministry could easily make a project financially unavailable. Also there was some concern that in the financially weaker SEBs (not though Maharashtra or Gujarat) private firms selling

surplus power would find it difficult to collect, as has apparently been happening to NTPC. Thus, the investor face a cap on his potential returns that is less than what he would expect from his normal investments, and also a not insignificant potential for losing a great deal of monev.

Third, there was concern about managing the technologies, since there was overall not a great deal of experienced in industry in power generation. Several respondents felt it was difficult enough to hire or train competent boiler operator without the added complications of power generation. Generally, there was an overall lack of knowledge of cogeneration possibilities and equipment among industry engineers. In addition, there was dissatisfaction regarding the quality and cost of domestic power generating systems, particularly gas and steam turbines. At the same time, it was difficult getting foreign exchange and approval for foreign systems and spare parts.

Thus the major reason for considering power generation at all was to ensure reliable power.

However, all the industry representatives were quite aware of th sever power shortages in India, and said that if they must go into the power business to key their plants operating they would do so. This was shown by the large number of plants that in recent years have installed diesel generator sets to provide backing power. (Typically, these are sized to provide 40 to 60 percent of plant's normal demand).

But these systems are viewed only as emergency backup, and few firms have actively investigated generating all or a portion of their power requirement on

a regular basis (e.g., cogeneration) and in particular most have not looked at generating surplus power for sale to the power grid. Firms which are actively considering some kind of cogeneration scheme have said they prefer a "turnkey" operation, in which someone else experienced in this area would construct and initially operate the system, and train the plant's personnel to take over.

Attitude Toward Government Policies

Both public and private industry had a number of comments on government policies affecting non-utility power generation in general and private power generation in particular. The policies of most importance were in three areas: private power generation, fuel supplies, and pricing, and taxation.

There was agreement among both public and private industrialists that the traditional Indian approach to "captive" power must change, in light of the serious power shortages which have already severely affected industry, and which will most likely become worse before they become better. Specifically, the government must remove restraints on private power by streamlining the approval process for private power, or possibly eliminating it altogether. There has been movement in this direction on the part of the central government and some of the SEBs, but as yet there has been no clearly articulated policy on which long term plans could be made. In particular, few SEBs have provisions for purchase of surplus power from private generators. Thus private generation is perceived to be discriminated against. These industrialists wanted a clear policy statement on the central and state levels encouraging non-utility power generation and treating it on a

par with public power generation, for both large and small units. As an example of the inadequacy of the current government policy on captive power generation some industry representatives pointed out the fact that according to current policy small plants, under 25 MW, are not required to obtain permit from central government. This is expected to facilitate installation of such units. However, in reality, if the cost of such a project exceeds Rs 50 million, or it requires imported equipment, or requires supply of coal, the regular licensing procedure should be followed. Therefore, in practice most captive plants would need to get approval from the central government, except for very small diesel generators.

A second area of government policy concern is fuel supplies and price. In particular, industry was interested in using natural gas for power generation in both Gujarat and Maharashtra. At present, this is reserved first for fertilizer and petrochemical plants, then for large utility power generation with combined cycle plants, then for industry requiring clean fuel, and finally, for steam raising or cogeneration by industry. As a practical matter, there is no natural gas available for steam raising or cogeneration, although it is being used for cogeneration in the fertilizer plants.

While industrialists understand the reasons behind these priorities, they feel that they need to be reconsidered in the light of new gas discoveries over the past few months, and in light of the critical power shortages in part of the country. There is confusion regarding exactly how much "associated" and "free" gas is available, with estimates ranging from 15 to over 60 years at consumption levels expected to be reached in the next fe years when new fertilizer and power plants running on gas in Gujarat are commissioned.

Closely allied to this is the question of how such gas would be prices. Currently there is no firm policy, with each customer negotiating its own price. Thus the prices range from old contracts at 250 Rs/000 cu-m to newer contracts at 3000 Rs/000 cu-m. These concerns are particularly crucial for gas turbine cogeneration systems, which might have significant surplus power for sale to the grid.

Finally, the industrialists mentioned taxation and incentive policies. Cogeneration systems qualify for a one-year write-off as an energy conservation investment. For many company's having but a single plant a cogeneration project may represent 20 to 40 percent of the total plant investment. A one year write-off may result in a larger paper loss, which would affect the ability of the company to pay dividends and cause the stock price to drop. While there was not overall consensus on what should be done, several industrialists suggested that the company should be allowed to depreciate the cogeneration investment at whatever rate it felt appropriate.

Import duties are another major concern of industry representatives. Import duty on industrial projects is 25 percent, and on power projects is 40 percent. A new fertilizer plant with cogeneration system, for example, would be allowed to installed with 25 percent import duty on imported equipment. But a if an operating fertilizer plant installs imported cogeneration equipment, it has to pay 102 percent custom duty on imported equipment. In addition, in some occasions, the industry finds it financially attractive to import cogeneration equipment, but the government would only allow purchase of domestic equipment where because of higher costs and lower performance quality, the project will become unattractive.

Several firms also felt other government incentives (which were not specified) would be useful. First, they would demonstrate the government's commitment to non-utility power policy, reducing the risk of a policy change making the investment uneconomic. Alternatively, the incentives may reduce the payback period, thus decreasing the project risk.

Attitudes Toward Financing

The Indian private sector organizations placed stringent financial requirements on power investments, typically 20 to 25 percent return on equity, after tax. Interestingly, public sector firms had a lower requirement of about 15 percent return on assets, pre-tax. The private sector requirement is similar to that of private firms in other countries the study team has worked in. The public requirement however is much lower than is usually encountered, and should make these firms much more receptive to cogeneration or other power system investments.

Allowed debt-to-equity ratio was also mentioned as a potential problem area. Generally, Indian financial institutions and investors like to have a D/E of 2/1 or less, with priority projects or industries allowed to go up to 4/1. For small firms in particular for which a cogeneration plant represents a significant portion of their capitalization, raising the necessary equity while financing their growth and paying out dividend will be difficult. In addition, the relatively thin capitalization of Indian equity markets make stock price sensitive to change in D/E ratio or reported earnings, and make the management of many private firms less willing to finance projects which are peripheral to their main lines of business.

It was generally felt that long-term financing would be made available if the equity portion of the investment could be raised. Interestingly, long-term credit is generally available at lower rates (14%, or 12.5% for priority projects such as power generation would likely be) than short-term loans (currently 15 to 18%). This is because the primary sources of long-term credit are government owned development banks and insurance firms: the Industrial Development Bank of India (IDBI), the Industrial Credit and Investment Corporation of India (ICICI), the Life Insurance Corporation (LIC), the General Insurance Corporation (GIC), and the Unit Trust of India (UIT). The interest rate charged by these organizations is set by the Ministry of Finance. Generally, it allows the financing organizations a two to three point spread to cover their expenses. However, obtaining a loan from these organizations can be quite time consuming, with waits of 1 year after the development organizations approve until the money is released not unusual.

One problem however with raising money through these development banks is that they require an equity conversion which allows them to convert up to 20 percent of the loan amount into equity. This option is exercised,thus diluting the earnings of the other shareholders and allowing the bank to nominate a director to the borrower's board from the bank's own staff.

Raising large sums (over $100 million) to finance large central power generating stations through the Indian capital markets is not considered a major stumbling block. Although the largest public offering to date has been about $50 million, four to five issues $100 million dollars or more apiece are expected by the end of 1986 or mid 1987 for new fertilizer plants in Gujarat.

If public firms wish to raise money from private sources they have the option of issuing tax-free bonds (free of income, wealth, delivery and other taxes), offering a 10% to 14% return. Because these bonds are issued with "no questions asked" about where the money to purchase the bonds come from, these are looked upon as one way of attracting the "black money" (i.e., money from the underground, nontaxpaying part of the economy) and using it to fund priority project.

An option many Indian companies are now turning to for long-term financing is leasing. The number of companies in India offering leasing service has gone from 2 in 1980 to over 150 presently. One firm, Prudential Industrial Captive Power Leasing Ltd., is offering to lease gas turbines for industrial cogeneration. Leasing offers several advantages over traditional financing.

First, it offers "off balance sheet" financing. This allows the company to exceed the 2/1-D/E ratio without adversely affecting its ability to borrow. In addition it may allow a company to in effect exceed the Rs. 200 million in assets threshold which would bring it under the structure of the MOnopoly and Restrictive Trade Practices (MRTP) Act. Finally, because lease payments are fully deductible and the government offers attractive tax incentives for investors in new plant and equipment (the leasers), the net after-tax cost to the lessee may be less than if the lessee purchased the equipment himself. Competition in leasing has reduced its costs to 14-17 RS/month per Rs.1000 investment.

One final financing problem mentioned by the industry representatives was the inability to directly accept loans from foreign manufacturers or lending institutions. When such financing was offered at concessionary rates, the

government accepted the loan and re-lent it to the firm, but at normal interest rates for 12.5 to 14 percent. In case of a gas turbine system offered to an Indian firm at less than 6 percent the government insisted the loan be paid back to the government at the higher rare, which made the project uneconomic.

Attitudes Toward Utility Scale Generating Plants

Indian industry representatives (both public and private) felt the major barriers to their involvement in development and generation of utility-size (over 100 MW) power plants were central and state government policies. Interestingly, there did not appear to be much concern about their technical capabilities for operating these systems, be they coal, oil, or gas-fired. They felt the skills either were readily available, or could be taught (e.g. at Tata Electric Company's Training Center). Also, the representative felt financing problems could be clarified or resolved prior to major expenditure o the project, so that this would carry only normal business risks. However, there was concern regarding government policies on large-scale power plants dedicated solely to the grid. Two large projects now under development, a 120 MW coal-fired plant in Gujarat and a 100 MW diesel plant in Faridabad, are dedicated to serving industrial plants owned by the power plants' developers, to ensure power for their plants in regions which face severe power shortages. Only minor amounts of power are fed to the grid as surplus to be used by others. To the knowledge of the study team, no one has come forth outside of the existing utilities proposing a large utility power plant solely for selling power to the grid, to supplement generation investments by the regular utilities. Primarily, this is because the potential

investor feel the SEBs ar hostile to the idea of power generation outside their direct ownership. While generating plants to serve primarily the needs of local industrial plants are acceptable and even encouraged, plants developed solely to feed the grid are in effect direct competition of the limited capital funds. Since the SEBs do not believe the private sector can generate power more cheaply than the public utilities, they resist strongly any moves to permit this.

CHAPTER 3: POSSIBLE APPROACHES TO DEFINING ELECTRICITY PURCHASE PRICES

Independent electricity generators will, in most cases, need to rely on the electric utilities to sell their power, either directly to utilities or indirectly to other customers through the utilities distribution network. Cogeneration systems, in addition will need to rely on utilities for back-up power during system failure or maintenance. Therefore, the terms of interactions between utilities and independent generators play a key role in the feasibility and viability of such power generation options. The main component of such interactions is the purchase price that utilities are willing to pay for independently generated power or the fee they charge for transmitting the power to other customers. The purchase price, in fact, determines the financial viability of any non-utility power generation project.

This chapter focuses on identifying major issues of utility-independent generator interactions and defining an electricity purchase price in Gujarat and Maharashtra. First, the U.S. experience with regulatory reforms intended to enhance non-utility power generation options is reviewed. Then, possible approaches for defining electricity purchase price are explained, and finally, some preliminary estimates of such a price for SEBs and utilities in Gujarat and Maharashtra are made.

THE U.S. EXPERIENCE: PURPA

In an effort to reduce dependence on imported oil, to increase energy conservation, and to promote the use of indigenous energy sources, in 1978 the U.S. Congress passed a set of regulations providing incentives for specific measures supporting these objectives. The regulations included: tax incentives for energy conservation investments, mandatory energy efficiency standards, restructured electricity tariffs, a special tax on fuel-inefficient automobiles, tax incentives for investing in the development of indigenous energy resources, and the prohibition of certain fuels for certain end uses.

