NON-UTILITY POWER GENERATION IN THE INDIAN STATES OF GUJARAT AND MAHARASHTRA: POTENTIAL, IMPEDIMENTS, AND POLICY ISSUES

Final Report

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CURRENCY EQUIVALENTS

Currency Unit	=	Rupees (Rs)
Rs. 1.00	=	Paise 100
U.S. $ 1.00	=	Rs. 12.5
Rs. 1.00	=	U.S. $ 0.08

ABBREVIATIONS AND ACRONYMS

AEC	Ahmedabad Electric Company
BEST	Bombay Electric Supply & Transport
BHEL	Bharat Heavy Electricals Limited
BMC	Bombay Municipal Corporation
BSES	Bombay Surburban Electricity Supply
CEA	Central Electricity Authority
CFR	Cane field residues
CO	Carbon monoxide
CRF	Capital recovery factor
D/E	Debt to equity ratio
DNES	Department of Non-Conventional Energy Sources
E/T	Electric-to-thermal demand ratio
FICCI	Federation of Indian Chambers of Commerce & Industry
GACL	Gujarat Alkalies & Chemicals Limited
GEB	Gujarat Electricity Board
GIC	General Insurance Corporation
GIPC	Gujarat Industries Power Company
GNFC	Gujarat Narmada Valley Fertilizer Company
GOI	Government of India
GSFC	Gujarat State Fertilizers Company
GWh	Gigawatt-hour
HA	Hectare
HT	High Tension
ICICI	Industrial Credit & Investment Corporation of India
IDBI	Industrial Development Bank of India
KCAL	Kilocalories
KG	Kilogram
KL	Kiloliters
kWh	Kilowatt-hour
LCC	Life-cycle cost
LRDRR	Long-run differential revenue requirements
LRMC	Long run marginal cost
LSHS	Low Sulphur Heavy Stock
mmBtu/hr	Millions of British Thermal Units per hour
MSEB	Maharashtra State Electricity Board

MVA	Million Volt-Amper
MW	Megawatt
NHPC	National Hydro Power Corporation
NOx	Nitrogen Oxides
NPC	National Productivity Council
NTPC	National Thermal Power Corporation
O&M	Operation and maintenance
Ps	Paisa
PSI	Pounds per square inch
PURPA	Public Utility Regulatory Policies Act
REB	Regional Electricity Board
REC	Rural Electrification Corporation
RPM	Revolutions per minute
Rs	Rupees
T&D	Transmission & Distribution
T/hr	Tonnes per hour
TAPS	Tarapour Atomic Power Station
TPD	Tonnes per day
USAID	U.S. Agency for International Development

EXECUTIVE SUMMARY

Background

India's power generation capacity has increased significantly over the past few decades, rising from 1,712 MW in 1950 to over 42,000 MW in 1986, for an annual growth rate of about 9 percent, significantly higher than the rate of growth of GNP. At the same time, however, several factors -- population growth, agricultural expansion, industrial growth, and rising energy use -- have boosted the demand for electricity. As a result, the country is facing a power shortage that averages over 10 percent and ranges between 15 percent and 40 percent in some states, such as Karnataka and Haryana.

The power shortage has many insidious effects on the Indian economy. One of the most crippling ones is the loss of productivity that an insufficient and unreliable supply of power causes in industry. For example, a study by the Federation of Indian Chambers of Commerce and Industry estimates the loss of production to the Indian industry because of a 10 percent power shortage at Rs. 70 billion ($6 billion), or about 12 percent of the total industrial production in India.[1]

Since India's power sector is dominated by the central and state governments, financing the necessary supply expansion has become a major burden on both state and central government resources. In the Seventh Plan, for example, energy investments absorb well over 30 percent of the total budget with power the largest component. Further expansion is unlikely and would have a negative impact on other critical sectors such as agriculture and health. Despite this level of spending for capacity expansion, the power supply is falling further behind demand. For example, electricity demand during the Seventh Plan is projected to increase by about 30,000 MW, but only 22,000 MW of new capacity will be added because of insufficient funds.

A number of technical, financial, and managerial difficulties in the power sector of India make the prospects for an adequate supply in the near future very unlikely. Most state electricity boards (SEBs) have suffered from financial losses year after year. Current losses stand at over $1 billion per year. This financial difficulty is in part due to the existing tariff structure, which is not based on economic pricing of electricity. The principle of economic pricing of power generally gives way to social and agricultural

[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.

objectives. In addition, many SEBs are hampered by the poor condition of their plant and equipment. Inadequate maintenance, deficiencies in manufacture, unavailability of spare parts, and the poor quality of coal contribute to the poor state of thermal power plants. As a result, the plant load factor of some SEB units is below 50 percent. Furthermore, transmission and distribution systems have suffered from inadequate maintenance and overloading, resulting in T&D losses of over 20 percent. Finally, the management practices of some SEBs are outmoded and inadequate and the pace of improvements has been slow. The combination of these factors will continue to constrain efforts to improve the power supply in India despite anticipated rehabilitation and expansion efforts.

In light of the financial difficulties of the government and the state electricity boards that prevent greater expansion of the country's generation capacity, growing consideration is being given to opportunities for electricity generation outside the existing power sector for sale to the grid. There are many power generation options that can be most efficiently developed by non-utility entities. For example, industries with substantial steam demand can install cogeneration systems and supply their own power needs while producing steam. 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. In addition, non-utility entities, in particular the private sector, can get involved in developing large scale power plants to reduce the financial and managerial burden on the government and the electric utilities.

If non-utility power generation activities are expanded, the financial and technical pressure on existing power utilities would be reduced, enabling them to devote more of their resources to improving operations and the quality of the country's power supply.

There have been a number of recent initiatives in India in non-utility power generation. For instance, a number of industries in Gujarat are cooperating to build a 120 MW power generation facility for their own use, using the existing power network for distributing their power. A similar private project is underway in Faridabad, Haryana, where a group of industries is planning to install and operate a 120 MW diesel power plant in order to cope with the severe power shortage in the state. These non-utility entities, however, are planning to build these plants primarily to satisfy their own power requirements. This study will examine the possibilities for going one step further by exploring the potential for and impediments to power generation not only for on-site use but also for sale to the grid or other customers. Such power generation options are being pursued in a number of developing countries. In Turkey, for example, a private consortium is planning to build and operate a 960 MW imported coal-fired power plant with electricty sold to grid. This is very similar to activities contemplated in

Tamil vadu, where private-sector development of two 210 MW coal-fired power plants are under consideration.

The focus of this study will be on Gujarat and Maharashtra, two of the most industrialized states in the country. These states represent over 25 percent of the demand for electricity in the country and contain over 25 percent of the generation capacity. They are both experiencing power shortages, although to a limited extent in Maharashtra. In the Western region of India, containing the states of Gujarat and Maharashtra, the power generation capacity deficit is projected to grow from 1,605 MW in 1986 to over 7,560 MW in 1995. The state electricity boards respond to these shortages by direct load shedding to rural and industrial customers. They have been unable to expand capacity fast enough to meet demand because of several factors, the primary one being their poor financial situation. In both states, the SEBs have been operating at a financial loss in the past few years, amounting to Rs.-2.8 crore in Gujarat and Rs.-29.4 crore in Maharashtra as of 1984.

More importantly for this study is the fact that there are a number of private utilities in Gujarat and Maharashtra so there is a precedent for the generation and sale of power by facilities outside the existing SEBs. Finally, the Gujarat Electricity Board has been very receptive to the idea of non-utility power generation and has encouraged the development of some private power systems.

STUDY OBJECTIVES

The objectives of this study are:

(1) Preliminary identification of the technical, economic, and financial potential for non-utility power generation including industrial cogeneration and systems using renewable and indigenous energy resources in Gujarat and Maharashtra.

(2) Identification of the technical, economic, financial, and institutional 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 from Hagler, Bailly & Company during July 26 - August 23, 1986. The team was assisted by the staff of the National Productivity Council (NPC) in New Delhi, Gujarat, and Maharashtra.

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STUDY FINDINGS

The study findings are organized in two categories: power generation potential and major impediments.

Power Generation Potential

The preliminary analyses conducted in this study reveal that the financially attractive non-utility power generation potential in Gujarat and Maharashtra could exceed 2,600 MW during the 1986-1996 period. The private sector could potentially finance, build, own, and operate enough capacity to significantly reduce the current and projected power shortages in Gujarat and Maharashtra.

Industrial cogeneration accounts for the vast majority of this potential, perhaps exceeding 2,000 MW by itself (see Exhibit 1). The estimate of the potential could be lower or higher depending on the availability and cost of natural gas, the purchase price for power, regulations governing interconnection with the utility, and the cost for backup power, among other things. This estimate may be on the conservative side since no calculation of the cost of load shedding is included in the analysis. The financial and managerial problems caused by load shedding are one of the major incentives for cogeneration investment in India.

The industries with the highest potential are the fertilizer, basic chemicals, refinery, and pharmaceutical industries. About one-third of the cogeneration potential lies in existing plants (retrofit or replacement of existing steam generating equipment), and almost all the potential comes from topping cycle cogeneration systems, where steam is used first for power generation and then for industrial processes. Over two-thirds of this potential lies in government-owned industries. In the analysis of cogeneration potential it is assumed that natural gas is available only to fertilizer and petrochemical industries. However, if natural gas is made available to all industries, the analysis indicates that the cogeneration potential could be over 3,000 MW over the 1986-1996 period. The potential for bottoming cogeneration is estimated at only 50 MW, mainly in refineries and in fertilizer and petrochemical plants.

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

Exhibit 1

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

Technology	Economic		Financial	
	Generation Costs[1] (Ps/kWh)	Potential (MW)	Generation Costs[2] (Ps/kWh)	Potential (MW)
A. Small Scale				
Cogeneration				
Industrial Topping Systems	Under 80	2,550	Under 130	2,150
Industrial Bottoming Systems	55-77	50	70-120	50
Commercial Systems[3]	Under 80	30	Under 160	30
Power Only				
Sugar Cane Residue-Fired Systems	40-49	425	49-66	425
Other Agrowaste-Fired Systems	40-49	nil	49-66	nil
Coal Fired Systems	60-99	(4)	92-169	(4)
Gas Fired Systems	78-117	(4)	120-189	(4)
Municipal Waste-Fired Systems[1]	148	--	195	--
Hydroelectric Systems	N.A.	N.A.	N.A.	N.A.
Dendrothermal Systems	1.54	--	2.83	--
B. Large Scale				
Coal-Fired Systems	76-103	(4)	95-145	(4)
Diesel Generators	88	(2)	93-94	(2)
Combined Cycle	64-97	(4)	67-114	(4)

1 Systems with electricity costs of under Ps. 80/kWh are considered economically attractive. This figure reflects the avoided cost to utilities from power supplied by non-utility generators and is estimated based on the long run marginal cost of electricity generation to GEB and MSEB.

2 Systems with electricity costs of under Ps.130/kWh are considered financially attractive. This figure reflects the current price of electricity to industry in Gujarat and Maharashtra.

3 Analysis was done only for Bombay.

4 There is no resource limitation for these systems. Therefore the total potential could, in theory, replace a major portion of expansion needs in Gujarat and Maharashtra during 1986 - 1996.

Source: Hagler, Bailly & Company

The potential for power generation from bagasse and cane residue over the next 10 years is estimated at about 425 MW -- 75 MW in Gujarat and 350 MW in Maharashtra. This resource represents the least expensive power option of those studied. Power can be generated from sugar cane wastes during the dry season, from November to April. Since this is the period of peak agricultural electricity demand and minimum hydroelectric power availability, developing power systems using bagasse and cane waste could reduce the peak generation expansion requirements of utilities substantially, at the same time reducing the use of oil for peaking units.

The potential from other agrowastes is very limited. It is estimated to be only 30 MW, solely in Gujarat.

Small-scale power generation from domestic fossil fuels, i.e., natural gas and coal, is 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 and priced at concessionary rates. The actual size of the potential for these options depends 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 financial generation potential as their costs are considerably higher than the cost of electricity from the grid.

Finally, large scale conventional power systems fueled by domestic fossil fuels, e.g. coal, natural gas, and fuel oil, have generation costs that are competitive with those of the electric utilities. They not only can reduce the cost of power to industry but also present a valuable addition to state-owned power plants by bringing new private capital and management into the power sector. Based on the existing private utility performance in India, it is likely that private sector large-scale power plants will be operated more efficiently and reliably, thus increasing the efficiency of the nation's electricity supply.

Major Impediments

The potential for non-utility power generation in India is substantial and is just beginning to be realized. The study team found that the prime motivation for non-utility entities to venture into power generation activities has been their concern about the unreliability of the power supply from the grid. The

team found that there are 5 major impediments keeping non-utility entities from investing in power projects.

Lack of Clear Government Policy

The primary barrier to the development of non-utility power systems in India is the lack of concrete national and state policies permitting private power generation and establishing a framework for selling power to the grid or other customers. Although some government policies are designed to facilitate licensing of captive power projects, in practice almost all facilities must go through the extensive permitting process. Specifically, the licensing process for private power plants of 25 MW or less is greatly simplified, but so many exceptions exist that most plants, regardless of their size, must follow the more time-consuming licensing process. The central government's position as expressed to the study team is that policies defining the terms of interaction between private generators and the SEBs should be developed by the state governments. Policies in state governments are not well formulated and there is little precedent and few established procedures for selling power to the grid. This situation creates uncertainty in the market that inhibits the development of private power generation. Industry and private investors are hesitant to commit resources to private generation not knowing if the central government and state electricity boards will look favorably on their efforts.

Difficulty in Financing Power Projects

Financing problems also inhibit the private sector from investing in power generation systems. Obtaining funds to finance power projects can be very difficult. In the first place, these projects face competition for the limited investment funds from private-sector non-power projects. In the second place, even where funds are available from development banks, it can take a long time and great effort to obtain such funds, which limits their usefulness and desirability.

Industries and private investors often hesitate to invest in private power projects since they can often earn higher rates of return on other projects for several reasons. Government regulations limit profits on power projects to 2 percentage points above the prevailing interest rate. Investors typically expect a return of 20 to 25 percent on equity, but since prevailing interest rates are around 12 percent, power projects will yield a much lower rate of return. In addition, import duties, restrictions on the importation of power equipment, and foreign exchange restrictions add further limitations that reduce the expected rate of return on many power projects. Import duties are 40 percent on equipment for power projects in new facilities and they can be over 100 percent on equipment for retrofit projects. Finally, investments in plant equipment to increase production often appear to be the most

productive use of funds in many Indian industries and decision-makers would rather invest their limited funds in expanding output than in installing power systems.

However, these financing difficulties appear to be surmountable. In at least one case of private power development in India -- the Faridabad project -- developers have had very little difficulty arranging a mixture of private and public financing.

Uncertainty of Fuel Supplies and Availability

The private sector also hesitates to invest in power projects fearing that they will not be able to obtain reliable supplies of good-quality fuel. The current government policy limits access to natural gas, complicated licensing procedures hamper access to coal, and the expense of using oil add together to create a significant disincentive to private power generation. The supply of natural gas is essentially limited by the government to fertilizer and petrochemical plants. A few gas-turbine power plants have been given access to natural gas recently, but under current policy industry cannot expect to receive supplies for power generation. Coal is distributed by the government and supply priority is given to the SEBs and large industries. Coal supplies are available to potential power generators, but obtaining good quality coal at a reasonable price requires a major effort to track supplies and push the required paperwork through the extensive bureaucracy. Few industries can afford to devote such resources to their fuel supply. The problem of railway wagon shortages and the substantial cost difference between coal transport by rail and by road add to the supply uncertainty of this fuel.