Of particular interest to this study is the Public Utility Regulatory Policies Act of 1978 (PURPA), which dramatically changed the legal standing of certain broad categories of private power generation in the United States. Prior to 1978, U.S. electric utilities were under no obligation to interconnect with private power producers for the purpose of accepting power from them, nor were there clear guidelines on how rates for supplementary and backup power to such facilities should be developed. Today, that is no longer true. Under PURPA, electric utilities must interconnect with independent generators (those that meet certain size, fuel use, and efficiency criteria) to purchase power from them and sell power to them.

In addition, PURPA requires that the power purchase rate for such facilities be based on the energy costs (i.e., the fuel cost and operation and maintenance costs) and capacity costs that the electric utility avoids incurring as a consequence of the power provided by the independent facility. Furthermore, PURPA requires electric utilities to sell power to independent facilities for the following purposes: (i) to supplement a facility's own

power; (ii) to serve as backup for use during forced outages at the facility; and (iii) for use during periods of scheduled maintenance.

In addition to the above provisions, PURPA set new standards for electricity rates charged by utilities such as cost-of-service pricing, prohibition of declining block rates, time-of-day rates, and seasonal rates. Under these standards, electricity tariffs should be directly linked to the utility's marginal cost of supplying power to each specific class of customer.

Eligibility Criteria

To be eligible for the benefits of PURPA, a facility must qualify as either a "small power producer" or a "cogenerator." A small power production facility is defined as one using biomass, waste, renewable resources, or any combination of these as its primary energy source. More than 50 percent of the total energy input must be from these sources, and the use of oil, natural gas, and coal must not, in the aggregate, exceed 25 percent of total energy input. Furthermore, the total capacity of a small power production facility cannot exceed 80 MW.

Cogeneration facilities are defined as those using energy sequentially to generate electricity and useful thermal energy. Cogenerators must meet certain operating and efficiency standards. For topping cycle cogeneration systems, the usefully employed thermal energy must constitute at least 5 percent of the total energy output. For oil- or natural gas-burning cogeneration systems, the sum of the electrical output and one-half the total useful thermal output must be at least 42.5 percent of total oil and gas input to the facility, or 45 percent if the useful thermal energy output is less than

15 percent of the total energy output of the facility. For bottoming cycle cogeneration facilities, the only requirement is that the useful power output be at least 45 percent of any oil or natural gas used for supplementary firing. There is no upper limit to the size of a qualifying cogeneration system.

Purchase Price

Independent electricity generators will usually have to rely on utilities for the sale of their power or its transmission to other customers. Therefore, the price that utilities will be willing to pay for the electricity, or the price they charge for transmitting the power, will have a direct impact on the financial returns of such power projects. The theoretical definition of the purchase price is rather straightforward. The "avoided cost", or purchase price, is defined as the energy and capacity costs that the utility would avoid incurring as a consequence of the power provided by the independent generator -- i.e., the utility's marginal savings. Avoided costs have little relation to the utility's normal rates for sales, which are based on the utility's average costs; avoided costs may be either higher or lower than the rates for sales.

The energy component of the avoided costs, consisting of fuel and O&M expenses, can be interpreted as the variable cost component of the utility's marginal savings. Since there will always be some variable cost savings when power is provided by an independent generator (except during rarely occurring low load periods), there will always be some energy component to the avoided costs.

The capacity cost component consists of those generation, transmission, and distribution capacity expenses that can be avoided because of the power

provided by the independent generator. In determining the utility's ability to avoid capacity costs, future needs for capacity must be considered as well as immediate needs. In addition, the value of power from an aggregate group of small generators should be evaluated (rather than considering the effect of each facility individually). Moreover, a utility's ability to avoid purchases from other utilities and to increase sales to other utilities should be accounted for.

The determination of when capacity costs are actually avoided and the magnitude of these costs is not a simple matter. For example, the mere fact that a utility will be purchasing new capacity does not always imply that there are capacity costs that can be avoided. Consider, for example, a utility with excess capacity that has high operating costs because it is burning expensive oil at the margin. Assume also that this utility is experiencing slow growth in load. If there are new capacity options available to the utility that will provide power at a cost below the variable costs of oil, investment in new capacity may be justified, even though new capacity is not needed to maintain system reliability because of growing loads. The justification is one of economic efficiency -- the purchase of a new unit may result in lower costs to the customers, even though it will add even more excess capacity. In many such cases, power provided by independent generators is unlikely to alter the conclusion that new capacity investment should not be considered "avoidable" and would have no avoided generation capacity costs associated with it.

Implementation

Since PURPA was signed into law in 1978, investment in cogeneration and independent power production facilities has expanded dramatically. In 1980, 28 facilities were granted qualifying facility (QF) status, with a total potential capacity of 703 MW. In the first three quarters of 1984, 349 facilities were granted QF status, enabling them to take advantage of PURPA provisions, with a total potential capacity of 3,414 MW. Pacific Gas & Electric, a major California utility, for example, signed contracts with 273 QFs in 1984 with an estimated capacity of 4,204 MW.[1]

By stimulating investment in cogeneration systems, PURPA has served to increase the efficiency of electricity generation. In 1983, The Electric Power Research Institute estimated that 11,000 MW of cogeneration capacity had been installed. By 1995, cogeneration capacity is expected to reach 26,000 MW, and by the year 2000, 40,000 MW.[2]

PURPA has also stimulated the development of renewable energy resources, including biomass, wind, and geothermal. As of 1984, for example, 1,354 MW of geothermal capacity was developed. High-temperature solar thermal and photovoltaic systems have also been installed.

METHODS OF CALCULATING AVOIDED COSTS

Several methods of computing avoided costs have been developed for use in designing purchase rates. Avoided costs are, for all practical purposes,

[1]"Utility Involvement in Cogeneration and Small Power Production Since PURPA," Power Engineering, September 1985.

[2]Ibid.

marginal costs, and these methods are essentially marginal cost computational procedures. The approaches differ not only in their computational details but in their implicit conception of marginal cost. Among the major differences in the methods are the use of short- or long-run costs as the basis for the analysis and the treatment of capacity costs.

The three most frequently used approaches to computing avoided costs are: 1) the peaker approach, in which both marginal energy and marginal capacity costs are computed in the short run; 2) the proxy unit approach; and 3) the long-run differential revenue requirements approach (LRDRR), in which both marginal energy and marginal capacity costs are computed in the long run. A brief description of each approach follows.

The Peaker or Short-Run Approach

One of the more common methods for separately calculating marginal energy and capacity costs involves the use of the so-called peaker approach. In this approach, short-run production costs are combined with short-run capacity costs. This approach has the virtue of simplicity; short-run production costs can be obtained from a utility system simulation model or from recent data on actual utility operations, yielding the short-run production costs with a minimum of effort. The marginal capacity cost is estimated as the cost of a peaking unit.[3]

[3]The main justification for using the cost of the small peaking unit as a surrogate for capacity costs is that a utility could, at least theoretically, purchase such a unit on short notice if load growth warranted doing so. If the utility actually purchases some other, more expensive, type of capacity, it will do so because of the overall costs of the more capital-intensive plant. The more expensive unit is not being purchased solely to meet the utility's capacity needs, but is serving also to lower energy costs; marginal capacity costs are

The peaker approach will yield acceptable marginal cost results if a utility's generating mix is already optimal. Even in a non-optimal utility, such an approach may yield reasonable estimates of the short-run marginal costs of energy and capacity if oil-fired peaking units are used during peak loading periods. As long as oil is the marginal fuel during most hours of the year, the peaker approach will yield approximately correct marginal costs. The approach is especially suitable for determining short-run avoided costs for use in tariffs for the purchase of energy provided on an "as-available" basis; i.e., with no firm commitment by the facility owner.

However, the peaker approach is generally inappropriate for estimating long-run marginal costs if oil is not the marginal fuel most of the time, and the utility is also investing in new capital-intensive baseload facilities. Only if the "energy" component is redefined to include that portion of a capital-intensive plant that is properly associated with the plant's fuel displacement function will the peaker approach yield an acceptable result. Such a broad interpretation of "energy" costs is rarely seen in practice.

Hence, the sum of the components of the marginal costs, computed using the peaker approach as it is usually applied, is not necessarily representative of actual present or future marginal costs.

The Proxy Unit Approach

An approach that is used in several states in the United States for long-run rates in long-term contracts is the "surrogate" or "proxy" plant approach. In

then properly measured by the cheapest type of capacity that can be purchased to fulfill capacity requirements.

essence, this is a long-run marginal costing procedure. In this approach, the cost of a generic generating facility or a generating facility actually being planned by the utility is selected as a measure of the value of power to the utility, and hence as an appropriate measure of marginal costs. Marginal energy and marginal generation capacity costs are calculated jointly.

There are various ways of implementing this approach. One possibility is provided as an illustration: if a utility coal plant is selected as the basis for the rates, the energy costs associated with that facility are paid to the independent generator on a kWh basis, based on the costs for the fuel and estimated O&M costs in each year.

The total estimated installed cost of the utility plant is deflated to the year in which the independent generator begins providing power and is converted into a levelized annual payment. This annual payment can be paid on a peak kW basis, provided the independent generator meets certain reliability and supply characteristics criteria, or on a kWh basis where the kWh rate is determined using the estimated annual capacity factor for the utility plant.

The Long-Run Differential Revenue Requirements Approach (LRDRR)

In this approach, avoided costs are based on long-run marginal costs. The utility's future revenue requirements (total annual costs) are estimated both with and without the contribution of the qualifying facility for a 15- to 25-year period. The utility's capacity plan is separately optimized for the two cases; the present value of utility operating and capacity expenditure over some defined period (usually about 20 years) is minimized for utility loads that, in the first case, ignore the QF and, in the second, include its

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contribution. The difference in future revenue requirements between the two cases is directly attributable to the assumed contributions from the QF and, hence, is the estimated total avoided cost.

With the LRDRR approach, avoided costs are computed in a single, integrated analytical procedure, eliminating the need for separate avoided energy cost and avoided capacity cost computations. The integrated computation ensures that energy and capacity components of the resulting total avoided cost are consistent.

The LRDRR approach permits the avoided costs of the small power producer and cogenerator to be tailored to the particular supply characteristics of the generating facility. In calculating the utility's revenue requirements with the facility present, the net loads to be met by the utility are reduced in a manner consistent with the QF's supply characteristics. Furthermore, by breaking up the utility's future capacity options into small increments, and by treating the contributions from the facility as part of an aggregated group of similar facilities, a realistic assessment of the capacity value of the QF to the utility is obtained.

AVOIDED COST ESTIMATES IN GUJARAT AND MAHARASHTRA

To estimate the avoided costs of the utilities in Gujarat and Maharashtra, we use the "proxy unit" approach. In this scheme, the capital cost of future units, as planned in each state's expansion plan, will determine the demand charge and the variable charge of the least efficient existing units is taken as the energy cost. The rationale for this approach is that as the new capacity comes on line, utilities will use the least efficient units only on the margin

and the more efficient new units for the longest hours possible. Therefore, a non-utility generator will replace the new units for capacity costs and the old ones for energy costs. this applies to units which are capable of providing firm capacity. In this analysis we will take the entire power generation system in each state as a single utility and determine the avoided cost. In addition, we will estimate the avoided cost for each utility based on the specific conditions applying to them.

Gujarat

There are two utilities in Gujarat, the Gujarat Electricity Board (GEB), and the Ahmedabad Electric Company (AEC). The total generation capacity in Gujarat, as of March 1986, is 3,283 MW, of which 300 MW is hydro and the 2,983 MW is thermal. Since the variable operation costs of hydro plants are much lower than thermal plants, when available, utilities will run them at full capacity and reduce their need for thermal units. Therefore, non-utility generated power will not be competing with power from hydroelectric plants but with electricity from thermal units.

The variable operation and maintenance costs of thermal plants in Gujarat vary between 36.4 and 52.4 Ps./kWh (see Exhibit 3.1). All thermal units run on coal with fuel oil or LSHS as support fuel when available. Only one unit at Dhuvaran plant located in Kheda runs entirely on oil. The price of coal available to GEB is 380-400 Rs/tonne. In contrast, AEC pays 534 Rs/tonne for its coal needs. The price of oil available to GEB is 2,520 Rs/1000 lit, and to AEC is 3,032.38 Rs/tonne[4]. This explains the higher generation costs

[4]. National Productivity Council

Exhibit 3.1

Variable Generation Costs of Thermal Plants in Gujarat

Plant	Capacity (MW)	Availability (1) Factor (%)	Fuel(2)	Average Fuel Consumption (3) Coal (kg/kWh)	Average Fuel Consumption (3) Oil (l/kWh)	Average (4) Fuel Cost (Ps/kWh)	O&M (5) Costs (Ps/kWh)	Total Variable Costs (Ps/kWh)
Urai	850.0	74.4	Coal/Oil	0.59	0.025	29.9	12.0	41.9
Wanakburi	840.0	59.4	Coal/Oil	0.54	0.028	26.1	12.0	38.1
Dhuvaran	534.0	89.8	Coal/Oil	0.61	n.a.	24.4	12.0	36.4
Gandhinagar	240.0	61.6	Coal/Oil	0.64	0.015	29.4	12.0	41.4
Sabarmati	220.0	73.5	Coal/Oil	0.7	0.012	47.4	12.0	52.4
AEC	161.0	88.8	Coal/Oil	0.7	0.012	40.4	12.0	52.4
Utran	61.0	n.a.	Coal/Oil/ Gas	n.a.	n.a	n.a.	n.a.	n.a.

(1) Availability Factors provided by NPC.

(2) Fuel oil or LSHS is used only as a support fuel when available.

(3) Fuel consumption data from NPC.

(4) Fuel costs for GEB plants are calculated based on average coal price of 400 Rs/tonne and average oil price of 2,520 Rs/1000 lit. The price of coal available to Ahmadabad Electric Company (Sabarmati and AEC plants) is 532 Rs/tonne. Fuel prices provided by NPC and GEB.

(5) O&M costs are estimated to be equal to average O&M costs for thermal plants in Maharashtra, see Exhibit 3.5.

Source: Hagler, Bailly & Company, based on data from NPC.

for AEC plants (AEC and Sabarmati). The O+M costs of these units are assumed to be the same as the average O+M costs of thermal units in Maharashtra. To estimate the avoided energy cost of electricity to GEB and AEC, one should also consider the transmission and distribution losses in their grid. Currently, the T&D losses in GEB grid is over 20 percent. T&D losses in AEC grid is about 10-12 percent. Therefore, if the independent generator is located close to major load centers, and the generated power could be distributed over a shortage distance the value of this electricity to the utility could be up to 20 percent high than the marginal generation cost at thermal plants. In addition, if enough independent units are operating throughout the state, in the long run, the need for transmission network extension could be drastically reduced. This in turn would increase the value of non-utility power to the existing utilities.

To estimate the avoided capacity cost of non-utility power to the power sector in Gujarat, we assumed that if enough capacity is made available from such units, the need for expanding the GEB and AEC's generation capacity would be diminished. Therefore, the capital cost of future plants will be the avoided capacity cost to GEB or AEC. For future plants we have taken those that are submitted to the Planning Commission for approval (see Exhibit 3.2). The levelized capital cost of these units is estimated between 30.5 and 63.4 Ps./kWh, with the high number for a hydro plant. These estimates are based on a capacity factor of 60 percent and a capital recovery factor of 20 percent. The capital cost estimates are those submitted to the Planning Commission (see Exhibit 3.2). Based on the estimated avoided energy and capacity charges shown in Exhibits 3.1 and 3.2, the total avoided cost to

Exhibit 3.2

Capital Cost of Future Plants in Gujarat

Plant (1)	Capacity (MW)	Estimated Cost (Rs.Crores)(2)	Levelized Cost (Ps/kWh)(3)
Gandhinagar Thermal Extn. Unit - 4	210	163.88	30.5
Kutch Lignite Extension	70	69.25	38.5
Panam Canal Bed Power House	2	3.33	63.4
Utran Thermal Power Station (Replacement Units)	120	112.42	36.0
Average Thermal Plant Installed(4) during 1984-85 in India		[8777.6 Rs/kW]	33.4

(1) Plants awaiting investment approval of Planning Commission.

(2) As quoted in "Current Energy Scene in India" by Center for Monitoring Indian Economy, July 1986, p. 26.

(3) Assuming CFR = 0.20, and plant capacity factor of 60 percent.

(4) NPC

Source: Hagler, Bailly & Company

utilities in Gujarat is 90.5 Ps./kWh. If one also considers the savings due to reduced T&D losses, the avoided cost could be as high as 1.0 R/kWh.

In the short run, there are other factors which also determine the value of the non-utility power to AEC and GEB. AEC, for example, does not have enough generation capacity to satisfy the demand on its network and imports power from GEB. AEC's generation units, operate on maximum load with very little fluctuations during the entire period and the difference between the power generated and demand is supplied by imports from GEB (see Exhibit 3.3). The cost of power from GEB is, on the average, 75 Ps./kWh[5]. Therefore, in the short term, this would determine the avoided cost to AEC. Similarly, GEB is purchasing power from a number of suppliers at costs as high as 98 Ps./kWh (see Exhibit 3.4), representing the avoided cost to GEB.

It is important to realize that currently there is a power shortage in Gujarat and the industry receives power cuts regularly. The average price of electricity supplied to large industries (HT) is about 1.3 Rs/kWh. These industries are the first to receive cuts during shortage. Therefore, one could argue that the actual value of an additional unit of electricity during power cuts to GEB or AEC is 1.3 Rs/kWh, since this is the price they can sell it for (with adjustments for T&D loss and wheeling charge).

In Gujarat, GEB has already set a precedent for purchasing electricity from an independent supplier at 1.4 Rs/kWh, even higher than what GEB considers its long run marginal cost of generation, 95 Ps/kWh[6].

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5. in 1985, AEC purchased 447 GWh of electricity from GEB at cost of Rs336.2 million, as indicated in AEC's 73rd Annual Report, 1984-85, pp.46-47.

6. Gujarat Electricity Board, meetings held on August 8, 1986 (see Appendix B).

Exhibit 3.3

Cost of Electricity Purchased by GEB

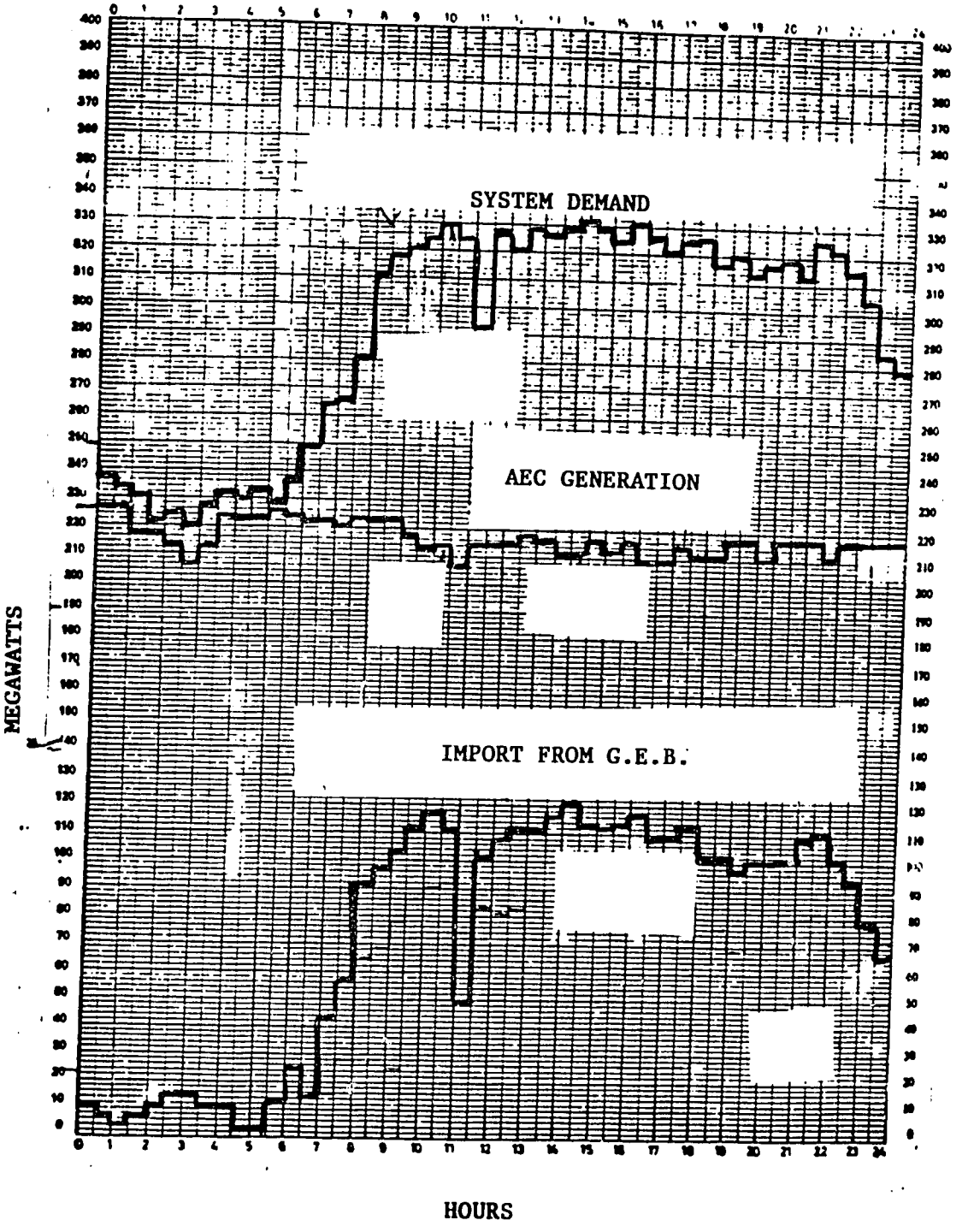
Supplier	Average Rate (Ps./kWh)				
	Energy Charge	Fuel Adj. Charge	Wheeling Charge	Other Charge	Total
T.A.P.S.	34.89	2.40	-	-	37.29
a) M.S.E.B.	39.70	2.59	4.62	-	46.91
b) MSEB power supply based on Uran gas based power station.	98.00	-	-	-	98.00
N.T.P.C.	34.50	2.49	4.62	15.77	57.39
Tatachemical	30.00	18.00			48.00

Source: Gujarat Electricity Board

EXHIBIT 3.4

LOAD CURVE, GENERATION & IMPORT OF AHMADABAD ELECTRICITY CO.

FOR AUGUST 4, 1986



SOURCE: AHMADABAD ELECTRICITY COMPANY

Maharashtra

The variable generation cost of electricity for MSEB system is between 36.5 and 60.0 Ps./kWh (see Exhibit 3.5). The price of coal available to MSEB is 300 Rs/tonne, and the price of oil is 2,520 Rs/1000 lit[7]. Only one unit in MSEB system uses gas, Uran plant, and the price of gas is 680 Rs/1000 m^3[8]. The transmission and distribution losses in Maharashtra grid, similar to Gujarat, is 15 to 20 percent. There are no expansion projects currently being considered by the Planning Commission for Maharashtra, except a waste heat recovery system to be added to the existing gas turbine at Uran. Therefore, for the avoided capacity charge we have used the average cost of thermal plants commissioned during 1985, estimated at 34 Ps./kWh (see Exhibit 3.2). Therefore, the total avoided cost of MSEB (energy and capacity) is between 70.0 and 94.0 Ps./kWh, approximately the same as that of GEB. The transactions between different suppliers in Maharashtra also gives indications of avoided cost to utilities. For example, MSEB purchases power from Tata Electric Company at 80 Ps./KWh, which in the short run is their avoided cost. Of course, similar to Gujarat utilities, MSEB supplies electricity to the large industrial customers at an average price of 1.3 Ps./kWh. Therefore, at least during power cuts to industry due to shortage, any electricity provided to MSEB at prices below this figure could be profitably sold to the industrial customers (with consideration for T&D losses and wheeling charges).