Uncertainty of Equipment Availability and Quality

The private sector also hesitates to invest in power generation because government regulations intended to protect domestic manufacturers of power equipment often require the use of equipment that in some cases is more expensive and of lower quality than imported equipment. This can eliminate any financial and energy-efficiency benefits that power projects offer. In addition, it often takes longer to obtain domestic equipment than imported equipment. A typical lead time for obtaining domestic power equipment is over 3 years, while foreign equipment can be delivered in less than 18 months.

Uncertainty About the Terms of Interconnection to the Grid

A final reason that the potential for private power is not being met is that the ill-defined state of the terms of interconnection to the grid gives the

private sector no assurance that it will be treated fairly when it installs power generation equipment. Independent electricity generators will, in most cases, need to rely on existing electric utilities or the SEBs to sell their power, either directly to the utilities or indirectly to other customers through the utilities' distribution network. Cogeneration systems will also need to rely on utilities for backup power during system failure or maintenance. Many of the issues that need to be defined to govern this interaction have not been spelled out in regulations and policies. Standards on metering requirements, protective and control devises, performance requirements, and other technical factors vital to successfully interconnecting power systems need to be clearly defined. In the absence of well-defined terms of interconnection, industry will face high technical risks as it installs generation equipment.

Financial interconnection issues are also not clearly defined in India. Procedures for determining the cost of back-up power and the buy-back rate -- the price a utility pays for independently generated power -- need to be established. In their absence, utilities often charge unreasonably high rates for backup power and pay low rates to purchase power. The existing uncertainty is discouraging industry from supplying power to the grid.

RECOMMENDATIONS

Based on the findings of this study, several measures are recommended to increase the participation of non-utility entities in power generation in India in general, and in Gujarat and Maharashtra in particular. The recommendations are divided into two categories: general and specific.

General

1. It is necessary to define and publicize a clear policy on non-utility power generation, covering cogeneration and power-only systems. The primary policy issues are:

(i) Permission for independent generators to operate in parallel with, and sell electricity to, the grid.

(ii) The establishment of a straightforward procedure for licensing independent generation systems. This procedure should cover construction and operation permits, import licenses, financing, and fuel supplies.

(iii) Definition of the terms of interaction between the SEBs and non-utility generators. These terms should spell out the technical requirements for interconnection and parallel operation.

(iv) Definition of a price that utilities will pay to independent power generators for electricity and the cost of backup power.

In defining this policy, the following should be taken into account:

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

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

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

2. An important issue for non-utility power generators is the purchase price that the SEBs pay for power. Guidelines should be established for defining this price. A price policy based on the avoided costs of the SEBs offers a fair value for non-utility-generated power and has proven to be an effective incentive for the development of non-utility power generation in other countries, e.g., the United States. This policy will lead to the efficient allocation of resources and expanded generation capacity. In defining a fair purchase price, the following issues should be taken into account:

(i) The SEB's relatively high generation costs that will result from future plants

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

(iii) The increased value of private power to utilities based on the season, time of day, and region

(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 systems.

Specific

In addition to the general recommendations presented above, a number of more specific measures could be taken to speed up the development of non-utility power development.

1. In light of the importance to industry of an adequate supply of electricity, the large industrial cogeneration potential, and the high efficiency of

cogeneration systems, the policy on limiting the natural gas supply to industry should be revisited. Gas-fired cogeneration systems are relatively simple to operate and have low operation and maintenance costs compared to coal-fired systems. Allowing the industry to use natural gas could greatly expand the cogeneration capacity in the country and result in a highly efficient use of the valuable natural gas resource. Similarly, access to natural gas could draw investors into the development of large scale simple or combined cycle power systems to generate electricity for sale to the grid.

2. Similarly, in light of the inadequate supply of power in the country, the policy of limiting the rate of return on power investments to 2 percent above the interest rate should be reevaluated as an incentive to bring more capital into power activities.

3. Leasing and third-party financing of power plants could alleviate some of the financing difficulties associated with non-utility power options. In light of the cogeneration potential in government-owned industries, the government should consider implementing such financing schemes in its facilities.

4. Since industrialists in India are very concerned about the quality and cost of domestic power equipment, international competitive bids for private power systems should be encouraged.

5. Since there is a considerable potential for power generation in the sugar industry that is constrained by the unavailability of proper equipment (small but efficient steam turbines), avenues for developing the capability for manufacturing such power systems should be identified and pursued. Joint venture efforts with foreign manufacturers should be considered to develop and locally manufacture proper power systems based on waste fuels for the sugar industry.

6. Training should be provided for utility and energy planning personnel in defining the purchase price for electricity (according to SEBs' avoided costs). In addition, technical assistance should be provided to industrial cogenerators and independent power generators on interconnection technologies and requirements and on operating in parallel with the grid. In light of the extensive experience of U.S. utilities and cogenerators in such activities, opportunities should be explored for transferring this technical know-how to India.

7. Publicizing local non-utility power generation activities and proposals should be supported, in particular those projects that involve the interaction between SEBs and non-utility generators.

8. Additional demonstration projects should be undertaken to reduce uncertainty about interconnecting with the grid.

9. Studies should be undertaken in other parts of India by local consultants to verify the potential for non-utility power generation to provide a solution to the country's power shortage. Other industrial states with chronic power shortages, in particular, should be early targets of such studies.

10. The feasibility of private power generation dedicated to large industrial complexes or industrial parks should be assessed.

11. If not already available, a detailed analysis of the cost of load shedding should be done so that a more accurate estimate of the economic value of the incremental non-utility power generation can be developed.

INTRODUCTION

India's power generation capacity has increased significantly over the past few decades, rising from 1,712 MW in 1950 to more than 42,000 MW in 1986, for an annual growth rate of about 9 percent. At the same time, however, several factors -- population growth, agricultural expansion, industrial growth and rising energy use -- have boosted the demand for electricity. As a result, the country now faces a power shortage that averages 10 percent and ranges between 15 and 40 percent in some provinces, such as Karnataka and Haryana.

Because of India's socioeconomic priorities, a large share of this power deficit is borne by the industrial sector. During supply shortages, for example, the agricultural sector has priority over the industrial sector, which necessitates power cuts to industry that sometimes reach 80 percent of industrial requirements. The economic loss stemming from these power cuts is tremendous. A study by the Federation of Indian Chambers of Commerce and Industry (FICCI),[1] for example, estimates that a 10-percent power shortage in the industrial sector can cause an annual production loss of Rs. 70 billion ($6 billion). By way of comparison, total annual industrial production is about Rs 620 billion ($50 billion).[2]

Industry must contend not only with the inadequacy of supply, but also with the unreliability of the entire power system. In most provinces, there is no advance notice of when a power cut will be imposed, or how great it will be, which causes disruption in production schedules.

Since India's power sector is dominated by the central and state governments, financing the necessary supply expansion has become a major burden on both state and central government resources. In the Seventh Plan (1985-1990), for example, power activities absorb over 20 percent of the total budget, which is equivalent to over 60 percent of the total energy sector budget. Despite the allocation of funds for capacity expansion, supply is falling further behind demand. For example, electricity demand during the Seventh Plan is projected at about 30,000 MW of additional capacity, but only 22,000 MW of new capacity will be added because of funding shortages. There is already a 5,000 MW shortfall in supply from the Sixth Plan, and this deficit, coupled

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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] World Bank, World Development Report 1985.

with the expected 8,000 MW shortage in the Seventh Plan, totals a massive 13,000 MW shortfall.

NON-UTILITY POWER GENERATION

In light of the financial constraints on government and SEBs from expansion of the country's generation capacity, an alternative source of financing power development is needed. One possibility is to encourage power generation outside the traditional structure of the power sector for sale to the grid. Non-utility entities have a number of options at their disposal for efficiently generating power. For example, industries with substantial steam demand can install cogeneration systems to meet their power and steam needs and sell their excess power to the grid or to nearby customers. Some industries may have access to low-cost fuels such as rice husks, bagasse, and low-grade petroleum that could be efficiently used on-site to generate power. These schemes can be efficiently developed by local communities, reducing the need for transmission network expansion. In addition, non-utility entities, particularly in the private sector, can help to develop large-scale power plants that will reduce the financial burden on the government and the electric utilities.

In recent years, many organizations experiencing insufficient and unreliable power supply have been pursuing various power generation activities. For example, the Bharat Aluminum Company at Korba is installing four units of 67.5 MW capacity each, and the National Fertilizer Industries is installing two units of 15 MW each. A number of private industries in Faridabad are proposing to jointly commission a 100 MW diesel generator. Five major government industries in Baroda are planning to installed a 120 MW coal-fired thermal power plant. And a consortium of some 12 private-sector firms are considering building two 210 MW coal plants in Tamil Nadu with the support of the Tamil Nadu Electricity Board.

So far, with the exception of the Tamil Nadu project, the main purpose of such projects has been to supply the owners power requirements. The sale of excess power from such independent generators to the grid, is the exception, not the rule. But given the appropriate regulatory and economic environment, some organizations could generate power for the sole purpose of sale to the grid.

In fact there are precedents for sale of power to the grid in India. Tata Electric Company in Bombay, for example, is a private utility that generates power and supplies it at high and medium voltage to large customers and to the Maharashtra State Electricity Board. The Ahmedabad Electric Company, another private utility, generates and distributes electricity in Gujarat.

If such private generation activities were expanded and large non-utility power generation capacity were brought on line, the financial pressures on existing power utilities would be reduced and the quality of the power supply in the country would improve. In addition, the entry of independent power generators into the electric power system could be the first step on the road to fundamental changes in the structure of the electric power industry, which could lead to a more efficient utilization of resources invested in the power sector.

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 for sale of electricity to the grid based on national resources and more efficient use of energy. Because of PURPA, over 15,000 MW of non-utility power generation capacity was developed between 1980 and 1985, reducing the need for utility expansion.

STUDY OBJECTIVES

In light of the power situation in India, this study sought to examine the potential for and impediments to the development of non-utility power generation for sale to the grid. To control the size of the study, the scope of work was limited to two states -- Gujarat and Maharashtra. These two western states are among the most industrialized in India and are known to have progressive State Electricity Boards. In addition, a few private utilities are already operating in these states, which increases the likelihood of new developments in power production outside the SEBs.

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 systems using renewable and indigenous energy resources in Gujarat and Maharashtra.

(2) Identification of the technical, economic, financial, and institutional 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 Hagler, Bailly & Company consultants from July 26 to August 23, 1986. The team was assisted by the staff of the National Productivity Council (NPC) in New Delhi, Gujarat, and Maharashtra. The scope of work for the study is presented in Appendix A.

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

REPORT ORGANIZATION

The study report consists of four chapters:

In Chapter 1, the existing power situation in India in general and in Gujarat and Maharashtra in particular is described.

In Chapter 2, an initial estimate is made of the technical, economic, and financial potential of power production from industrial and commercial cogeneration as well as from other non-utility power generation options in Gujarat and Maharashtra.

In Chapter 3, major issues and impediments associated with the development of non-utility power generation in India are identified and discussed.

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

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

CHAPTER 1: THE POWER SITUATION IN INDIA

The purpose of this chapter is to review the current power sector structure in India and identify the major characteristics of the power situation that necessitate the development of non-utility power. The chapter begins with a review of the power situation in the country, identifying key power organizations and their roles, comparing current and projected electricity supply and demand, and describing the major causes of the inadequate power supply. Then, the power situation in Gujarat and Maharashtra is examined. Finally, the existing non-utility power generation activities in these states are reviewed.

POWER SECTOR STRUCTURE

The power sector structure in India has changed from scattered units owned and operated by private firms or state organizations to a centralized system where most expansion decisions are made by the central government and system operation and management is the province of the state governments.

At the time of India's independence in 1947, there were scattered generating facilities supplying surrounding towns and industries. The scattered generators were generally run by state governments, or in some cases, by local authorities and private companies. The industrial generators were part of the industrial plants, which 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 electricity generation undertakings and defined the safety requirements. The administration of the Act was left to the state governments.

Soon after independence, the central government decided to centralize power sector planning and make the state governments responsible for the management of power systems. For this purpose, the government passed the Electricity Supply Act of 1948. Under this act, the Central Electricity Authority (CEA) and the State Electricity Boards (SEBs) were formed.

CEA is responsible for developing national power policy and coordinating the various agencies involved in supplying electricity. It is formally responsible for approving investment proposals, providing consulting support to the SEBs, assisting in the integration of supply systems, training personnel, and conducting research and development. CEA is administered by the Department of Power within the Ministry of Energy.

The SEBs are government-owned autonomous corporations responsible for the generation, transmission, and distribution of electricity at the state level. Although the SEBs are theoretically free to manage 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. The SEBs own and operate over 85 percent of the power system in the country.

As a first step toward power system integration in the country, the government created the Regional Electricity Boards (REBs) in 1964. The REBs are responsible for coordinating the operation of the SEBs on a regional level. They are, in effect, associations of SEBs. There are five REBs in India; they are charged with the preparation of coordinated maintenance schedules, the development of integrated operations and efficient generation schedules, and the formulation of pricing policies for the inter-state transfer of power. Similarly, to coordinate rural electrification efforts in the country and provide financial and technical assistance to SEBs, the government established the Rural Electrification Corporation (REC) in 1969. Currently, REC finances over 70 percent of all rural electrification investment in the country.

Faced with the low operating efficiency of the SEBs and their inability to fund the expansion of their generation capacity needed to satisfy growing demand, the government created the National Thermal Power corporation (NTPC) and the National Hydropower Corporation (NHPC) in 1975 to construct and operate large power stations and associated transmission facilities. The NTPC has already established a number of large pithead thermal stations. The NHPC is engaged in setting up hydro-electric stations, but since the states control water rights and are reluctant to relinquish rights to the central government, hydropower project development is more difficult and protracted.

Another government organization involved in power generation in India is the Department of Atomic Energy, which is responsible for the country's nuclear plants.

In addition to these government entities, there are five private utilities in the country, two of them involved only in distribution activities.

ELECTRICITY SUPPLY AND DEMAND

India's power generation capacity stood at over 42,000 MW in 1985, with coal accounting for almost 60 percent, hydro for 34 percent, and oil, nuclear energy, and natural gas for the remainder. 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.

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As projected in the Seventh Plan, the country's generation capacity is expected to exceed 64,700 MW by 1990, 31 percent from hydro, 67 percent from thermal, and 3 percent from nuclear power (see Exhibit 1.1). Power plants operated by NTPC and NHPC will represent over 22 percent of total generation capacity (14,000 MW).

Nonetheless, the power supply will not keep pace with demand. According to CEA, between 1985 and 1995 the demand for electricity will grow by 10 to 11 percent per year, while the generation capacity will expand at an annual rate of 8 percent.

In the last 5 years, power shortages averaged an estimated 13 percent of electricity demand. In 1985-1986, only two states -- Kerala and Andhra Pradesh -- had no power shortages. The extent of power shortages in other states is shown in Exhibit 1.2. The industrial sector, has been hardest hit, with some plants in Haryana, for example, receiving power cuts as high as 100 percent of their demand during peak hours (see Exhibit 1.2).

Industry accounts for 60 percent of total electricity consumption, agriculture for 16 percent, and the residential and commercial sectors for the rest. Agriculture's share has grown steadily owing to increased electrical irrigation pumping made possible by rural electrification and encouraged by heavy subsidies.

As indicated by the projections of electricity demand and supply in India, power shortages are expected to continue well into the next decade and perhaps beyond. In the Western region, for example, the peak power generation capacity deficit is projected to grow from 1,605 MW in 1986 to over 7,560 MW in 1995 and the energy deficit to grow from 2,405 GWh to over 22,800 GWh in 1995 (see Exhibit 1.3).