7. National Productivity Council
8. Ibid.

Exhibit 3.5

Variable Generation Costs of Thermal Plants in Maharashtra

Plant	Capacity (MW)	Availability (1) Factor (%)	Fuel(2)	Average Fuel Consumption (3) Coal (kg/kWh)	Oil (kg/kWh)	Gas (Ms/kWh)	Average (4) Fuel Cost (1/kWh)	O&M (5) Costs (Ps/kW)	Total Variable Costs (PS/kWh)
Koradi	1,100.0	49.6	Coal/oil	0.701	0.11	-	49.0	11.0	60.0
Nasik	910.0	84.1	Coal/oil	0.64	0.024	-	25.5	13.0	38.5
Chandrapur	840.0	36.3	Coal/oil	1.11	0.023	-	39.0	6.0	45.0
Uran	672.0	n.a.	Gas	-	-	0.347	24.0	12.0	36.0
Bhusawal	482.5	65.7	Coal/oil	0.673	0.017	-	24.0	20.0	44.0
Parli	480.0	81.9	Coal/oil	0.620	0.053	-	32.0	5.0	37.0
Paras	92.5	80.7	Coal/oil	0.888	0.009	-	29.5	7.0	36.5
Khaperkheda	90.0	45.6	Coal	1.12	-	-	34.5	18.0	52.2
Chola	40.0	n.a	Coal	n.a.	-	-	n.a.	n.a.	n.a.
Ballarshah	18.0	n.a	Coal	1.08	-	-	32.0	17.0	49.0

(1) Availability Factors provided by NPC.

(2) Fuel oil or LSHS is used only as a support fuel when available.

(3) Fuel consumption data from: MSEB, "1984-85 Administration Report," Appendix IV-A, pp. 12-13.

(4) Fuel cost are calculated based on average coal price of 300 Rs/tonne, fuel oil price of 2,520 Rs/1000 lit, and natural gas price of 680 Rs/100M3. Price data provided by NPC.

(5) O&M costs are estimated NPC.

Source: Hagler, Bailly & Company, based on data from NPC and MSEB.

CHAPTER 4: CONCLUSIONS AND RECOMMENDATIONS

In this chapter, the major conclusions of this study are presented and recommendations on measures to encourage the development of non-utility power generation in India, in general, and in Gujarat and Maharashtra in particular are made.

CONCLUSIONS

Potential

The preliminary analyses conducted in this study reveal that the financially attractive non-utility power generation potential in Gujarat and Maharashtra over the next 10 years is about 3,000 MW. By financially attractive potential we refer to the amount of generation capacity that can be developed that will result in lower electricity costs than that supplied by the existing state electricity boards and electric utilities in Gujarat and Maharashtra.

About 2,300 MW of this potential is from industrial cogeneration (see Exhibit 4.1). The industries with highest potential are fertilizer, basic chemicals, refineries and pharmaceuticals. About one third of the cogeneration potential lies in the existing plants (retrofit or replacement of existing steam generating equipment). Almost all this potential comes from topping cycle cogeneration systems where steam is used first for power generation and then for industrial processes. The potential for bottoming cogeneration is

Exhibit 4.1

Electricity Generation Costs and Potential for Nonu-tility Power Options (1986-1996)

Technology	Economic		Financial	
	Generation Costs (Ps/kWh)	Potential (MW)	Generation Costs (Ps/kWh)	Potential (MW)
A. Small Scale				
Cogeneration				
Industrial Topping Systems	Under 85	1,300	Under 130	2,280
Industrial Bottoming Systems	55-77	50	70-120	50
Commercial Systems[1]	Under 80	30	Under 1.60	30
Power Only				
Sugar Cane Residue-Fired Systems	40-49	425	49-66	425
Other Agrowaste-Fired Systems	40-49	neg	49-66	neg
Coal Fired Systems	60-99	(2)	92-169	(2)
Gas Fired Systems	78-117	(2)	120-189	(2)
Municipal Waste-Fired Systems [1]	148	--	195	--
Hydroelectric Systems	N.A.	N.A.	N.A.	N.A.
Dendrothermal Systems	N.A.	N.A.	N.A.	N.A.
B. Large Scale				
Coal-Fired Systems	76-103	(2)	95-145	(2)
Diesel Generators	88	(2)	93-94	(2)

(1) Analysis was done only for Bombay

(2) The potential is not meaningful since there is no resource limitations for these systems.

Source: Hagler, Bailly & Company

estimated at only 50 MW in refineries, and fertilizer and petrochemical plants.

The study also looked into the cogeneration potential in commercial buildings in Bombay. It found that cogeneration systems are only suitable for large hotels and hospitals, with a continuous demand for hot water for domestic needs and steam for air conditioning. However, only applications in large hotels were found to be financially attractive. In Bombay alone the estimated potential for commercial cogeneration in large hotels over the next 10 years is estimated at about 50 MW.

The potential for power generation from bagasse and cane residue over the next ten years is estimated at about 425 MW -- 75 MW in Gujarat and 350 MW in Maharashtra. This resource represents the least expensive power option among those studied in this report. The potential from other agrowastes is very limited. In Maharashtra, rice husks, groundnut shells, sawdust, and other agrowastes are already being fully used and no excess is available for power generation. In Gujarat, 30 MW are being generated from these resources. Power can be generated from these resources during the dry season, November to April, which is the period of peak agricultural electricity demand and minimum hydroelectric power availability. Therefore, their development could reduce the peak generation expansion requirements of utilities.

Power generation options from domestic fossil fuels, i.e., natural gas and coal, are estimated to be only marginally competitive with power from utilities. The cost of power from small-scale (under 50 MW) coal-fired systems, in particular, is expected to be considerably higher than the utilities'

generation cost. Natural gas-fired systems, however, could generate power at financially attractive rates in sizes over 20 MW if gas is made available to non-utility generators at concessionary rates. The actual size of the potential for these options would depend on the government's policy on the supply and price of fossil fuels for power generation.

Dendrothermal and other renewable power systems do not represent any considerable generation potential.

Finally, large scale conventional power systems fueled by domestic fossil fuels, e.g. coal and fuel oil, are found to have generation costs competitive with those of the electric utilities. The financial cost of electricity from large coal-fired plants is estimated at 95 to 145 Ps./kWh, and that of electricity from slow-speed diesel generators running on fuel oil at 93 Ps./kWh (compared to the cost of electricity from the utilities at 130 Ps./kWh). At these costs, large scale power plants developed by the private sector would represent a viable solution to power shortages in the country.

Current Environment

The study team found that there are basic differences in the current power sector structure and power supply environment in Gujarat and Maharashtra, which to a large extent determine the development of non-utility power options in these states. In Gujarat, a severe power shortage causes the utilities to commonly cut the power supplied to industry by 10 to 40 percent, with even higher cuts during the dry season and peak agricultural demand. As a result, industry is experiencing high production losses and is very willing to explore and develop alternative power supply options, as indicated by the fast pace at

which they are installing captive power units. In addition, the Gujarat Electricity Board (GEB) has shown extreme interest in encouraging such options. GEB is purchasing power from a number of industries with excess power at prices equivalent to the industries' generation costs. GEB is also purchasing power from a wind farm at prices even higher than its own avoided costs, to verify the feasibility of renewable power sources and to encourage the future development of such resources.

In Mahrashtra, on the other hand, the power shortage is only marginal with roughly 10 percent cut to some industries during the dry season. Otherwise, the power supply is very reliable and steady. Industry is installing some captive power units, but as the supply situation in the past 3 years has improved, and is expected to continue improving at least for the next four years, the momentum for self-generation or captive power generation has slowed down. The Maharashtra State Electricity Board (MSEB) and the private utilities in the state are less enthusiastic about non-utility power options than their Gujarat counterparts. For example, parallel operation with the grid is not allowed in Maharashtra and only a few exceptions have been made. In addition, the Maharashtra utilities tend to believe that non-utility power, even from cogeneration systems, will not be able to compete with power supplied by the grid in reliability and cost. Finally, in large urban areas, especially in Bombay and Pune, due to government efforts to reduce population growth and air pollution, industrial expansion has been very limited. As a result, utilities are faced with a very slowly growing industrial power demand. Since industries to a large extent subsidize the low electricity tariff to residential and agricultural customers, the utilities in Maharashtra, in general, are very concerned about the impact on their financial status of

losing their large industrial customers. This to a large extent has contributed to the utilities' lack of enthusiasm for non-utility power generation.

Gujarat and Maharashtra are very similar in terms of the structure of electricity tariffs and the cost of power to large and medium industries, which happens to be among highest in the country (over 120 Ps./kWh). In addition, the long run marginal electricity generation cost of utilities in Gujarat and Maharashtra is very similar and close to 80 Ps./kWh (this does not include the transmission and distribution costs which could raise the marginal cost of electricity supply to over 100 Ps./kWh).

Major Issues

The major impediments to non-utility power generation development in Gujarat and Maharashtra can be divided into three categories: technical, economic/financial, and institutional.

Technical Issues

In general, information on power generation equipment performance and costs among non-utility entities is scarce. This applies in particular to requirements for interconnecting to the grid. In addition, some industries have experienced difficulties in operating their generation systems in parallel to the grid. The industrial representatives indicated that their staff need training on operating power equipment and interconnection procedures.

Perspective power generators in general have a perception that the domestic power equipment and systems that are available are of poor quality. This has had an adverse impact on their desire to install power generation

equipment. In addition, for some power options, the necessary equipment cannot be found in India, affecting the prospects for developing such options, e.g. small efficient steam turbines for power generation in the sugar industry.

Economic/Financial Issues

The government has traditionally dominated power sector activities in India, and all non-government power activities are highly regulated. Therefore, the private sector is very apprehensive about entering into such activities. Specifically, the private sector is concerned about the allowable rate of return on power projects, which is determined by the government and is currently at 2 percent over the interest rate. At such rates, the private sector would find investments in nonpower projects more attractive than those in power projects. In addition, there is an excise tax on power generated even when generated for self-consumption.

Non-utility power producers are also concerned about the price utilities or state electricity boards (SEBs) would pay for their power while cogenerators are concerned about the rate utilities would charge for providing backup power. No policies currently set the price of such transactions. Finally, non-utility power generators, in general, and the private sector in particular are concerned about financing power projects. Most power projects are capital intensive and current government policies require a debt-to-equity ratio of 2:1 or less. The private sector would like to see a less restrictive policy on investments in power projects. In addition, the private sector would like to see more liberal policies on access to foreign exchange for power projects. Finally, the private sector wants the government banks to remove

or reduce the markups on supplier's credit to make investment in power projects more attractive.

Institutional Issues

The major institutional issues that concern non-utility power generators are:

- Fuel availability and prices. The government sets the priorities for fuel supply and prices in India. It is not clear, at present, if independent generators will have access to fuel or not, and if they will at what price.

- Import licenses and duties. The current government policy is not clear on conditions under which the importation of power generation equipment will be allowed. Furthermore, there is uncertainty with regard to the amount of duty charged on imported power equipment. Under current regulations, import duty rates could be between 20 percent and 105 percent.

- Sale of power to SEBs. Although various government representatives have implicitly emphasized the need for private sector power generation, there are no explicit policies setting the terms of interaction between existing electric utilities and independent power generators. The issues of main concern are the purchase price -- the price utilities would pay for non-utility power -- and the requirements for interconnection with the grid.

The existing policy (of not requiring a permit from CEA for plants smaller than 25 MW) has proven to be ineffective since the generators need to obtain

licenses for importing equipment, for obtaining their fuel supply, and for financing the project. This process is known to be very time consuming and discouraging.

RECOMMENDATIONS

Based on the findings of this study, in order to increase the participation of non-utility entities in power generation in India, in general, and in Gujarat and Maharashtra, in particular, the following measures are recommended.

1. The government should define and publicize a clear policy on non-utility power generation, covering cogeneration and power-only systems. This policy should:

   (i) Allow independent generators to operate in parallel with, and sell electricity to the grid. In particular, a standard format should explicitly define the technical requirements for interconnection.

   (ii) Define the terms of interaction between SEBs and non-utility generators. These terms should spell out the technical requirements for interconnection and parallel operation, the purchase price, and the cost of back-up power.

   (iii) Define a straightforward procedure for licensing independent generation systems. This procedure should cover obtaining construction and operation permits, import licenses, financing, and fuel supply.