MAJOR CONSTRAINTS ON THE POWER SECTOR

The inability of the power sector in India to supply enough electricity to the country stems from a number of financial, technical, and managerial difficulties. Most SEBs have suffered financial losses year after year. During the Sixth Plan period, for example, the losses exceeded Rs. 45 billion. In the first two years of the plan alone, only two SEBs -- those in Andhra Pradesh and Tamil Nadu -- experienced no losses; the net losses for the remaining SEBs were over Rs. 14 billion (see Exhibit 1.4). In the Seventh plan period, the SEBs are expected to exceed Rs. 117 billion. Almost all SEBs' capital expenditure is financed by debt, primarily loans from state governments. Recognizing the unsatisfactory state of SEB finances, the government of India has, through an amendment to the Electricity Supply Act enacted in April 1985, required SEBs' to earn an annual return, after meeting operating expenses, taxes, depreciation and interest, of at least 3 percent on

Exhibit 1.1

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 1.2: Power Cuts/Restrictions in Force during March 1986

	Cuts	
	Demand	Energy
Delhi	Peak period restriction on industries	10%
Haryana	2 off days/week up to 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.	50%
	Agricultural consumers were supplied power for 6-21 hrs./day.	
Mimachal Pradesh	Peak period restrictions on industries	-
Jammu & Kashmir	15 hrs./day suupply in Jammu and Srinagar for general industrial commercial, domestic and agricultural consumers	-
Punjab	30% demand cut between 1800 hrs-2200 hrs. with peak hour restrictions for industries getting supply from independent feeders including continuous process industries.	-
	Agricultural consumers were supplied power for 8 3/4 hrs.-24 hrs./day depending upon day-to-day availability.	
Rajasthan	Peak period restrictions on industries	0-30%
	Agricultural consumers were supplied power for 8-10 hrs./day.	
Uttar Pradesh	Restricted supply for certain categories of industries. 1 day/week closure for general industrial 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.	
	0% - 13%	
Maharashtra	24 hrs. power suupply rural areas	-
	0% - 20%	
Karnataka	Peak period restrictions on industries	0-70%
	15% - 40%	
Tamil Nadu	All A.T. essential, commercial, agricultural & industries with demand of 130 KVA and less were exempted.	15-40%
	Agricultural consumers were supplied power as per the grouping of rural feeders	
	15% - 40%	
Pondicherry	All H.T. essential commercial, agricultural and industries with demand of 130 KVA and less were exempted.	15-40%
	Agricultural consumers were supplied power as per the grouping of rural feeders.	
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.

Exhibit 1.3

Power Supply Positions of Western Region (On-Going/Sanctioned Schemes Only)

Installed Capacity (MW)	FY'85	FY'86	FY'87	FY'88	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95	Average Annual Growth Rate FY'85-FY'95 (%)
Hydro	1,822	1,372	2,144	2,299	2,552	2,732	3,038	3,443	3,568	3,568	3,568	6.9
Thermal	10,695	11,967	12,177	13,517	15,187	16,317	17,097	17,667	18,167	18,167	18,167	5.4
Nuclear	420	420	420	420	420	420	655	655	890	890	890	9.7
Total	12,937	14,359	14,741	16,236	17,739	19,469	20,790	22,000	22,625	22,625	22,625	5.7
Peak Availability (MW)	7,317	8,035	8,463	9,136	10,049	10,946	11,817	12,584	131,778	13,376	13,376	6.2
Peak Demand (MW)	8,652	9,640	10,220	11,245	12,273	13,459	14,701	16,058	17,544	19,165	20,938	11.0
Surplus/(Deficit) (MW)	(1,335)	(1,605)	(1,757)	(2,109)	(1,244)	(2,513)	(2,884)	(3,474)	(4,366)	(5,789)	(7,652)	-
Energy Availability (GWh)	47,820	52,887	57,795	62,538	(68,247)	73,757	80,529	86,498	91,684	94,988	96,431	7.3
Energy Requirement (GWh)	50,225	55,500	59,084	64,538	70,416	76,618	83,744	91,467	99,913	109,148	119,245	9.6
Surplus/(Deficit)(GWh)	(2,405)	(2,613)	(1,289)	(2,000)	(2,169)	(2,861)	(3,485)	(4,969)	(8,229)	(14,160)	(22,814)	-

Source: CEA, June 1985 (12th Electric Power Supply of India).

Exhibit 1.4

Cumulative Profits (+)/Losses (-) of SEBs Up to March 1982, 1983 and 1984 (Rs. crore)

State Electricity Board	Up to 31 March 1982	Up to 31 March 1983	Up to 31 March 1984
Andhra Pradesh	+ 5.6	+ 15.9	+ 26.6
Bihar	-115.9	-106.8	-119.5
Gujarat	- 31.2	- 31.2	- 28.4
Haryana	-142.7	-197.91	-238.6
Himachal Pradesh	- 52.3	- 59.6	- 70.7
Karnataka	+ 83.1	+111.6	+113.1
Kerala	+ 13.4	+ 9.6	- 2.1
Madhya Pradesh	- 33.1	- 31.1	- 32.5
Maharashtra	+ 19.2	- 1.4	- 29.4
Orissa	- 44.8	- 49.3	- 42.6
Punjab	- 69.8	- 73.1	- 89.5
Rajasthan	- 10.4	- 41.9	- 88.2
Tamil Nadu	+ 88.2	+ 93.5	+ 83.2
Uttar Pradesh	-483.1	-531.6	-607.2
West Bengal	- 48.8	- 83.3	-121.0
Assam	- 75.4	- 98.8	-147.7
Meghalaya	- 24.1	- 25.2	- 29.5
Cumulative Losses	-1131.6	-1343.2	-1646.9
Cumulative Surplus	+209.5	+230.6	+222.9
Cumulative Net	-922.1	-1112.6	-1424.0

Source: **Center For Monitoring Indian Economy "Current Energy Scene in India" July 1985**

their historically valued fixed assets. Many SEBs, particularly those of the poorer states, are expected to experience considerable difficulty achieving this level of performance. The fact that the SEBs do not generate enough revenue to cover their expenses prevents them from borrowing funds from most international development agencies that provide loans for power sector development. The World Bank, for example, requires that over 30 percent of the capital needed for expansion come from utility revenues.

The financial difficulty of SEBs is in part due to their tariff structure which does not fully represent economic pricing, i.e. long-run marginal cost (LRMC) pricing. An analysis of 1981 SEB tariffs, for example, indicated that they were on average only 52 percent of LRMC; industrial tariffs were almost 90 percent, domestic 36 percent; and agricultural only 27 percent. Despite espousing energy prices which reflect true costs in both Sixth and Seventh Plans, the government of India and the states have, until now, opposed the principle of economic pricing of power, for reasons associated with social and agricultural objectives. Any program in pricing reform, therefore, is likely to be very slow.

In addition, the operations of some SEBs are hampered by the poor condition of their plant and equipment. Factors that have contributed to the poor state of thermal plants include inadequate maintenance (due to capacity shortages), deficiencies in manufacture, non-availability of spares, and the poor quality of coal. As a result the plant load factor of many SEB units is below 50 percent (see Exhibit 1.5). Furthermore, transmission and distribution (T&D) systems have suffered from inadequate maintenance and overloading due to inadequate investment, resulting in T&D losses of over 20 percent (see Exhibit 1.6).

Finally, the management practices of some SEBs are generally outmoded and inadequate, and pace of improvements has been very slow. The combination of these factors will constrain efforts to improve the power supply in India.

The generation of electricity by non-utility entities, however, can reduce the pressure on the SEBs to expand capacity; and can introduce capital sources that have traditionally been unavailable to the power sector. As the pressure to expand decreases, the SEBs will be able to devote more of their resources to the improvement of operational and managerial efficiency. In addition, non-utility entities will expect no financial support from the government and will thus be motivated to operate efficiently.

The few private-sector utilities operating in India, are generally performing well financially and have plant load factors that are consistently higher than those of the SEBs (see Exhibit 1.5). This high quality of operation is one reason that these utilities are able to obtain financial support from international organizations to expand their systems.

Exhibit 1.5

Plant Load Factor of Thermal Plants (percent)

	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86*
Electricity Board						
Delhi	60.0	50.0	51.0	47.7	51.1	51.0
Haryana	31.7	37.3	32.2	31.1	34.7	23.8
Jammu & Kashmir	2.0	19.1	1.0	1.5	-	-
Rajasthan	-	-	-	41.2	57.2	57.5
Punjab	37.6	41.8	51.0	57.7	64.3	58.9
Uttar Pradesh	37.5	37.6	39.6	34.1	311.6	47.1
Gujarat	50.0	53.6	57.9	55.3	54.0	55.1
Madhya Pradesh	52.4	49.9	58.5	53.1	51.7	57.7
Maharashtra	52.6	49.4	50.2	51.0	46.6	54.8
Andhra Pradesh	36.3	46.6	51.1	54.6	54.4	67.3
Tamil Nadu	34.5	37.8	44.0	39.4	49.0	62.8
Karnataka	-	-	-	-	-	33.5
Bihar	31.4	34.4	38.5	32.8	30.5	34.1
Orissa	34.0	34.9	34.2	33.3	32.2	31.7
West Bengal	42.1	37.6	38.5	34.9	36.5	43.2
Durgapur Projects	29.0	31.0	36.0	30.3	28.7	
Assam	36.5	34.8	36.9	34.2	29.6	27.5
Central Sector						
National Thermal Power Corporation	46.0	49.7	48.7	53.5	53.6	
Neyveli	60.0	65.0	73.0	74.2	77.2	
Damodar Valley Corporation	37.5	51.7	49.6	46.1	48.6	49.4
Private Sector						
Ahmedabad Electric Company	55.0	576.0	69.1	77.3	71.3	
Sabarmati	58.0	67.0	77.4	73.2	71.4	
Trombay (Tata)	70.0	77.0	75.1	75.1	65.7	
Calcutta Electric Supply including Titagarh	57.0	57.0	57.6	52.7	54.0	
All-India	44.2	46.4	49.4	47.9	50.1	52.4

Source: **Center for Monitoring Indian Economy "Current Energy Scene in India," July 1985.**

Exhibit 1.6

Transmission and Distribution Losses of SEBs: 1980-81 to 1984-85 (percent)

SEB/Department	1980-81	1981-82	1982-83	1983-84	1984-85
Assam	19.31	21.31	21.46	20.92	20.00
Andhra Pradesh	22.55	23.41	23.58	21.38	21.23
Bihar	22.07	23.14	22.16	22.21	23.14
Gujarat	19.78	29.93	20.82	21.68	24.19
Haryana	22.63	19.76	19.27	19.56	21.81
Himachal Pradesh	19.34	17.30	19.05	18.78	21.04
Jammu & Kashmir	48.05	44.69	40.26	40.38	36.00
Karnataka	24.58	21.98	21.64	20.98	22.00
Kerala	14.86	15.16	20.56	28.25	25.00
Maharashtra	16.21	15.30	15.22	14.84	14.50
Madhya Pradesh	22.33	22.57	21.11	19.45	19.15
Meghalaya	9.08	8.04	7.07	6.10	7.20
Orissa	19.19	18.97	18.09	17.99	18.00
Punjab	19.58	19.95	19.77	17.03	16.98
Rajasthan	26.59	25.40	26.15	25.29	25.25
Tamil Nadu	19.12	18.51	18.53	13.75	18.36
Uttar Pradesh	15.64	18.67	18.770	18.21	19.00
West JBengal	13.68	16.24	19.39	20.54	17.80
All-India (Utilities)	20.56	20.71	20.88	20.86	21.00

Source: **Center for Monitoring Indian Economy "Current Energy Scene in India," July 1985**

To identify the potential for and impediments to the development of non-utility power generation in India, this study concentrates on the two states of Gujarat and Maharashtra. The states are among the most industrialized in India, and represent over 25 percent of power supply and demand in the country. In addition, both have experience with private-sector utilities that have performed reliably. Furthermore, one state has apparently welcomed non-utility power generation as a way to relieve the power shortage. There is thus already momentum for change.

POWER SITUATION IN GUJARAT

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

The total generation capacity in Gujarat, as of March 1986, was 3,280 MW, of which 300 MW was generated by a hydro plant and the rest from thermal units (see Exhibit 1.7). The AEC owns and operates two units of 161 MW and 220 MW capacity. The remaining plants are operated by GEB. During the Seventh Plan, Rs. 12.7 billion have been allocated to the GEB for system expansion. The existing GEB expansion plan calls for the addition of 960 MW of thermal capacity and 125 MW of hydro capacity during this period (see Exhibit 1.8).

The primary fuel for the thermal plants is coal, with oil used only as a backup fuel. Only one unit, a 280 MW plant at Dhuvaran, runs entirely on oil. There is also a 54-MW gas turbine unit at Dhuvaran, but it is not in use because of lack of natural gas. Currently, only the Utran plant has access to natural gas, but only enough to fuel a 32-MW unit.

The availability factor for the GEB plants varied between 42 percent and 97 percent during 1984-1985, with an average of 72 percent. The plant load factor for the GEB plants ranges from 30 percent to 76 percent with an average of 53 percent. In contrast, the availability factor for the AEC plants is over 80 percent and the plant load factor over 70 percent.

Although the generation capacity in Gujarat is growing, it still cannot keep pace with demand. For example, 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 1.9.A). During the wet season (May to October) the agricultural load is lower, and the peak demand is thus about 500 MW below that of the dry season. Nonetheless, even during the wet season in 1985 there was a shortage of about 450 MW (see Exhibit 1.9.B). As a result, the GEB

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Exhibit 1.7

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) Hydroelectric		
Ukai	Surat	300.0
Total		**3,283.0**

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

Exhibit 1.8

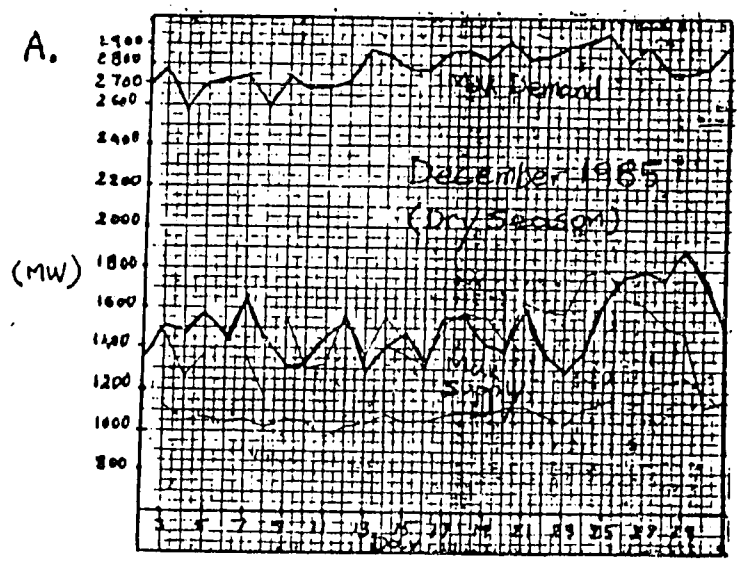
Capacity Additions During Seventh Plan

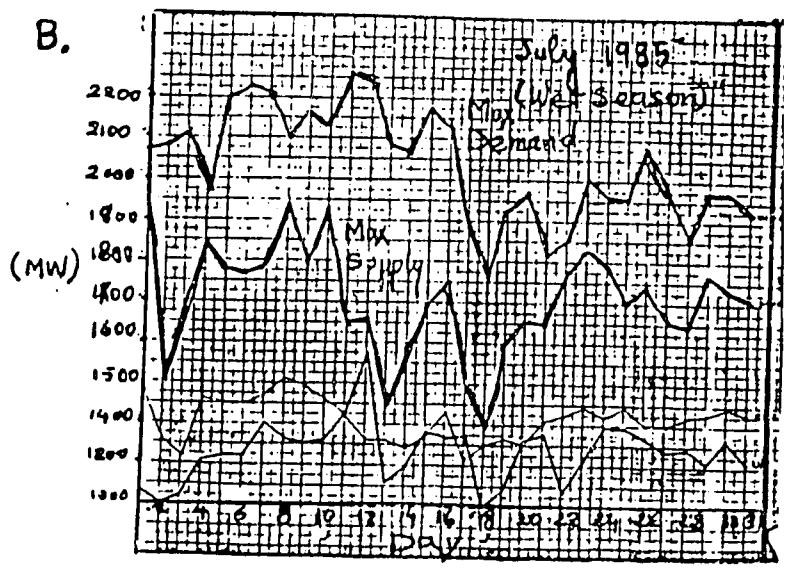
Plant	MW
Gujarat	
A. Thermal	
Wanakori Extension, Kheda	630
Sikka, Jamnagar	120
Gandhinaga Extension, Gandhinagar	210
Total	**960.0**
B. Hydroelectric	
Ukai Left Bank Canal, Surat	5
Kadana Pumped Storage, Panch Mandi	120
Total	**125**
Maharashtra	
A. Thermal	
Chadrapur Extension, Chandrapur	420
Urban Gas Extension, Raigad	324
Khaperkheda Extension, Nagpur	420
Parli Extension, Bid	210
Urban Gas Turbine, Unit-8, Raigad	108
Total	**1,482.0**
B. Hydroelectric	
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 1.9

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





Source: Gujarat Electricity Board

reduced demand by direct load shedding to rural and industrial customers, and by holiday load staggering (see Exhibit 1.10). According to the GEB, this deficit is expected to continue through the Seventh Plan. The capacity deficit was put at 798.5 MW in 1985-86, and is projected to reach 1,226 MW by 1990 (see Exhibit 1.11).