In defining this policy, the government should take into account:

(i) The impact of power shortages on the economic growth and prosperity, especially in the industrial sector

(ii) The inability of SEBs to satisfy the growing demand for electricity

(iii) The positive impact of some non-utility power options on increasing fuel use efficiency and the reliance on domestic fuels.

(2) An important issue for non-utility power generators is the purchase price utilities pay for power. The government should establish guidelines on defining this price. A price policy based on the avoided cost of SEBs presents a fair value for the non-utility-generated power. This will lead to the efficient allocation of resources and expanded generation capacity. In defining the purchase price, the government should take into account such issues as:

(i) The relatively high generation cost of SEBs that will result from future plants

(ii) The excessive transmission and distribution losses of the grid

(iii) The seasonal, time of day, and regional values of private power to utilities

(iv) The cost of providing power to remote areas and associated premiums that might be considered for power generated in these areas

(v) Special incentives for private businesses that are the first to invest in power generation.

3. The government should provide training in defining purchase price (according to SEBs' avoided costs) to utility personnel. In addition, the government should provide technical assistance to industrial cogenerators and independent power generators in interconnection to and parallel operation with the grid. In light of the extensive experience of U.S. utilities and cogenerators in such activities, the government should explore opportunities for transferring this technical knowhow to India.

4. Since there is a considerable potential for power generation in the sugar industry that is constrained by the shortage of proper equipment (small but very efficient steam turbines), the government should identify and pursue avenues for developing the capability for manufacturing such power systems in the country.

5. The government should publicize local non-utility power generation activities, in particular those projects that involve interaction between SEBs and non-utility generators. The government should undertake demonstration projects to reduce the uncertainty about interconnecting with the grid.

APPENDIX A: SCOPE OF WORK

Attachment I

PROPOSED SCOPE OF WORK

Background

The analysis will examine the impediments to and potential for non-utility electrical generation primarily in the private sector. The team will visit with key power sector, private sector, and government policy officials to determine their views, collect and analyze existing data and information, and debrief the mission and GOI on preliminary findings and recommendations. A draft report will be prepared before departure and a final report will be prepared within 21 days after receipt of mission and AID/W comments.

The study will not examine remote non-grid connected electrical generation issues.

Study Objectives

- preliminary identification of the economic and financial potential for cogeneration and private sector power production from renewable and indigenous resources,
- identification of the policy, regulatory, institutional and other impediments to non-utility private sector electrical generation from cogeneration or renewable/indigenous resources for sale to the grid;
- development of recommendations and an action plan for addressing the impediments to non-utility generation.

SCOPE OF WORK

A. Background

1. Scope of Analysis: The Contractor shall undertake the analysis in the states of Maharashtra and Gujurat and shall include the examination of current central government policies, plans, and authority and the interaction between the two states and central entities.

2. Description of country energy situation: Using existing data, the Contractor shall briefly describe the current country energy and power situation and the factors influencing the introduction of non-utility electrical generation. Such factors may include power sector constraints, e.g., capital availability, inadequate generation capacity, system reliability and size and type of industrial base and capacity for cogeneration.

3. The Contractor shall briefly describe the U.S. experience with the Public Utilities Regulatory Policy Act (PURPA) in fostering non-utility electrical generation.

B. Current Off-system Generation: The Contractor shall

1. Identify any current purchase arrangements between public utilities and non-utility generators of electricity.

2. Identify any projects under discussion or in the planning stage.

3. Determine the amount of, type, and trend in captive generation.

C. Potential for Off-system Generation:

The Contractor shall estimate the potential for non-utility renewable or indigeneous energy based-generation and cogeneration and assess the character of the generation, i.e., intermittent, seasonal, daily peaks, etc. In particular, examine the potential for autonomous generation in industrial parks.

In preparing the study, the Contractor shall make preliminary estimate of industrial cogeneration potential; use existing industrial data and growth projections and identify the market for cogeneration by industry type, size of current and projected electricity/steam demands, applicable cogeneration technologies and energy supply (coal, gas, etc.); specify types of cogeneration systems relevant to the industrial market and indicate their financial viability; indicate the payment by the utility for surplus generation that would make the system financially attractive; provide an estimate (range, if appropriate) of potential electrical generation that could be available for sale to the grid and an estimate of the capital investment needed.

Based on existing information, the Contractor shall estimate the potential electricity from the non-utility options that could be developed and identify the energy resource, conversion technology and possible institutional arrangements for generating the electricity. For example: wind, wind conversion systems and private partnership, coal, fluidized bed combustion system and industrial firm.

D. Utility System Description: The Contractor shall

1. Briefly describe the utility system including fuel use trends and options, marginal cost of generation, load projections, tariffs and system expansion plans; identify the sources of financing for generation expansion and the constraints.

2. Determine the utility's technical concerns about off-system generation such as system protection, metering, reliability, etc., and any related concerns about the purchase of non-utility generation.

3. Identify the factors affecting the utility's marginal costs; determine the level of detail that exists for consumption data such as seasonal and daily peaks; specify an approach to calculating an estimated avoided cost (marginal cost) and the price a utility might reasonably be expected to pay for firm and intermittent power; make an estimate.

E. Power Sector Policies: The Contractor shall analyze the policy/legal/regulatory framework governing the power sector including:

- government policy on non-utility generation of electricity for sale to the grid.

- legal and regulatory authority for generation of electricity, and rate setting mechanism and source of authority.

- relationship between central authorities and state authorities with respect to control over power generation, tariffs, financing, etc.

F. Impediments to Non-utility Generation: The Contractor shall

1. Analyze the policy, legal, regulatory, institutional or other problems and impediments to off-system generation;

2. Determine the positions of key institutions, industries and individuals concerning the impediments to and potential for private sector non-utility generation. Such groups include, but are not limited to, the utilities, government ministries or commissions responsible for energy and utilities, key industrial and private sector entitities and policy makers.

3. Determine the current status of cogeneration, e.g., trend in use, system manufacturers. Identify the interaction between Indian and U. S. cogeneration manufacturers, potential for and impediments to greater collaboration.

G. Costs and Benefits of Non-utility Generation: The Contractor shall identify the costs and benefits of the indigeneous/renewable-based non-utility electrical generation from the utility, user and national perspective.

H. Recommendations: The Contractor shall provide policy/legal/regulatory and other recommendations that will foster introduction of cogeneration and private indigenous/renewable energy-based generation for sale to the grid, and describe AID's option to foster such generation.

I. The Contractor shall prepare a draft report before departure from the country and provide 40 copies of the final report including a complete executive summary within 21 days of receipt of comments on the draft from USAID/New Delhi and AID/ANE/TR/ENR in addition to any report requirements of the basic contract.

J. It is expected that the Contractor will utilize, as appropriate, Indian entities , e.g., AIEI, TERI, to facilitate field work, analysis and report preparation.

INDIA/PURPA STUDY

Preliminary Estimate of Cogeneration Market in the Commercial Sector

Scope of Work

The team will conduct a preliminary assessment of the market for cogeneration in the city of Bombay.

The commercial sector will be broken down into four subsectors: office buildings, hotels, hospitals and other buildings. In each of these subsectors the team will successively:

1) Develop profiles of building stocks by size and electric load. These will be derived from information gathered by the subcontractors from the electric utilities and appropriate organizations dealing with construction statistics.

2) Develop simplified thermal load profiles emphasizing water heating and space cooling uses in relationship to weather data.

3) Conduct case studies of the technical, economic and financial characteristics of typical cogeneration systems and their representative applications.

4) Extrapolate results for each subsector to develop market estimates through the year 1996, broken down into three categories: new, replacement and retrofit.

5) Summarize attitudes/impediments/policy issues related to development of cogeneration in the sector, based upon information provided by NPC and 4-6 direct interviews with building managers.

6) Identify priority areas for further analysis with preliminary scope of work.

A total of 15 man-days are needed to carry out these 6 tasks, provided that basic data can be gathered by subcontractors prior to initiation of the analyses.

राष्ट्रीय उत्पादकता परिषद
National Productivity Council

'उत्पादकता भवन', लोदी रोड
नई दिल्ली-११०००३
'Utpadakata Bhavan', Lodi Road
New Delhi-110003

No.80732
14th April, 1986.

Mr. T.C. Nicastro,
Director (Technology Development & Enterprise),
USAID,
West Building,
Chankyapuri,
NEW DELHI-110 021.

SUBJECT : STUDY TEAM FOR ANALYSIS OF PRIVATE SECTOR ELECTRICAL GENERATION SPONSORED BY USAID - NPC SUPPORT.

Dear Sir,

This has reference to the discussions Mr. S. Padmanabhan and Mrs. Elisabeth Millard of USAID had with us on Friday, the 11th April, 1986 on the above subject seeking NPC's services for coordinating the work of the above team during their visit to India for a period of four weeks.

NPC would be happy to provide its services for giving necessary support to the team and the terms and conditions for our services are detailed below:-

I. SCOPE OF WORK

i) NPC Consultants would be associated with the team during their stay in India. We would also arrange meetings with various personnel involved in the subject.

ii) It is proposed that the team members may visit Bombay and Gujarat apart from Delhi during their stay. The detailed itinerary would be worked out after further discussions wi USAID.

iii) NPC would arrange to collect the pertinent information/ material on the subject to the extent possible from variou sources to help the study team in their work.

iv) Arrangements for office accommodation for the team members may be made directly by the team/USAID as it would not be possible for NPC to arrange for office accommodation due to space problems in our office.

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v) Arrangements for visit to industries and other organisations by the members would be made by NPC.

II. TERMS AND CONDITIONS

i) For carrying out the above tasks, NPC would be charging a consolidated sum of Rs.48,000/- (Rupees forty eight thousand only). This includes our professional charges, expenses towards travel, stay and conveyance of the NPC consultants who would be involved with the team and other miscellaneous expenses This does not include the travel and local conveyance expenses of the study team members.

ii) 50% of the total amount (Rupees 24,000/-) would be paid in advance before the commencement of the work and balance amount would be paid within 15 days after the completion of the assignment.

iii) One of the NPC consultants would be associated with the team throughout their stay in India. Additionally, team members would be accompanied by NPC Consultants during their visits to various places by suitable NPC conslutants located in our offices at Bombay and Ahmedabad.

iv) Notice period of four weeks is required to make necessary preparatory work before the team arrives in India.

In case you require any more information, please feel free to write to us. Upon receipt of your confirmation of our proposal, further details could be worked out based on mutual discussions.

Thanking you,

Yours faithfully,

V. Raghuraman

(V. Raghuraman)
Director (FE),
for Director-General.

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APPENDIX B: LIST OF CONTACTS

NEW DELHI

Monday, July 28, 1986.

10:00 A.M.
Organization: U.S. Agency for International Development
Main Topic: Kick Off Meeting
Present: Richard Blue, Deputy Director,
S. Padmanaban, Energy Specialist, Diana Swayne
AS, JS, PS

12:00 P.M.
Organization: National Productivity Council
Main Topic: Kick Off Meeting
Present: Mr. V. Raghuraman, Director,
K.C. Mahalan, Deputy Director,
S.B. Sadananda, Deputy Director,
S. Padmanaban, AID
AS, PS, JS

2:30 P.M.
Organization: Association of Indian Engineering Industry
Main Topic: Power Generation Activities in Indian Industry
Present: Mr. N. Srinivasan, Deputy Director
AS, JS, PS

4:00 P.M.
Organization: National Federation of Sugar Factories
Main Topic: Captive Power in Indian Sugar Industry
Present: Mr. P.J. Manohar Rao, Managing Director,
Mr. K.C. Mahajan, National Product Council
AS, JS, PS

Tuesday, July 29, 1986.

10:00 A.M.
Organization: Tata Energy Research Institute
Main Topic: Background Information on Energy in India
Present: Dr. R.K. Pauchari, Director,
Dr. S. Ramesh, Senior Fellow,
Dr. Ashok Gadgie, Fellow,
Dr. V.V. N. Kishore, Fellow
AS, JS, PS

3:00 P.M.
Organization: Bharat Heavy Electricals Ltd.
Main Topic: Power Generation Equipment
Present: Mr. N.K. Dutta, General Manager,
Mr. A.K. Chakrabarti, General Manager (CEC),
Mr. Mahajan, NPC
AS, JS, PS

Wednesday, July 30, 1986.