According to GEB, the long run marginal cost of generation to the Gujarat grid is about Ps. 95/kWh. Currently, however, GEB is purchasing electricity from a number of out-of-state suppliers at costs ranging from Ps. 42/kWh (for electricity from NTPC) to Ps. 98/kWh (for electricity from MSEB).

To relieve the power shortage, the GEB has taken a number of steps to encourage non-utility power generation. For example, the GEB purchases power from a wind farm at Rs. 1.4 per kWh, well above the marginal generation cost of its system, in particular, to demonstrate the feasibility of such power options and to stimulate future developments. In addition, the GEB is purchasing power from, or wheeling power for, a number of industrial plants with excess supply. It will also allow the development of a 120-MW power plant by a number of industries for their own use. This plant will be operated in parallel with the GEB system, using the existing grid to supply power to its owners.

POWER SITUATION IN MAHARASHTRA

In addition to the Maharashtra State Electricity Board (MSEB), there are three private utilities in Maharashtra. 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 distribution companies that operate in and around Bombay, respectively. They purchase their power from the MSEB and Tata Electric Company. The private utilities must renew their operating licenses periodically with the MSEB. In addition to these utilities and the MSEB, the Atomic Power Authority of India operates a nuclear plant in Maharashtra.

The total installed generation capacity in Maharashtra, as of March 1986, was 7,200 MW; thermal plants supplied 4,883 MW, gas turbines supplied 672 MW, the nuclear plant supplied 320 MW, and hydroelectric plants supplied the remaining 1,325 MW (see Exhibit 1.12). The 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 owns and operates about 830 MW of thermal and 276 MW of hydroelectric capacity. During 1984-1985, 63.5 percent of the electricity generated in Maharashtra came 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 1.10

Peak Load and Restrictions in Gujarat System (1985-1986)

A.	Gujarat system estimated peak unrestricted demand		2,967 MW
B.	Generation availability at time of peak demand		2,017 MW
C.	Restrictions required to bridge gap between supply and demand		950 MW
	1) Load shedding in rural areas	560 MW	
	2) Holiday staggering to Industry	120 MW	
	3) 50 percent demand cut to high tension Industry	200 MW	
	4) Loss due to low system frequency (49.3 cycle/sec)	70 MW	

Source: Gujarat Electricity Board

Exhibit 1.11

Peak Demand, Installed Capacity Required, and 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 on March 31, 1985	3,383.5	3,383.5	3,383.5	3,383.5	3,383.5
Additions from approved and ongoing schemes	210	425	875	1,335	1,337
Additions from central sector schemes	-	-	-	100	491
Additions from new/ unapproved schemes	-	-	-	-	90
Total additions	210	425	875	1,435	1,918
Retired capacity	-	-	25	145	218.5
Net installed capacity	3,593.5	3,808.5	4,233.5	4,673.5	5,083
Expected deficit	798.5	1,008.5	1,049.5	1,107.5	1,226

Exhibit 1.12

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) Hydro		
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.**

Most of the expansion efforts of the MSEB are funded by government loans. In 1983-1984, for example, only 10 percent of the Rs. 345 billion spent by the MSEB came from its internal resources; the rest was borrowed from the government (58 percent), the public (3.9 percent), and the Life Insurance Corporation (LIC), the Industrial Development Bank of India (INBI), and Rural Electrification Corporation (REC) (27.5 percent). This low level of self financing of expansion efforts is largely because of the inadequacy or MSEB's electricity rates as compared to their long run marginal cost of supply. During the Seventh Plan, 1,480 MW of thermal and 365 MW of hydro capacity are planned for installation in Maharashtra (see Exhibit 1.8).

The availability factor of MSEB thermal units varies between 29 percent and 94 percent, with an average of 67 percent. During 1984-1985, the plant load factor was between 45 and 51 percent. In contrast, the availability factor for Tata Electric Company plants is between 74 percent and 98 percent, with an average of 86 percent, and the plant load factor is between 51 percent and 71 percent, with an average of 65 percent.

Over 49 percent of electricity demand in Maharashtra (measured in kWh) comes from the industrial sector, with agriculture accounting for 16 percent, the domestic sector for 13 percent, and the commercial sector 6 percent. Public lighting, interstate, and other categories account for the remaining 15 percent.

Power shortages in Maharashtra have been limited in recent years. There are no energy cuts (blackouts) to domestic and commercial customers or textile plants. Only general industrial facilities and continuous process industrial facilities have had energy cuts on the order of 10 percent and 5 percent, respectively, during peak demanded periods. The demand cut (limitation on peak demand) to essential customers and service industries has been removed. However, general industries, continuous process industries and textile industries received peak demand cuts of 15, 10, and 10 percent respectively (see Exhibit 1.13).

EXISTING NON-UTILITY POWER GENERATION

Most of the existing non-utility power generation facilities in India are located in the industrial sector. Many industrial facilities have their own captive power plants to supplement power purchased from utilities or for emergency use during grid supply interruptions. An NMB survey of 2,751 industrial facilities with demand of over 100 kW indicates that 1,576 of them have

Exhibit 1.13

Demand and Energy Restrictions in Maharashtra (1984-1985)

Category of Consumers	Power Cut (%)
Energy Cut:	
Domestic	0
Commercial	0
General Industry	10
Continuous Process Industry	5
Textile Industry	0
Essential Consumers	0
Service Industry	0
Seasonal Consumers	0
Demand Cut:	
General Industry	15
Continous Process Industry	10
Textile Industry	10
Essential Consumers	0
Service Industry	0

Notes: There are no power cuts for the Industrial units outside Bombay and Pune Metropolitan regions having their sanctioned demand up to 250C KVA.

Agricultural consumers have no restriction on power use.

Source: Maharashtra State Electricity Board

captive plants.[1] According to the Advisory Board on Energy[2], the total installed non-utility power generation capacity in India in 1984-1985 was about 3,500 MW; this capacity generated 10 billion kWh of electricity, which represented over 6 percent of all electricity generated for that period.

The government has decided to step up captive power generation in the industries like steel, fertilizers, refineries and aluminum. For example, 2,573 MW of generation capacity has been approved by the Central Electricity Authority (CEA) and is expected to be commissioned in the next 5 years. Of this 2,573 MW, 1,005 MW will be in the aluminum industry and 786 MW in the steel industry[3]. Industries applying for captive power permit to CEA are expected to install cogeneration facilities if there is sizeable on-site steam demand justifying such systems.

There is a sizable and growing captive power capacity in Gujarat and Maharashtra. In 1982-1983, over 294 MW of captive power in Gujarat generated over 720 GWh, which represented a capacity factor of over 28 percent (see Exhibit 1.14). In Maharashtra in 1982-1983, 434 MW of captive generation units generated over 700 GWh of electricity, which represented a capacity factor of roughly 19 percent.

In both states, steam plants, mostly cogeneration systems, account for about 45 percent of installed non-utility capacity (see Exhibit 1.15). Over 50 percent of the captive capacity comes from diesel generators used primarily for backup during utility supply interruptions. Very few gas turbines are used for power generation. The capacity factor for the steam plants is 40 percent, while that for the diesel generators is only 12 percent. These figures indicate that the diesel units are used only for backup, while the steam units are operated more or less continuously for process needs.

The captive power generation capacity in Gujarat and Maharashtra has increased substantially since 1982; it is estimated at 685 MW and 650 MW in 1986, respectively[4]. The share of cogeneration systems appears to be growing. In Gujarat, for example, the cogeneration capacity has grown from

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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 Indian Economy, "Current Energy Scene in India", July 1986.

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

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Exhibit 1.14

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 1.15

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

State	Total No. of Industries Having Captive Plants	Installed Capacity (MW)			
		Steam	Diesel	Gas Turbine	Total
Gujarat	134	167 (45%)	128 (55%)	-	295 (100%)
Maharashtra	286	188 (43%)	226 (52%)	29 (5%)	434 (100%)

Source: NMB

166 MW in 1982 to over 400 MW in 1986. The breakdown of this capacity among industry groups is shown in Exhibit 1.16.

To cope with the power shortage, a number of non-utility organizations in India are installing their own large generation units and will use the grid to transmit power to their members. For example, five public industrial facilities in Gujarat -- Gujarat State Fertilizers Company, Gujarat Narmada Valley Fertilizer Company, Petrofils Cooperative Limited, Gujarat Alkalis & Chemicals Limited, and Heavy Water Project, Baroda -- are in the process of installing a 120 MW coal power plant. This plant will supply power to the Gujarat Electricity Board (GEB) grid and in return the participating facilities will receive power from the GEB. A group of private industries in Faridabad, Haryana is planning to install a 100 MW diesel plant to supply part of its power needs. This plant will also use the existing grid for distributing its power. Similarly, a number of private firms are planning to install a 210 MW coal-fired plant in Tamil Nadu. In all these cases, the resulting electricity costs are expected to be lower than the cost of power from the grid.

In addition to the conventional captive power systems discussed above, a wind power generation plant is operating in Gujarat with a capacity of under 2 MW; the power is supplied to the GEB.

Exhibit 1.16

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

CHAPTER 2: 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, and then 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: cogeneration in industrial facilities and commercial buildings such as hotels and hospitals; and power-only systems, i.e., systems developed for the sole purpose of generating electricity for sale.

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 has been 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.

Cogeneration systems can also be used in commercial buildings such as hospitals and hotels to simultaneously produce electricity and steam. In this application, the steam could be used for air conditioning or 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 small 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 systems may use domestic fossil fuels such as coal and natural gas.

The technologies that appear most attractive for large 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, the private sector or other non-utility entities make investments that would normally be made by state electricity boards or the central government. This option would thus relieve the financial burden of generation expansion currently borne by the state and central governments.

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 potential 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 and factors out of "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 price of power provided by utilities. 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 that actual returns to the investor.

The key economic and financial costs and assumptions used in these analyses are summarized in Exhibits 2.1a and 2.1b, and are further explained in

Exhibit 2.1a

Key Assumptions for Economic Analysis

- Fuel Costs:

	Unit Cost	Heat Content	$/mmBtu
Natural Gas	1.85 Rs./m3	36,850 Btu/m3	4.0
Diesel Oil	1.8 Rs./lit	36,478 Btu/lit	4.0
Furnace Oil	1.8 Rs./kg	40,474 Btu/kg	3.5
Coal	260-600 Rs./ton	19,840 Btu/kg	1.05-2.42

- Value of Electricity: 0.80 Rs./kWh

- Marginal Productivity of Capital: 12 percent

- Standard Conversion Factor: 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

- U.S. $1.00 = Rs. 12.5

Source: Hagler, Bailly & Company

Exhibit 2.1b

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: 10 years
- Energy Prices:

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

- U.S. $1.00 = Rs. 12.5

Source: Hagler, Bailly & Company

Appendix C. In the economic analysis, the cost of natural gas has been estimated by reference to international fuel oil parity at Rs.1.85/m^3. The economic cost of coal was provided by ONGC and contains mining and transportation costs. In the financial analysis, fuel costs are the actual market prices of each fuel.

In the economic analysis, it is assumed that the economic cost of electricity is equal to the long-run marginal generation cost of electricity to GEB and MSEB. This assumption is based on the avoided cost concept which is discussed in detail in Appendix E. In simple words, the electricity generated from a non-utility power plant could in effect reduce the need for electricity generation by the utility, resulting in reduced generation costs to the grid. This cost saving or "avoided cost" is a fair value for the non-utility supply. The estimate of this value is based on the power plant mix and generation costs of power plants in GEB and MSEB systems as well as the characteristics of electricity supply from the non-utility generator. For example, if a non-utility power plant can reliably supply firm capacity, the utility will realize large avoided costs from not installing additional peak generators. On the other hand, if the non-utility generators only provide interruptible energy (kWh) to the grid and no firm capacity, the utility's avoided cost will be limited to its variable generation costs.

In the economic analysis, it is assumed that the average value of non-utility electricity to the grid is 80 Ps./kWh. This figure represents the long-run marginal generation cost of electricity to GEB and MSEB. In Appendix E, capacity and energy components of this cost are discussed in length. It is important to realize, however, that this figure is a first approximation of the avoided cost. Estimating a more accurate value of avoided cost requires an integrated production costing analysis of each utility taking into account the quantity, quality, and location of non-utility power sources.

It should also be realized that in the economic analysis no attempt has been made to estimate the full economic value of electricity to the economy. It is believed that economic losses resulting from power shortages far greater than the cost of electricity supply. This, however, should be an important issue in developing national non-utility power generation policies.

In the financial analysis, it is assumed that the current price of electricity to industry is the financial value of electricity. According to industry representatives, the average price of electricity in Gujarat and Maharashtra is about Rs.1.30/kWh. This figure contains demand charge, energy charge, fuel adjustment charge and other supply expenses and applicable taxes.

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 was not the purpose of this study, however, 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 not 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).

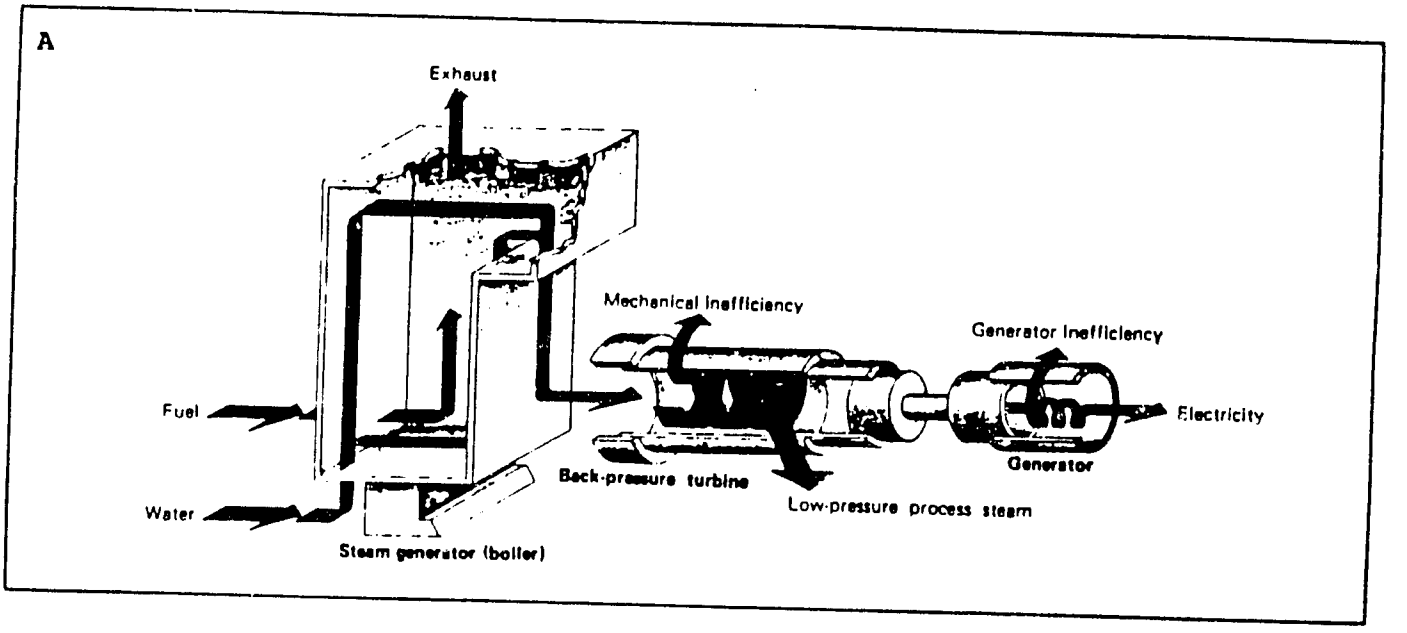
ADDITIONAL INDUSTRIAL COGENERATION

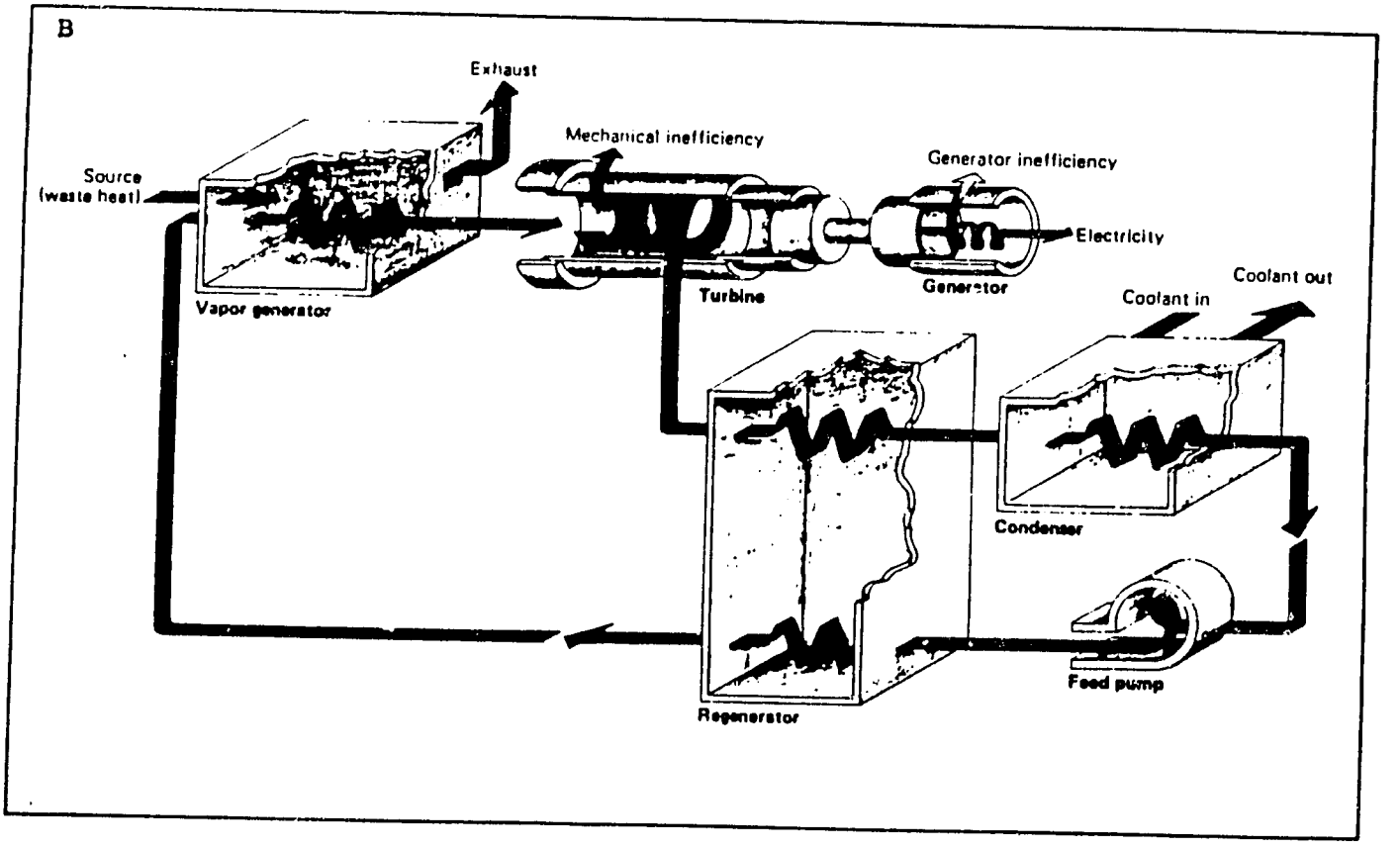
In this section, the potential for additional cogeneration in the industrial sectors of Gujarat and Maharashtra is estimated assuming that such systems will be able to sell their excess power to the grid. Cogeneration systems fall into two categories: topping systems and bottoming systems. In a topping system, thermal energy exhausted in the production of electrical or mechanical energy is used in industrial processes (see Exhibit 2.2a). 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 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 at 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

Exhibit 2.2a Steam-Turbine Topping System

2.2b Rankine Bottoming System





the turbine is used directly in the process (see Exhibit 2.2b). 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

Technical Potential

The potential for industrial cogeneration depends on industry's heat and electricity needs, the price of fuels and electricity, and the cost of cogeneration equipment. To develop a first approximation of the technical potential for topping cogeneration in Gujarat and Maharashtra, we assume that all industries with a steam demand of over 20 tons per hour will install boiler steam turbine cogeneration systems regardless of fuel prices or technology costs. Industries with a steam demand less than 20 tons per hour are in general considered too small for cogeneration systems. Typical thermodynamic characteristics of boiler steam turbine cogeneration systems are presented in Exhibit 2.3. Among available cogeneration technologies, these systems generate the minimum amount of electricity for a required amount of steam (low E/T).[1] The 1985 steam demand in Gujarat and Maharashtra industries is shown in Exhibit 2.4 and is about 30.3 x 10^{12} kcal (120.4 x 10^{12} Btu). Assuming 1,100 Btu per lb of steam demand, the total steam demand is 49.7 million tonnes per year (in 1985). In a typical boiler steam turbine cogeneration plant the turbine workout -- the amount of thermal energy that converts to electricity as steam goes through the turbine -- is roughly 351 Btu/lb. Assuming a turbine efficiency of 95 percent, the total electricity generation potential in Gujarat and Maharashtra industries would be about 10.7 billion kWh per year, or about 1,875 MW in 1985 based on a capacity factor of 65 percent. Assuming the industrial growth rates indicated in Exhibit 2.5, the total technical cogeneration potential in 1996 will be about 3,700 MW.

If industries install other types of cogeneration systems with higher electric to thermal ratios, the technical power generation potential could increase by a factor of two or more.[2] Therefore the technical potential for cogeneration in Gujarat and Maharashtra could be as high as 7,000 MW. As a first approximation it is assumed that the technical potential is about 5,000 MW.

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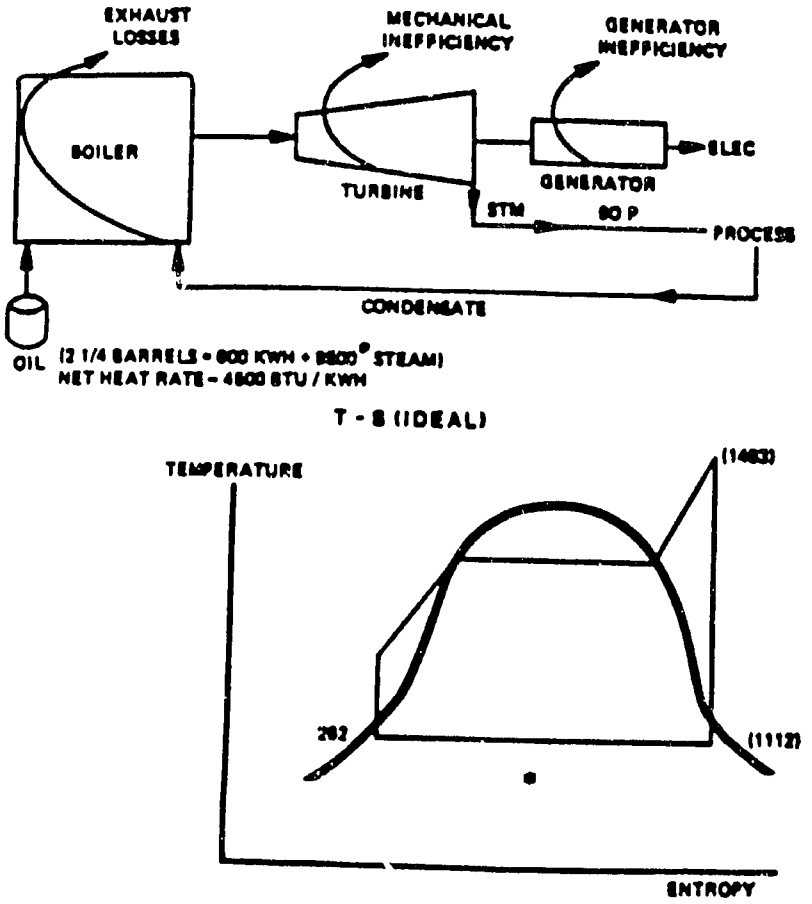
[1] Ration of the end use electricity demand (in theoretical Btu equivalent of 3,412 Btu/kWh) to the end use steam demand (in Btu).

[2] The E/T for a boiler steam turbine system is from 0.1-0.3, for gas turbines with waste heat recovery boilers about 0.05, and for diesel engines with waste heat recovery boilers over 0.80.

Exhibit 2.3

Thermodynamic Characteristics of a Typical Boiler Steam Turbine Cogeneration System



*HEAT LOSS CHARGED TO PROCESS
( ) TYPICAL ENTHALPYS
TURBINE WORKOUT = 1483 - 1112 = 351 BTU/lb
STEAM WORKOUT = 1112 - 262 = 850 BTU/lb
PLANT EFF$_{(ACT)}$ = 72%

Exhibit 2.4

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. Maharashtra (P)	605.15	100.00	-	-	100.00
Rayons					
a. Gujarat (P)	377.25	100.00	-	-	100.00
b. Maharashtra (P)	653.25	-	100.00	-	100.00
Pulp & Paper					
a. Gujarat (P)	392.10	100.00	-	-	100.00
b. Maharashtra (P)	804.00	26.67	73.33	-	100.00
Refineries					
a. Gujarat (G)	1281.40	-	-	100.00	100.00
b. Maharashtra (G)	1812.50	-	-	100.00	100.00
Fertilizer					
a. Gujarat (G)	8307.60 1.60	-	98.40	100.00	
b. Maharashtra					
(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. Maharashtra					
(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. Maharashtra (P)	388.60	100.00	-	-	100.00
Pharmaceuticals					
a. Gujarat (P)	743.70	28.00	72.00	-	100.00
b. Maharashtra (G)	125.60	100.00	-	-	100.00
Tyres					
a. Gujarat	--	--	--	--	--
b. Maharashtra (P)	214.40	100.00	-	-	100.00
Soaps					
a. Gujarat	--	--	--	--	--
b. Maharashtra (P)	201.00	100.00	-	-	100.00
Foods					
a. Gujarat(G)	100.50	100.00	-	-	100.00
b. Maharashtra (P)	388.60	100.00	-	-	100.00

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

Source: National Productivity Council

Exhibit 2.5

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

Economic and Financial Potential

To identify the economic and financial potential for topping cogeneration, the study team used a computer model developed by Hagler, Bailly and used in the United States and other countries. A detailed description of this model is presented in Appendix D. The model simulates the market for cogeneration equipment based on industrial steam demand, fuel and electricity prices, technology costs, performance, and availability, and the relevant regulatory and tax environment in a country or a region. For each technology, the model computes the life-cycle cost (LCC), calculates its market share, and determines the total market size over the period of analysis. In the following paragraphs, the input data and the market assessment procedure for Gujarat and Maharashtra are briefly described.

The starting point for assessing the market size or the potential for cogeneration is to determine the demand for industrial process steam. Industry in each state is divided into public and private categories. This division is necessary because of differences in the availability of funds and fuels, in the minimum acceptable rate of return on investment, and in the applicable tax rates. Only industries with steam demand of over 20 tonnes per hour are considered, as the thermal and electrical loads for units with smaller demand are often too low to justify cogeneration investments. The 1985 steam demand in the industries of Gujarat and Maharashtra is shown in Exhibit 2.4. These figures do not include the steam already produced by cogeneration systems. The expected rate of growth for each industry group is shown in Exhibit 2.5. The distribution of steam by fuel type and by electric-to-thermal load ratio is shown in Exhibits 2.6 and 2.7. The information presented in Exhibits 2.4 to 2.7 was provided by the National Productivity Council (NPC), based on its experience and available industry data in Gujarat and Maharashtra from the Seventh Plan Document published by the Planning Commission, various issues of Urja Energy Monthly, and the 1985 and 1986 issues of Current Energy Scene in India published by the Center for Monitoring the Indian Economy.

An industrial facility 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 costs and benefits of each system on a life-cycle basis. It assumes that the facility will be allowed to sell its excess electricity to the grid. Therefore, the cost of electricity to the facility and the price that the utility (or other customers) will pay for the excess power are both taken into account. The fuel and electricity prices used in the model are those presented in Exhibits 2.1a and 2.1b.

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Exhibit 2.6

Steam Distribution by Fuel Type (percent)

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

Source: National Productivity Council

Exhibit 2.7

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

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

Source: National Productivity Council

Nine cogeneration technologies are considered in this analysis:

- 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
- Oil-fired diesel engine with waste heat recovery boiler.

The capital and O&M costs of these technologies 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 extensively by the industry. The other technologies are relatively new to the industry, and will penetrate the market at 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 the late 1980s and the combined cycles in the early 1990s, while the conventional boiler steam turbines are already in wide use.

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 the highest net benefit. Based on the input data provided in Exhibits 2.7 through 2.10, the model estimates an economic potential for topping cogeneration of 2,546 MW in Gujarat and Maharashtra industries (see Exhibit 2.11a).

The estimated financial potential for industrial topping cogeneration systems in Gujarat and Maharashtra over the next 10 years is 2,150 MW (see Exhibit 2.11b). The industries with the largest potential are the fertilizer, basic chemicals, and refinery industries with potentials of 784 MW, 591 MW, and 339 MW respectively. About one third of the potential, roughly 710 MW, lies in existing facilities, with the remaining 1,440 MW in plants that will come on line between 1986 and 1996. The availability of natural gas will have a major 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, the team assumed that only fertilizer plants and refineries will have access to

Exhibit 2.8a

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

Industry	Potential (MW)		
	Gujarat	Maharashtra	Total
Textile	43	36	79
Rayon	23	31	54
Pulp & Paper	21	36	57
Refineries	104	148	252
Fertilizer	433	279	712
Basic Chemicals	761	157	928
Dyes	18	58	76
Food	12	29	41
Pharamaceutical	250	53	303
Tyres	0	13	13
Soaps	0	41	41
Total	**1,665**	**881**	**2,546**

Source: Hagler, Bailly & Company

Exhibit 2.8b

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

Industry	Potential (MW)		
	Gujarat	Maharashtra	Total
Textile	26	22	48
Rayon	14	21	35
Pulp & Paper	13	24	37
Refineries	140	199	339
Fertilizer	474	310	784
Basic Chemicals	486	105	591
Dyes	11	40	51
Food	7	20	27
Pharamaceutical	164	37	201
Tyres	0	9	9
Soaps	0	28	28
Total	**1,335**	**815**	**2,150**

Source: Hagler, Bailly & Company

Exhibit 2.8c

Distribution of Financial Potential for Industrial Topping Cogeneration in Private and Government Industries (1986-96)

	Potential (MW, %)		
	Private	Government	Total
Gujarat	463 (35%)	872 (65%)	1,335 (100%)
Maharashtra	285 (35%)	530 (65%)	815 (100%)
Total	**748 (35%)**	**1,402 (65%)**	**2,150 (100%)**

Source: Hagler, Bailly & Company

natural gas. If all industries were able to use natural gas, the computer runs indicate that the financial potential will be over 3,000 MW. The increase in cogeneration potential in this case is mainly because of the low capital and O&M costs of gas-fired cogeneration systems (assuming all other inputs remain the same).