10:00 A.M.
Organization: Petroleum Conservation Research Association
Main Topic: Energy Conservation in India
Present: Mr. P.K. Goel, General Manager,
Mr. K.C. Mahajan, NPC
AS, JS, PS

2:00 P.M.
Organization: Department of Non-Conventional Energy Sources
Main Topic: Renewable Resources for Power Generation
Present: Dr. J. Gururaja, Advisor,
Mr. K.C. Mahajan, NPC
AS, JS, PS

Monday, August 4, 1986

10:00 A.M.
Organization: Dept. of Non-Conventional Energy Resources
Main Topic: Renewable Resource Power Potential
Present: Dr. O. P. Vimal, Director
Dr. J. Gururaja, Adviser
J. P. Meena, Specialist, Solar and Wind
JS

2:00 P.M.
Organization: Urja Energy Monthly
Main Topic: Potential for Private Power
Present: Dipak B. R. Chaudhuri, Editor
JS

Tuesday, August 5, 1986.

10:00 A.M.
Organization: Advisory Board on Energy
Main Topic: Energy Resources of India and Potential
Present: Prabir Sengupta, Joint Secretary
S. Padmanaban, USAID
JS

2:00 P.M.
Organization: Indian Council for Research on International Economic Relations
Main Topic: Electric Utility Avoided Costs
Present: Kishore Jethanandani
JS

Wednesday, August 13, 1986

2:00 P.M.
Organization: Ministry of Petroleum and Natural Gas
Main Topic: Fuel Availability for Non-utility Power Generations
Present: Mr. Vijay L. Kalkar, Adviser, Economic Policy & Planning
Mr. K.C. Mahajan, NPC
JS, PS

Thursday, August 14, 1986

10:00 A.M.
Organization: Faridabad Captive Power Systems
Main Topic: Faridabad Power Project
Present: Mr. N. Balasundaram, Director,
Mr. K.C. Mahajan, NPC
PS

4:00 P.M.
Organization: U.S. Agency for International Development
Main Topic: Debriefing
Present: Owen Cylke, Director,
Thomas J. Nicastro, Chief, Office of Technology Develop Enterprise,
S. Padmanabann, Energy Specialist,
David Jhirad, USAID Washington
AS, JS, PS

Tuesday, August 19, 1986.

11:00 A.M.
Organization: Central Electricity Authority
Main Topic: Non-utility Power Generation
Present: Mr. S.K. Aggarwal, Member (Planning)
Mr. K.C. Mahajan, NPC
PS, JS

Wednesday, August 27, 1986

10:00 A.M.
Organization: Intech Consultants Pvt Ltd
Main Topic: Indian Electric Utility Problems
Present: Dr. Ashok Desai, President
JS

2:00 P.M.
Organization: Private Consultant
Main Topic: Costs of Waste-to-Energy Systems
Present: Abraham Michaels, P. E.
JS

Thursday, August 28, 1986

10:00 A.M.
Organization: Tata Energy Research Institute
Main Topic: Cost and Performances of Renewable Energy Systems in India
Present: Dr. V. V. N. Kishore, Fellow
Ms. Idrisa Pandit, Information Analyst
JS

GUJARAT

Wednesday, August 6, 1986.

11:00 A.M.
Organization: Gujarat Industrial Power Company (GIPCO)
Main Topic: Non-utility Power Generations
Present: Mr. H.R. Patankar, Principal Secretary to Government
Mr. H.B. Bhatt, Adviser,
Mr. R. Kapoor, NPC
AS, PS

3:00 P.M.
Organization: Ahmedabad Electricity Company (AEC)
Main Topic: Private Utility Operation in India
Present: Mr. Lldayan K. Sheth, General Manager (Commercial)
Mr. Shashi Kant Shari, General Manager (Finance)
Mr. J.J. Rana, Company Secretary,
Mr. S. Datta, Advisor/Consultant,
Mr. R. Kapoor, NPC
AS, PS

Thursday, August 7, 1986.

10:30 A.M.
Organization: Gjuarat State Fertilizer Company (GSFC)
Main Topic: Captive Power in Industry
Present: Mr. S.K. Grover, General Manager,
Mr. V. Charandas, Executive Director,
Mr. C.G. Patel, Executive Director, Operations,
Mr. R.Kapoor, NPC
AS, PS

3:30 P.M.
Organization: Sarabhai Common Services
Main Topic: Captive Power in Industry
Present: Dr. R.K. Mehta, President,
Mr. S.M. Rangnekar, Vice President,
Mr. C.V.S. Narayanaz, Finance Director,
Mr. R. Kapoor, NPC
AS, PS

5:00 P.M.
Organization: Prudential Industrial Captive Power Leasing
Main Topic: Leasing Power Equipment
Present: Mr. Arun Patel, Managing,
Mr. R. D'Sally, Director,
Mr. N.T.N. Sandesara, Director,
Mr. R. Kapoor, NPC
AS, PS

Friday, August 8, 1986.

Organization: GEB
Main Topic: Non-utility Power Generations
Present: Mr. J.S. Aiyar, Executive Director,
Mr. H.J. Patel, Chief Engineer,
Mr. R. Kapoor, NPC
AS, PS

Saturday, August 9, 1986.

10:00 A.M.
Organization: Krishak Bharati Cooperative
Main Topic: Cogeneration
Present: Mr. H.G. Nayak, General Manager,
Mr. B.B. Kavsnik, Superintendent,
Mr. J.V. Patel, Senior Engineer,
Mr. Satish Chandra, Assistant Superintendent,
Mr. R. Kapoor, NPC
PS

Sunday, August 10, 1986.

10:00 A.M.
Organization: Hindustan Brown Boveri Ltd.
Main Topic: Power System Equipment
Present: Mr. P. Sekhar, Deputy General Manager
Mr. V.V.R. Murty, Manager,
Mr. R. Kapoor, NPC
PS

Monday, August 11, 1986.

10:00 A.M.
Organization: IFFCO
Main Topic: Cogeneration
Present: Mr. V.J. Patel, Superintendent,
Mr. R. Kapoor, NPC
PS

Tuesday, August 12, 1986.

3:00 P.M.
Organization: Department of Mines & Energy
Main Topic: Non-utility Power Generation
Present: Mr. J.D. Gaffar, Secretary,
Mr. R. Kapoor, NPC
PS

MAHARASHTRA

Thursday, July 31, 1986.

10:00 A.M.
Organization: Tata Electric Companies
Main Topic: Trombay Plant Visit
Present: Mr. M.V. Rao, General Manager
Mr. C.P. Kulkarni, Chief Load Dispatcher
Mr. A. Ramadas, Superintendent
Mr. K.C. Mahajan, NPC
AS, JS, PS

3:00 P.M.
Organization: Center for Monitoring the Indian Economy
Main Topic: Economic and Energy Statistics
Present: Devraj Chauhan
JS

Friday, August 1, 1986.

10:00 A.M.
Organization: Hindustan Lever Limited
Main Topic: Industrial Cogeneration
Present: Mr. K. K. Nayar, General Factory Manager
Mr. K.C. Mahajan, NPC
AS, JS, PS

Organization: Tata Electric Companies
Main Topic: Private Utility Operation
Present: Mr. M.V. Rao, General Manager
Mr. S.P. Manaktala, Managind Director
Mr. K.R. Pandit, Vice President
Mr. K.M. Gherda, Managing Director
Mr. K.C. Mahajan, NPC

Saturday, August 2, 1986.

11:00 A.M.
Organization: Taj Mahal Hotel
Main Topic: Cogeneration in Commercial Buildings
Present: Mr. S.V. Bhida, Chief Engineer
Mr. K.C. Mahajan, NPC
AS, JS, PS

Monday, August 4, 1986.

10:00 A.M.
Organization: Bombay Electric Supply and Transport
Main Topic: Private Utility Operation
Present: Mr. R.K. Menon, Chief Engineer
Mr. S.V. Upasani, Division Engineer
Mr. D.S. Talwai, NPC
AS, PS

2:30 P.M.
Organization: Thermax Private Limited
Main Topic: Availability of Power Equipment in India
Present: Mr. Shyam Shankaran, Deputy Manager
Mr. M.S. Unnikrishnan
AS, PS

Tuesday, August 5, 1986.

11:00 A.M.
Organization: Hindustan Petroleum Corporation Limited
Main Topic: Captive Power in Industry
Present: Mr. R.V. Rao, General Manager-Projects
Mr. P.C. Ghosal, Manager
AS, PS

3:00 P.M.
Organization: Industrial Credit & Investment Corp. Ltd.
Main Topic: Financing Energy Projects
Present: Shri R.V. Bhargava, General Manager
Mr. K.C. Mahajan
AS, JS, PS

Wednesday, August 6, 1986

10:00 A.M.
Organization: Kirloskar Cummings Ltd.
Main Topic: Markets for Diesel Gensets
Present: Y. S. Joshi, Manager, Power Engineering
Rajeev Lonkar, Sales Engineer

2:00 P.M.
Organization: Kirloskar Consultants, Ltd.
Main Topic: Indian Cogeneration Systems' Potential
Present: S. K. Tasgaonkar, Vice President (Engineering)
A. V. Bhagwat, Assoc. Vice President
D. S. Gandhe, Executive
S. C. Namjoshi, Consultant
JS

Thursday, August 7, 1986.

10:00 A.M.
Organization: Oil and Natural Gas Commissions (ONGC)
Main Topic: Prices, Costs and Availability of Natural Gas
Present: I. L Budhiraja, General Mgr. (Production)
A. M. Bhatt, Dy. General Mgr. (Terminals)
JS

1:00 P.M.
Organization: Bombay Municipal Corporation
Main Topic: Municipal Waste to Energy
Present: Chief Engineer, Wastes
JS

3:00 P.M.
Organization: Maharashtra State Electricity Board
Main Topic: Private Power in Maharashtra
Present: P. S. Deshmukh, Chief Engineer, Planning
Mr. Giadre, Technical Director
Mr. Kagalkar, Chief Engineer, Dispatch
Mr. Gurshahaney, Executive Engineer, Commercial
JS

4:30 P.M.
Organization: Jaslok Hospital and Research Center
Main Topic: Hospital Energy Consumption
Present: S. Masurekar, Manager
J. M. Shaikh, Engineer
JS

Friday, August 8, 1986.

10:00 A.M.
Organization: Govt. of Maharashtra
Main Topic: Govt. Attitudes toward Private Power Generation
Present: P. Abraham, Secretary (Energy and Environment)
JS, AS

1:00 P.M.
Organization: Industrial Development Bank of India (IDBI)
Main Topic: Indian Capital Markets and Financing Practices
Present: S. Subramanian, Manager
B. R. Sengupta, Manager (Technology)
JS3:00 P.M.

3:00 P.M.
Organization: Development Consultants Pvt. Ltd.
Main Topic: Private investment in Power and Cogeneration Systems
Present: G. C. Nundy, Deputy General Mgr.
I. A. Mukaddam, Mgr., Bombay
JS

Saturday, August 9, 1986.

10:00 A.M.
Organization: Luz International Ltd.
Main Topic: Solar Power Systems
Present: Jay A. Friedman, Director, International Sales
JS

2:00 P.M.
Organization: Thermax
Main Topic: Markets for Power Equipment
Present: Sudhir Mohan, Product Mgr. Heat Recovery
JS

Monday, August 11, 1986.

10:00 A.M.
Organization: Indian Merchants' Chamber
Main Topic: Private Investment in Power Systems
Present: S. I. Padhya, Deputy Director
JS

1:00 P.M.
Organization: Lula Tandon Consultants Pvt Ltd
Main Topic: Commercial Building Cogeneration Potential in Bombay
Present: Suresh Lulla, President
Dinesh Tandon
JS

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Tuesday, August 12, 1986.