About 65 percent of the industrial cogeneration potential lies in government owned industries (see Exhibit 2.8c). More detailed results of the cogeneration market in Gujarat and Maharashtra, including the market potential according to various technologies are presented in Appendix D.

It should be realized that the above figures are rough estimates of the potential and depend on input values used in the model. Any modifications in input parameters, such as, fuel prices, fuel availability, electricity prices, technology diffusion rates, could have large impacts on the size of the potential. In a more detailed analysis, it is possible to conduct different computer runs in order to evaluate the impact of each input variable on the potential.

Potential for Bottoming Cogeneration Systems

Bottoming cogeneration is suitable for industries with exhaust streams at 300°C or more. In general, bottoming systems that generate less than 500 kW of electrical output (which corresponds to waste heat streams of over 10 mmBtu/hr) are neither readily available nor economically viable. Therefore, in this analysis, the team concentrated on industries with continuous waste heat streams of over 10 mmBtu/hr. The prime candidates for such systems are the 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 kiloliters per year, corresponding to waste heat streams of 1.0 to 5.0 mmBtu/hr. Therefore, none of these plants is a viable candidate 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 operation.

Refineries, petrochemical plants, and fertilizer plants are the only facilities in Gujarat and Maharashtra that have any viable bottoming cogeneration potential. According to NPC, ten 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 industrial growth average of 7 percent per year between 1986 and 1996, the cumulative 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, the economic levelized cost of electricity from bottoming cogeneration systems ranges from 55.4 to 77.0 Ps./kWh and the financial levelized costs range from 69.8 to 119.9 Ps./kWh (see Exhibit 2.9). These costs compare favorably with both the estimated long run marginal generation cost of utilities and the current price of electricity to industry. Therefore, the entire technical potential is both economically and financially attractive.

COGENERATION IN COMMERCIAL BUILDINGS

In recent years, attention has turned to the possibility of installing 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 building complex. 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 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 overall system efficiency of 70 to 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) that a diesel system can match more easily than the other systems. For example, typical E/Ts for commercial buildings in India and other countries are between 1 and 10 and in some cases even higher, since most commercial buildings require electric power for lights, air conditioning, elevators, and equipment, while thermal power is needed only for hot water. Diesel cogeneration systems normally have E/T ratios of 0.8 to 1.1, while boilers with steam turbines have E/Ts from 0.1 to 0.3, and gas

Exhibit 2.9

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 Industry	Public Industry
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.

turbines with waste heat recovery boilers have E/Ts from 0.3 to 0.5. Thus, diesel systems give a better match of supply and demand.[3]

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 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 a day or more because of the unreliability of grid power.

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 for systems operating only on standby, it is for systems operating continuously in densely populated areas. In many cases, a separate building has been built to house the diesel system. A mitigating factor for diesel 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 in which large buildings are usually cited. Large diesels with good operating practices will emit approximately 1.6 kg of NOx, 0.03 kg of particulates, and 0.4 kg of carbon monoxide per 100 kWh generated. In comparison, a large central coal-fired power plant with good controls will emit 0.3 kg of NOx, 0.14 kg of particulates, and 0.02 kg of carbon monoxide per 100 kWh.

While emission control technologies are available for diesels, these must be monitored closely; it is easy for them to go out of adjustment as diesel output changes to meet load variations. If this occurs, 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 that give the pollutants time to disperse before they reach ground level. Several organizations in the

[3] Part of all of the electrical demand for air conditioning can be satisfied using steam in an absorption chiller. This has the next effect of reducing the electric-to-thermal demand ration.

Bombay area interviewed in the course of this study indicated that environmental problems were of serious concern in the area, as evidenced by restrictions on coal use by industry. While no specific regulations exist for diesel emissions, they might be introduced 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 the space needed 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 urban areas, where many of the larger buildings are located and where land is very expensive or simply not available.

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

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 Bombay Electric Supply and Transport (BEST) provides electrical service to most of Bombay. In 1984-1985, commercial buildings accounted for 684 million kWh, or 37.5 percent of BEST's total sales of 1,703 million kWh. Assuming a 40 percent overall load factor for commercial buildings (BEST did not estimate this figure; rather, it is approximately equal to that realized in the United States), total commercial building sector demand would be 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 the potential is likely to be realized.

Experience in the United States and Europe indicates 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 that may have some heating demand, because large buildings usually 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.

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After discussions with building owners and operators and with consultants, the study team focused its efforts in Bombay on large hotels and hospitals as representing the most attractive cogeneration opportunities. Office buildings were felt to have a very low potential because they have little thermal load. The two building types that appeared to have significant thermal loads were 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 between 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 1,528 rooms, or one-third 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 figures are representative of the remaining hotels (and they appear reasonably close to consumption in other countries), and if the hotel population grows at 3.6 percent per year (the expected Indian urban population growth rate between now and 1996), this sector will have 7,043 rooms by 1996, with a cogeneration technical potential of 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 percent of all the hospital beds in Maharashtra, or approximately 16,340 beds. The total number of beds is projected to grow at 2.6 percent per annum, for a total of 24,000 hospital beds in the greater Bombay area by 1996. These three hospitals together had a total of 1,100 beds, with a specific power demand of about 2.7 kW/bed. This implies that 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 as offering 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. Diesel generator sets and waste heat boilers for generator sets having individual outputs of 1 MW or less are manufactured in India at present. Manufacturers estimate that the foreign exchange portion of the generator sets

and waste heat boilers is equal to 10 percent of the installed cost, and the portion for the absorption chillers is equal to 40 percent of the installed cost. Transfer payments such as taxes, duties, and profits are equal to approximately 15 percent of the installed costs for generator sets and boilers and 20 percent 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 generator sets and boilers and 0.90 for absorption chillers.

The economic potential of commercial building cogeneration is estimated for a large hotel, a medium-sized hotel, and a large hospital in Exhibits 2.10a, 2.11a and 2.12a. These indicate that commercial cogeneration does not appear to be economically viable in these buildings. This economic unattractiveness is the result of the relatively high cost of the imported oil needed to fuel these systems and the relatively low economic costs of electricity from the grid produced by domestic coal and hydropower. This does not mean that 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, based on current estimates of economic costs, there is no economic potential at present.

Financial Potential

The financial performance of commercial building cogeneration systems is summarized in Exhibits 2.10b, 2.11b, and 2.12b. These indicate that cogeneration systems appear attractive for the hotels, but not for the hospitals. The hotels are attractive because of 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. At least one major Indian hotel chain has installed a diesel cogeneration system at a hotel in Calcutta, mainly because of the poor reliability of electricity supply in that city. The chain has no plans at present to make a similar installations in their Bombay hotels, which for the past 5 years have had reliable electricity supplies. However, if the Bombay electricity supply situation were to deteriorate in the future to the point where the hotels required several hours of operation of standby diesel generators every day, the chain would look more closely at cogeneration systems.

SMALL-SCALE POWER-ONLY SYSTEMS

In this section, the potential for non-utility power generation from small-scale facilities is discussed. These power-only systems, which will be built solely for generating electricity for sale to utilities or other customers, include:

- Sugar cane residue-fired systems

Exhibit 2.10a

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 2.10b

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

Exhibit 2.11a

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 2.11b

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 2.12a

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	-	1 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/l, 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

Exhibit 2.12b

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

- Other agricultural waste-fired systems
- Fossil fuel-fired 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 crushed sugar cane available in the mill, or from leftovers at the field, such as cane tops and leaves. While power has been generate from bagasse for decades in medium-sized and large 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 potential is presented.

India is the world's largest producer of sugar cane of the 190 million tonnes produced annually, as much as 33 percent is consumed by the vacuum pan sugar factories to produce crystal sugar, 55 percent is consumed by gur and khandsari manufacturers (traditional small-scale operation), and the remaining 12 percent is used for seed and chewing purposes. There are as many as 366 sugar factories now operating in 18 different states and union territories of India. The distribution of these 366 sugar factories in the private sector, public sector, and cooperative sector is shown in Exhibit 2.16.

Several features of the Indian sugar industry should be emphasized:

1. Only 33 percent of all the cane produced is used in conventional sugar mills to produce (white) sugar.
2. Most sugar mills are privately owned, generally through cooperatives (see Exhibit 2.13)
3. Sugar mill capacity is standardized with a basic unit sized at 1,250 tonnes of cane per day (tpd) in crushing capacity; only three mills have a daily capacity greater than 5,000 tpd (see Exhibit 2.14).

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Exhibit 2.13

Total Number of Installed Sugar Factories

State/Union Territory	Private	Public Sector/ State Owned	Coop.	Total
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 2.14

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 Pradesh	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 two or three boilers. The Government of India has established specifications for the plant and machinery required in new sugar factories. The steam and power generation equipment specifications equipment for a typical 1,250 tpd factory are described in Exhibit 2.15.

Technical Potential

A committee created by the Delhi Productivity Council submitted a report on energy conservation and surplus power generation in the Indian sugar industry in November 1982. According to this report, all existing sugar factories in India would be able to produce 1,800 MW of surplus electric power by installing high pressure boilers and special types of power generators. The conditions for and potential of power generation from cane field residue were not 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 2.16). Based on these statistics, it was possible to develop 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
- There are 4 net tonnes of CFR available for each acre of cane cultivation, or 10 tonnes/hectare
- Only sugar mills sized at 1,250 tpd or higher can generate power
- The crushing season lasts for an average 158 days (5.25 months) in Maharashtra and 137 days in Gujarat (4.6 months). In this preliminary estimate, an average of 150 days for both states was used.

The 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 2.16). These estimates should be considered on the high end of realistic for two reasons. First, the estimate of potential power from bagasse is based on the production from modern, efficient power plants that are well maintained. Most of the equipment in India fails to meet these specifications and would likely produce 5 to 10 percent less excess energy. Secondly, since there is no experience in India in harvesting CFR for power

Exhibit 2.15

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

Exhibit 2.16

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 basis of 4 tonnes/acre - Source: Federation for White Sugar Mills.

generation, it seems likely that less than 40 tonnes/hectare of CFR can be collected for power generation. In addition, there are competing uses for CFR, e.g., thatching roofs, cooking fuel, etc., which may reduce the available supplies.

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

Economic and Financial Potential

According to Indian sources, the cost of these measures would be about Rs. 200 million (US $1.6 million) for new factories (incremental capital cost only) sized at 1,250 tpd and Rs. 50 million (US $4 million) for retrofitting existing mills (see Exhibits 2.17 and 2.18). Both capital costs are for 5 MW installed electric capacity. These numbers are in line with a more recent World Bank study that estimates the specific investment cost at U.S. $480/kW for similar situations.[4]

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 now entirely used for cattle feed and are not included 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 the mill gate for an economic cost of Ps. 40-49 and for a financial cost of Ps. 49-Ps. 66 (see Exhibit 2.19). Because these numbers are below both the economic and financial marginal cost of power, Rs. 0.80/kWh and Rs. 1.30/kWh, respectively, all the technical potential is economically and financially attractive. Therefore, the economic and financial potential for power from cane residue is estimated at 350 MW in Maharashtra and 75 MW in Gujarat.

Potential for Other Agricultural 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 agricultural wastes available in Maharashtra are rice husks, paddy straw, ground nut shells, cotton sticks, sawdust, and animal dung. Together,

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

Exhibit 2.17

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 2.18

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 treatment 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

Exhibit 2.19

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

these resources total of 11.5 million tonnes, representing a theoretical potential of about 1,800 MW of power (see Exhibit 2.20). However, none of these wastes are available in sufficient quantities in a small number of places to warrant further investigation (see Exhibit 2.21). All wastes are currently being used as cattle feed, fuel, or construction materials, and are heavily traded. Given the existence of numerous other options for power generation, the team did not consider it worthwhile to pursue the analysis further.

In Gujarat, the same resources exist, but two by-products -- ground nuts and cotton seeds -- also appear to have some potential for power generation. According to a 1984 NPC study,[5] almost 500,000 tonnes of groundnut shells and 535,000 tonnes of various oil seeds would be available annually; another study,[6] however, lists smaller quantities -- 115,000 tonnes and 140,000 tonnes.

Using a mid-point of 300,000 tonnes of groundnut shells and 350,000 tonnes of cotton and other oil seeds and waste, and assuming that only 50 percent of these quantities correspond to locations where these wastes can be collected, the study team arrived 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 Fuel-fired Systems

These systems include diesel engines, gas turbines, and boilers with condensing steam turbines that run on imported diesel oil, domestic natural gas, or domestic coal. In this analysis, the team concentrated on systems fueled by domestic fuels -- coal and natural gas. As a practical matter, these schemes would not normally be cost-competitive with power from a 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 production 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-fired systems. Because the "technical potential" is not a meaningful number, it will not be estimated here.

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[5] National Productivity Council, 1984.

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

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Exhibit 2.20

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 2.21

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

Economic Potential

The estimated production cost for economically delivered natural gas is between Rs. 1,500 and Rs. 2,200 cubic meter. Using the capital cost shown in Exhibit 2.22, the cost of electricity from small natural gas-fired systems is Rs. 0.60/kWh to Rs. 0.99/kW (see Exhibit 2.22). These costs appear to be competitive with power from the existing utilities (i.e., competitive with their long-range marginal costs of about Rs. 0.80/kWh) for 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. The costs are higher primarily because of the much higher capital cost of small coal-fired systems (see Exhibit 2.23). Only at coal costs below Rs. 450/tonne would the cost of power from small coal-fired systems be competitive with the marginal cost of electricity generated by utilities (Rs. 0.80/kWh).

Financial Potential

The financial costs for power from these systems (that is, the price that the investor needs to meet his normal investment requirements) are estimated in Exhibits 2.24 and 2.25. 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. By comparison, the cost of electricity from the grid is about Rs. 1.3/kWh. Coal-fired systems in these relatively small sizes do not appear competitive with utility-supplied power, because the unit cost of electricity for these systems is higher than supplied power (Rs. 1.3/kWh) (see Exhibit 2.25).

The important issue with regard to the attractiveness of fossil fueled-fired systems is the availability and price of natural gas and coal. The government sets priorities in distributing the limited supply of coal and natural gas in the country. Currently, natural gas consumption is restricted to use as a feedstock in the fertilizer and petrochemical industry and to a few power plants. The coal supply is not as tight as that of natural gas, but utilities and large industrial facilities have priority in receiving coal. Furthermore, the price of both fuels is strongly controlled by the government. Therefore, the possibility of power generation from small fossil fueled-fired systems is directly linked to the government's policy on the supply of these fuels. The use of coal in particular could be greatly enhanced in India as advancements in fluidized bed combustion technologies are making them commercially viable.

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Exhibit 2.22

Economic Cost of Electricity from Small Natural Gas-Fired Single 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^3

Source: Hagler, Bailly & Company

Exhibit 2.23

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

Exhibit 2.24

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

System Size	Natural Gas Cost (Delivered Rs/1000 M^3)			
	2200		3000	
	Public Investment	Private Investment	Public Investment	Private Investment
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

- Capacity 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 2.25

Financial Cost of Small Coal-fired Boiler/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, which are delivered to six landfills. A study by the the National Environmental Engineering Research Institute characterized the waste composition[7] (see Exhibit 2.26). The waste has an average calorific value of 2,028 kcal/kg, with an energy content ranging from 900 to 4,300 kcal/kg.

The performance of the waste-to-energy plant is based on a design using proven U.S. technology.[8] A single plant having a 400 US ton per day capacity costs $9 million. Of this, $6 million represents the boiler cost (which is imported), $1 million represents the cost of the 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 of 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 at 33 MW, based on a 400 ton-per-day plant having a peak output of 4 MW.

Economic Potential

The economic potential of a Bombay waste-to-energy facility is estimated in Exhibit 2.27a. The economic capital cost of the system is Rs 131,250,000, based on a foreign exchange requirement of $6 million and local currency requirements of $3 million. 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 cost is not competitive with the team's estimated avoided cost of Rs. 0.8/kWh. However, the cost does not allow any credits for reducing the amount of waste that must be disposed of in landfills. The team's discussions with the Bombay Municipal Corporation (BMC) indicate that these landfill preparation costs are approximately Rs. 20/ton, with no charge for the land itself. If a credit of Rs. 18 per ton is given to the waste-to-energy project because it reduces the volume of waste that must be landfilled by approximately 90 percent, the economic cost is reduced to Rs. 1.37/kWh,

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[7] National Environmental Engineering Research Institute, "Characteristics of Bombay City Refuses," Nagpur, September 1985.

[8] The information on U.S. technology 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.

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Exhibit 2.26

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.

[1] Lower Calorific Value includes a 6% reduction for Hydrogen content.

Exhibit 2.27a

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

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 2.27b. To realize his required return on investment, a private investor would need Rs. 1.95/kWh, which is substantially above cost of electricity supplied by utilities in Maharashtra (Rs. 1.3/kWh). Thus, there is no financial potential for these systems.

Potential for Small Hydroelectric Systems

Many developing countries are interested in developing both small and large hydropower systems either to supply power to the grid or to remote areas. The study team tried to identify the potential for hydropower systems in India smaller than 25 MW and having a capital investment cost of less than Rs. 1 billion ($80 million). Based on experience in other developing countries, this is a reasonable upper limit on the size of a project that might be developed by private investors. Unfortunately, the study team was unable to find detailed information on small hydropower systems that would provide estimates of capital and operating costs and of annual outputs, so no realistic estimates of economic and financial potential could be developed. Information given to the study team on small hydroelectric sites in Maharashtra is shown in Exhibit 2.28. According to this information, 127 MW of small hydropower is being developed at 14 sites, and another 124 projects with a total capacity of 101 MW are under investigation.

Potential for Dendrothermal Systems

Dendrothermal systems are systems in which wood is burned in a boiler to generate power using a conventional steam turbine. The wood is grown on nearby "plantations," 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 the Development of Non-conventional Energy Sources (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 fast growing, can in many cases be grown on marginal lands unsuited for food crops, and have a relatively high heat content. Even though dendrothermal plantations have been under study for some time, there is limited actual experience to draw upon. As a result, the following estimates are somewhat speculative.

Exhibit 2.27b

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 131,250,000
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

Exhibit 2.28

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.

Source: Hagler, Bailly & Company

Technical Potential

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. Thus, the land used for energy plantations is restricted 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 (see Exhibit 2.29). The Advisory Board on Energy estimates that, given proper management and care, annual production from this land could be between 2 and 8 tonnes/hectare year, which gives a potential annual yield of between 22 and 94 million tonnes per year. Assuming a plant load factor of 60 percent and a heat rate of 129 kWh/tonne, the technical potential of dendrothermal plants in Gujarat and Maharashtra is between 580 and 2328 MW. These are only rough estimates, however. For example, actual yields of wood from social forestry projects in India have ranged from 0.8 tonnes/hectare year to over 20 tonnes/hectare year. In addition, there are reports that short-rotation high-density agroforestry techniques (HDAF) -- which eucalyptus planted on irrigated land at a 60 cm by 60 cm spacing and selectively cut, can provide as much as 112.5 tonnes/hectare/year. However, there was insufficient information on the economics of this technique to evaluate it in more detail as part of this study. Finally, such plantations require close management, because the yields are average ones over a cultivation cycle that requires between 3 and 10 years. Thus, care must be taken that wood is not harvested prematurely or stolen.

Even if the land is not suitable for crops and can be used for wood cultivation, it may make more sense to use the wood for cooking than power generation. India, as many other developing countries, is facing a severe shortage of fuelwood for cooking in rural areas. Therefore, the use of wood plantations for power generation may not be as attractive as using them to provide fuelwood to rural families. That decision, however, is beyond the scope of this study.

Economic Potential

The economic potential of dendrothermal plantations based on the costs in Exhibit 2.30. A study by the Gujarat Energy Development Agency estimated the costs of land preparation per hectare (including saplings, manure, leveling, and pesticides) to be approximately Rs. 5,175 ($414). This cost does not include any land rents, since the team does not foresee any productive alternatives to the marginal land used for these plantations. The cost is comparable to dendrothermal plantation costs developed by the study team in other countries. In addition, there are annual costs such as fertilizers, pesticides, and security incurred prior to the first harvest. Depending on the

Exhibit 2.29

Land Available for Dendrothermal Plantations (million ha)

Type of Land	Maharashtra	Gujarat	Fuelwood Output (t/ha/yr)
Open/Degraded Forest	1.116	0.200	3.0
Cultivable Wasteland	1.020	2.000	4.0
Barren/Uncultivable Land	1.725	2.486	2.0
Permanent Pasture/Grazing Land	1.592	0.850	6.0
Farm Perimeter Land	0.491	0.233	8.0
Total	**5.944**	**5.789**	**3.5**

Source: "Towards a Perspective on Energy Demand and Supply in (avg) India in 2004/05," Advisory Board on Energy, Government of India, May 1985.

Exhibit 2.30

Economic Costs of Power from a Dendrothermal Plant

Fuel Costs:

Land Preparation:	Rs. 360/tonne
Annual Collection/Delivery:	350/tonne
Total:	**Rs. 710/tonne**

Power Plant Annualized Costs:

Capital Investment:	Rs. 2,032/kW
Operation and Maintenance:	480/kW
Total:	**Rs. 2,512/kW**

Annual Powerplant Output: (60% load factor)	**5,256/kW**
Annual Wood Consumption: (20% efficiency, or 670 kWh/tonne)	**7.85 tonnes/kW/yr**

Total Power Costs:

Annualized Capital Cost:	Rs. 0.39/kWh
Annual O&M Costs:	0.09/kWh
Annual Wood Costs:	1.06/kWh
Total:	**Rs. 1.54/kWh**

Source: Hagler, Bailly & Company

type of tree, the type of land, the planting practices, and the climate, the first harvest occurs between the third and eighth year; for this analysis, the team assumed it would occur at the fourth year. No detailed estimates for these annual financial costs were available in the documents reviewed by the study team; therefore an estimate of Rs. 400/hectare/year was made, based on estimates made for other Southeast Asian developing countries. Thus, by the time harvesting can begin in the fifth year, the total capitalized investment is Rs. 9,900/hectare. The annualized economic cost is then Rs. 1,257/hectare or, given an output of approximately 3.5 tonnes/hectare, Rs. 360/tonne.

The costs of harvesting and delivering the wood to the power plant are estimated in the GEDA study at about Rs. 21/tonne, which comes to approximately Rs. 75/hectare. With annual costs of Rs. 400/hectare, the total cost is Rs. 475/hector, or Rs. 135/tonne. This cost appears low. Other countries have estimated these annual maintenance and collection costs to be on the order of $100 or more per collected tonne. In addition, the costs of wood in rural areas from forest residues is reported to be on the order of Rs. 350/tonne. This cost is probably lower than it would be for wood from an energy plantation, since those collecting the residues would not incur the costs for maintenance that an energy plantation would, although the energy plantation would presumably have a higher yield per hectare than forest residues would provide. Therefore, the study team used an annual cost of Rs. 350/collected tonne as the variable cost of wood from an energy plantation.

The wood itself is assumed to have a recoverable heat value of 3,500 kcal/kg, which assumes some drying of the wood prior to combustion. Estimates of this value have ranged from 2,000 to 4,500 kcal/kg, depending on the wood species, the moisture content, and the combustor characteristics.

The capital investment costs for a dendrothermal plant, including building, boiler, steam turbine, and auxiliaries, were estimated in the GEDA study to be Rs. 16 million/MW ($1,280/kW). These costs are comparable to those estimated in other developing countries for plants of 10 MW or more. The efficiency of these plants, after accounting for the power requirements of the plant itself is 20 percent. Annual operating and maintenance expenses are about 2 to 10 percent of the initial capital investment. Typical annual capacity factors are 40 to 60 percent. For this study, the team assumed that O&M costs were 3 percent of capital investment and the annual capacity factor was 60 percent.

A calculated value for power from dendrothermal plants of Rs. 1.54/kWh, somewhat more than estimates of marginal power costs to the conventional utilities, is given in Exhibit 2.30. Care must be taken in using this figure, however. In comparing it with the utility's marginal costs, power was assumed to be available to those rural areas where dendrothermal plants

might be cited. That will not always be the case. In addition, this analysis does not take into account the ancillary benefits of these systems such as reclamation of otherwise unusable and possibly eroding land, rural employment, and rural power. If these other factors are taken into account, then power from dendrothermal plants may be marginally attractive.

Financial Potential

The financial potential of dendrothermal power plants is based on the costs in Exhibit 2.31, using many of the same assumptions used in estimating the economic potential. The main differences are noted below.

The actual costs incurred were assumed to be the same for both the economic and financial cost estimates. As a practical matter, the economic costs might be expected to be slightly lower than the financial costs, to exclude the effect of transfer payments. However, the team was unable to find quantitative estimates of this effect. In addition, the interviewees felt this effect was relatively small, since in most cases, transfer payments such as taxes were only a minor part of actual cash flows (probably less than 5 percent). Therefore, the primary differences between the economic and financial analyses arise from the much higher capital recovery factor (0.243) used by the private sector; this factor is the result of the higher return on investment that the private sector requires and the taxes that the private sector must pay.

The capitalized investment when harvesting begins in the fifth year is Rs. 14,237, resulting in an annualized cost for land preparation of Rs. 3,460/hectare or Rs. 990/tonne.

The power plant capital cost is assumed to be the same, although the higher capital recovery factor results in an annualized capital recovery cost of Rs. 3,888. O&M costs are the same. One final cost that a private investor might face is a land rent. Generally, these rents would be low for the marginal land that the plantations would be expected to use. In other developing countries, they have been on the order of $10 to $15/hectare/yr. If such a charge were levied, it would increase the cost of the power in Exhibit 2.34 by approximately Rs. 0.05 to Rs. 0.08.

For the private investor, the financial cost of power from dendrothermal plants (that is, the price the investor would need to receive for the power to realize his required return on investment) is Rs. 2.83/kWh. This cost is substantially higher than current utility tariffs. Thus, these systems will not be financially attractive to private investors without significant government subsidies.

Exhibit 2.31

Financial Costs of Power from a Dendrothermal Plant

Fuel Costs:

Land Preparation:	Rs. 990/tonne
Annual Collection/Delivery:	350/tonne
Total:	**Rs. 1,340/tonne**

Power Plant Annualized Costs:

Capital Investment:	Rs. 3,888/kW
Operation and Maintenance:	480/kW
Total:	**Rs. 4,368/kW**

Annual Powerplant Output: (60% load factor)	**5,256/kW**
Annual Wood Consumption: (20% efficiency, or 670 kWh/tonne)	**7.85 tonnes/kW/yr**

Total Power Costs:

Annualized Capital Cost:	Rs. 0.74/kWh
Annual O&M Costs:	0.09/kWh
Annual Wood Costs:	2.00/kWh
Total:	**Rs. 2.83/kWh**

Source: Hagler, Bailly & Company

LARGE-SCALE POWER-ONLY GENERATION SYSTEMS

It is also possible for private non-utility entities to finance large-scale power plants (over 50 MW). The objective of this type of investment is to provide the power needed by SEBs that is not provided because of financial, institutional or other constraints. Well-developed systems are available 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 generation capacity.

The main issues associated with the development of large-scale power projects by the private sector are associated with the government's policy on allowable rate of return on investment, availability and price of fuels, access to imported equipment, and tax rates.

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

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

Using the capital and O&M costs of these plants, the study team estimated the economic and financial cost of power from similar units, using the fuel costs and other assumptions used to calculate electricity costs in this study. The team found that the economic cost of electricity from the 120 MW coal plant is between Ps. 76.3 and 89.5/kWh (see Exhibit 2.35) depending on the cost of coal (between Rs. 300 and 500/tonne). These costs are comparable with the economic marginal cost of electricity from the SEBs, especially at lower coal costs. Similarly, the financial cost of electricity from a 120 MW coal-fired plant is between Rs. 0.95 and 1.45/kWh, which is competitive with the marginal cost of power from the SEBs (at Rs. 1.3/kWh), especially for lower coal prices (see Exhibit 2.32).

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Exhibit 2.32

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

Similar electricity cost calculations were carried out for a 100-MW diesel plant. The economic cost of electricity from such a plant is about Ps. 87.7/kWh, which is close to the economic marginal cost of electricity generated by the SEBs (see Exhibit 2.33). The financial cost of power from a 100-MW diesel plant is estimated at Rs. 93.1 to 99.4/kWh, which is competitive with the marginal cost of power supplied by the SEBs or utilities -- roughly Rs. 1.3/kWh.

Finally, the team estimated the cost of electricity from combined cycle plants, which are among the most efficient ways of converting fuel energy into electricity. The National Thermal Power Corporation is planning to install about 1,600 MW of combined cycle units along the gas pipeline from Hazira to Jagdishpur during the next 5 years. The World Bank has already approved the loans for these projects.

The economic cost of electricity from combined cycle units, assuming capital costs similar to those of the NTPC plants, is between Ps. 63.8 and 90.2/kWh, depending on the cost of natural gas. If gas is the same price as fuel oil, Rs. 1,800/1,000 cubic meters the cost of electricity from these systems is competitive with the economic cost of power from the grid. Similarly, the financial cost of power from such units is competitive with the cost of power from the grid, even if the price of gas is equal to that of diesel oil (Rs. 3,300/1,000 cubic meters) (see Exhibit 2.34). Therefore, if natural gas is made available to the private sector for power generation, the cost of electricity from gas-fired units can compete favorably with the cost of electricity from the SEBs, both economically and financially.

Assuming that the government will allow use of natural gas and coal for large scale private power generation, theoretically, the entire capacity expansion plan of the GEB, MSEB, and NTPC can be developed by the private sector. This capacity represents a technical potential of over 3,000 MW by 1990. No specific projections of expansion plans beyond 1990 is available. Assuming a growth rate of about 8 percent per year in thermal generation capacity, by 1996 the cumulative private-sector generation capacity would be about 7,000 MW.

The exact cost of power from such units, and the feasibility of their development, depend on the government's policy on such projects. But this preliminary cost calculation indicates that such units could generate electricity at costs lower than the cost of power supplied by the SEBs. The economic and financial potential for power generation from such systems is limited primarily by the availability of financial responsibilities to the private sector. Considering that the existing private utilities in the past have been able to raise or borrow capital for expansion purposes, it is very likely that if allowed, the private sector could supply a major portion of the country's generation needs with large power plants in the coming years.