10:00 A.M.
Organization: American Express Bank
Main Topic: Indian Financial Markets
Present: A. G. Gaitonde, Asst. Treasurer and Mktg. Mgr
B. S. Shendy
JS

2:00 P.M.
Organization: Oberoi Towers Hotel
Main Topic: Hotel Energy Consumption
Present: A.V. Matthews, Asst. Chief Engineer
JS

APPENDIX C: ECONOMIC AND FINANCIAL ANALYSES

To determine the relative attractiveness of the various private sector power generation options, two types of analyses were performed: an economic analysis and a financial analysis. The economic analysis looks at the project from the viewpoint of a national economic planner. It attempts to determine the true costs and benefits to the nation's economy and to decide which of the available options represents the best investment of the nation's scarce resources. To do this, it looks only at the resource costs actually incurred. For example, it factors out the "transfer payments" such as taxes, duties, and profits which do not represent true actual costs but rather represent shifts of resources from one sector to another. Rather than using the "market prices" of labor and material, it use their "shadow prices" which represent the opportunity costs to the country of not having these resources available for other projects. Finally, instead of using the market cost of capital it uses a social cost which represents the opportunity cost of capital to the Thai economy.

The financial analysis looks at the project from the viewpoint of the investor. It determines the actual cash flows of a project using market values for capital costs, labor, and materials. It incorporates taxes, duties, profits, and other transfer payments explicitly, and determines the actual returns to the investor.

If there is a wide divergence between the relative attractiveness of projects as indicated by these two types of analyses, then serious thought must be

given to restructuring government policies which cause these distortions. For example, policies on energy pricing and taxation which cause the relative financial costs to depart significantly from the relative economic costs will cause investors to make non-optimal energy system choices. If these distortions are large enough they can result in a slowdown in the overall economic growth with the potential for contributing to social unrest.

Calculating the Levelized Annual Cost[1]

For both the economic and the financial analyses there are many approaches which can be used. For this study we used the Levelized Annual Cost (LAC) approach. This approach is equivalent to a Net Present Value (NPV) calculation in which each of the cash flows is determined and discounted to a present value. The LAC approach in effect converts the discounted NPV to a constant "levelized" annual value over the life of the project. It has the advantage of allowing a simple estimate of the energy cost (e.g. in Bahts/kWh) by dividing the LAC by the annual energy output. It provides a relatively simple means of estimating the impact on the apparent relative costs of various economic and financing options by providing a single number measure for what would otherwise be a complicated set of varying cash flows over the project life. The intuitive meaning of the LAC is that it is the average price the power output of the system must obtain in order for the investors to meet their desired returns.

[1] The derivations of the equations used here can be found in a number of treatises on economic and financial evaluation of energy projects. This discussion follows an outline presented in Calculating the Cost of Producing Energy for Regulated and Non-regulated Industry: Annual Report (May 1983 - May 1984); Decision Focus, Inc. for the Gas Research Institute; Contract No. 5082-511-0596; Chicago, Illinois; September, 1984

To calculate the LAC, the following equation is used:

LAC = (Annualized Cost)/(Annual Energy Output)

Where:

Annualized Cost = (Capital Investment) * (CRF)

+ (Annual O&M Costs)

+ (Annual Fuel Costs)

Annual Energy Output = Expected System Output in kWh per year

The Capital Recovery Factor (CRF), sometimes called the Capital Charge Rate, converts the initial capital investment into a series of equal annual charges which have the same NPV. When estimating the economic cost it is a function of the economic discount rate (i.e. the marginal return on capital for the economy, or the economic "hurdle rate") and the system lifetime. When estimating the financial costs the CRF is a function of the initial capital investment, the cost of equity capital (the investor's required return on investment, or his "hurdle rate"), the cost of debt capital, the fraction of debt and equity in the financing, the tax factors affecting the cash flows such as the marginal tax rate and the depreciation schedule used, and the system life.

For economic evaluation the Crf_e is calculated from the equation:

$$Crf_e(r,OL) = \frac{}{1 - (1 + r)^{-OL}}$$

where:

Crf_e = the economic Capital Recovery Factor

r = marginal economic return on capital ("hurdle rate")

OL = system operating life

For financial evaluation, the Crf_f is calculated from the equation:

$$Crf_f(r,OL,TR,TL) = \frac{CRF(r,OL)}{1 - TR} * \left(1 - \frac{TR}{TL * CRF(r,TL)} \right)$$

where:

Crf_f = the financial Capital Recovery Factor

r = the after-tax cost of capital

$= f_e r_e + (1 - TR) * f_c r_d$

f_e = fraction of equity in project financing

r_e = desired return on equity

r_e = desired return on equity

f_d = fraction of debt in project financing

r_e = cost of debt

TR = marginal tax rate

OL = system operating life

TL = system tax life

This formulation assumes the system is depreciated for tax purposes using a straight line schedule. It is possible to modify this formulation to allow accelerated depreciation, but our discussions with private firms and banks indicated that straight line depreciation is standard practice. For cases where different parts of the system have different lifetimes or tax treatments, a separate CRF and LAC can be determined for each part and the results then added.

Determining the Economic Costs

To determine the economic costs and benefits of the non-utility power options, the true "shadow costs" of capital, labor, and material for each project should be known. These are difficult to determine accurately and their values can vary significantly from year to year as the nation's and world economies change or as government policies change. The values used in this study were derived from documents and reports provided to the study

are summarized in Exhibit C.1. To simplify the analysis, all values are given in constant terms (i.e. net of general inflation).

The estimate for the marginal productivity of capita and the "standard conversion factor" was provided by World Bank staff in New Delhi, and corroborated by economists for Indian government and private organizations. The natural gas price was provided by ONGC and represents the estimated cost of "free" gas delivered to Gujarat and Maharashtra. Diesel oil and furnace oil prices are for imports delivered to Bombay, with a small additional charge for delivery. Coal prices are estimated from data provided by the Department of Coal, and include delivery to the plant. Electric power prices were estimated by study team based on information provided by NPC and other Indian organizations. The electricity prices represent the marginal cost of generation and high tension transmission as described in Chapter 3. The capital recovery factors were calculated by the study team based on applicable plant life and discount rates.

Determining the Financial Costs

The assumptions used for the financial analysis are summarized in Exhibit C.2. Fuel prices were provided by NPC are in accord with prices the interviewed industry representatives quoted. Electricity prices are based on the existing rates in Gujarat and Maharashtra to medium and large industries. The capital recovery factors are calculated by the study team based on the applicable tax rates, plant life, and discount rates.

Exhibit C.1

Key Assumptions for Economic Analysis

- Energy Costs:

	Unit Cost	Heat Content	$/mmBtu
Natural Gas[1]	2.2 R/m^3	36,850 Btu/m^3	4.8
Diesel Oil[2]	3.2 R/lit	36,478 Btu/lit	7.2
Furnace Oil[3]	3 R/kg	40,474 Btu/kg	5.9
Coal[4]	250-600 R/ton	19,840 Btu/kg	1.05-2.42
Electricity (to industry)			
Gujarat[5]	0.80 R/kWh	3,412 Btu/kWh	18.76
Maharashtra[6]	0.80 R/kWh	3,412 Btu/kWh	18.76

- Marginal Productivity of Capital: 12 percent

- Standard Conversion Factor[7]: 0.80

- Capital Recovery Factors (CRF):

System Life	CRF
10 years	0.177
15 years	0.147
20 years	0.134
25 years	0.127

Source: Hagler, Bailly & Company

1. ONGC
2. Imported price fob Bombay
3. Imported price fob Bombay
4. Indian Coal Board, Annual Report 1985
5. Hagler, Bailly estimate
6. Hagler, Bailly estimate
7. World Bank

Exhibit C.2

Key Assumptions for Financial Analysis

- Required Return on Equity (After Tax, Net of Inflation)

Private Investment	20 percent
Public Investment	15 percent

- Cost of Debt (Net of Inflation): 9 percent
- Debt/Equity Ratio: 2/1
- Marginal Tax Rate: 55 percent
- Depreciation Period: 1 year for cogeneration in existing plants, 10 years for other projects
- Energy Prices:

	Unit Cost	Heat Content	$/mmBtu
Natural Gas[1]	2.6 R/m^3	36,850 Btu/m^3	5.8
Diesel Oil[2]	3.2 R/lit	36,478 Btu/lit	7.2
Furnace Oil[3]	3.0 R/kg	40,474 Btu/kg	5.9
Coal[4]	700 R/ton	19,840 Btu/kg	2.8
Electricity[5]	1.3 R/kWh	3,412 Btu/kWh	30.48

- Capital Recovery Factors (CRF):

System Life	CRF Private	CRF Public
10 years	0.287	0.231
15 years	0.257	0.198
20 years	0.247	0.185
25 years	0.243	0.179

Source: Hagler, Bailly & Company

1. ONGC, NPC and industry representatives
2. NPC and industry representatives
3. NPC and industry representatives
4. NPC and industry representatives
5. GEB, MSEB, AEC, NPC, and industry representives

APPENDIX D: COGENERATION MODEL

Over the last few years, Hagler, Bailly & Company has developed a sophisticated computerized data base and set of market assessment models that offer a high degree of realism and flexibility in analyzing industrial cogeneration markets. These models simulate in detail the technology costs and performances, energy prices, and regulatory and tax environment faced by the industrial decision-maker, and the actual decision factors (such as the return on investment) that he uses. Because of this high degree of realism, our models have been used by numerous industrial and government clients.

Exhibit A.1 is a block diagram that depicts the overall model organization. The market assessment process entails four steps:

1. Segment the market
2. Compute life-cycle costs
3. Assess market shares
4. Determine total market size.

SEGMENT THE MARKET

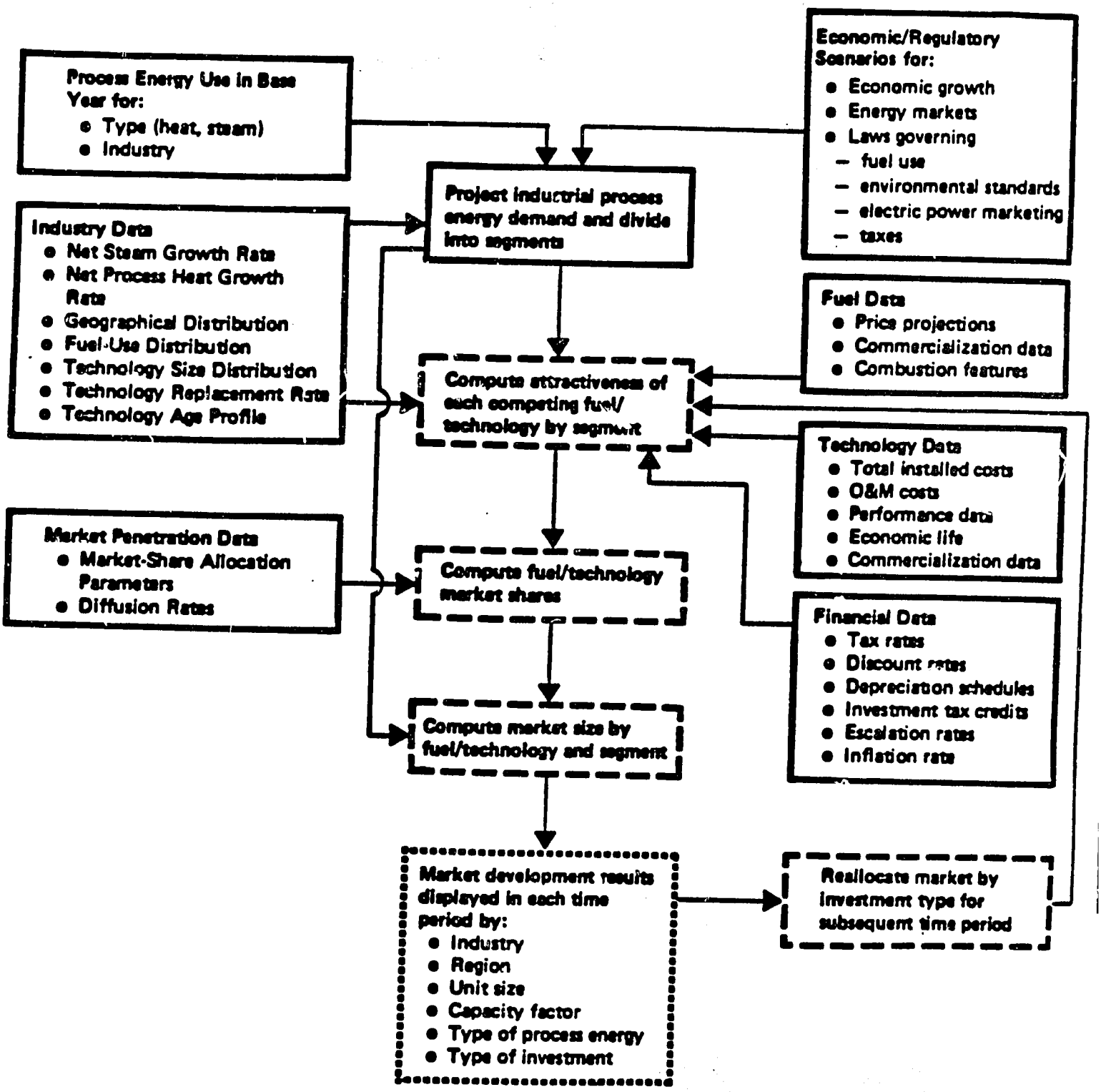
First, we divide the market for industrial steam-generating equipment into segments to examine more accurately the effect of various factors on the selection of steam-generating and cogenerating technology. The total market for industrial steam-generating equipment is disaggregated by the following categories:

- Geographical region
- Industry
- Class of fuel (i.e., purchased and waste)
- Electric-to-thermal ratio
- Boiler size
- Type of investment
- Type of fuel used in existing boilers
- Time period.

For each region, we obtain fuel and electricity prices and develop price projections. We also project steam

Exhibit D.1

Organization of Hagler, Bailly Market Models for Industrial Process Energy Applications



Key:
Market model inputs ———
Market model functions — —
Market model outputs ••••••

demand by industry and region over the length of the study period. For those industries that use waste fuels (or process residuals) that are not expected to have any significant commercial value, we disaggregate each industry's steam projections into the amount produced by purchased fuels and the amount produced by waste fuels. At this point, we treat the market segments using purchased fuels separately from those using waste fuels. That is, technologies using purchased fuels are allowed to compete only with one another, and technologies using waste fuels are allowed to compete only with one another.

In addition to its steam demand, we characterize each industry by its electric/thermal ratio (E/T) distribution. Such distributions are computed by first analyzing in detail the electric and steam requirements for the most energy-intensive processes within each industry over time, and then by integrating projected process mix changes over time.

We further categorize the projected process steam consumption for each industry/region segment by boiler size. We consider five steam-capacity size categories, e.g.:

1. 25-50 mmBtu/hr
2. 50-100 mmBtu/hr
3. 100-250 mmBtu/hr
4. 250-500 mmBtu/hr
5. Over 500 mmBtu/hr.

Size range is important because the cogeneration technologies considered have varying economies of scale; thus, some are economical only in a limited range of capacities. In addition, not all technologies are available in all size ranges. Finally, regulations such as the Clean Air Act or the Powerplant and Industrial Fuel Use Act affect each size range differently.

We also consider three types of investment for each industry/region segment:

1. **New**: industry growth in the market segment necessitates the addition of new steam-generating capacity.

2. **Replacement**: a certain percentage of the 1983 stock of steam boilers will be retired during

each year. This percentage is called the "phase-out ratio." We estimated phase-out ratios for each industry and applied them to the 1983 boiler inventory to estimate the replacement market in each industry/region segment.

3. Retrofit: some of the existing boilers that still have useful life may be, on a discretionary decision basis, retired early and replaced with new cogeneration or noncogeneration systems.

To facilitate computation and presentation of the results, the projection period is usually divided into 2-year increments, e.g., 1985-86, 1987-88, etc. The market sizes presented in the output represent sales. The actual installation is assumed to occur 1 to 3 years later, depending on technology, fuel, and system size.

COMPUTE LIFE-CYCLE COSTS

Within each of the segments, we calculate the life-cycle cost for each of the conventional technically feasible and legally allowed boiler and cogeneration technology/fuel options. To do this, the capital costs, annual operating and maintenance (O&M) costs, and performance parameters (e.g., efficiency) of each system are first calculated for each size range in which the system is available. We modify these costs on a regional basis to adjust for the coal types available and for environmental control requirements such as scrubbers.

Next, the after-tax cash flows are determined for the "book life" of the system (20 years). The cash flows are calculated assuming the installation takes 2 years. Investment tax credits and tax depreciation shields are explicitly included (if applicable) when the industrial party would actually benefit from them.

Sales or use of cogenerated electricity is assumed to be handled by the industrial operator in the most economically advantageous manner. For example, if the buyback rate is above the operator's retail rate, all power generated is sold to the utility at the buyback rate while the operator simultaneously purchases his requirements at the retail rate. If the buyback rate is less than the retail rate, the operator uses as much of the

power generated as possible to displace purchased power, and any excess is sold to the utility at the buy-back rate.

Financing is assumed to be 100-percent equity. Most industrial firms make this assumption when evaluating cogeneration opportunities. The discount rate (expressed in real terms) usually used is 20 percent for new and replacement installations. A 30-percent discount rate is usually assumed for retrofit installations. These are mean values developed by Hagler, Bailly personnel based on hundreds of interviews with industry decision-makers as well as site-specific assessments of industrial cogeneration opportunities. Different values can, of course, be used.

Once the net annual after-tax cash flows are determined, they are discounted, using the real discount rate (or hurdle rate) to determine the net after-tax life cycle cost for each competing technology in each market segment.

ASSESS MARKET SHARES

Once the life-cycle costs are determined, we evaluate the market shares of the competing technologies for purchased fuels and waste fuels separately using a logistic curve. This curve ensures that technologies having equal life-cycle costs in a particular market segment had equal market shares in that segment, while technologies having lower life-cycle costs than their competitors would dominate that segment, although they would not usually capture the entire segment. This is a more accurate representation of actual market behavior than to assume that the lowest-cost technology captures the entire segment, because site-specific variations in energy prices, capital costs, and process requirements tend to blur the estimated economic differences between the competing technologies.

New technologies entering the market usually face a long diffusion period during which they capture a smaller market share than cost comparisons alone would indicate, because potential purchasers are uncertain of the new technology's operating costs, performance, and reliability. There is also a time lag in disseminating information about a new technology to potential buyers. Our research indicates that between 7 and 15 years are required, after a new capital-intensive energy

technology is first demonstrated on a commercial scale, before that technology reaches the level of market penetration indicated by costs alone. We often assume a 10-year diffusion period in our cogeneration market studies.

In the retrofit market, each of the technologies must compete against an existing oil-, gas-, or coal-fired boiler. In evaluating the life-cycle cost, the boiler was assumed to have no capital cost, but to have annual O&M and fuel costs. This assumption includes the implicit assumption that the old boiler will be put on standby when the new one is installed, or will have a scrap value about equal to its removal cost.

The result of this step is a projection of the relative market shares of each of the competing technologies in each of the market segments.

DETERMINE TOTAL MARKET SIZE

Next the total market size is determined for each of the investment types: new, replacement, or retrofit. The new market results from additional steam demand that develops during the time period. It represents both new greenfield plants as well as expansions at existing facilities. The replacement market represents that portion of the 1983 boiler inventory that reaches the end of its useful life and must be replaced. It starts at approximately 2 percent of the inventory pe year, and increases slightly over the time period of the study. This increase simulates the vintaging of the initial inventory.

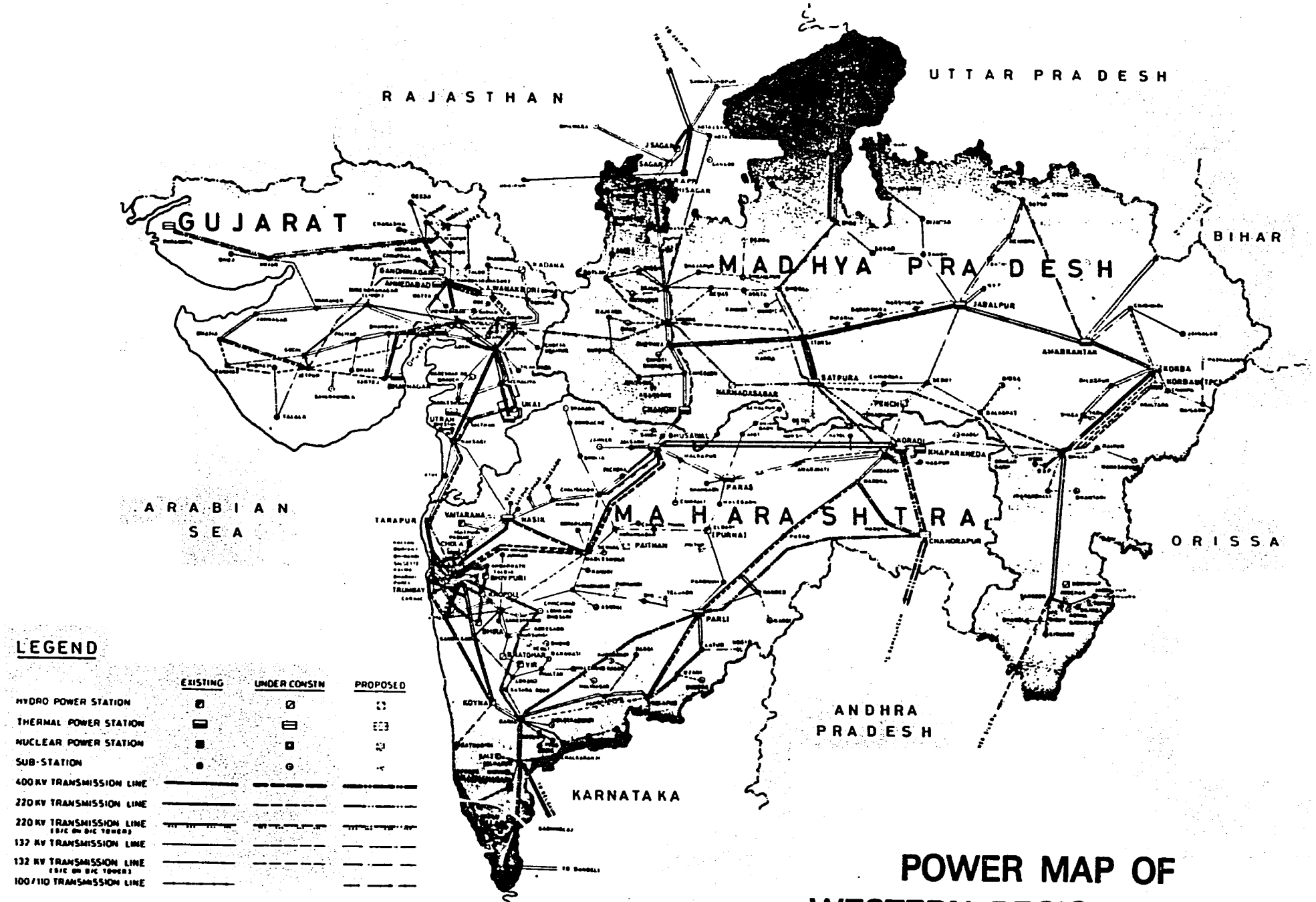
The retrofit market is considered to be the existing inventory of distillate oil-, residual oil-, natural gas-, and coal-fired boilers (and waste-fueled boilers for those segments using waste-fuels). Our cogeneration market assessment models use a dynamic allocation between the retrofit and replacement markets during the time period of the study, since boilers retrofitted in one time period will not be available for replacement in subsequent periods (or vice-versa).

The demand for steam-generating equipment in each market segment is then multiplied by the market share for

each technology to project sales volume* for that technology in that segment. Projected sales are converted to installed megawatts and summed by region, industry, size, investment type, and time period.

*Sales volume measured in steam generating capacity.

APPENDIX E: POWER MAP OF GUJARAT AND MAHARASHTRA



POWER MAP OF WESTERN REGIONAL GRID

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