Exhibit 2.33

Estimates Cost of Electricity from 100 MW Diesel Generator Plant

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

ssumptions:

System Life	= 15 years
Economic CRF	= 0.147
Financial CRF	= 0.257 (Private investment)
	= 0.198 (Public investment)

sed on the capital and O&M cost of Faridabad plant and 7,500 hours of operation per year.

sed on fuel oil costs of 3.0 Rs/kg.

rce: Hagler, Bailly & Company

Exhibit 2.34

Estimated Cost of Electricity from Combined Cycle Plants

Natural Gas Cost (Rs/1,000 m^3)	Electricity (Ps/kWh)		
		Financial	
	Economic	Private	Public
1,800 (1)	63.8	80.5	66.9
2,000	72.6	89.3	75.7
2,600	81.4	98.1	84.5
3,000	90.2	106.9	93.3
3,300 (2)	96.8	113.5	99.9

Assumptions:

Capital Cost	= $620/kW
Annual O&M Cost	= 3 percent of capital cost
Capacity factor	= 60 percent
Gas consumption	= 0.22 m^3 per kWh
Capital recovery factor	= 0.134 (Economic)
	0.247 (Financial, Private)
	0.185 (Financial, Public)

(1) Price of natural gas in par with the economic cost of diesel oil = (1.8 Rs.lit).

(2) Price of natural gas in par with the price of diesel oil (3.4 Rs./lit).

Source: Hagler, Bailly & Company.

SUMMARY

The electricity generation potential and cost of various non-utility power generation options are summarized in Exhibit 2.35. Systems with electricity costs less than Ps. 80/kWh in the economic analysis, and less than Ps. 130/kWh in the financial analysis are considered to be attractive alternatives to the grid supply. These figures represent the economic marginal cost of generation to the grid, and the current price of electricity to industrial customers, respectively.

Among the small-scale power generation options, industrial cogeneration and agricultural waste-fired systems represent the least-cost options. Based on this study's assumptions, the capital cost, fuel and electricity prices and availability of fuels, the economic potential for industrial cogeneration systems could amount to 2,600 MW and the financial potential could be as high as 2,200 MW. If the assumptions are varied, these estimates could be significantly different. For example, if natural gas is made available to all industries (as compared to the current practice where gas is available only to petrochemical industries) the financial potential for cogeneration will be over 3,000 MW.

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

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

The cost of electricity from small-scale fossil fuel-fired systems depends on the price of coal and natural gas, and varies between Ps. 60 /kWh and Ps. 117 /kWh for the economic cost, and Ps. 92 /kWh and Ps. 189 /kWh for the financial cost (see Exhibit 2.35). At low fuel prices and relatively large unit sizes, these systems could compete with power 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 power from the grid. Similarly, the high cost of electricity from dendrothermal systems makes this option unattractive.

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Exhibit 2.35

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

Technology	Economic		Financial	
	Generation Costs[1] (Ps/kWh)	Potential (MW)	Generation Costs[2] (Ps/kWh)	Potential (MW)
A. Small Scale				
Cogeneration				
Industrial Topping Systems	Under 80	2,550	Under 130	2,150
Industrial Bottoming Systems	55-77	50	70-120	50
Commercial Systems[3]	Under 80	30	Under 160	30
Power Only				
Sugar Cane Residue-Fired Systems	40-49	425	49-66	425
Other Agrowaste-Fired Systems	40-49	nil	49-66	nil
Coal Fired Systems	60-99	(4)	92-169	(4)
Gas Fired Systems	78-117	(4)	120-189	(4)
Municipal Waste-Fired Systems[1]	148	--	195	--
Hydroelectric Systems	N.A.	N.A.	N.A.	N.A.
Dendrothermal Systems	1.54	--	2.83	--
B. Large Scale				
Coal-Fired Systems	76-103	(4)	95-145	(4)
Diesel Generators	88	(2)	93-94	(2)
Combined Cycle	64-97	(4)	67-114	(4)

1 Systems with electricity costs of under Ps. 80/kWh are considered economically attractive. This figure reflects the avoided cost to utilities from power supplied by non-utility generators and is estimated based on the long-run marginal cost of electricity generation to GEB and MSEB.

2 Systems with electricity costs of under Ps.130/kWh are considered financially attractive. This figure reflects the current price of electricity to industry in Gujarat and Maharashtra.

3 Analysis was done only for Bombay.

4 There is no resource limitation for these systems. Therefore the total potential could, in theory, replace a major portion of expansion needs in Gujarat and Maharashtra during 1986 - 1996.

Source: Hagler, Bailly & Company

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

Finally, large scale power systems fueled by domestically available fuel oil, coal, and natural gas could produce electricity at costs competitive with the cost of power from utilities. The financial cost of electricity from large coal-fired plants is estimated at Ps. 95 to 145/kWh, and that of electricity from slow-speed diesel generators running on fuel oil at Ps. 93/kWh. The cost of electricity from combined cycle plants running on natural gas is estimated at Ps. 66.9 to 113.5/kWh. At these costs, large-scale power plants developed by the private sector represent a significant opportunity to reduce power shortages in India. They could, in theory, greatly reduce the need for government and SEB investments in power plants.

The estimated financial potential for the non-utility power generation options discussed in this chapter, in theory, could eliminate the power shortage in Gujarat and Maharashtra and reduce the expansion needs of the existing utilities in these states. In practice, however, we do not expect such a high level of development under current conditions. In the next chapter, the major causes of this underutilization of these important opportunities are discussed.

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CHAPTER 3: IMPEDIMENTS TO NON-UTILITY POWER GENERATION

To identify the major issues associated with non-utility power generation, the study team held discussions with over 100 representatives of the Indian government, utilities, industry, financial organizations and the private sector (see Appendix B for a list of meetings). A review of the discussions reveals five issues of prime concern:

- Lack of clear government policy
- Difficulty in financing power projects
- Uncertainty of fuel supply and availability
- Uncertainty of equipment availability and quality
- Uncertainty about terms of interconnection to the grid.

GOVERNMENT POLICY

The government in India controls every aspect of power generation: the supply and price of domestic power equipment and spare parts, capital and foreign exchange availability and costs, fuel availability and prices, tariffs for sale of power to public and private entities, and despatching of units. Therefore, government policy on non-utility power generation is among the most important issues concerning potential developers of such power options.

The government realizes the importance of a reliable and adequate power supply to economic growth and prosperity, and is aware that the existing power sector -- the SEBs -- is unable, in many areas, to provide it. For these reasons, the government appears willing to permit and encourage non-utility power generation in the country. In recent months, various government representatives have made numerous announcements supporting private-sector power initiatives. The central government has even enacted policies to facilitate the development of captive power generation units at industrial plants. However, most of the power generated by these plants is used on-site and not sold to the grid.

Current government policy is intended to encourage industrial facilities to install captive power plants[1]. For example, the government has allowed captive generation to "higher power sensitive units", permitting:

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

- Installation of indigenous diesel generating sets without hindrance for meeting stand-by and emergency requirements,
- Import of large diesel sets but after due processing in accordance with normal procedure,
- Installation of cogeneration system in industries, requiring processed steam or where waste heat is available. In fact, CEA requires industrial applicants for captive generation to explore cogeneration possibilities before a license for a power-only system is granted.

In addition, the government no longer requires facilities to obtain permission to install captive power generation units provided the capacity is less than 25 MW.

However, the central government has taken no explicit stand on the sale of power from independent generators to the SEBs or other customers. The central government's unofficial position is that policies defining the terms of interaction between private generators and the SEBs should be developed by the state governments. Officials in the central government believe that the SEBs should purchase independently generated power if its costs are lower than the state's marginal generation costs. They also believe that the SEBs will act in their self-interest and there is thus no need to establish a policy on the terms of interaction between the SEBs and independent generators.

Private-sector and industry representatives feel, however, that there is so much uncertainty in the government approach to non-utility power that such undertakings are very risky. For example, industrial representatives indicated that although the current policy exempts captive plants of less than 25 MW from the license requirement, it also contains provisions overruling this exemption. For example, if a plant costs over Rs. 50 million, or requires imported equipment, or uses coal as fuel, it must go through the licensing process. In practice, therefore, most captive plants -- except very small diesel generators -- still need to be approved by the central government. This view is shared by both private and public industries.

Finally, the government restricts the allowable financial return on private power (applicable to existing private utilities to 2 percentage points above the current "bank rate," or about 12 percent at present. This policy creates a major financing barrier to power projects.

State Government Policy

The SEBs could have a major impact on the development of non-utility power generation in their service territory. Independent power generators usually

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need to coordinate their operation with the grid. In the case of captive power plants, the facility must rely on the grid for part of its power supply and also for backup purposes. Thus, attitude and policies of the SEBs largely determine the pace of development of non-utility power projects.

In the absence of clear regulations on the terms of interaction between the SEBs and non-utility generators, it will be difficult for prospective investors to determine the financial attractiveness of such undertakings. Theoretically, the value of non-utility power to the grid should be set at the marginal cost of generating power by the SEBs. But even if the SEBs acknowledge the fairness of this concept, they will not be able to pay the price because their tariff structure does not allow economic pricing of power. Therefore, if the SEBs purchase power at their marginal cost and sell it below that price, in the Congress, they will only worsen their financial situation. Therefore, the economic pricing of electricity is very important to the development of non-utility power generation. However, considering the high economic cost of power shortages in the country, the possible financial impact of such transactions SEBs should be viewed in light of the greater positive impact on economic growth of the country.

The role of the SEBs can be seen in the states of Gujarat and Maharashtra. In Gujarat, for example, the Gujarat Electricity Board (GEB) is interested in receiving power from non-utility generators, which it considers a viable complement to the grid. As a result, it has allowed parallel operation with the grid, and in some cases is actually purchasing power from such units. For example, the GEB is buying power from a 2 MW wind power facility at a price well above the long-run marginal cost of its system (it is purchasing the wind power at Rs. 1.4 /kWh, compared with the long-run marginal cost of about Rs. 0.95/kWh). Furthermore, GEB is purchasing surplus power from Tata Chemical industry at costs reflecting the industry's variable cost. In addition, the GEB has granted permission to a group of industries in and around Baroda to install and operate a 120 MW plant and use the grid network to supply power to the member industries (Gujarat Industries Power Company). Finally, it is providing technical assistance to a number of facilities with captive power generators and has commissioned a study to estimate the potential for industrial cogeneration in the state. The GEB has thus done much to promote alternative power supply options in the state.

The Maharashtra State Electricity Board (MSEB), on the other hand, is not very enthusiastic about non-utility power generation. It does not believe that non-utility entities could generate power at costs competitive with those of utilities, and it has allowed parallel operation in only a few instances. This difference in attitude, is in part a reflection of the power supply situation in the two states. In Gujarat, there is a power shortage which is expected to continue through the next decade, while in Maharashtra, there is a relatively reliable and adequate supply of power.

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FINANCING NON-UTILITY POWER PROJECTS

Two issues are central to the financing of non-utility power projects -- the factors affecting the rate of return and the availability of investment funds.

Factors Affecting the Rate of Return

Several factors affect the financing of private power projects in India, lowering expected profits and thus discouraging facilities and outside investors. One of the most important factors is the allowable rate of return on equity. Indian private-sector organizations place stringent financial requirements on power investments, typically a 20 to 25 percent return on equity, after tax. Public-sector firms have a lower requirement of about 15 percent return, pre-tax. The private-sector requirement is similar to that of private firms in other countries the study team has worked in.

Government regulations, as defined in the Electricity Supply Act, hamper obtaining financing for power projects as they restrict the return on equity in power projects to 2 percent over the interest rates. At present this rate is about 12 percent. As a result, industry representatives, both public and private, generally prefer to invest their capital in normal business endeavors, rather than use a significant portion of it for a much less productive power system investment.

A second factor reducing the profitability of power projects is high import duties. The import duty on equipment for industrial projects is 25 percent, while it is 40 percent on equipment for power projects. However, if power equipment is imported to replace old equipment in an existing plant, the duty could be over 100 percent. Thus, if a fertilizer plant is built to include a cogeneration system, the duty on the imported equipment would be 25 percent, but if an operating fertilizer plant installs imported cogeneration equipment, it has to pay over 100 percent duty on the equipment.

Government import regulations also affect the profitability of some power projects. In some situations, the government requires a facility to purchase domestically manufactured power equipment. Because some domestic power equipment have higher costs and lower performance quality, this restriction may make a power project financially unattractive. Even if power equipment can be imported, high import duties can make the projects uncompetitive with other investments.

Tax regulations also have a major impact on the financial attractiveness of power projects. Cogeneration systems qualify for a one-year write-off as an energy conservation investment. For many companies with only one 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 its stock price to drop. While there was no overall consensus on what should be done, several industry representatives suggested that they should be allowed to depreciate cogeneration investments at whatever rate they felt appropriate.

Availability of Investment Funds

In general, because of the limited competition in the Indian market, most industries prefer investing their limited capital in production expansion projects to capture a higher share of the market rather than in power generation and efficiency improvement. This is primarily because of the high expected rate of return on investments in production activities and also because industry is unfamiliar with power systems operation and management. Often the primary incentive for industry to invest in power systems is to avoid the production losses caused by the unreliability of the power supply from the grid, and not the potential energy savings.

If private power projects are found economically attractive, there are some prospects for obtaining private and public financing. Long-term credit is generally available at lower rates than short-term loans. Such credit is usually provided at 14 percent, and priority projects can obtain loans at 12.5 percent. Power generation projects would be likely to qualify as priority projects. Short-term loans currently go for 15 to 18 percent. The private/public differential exists because the primary sources of long-term credit are government-owned development banks and insurance firms: the Industrial Development Bank of India, the Industrial Credit and Investment Corporation of India, the Life Insurance Corporation, the General Insurance Corporation, and the Unit Trust of India. The interest rate charged by these organizations is set by the Ministry of Finance, which generally 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; intervals of 1 year between the approval by the development organization of the project and the release of the money are not unusual.

Another problem with raising money through the development banks is the requirement that the loan agreement include a clause allowing the bank to convert up to 20 percent of the loan amount into equity. This option is often 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.

Acquiring the equity portion of the project is often crucial to obtaining long-term financing and represents a potential problem for Indian firms. Generally, Indian financial institutions and investors require a debt-to-equity (D/E) ratio of 2/1 or less, with priority projects for industry allowed to go up to 4/1. For small firms, where a cogeneration plant represents a

significant portion of capitalization, raising the necessary equity while financing growth and paying out dividends is difficult. In addition, the relatively thin capitalization of Indian equity markets makes the stock price sensitive to changes in the D/E ratio or reported earnings, and makes the management of many private firms less willing to finance projects that are peripheral to the firm's main lines of business.

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 or five issues of $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) that offer a 10-percent to 14-percent return. Because these bonds are issued with "no questions asked" about the source of the money used to purchase the bonds, they are looked on as one way of attracting "black money" -- money from the underground, non-taxpaying part of the economy -- and using it to fund priority projects.

An option many Indian companies are now turning to for long-term financing is leasing. The number of companies in India offering leasing services has gone from 2 in 1980 to over 150 at present. 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 provides "off balance sheet" financing, which allows the company to exceed the 2/1 D/E ratio without adversely affecting its ability to borrow. In addition, leasing may allow a company to exceed the Rs. 200 million in assets threshold that would bring it under the jurisdiction of the Monopoly and Restrictive Trade Practices Act. Finally, because lease payments are fully deductible and the government offers attractive tax incentives to those who invest in new plant and equipment, the net after-tax cost to the lessee may be less than it would be had the lessee actually purchased the equipment. Competition in leasing has reduced its costs to Rs. 14-17/month per Rs. 1,000 investment.

One final financing problem mentioned by industry representatives was the prohibition on accepting loans from foreign manufacturers or lending institutions. When such financing is offered at concessionary rates, the government accepts the loan and in turn lends it to the firm, but at normal interest rates of 12.5 to 14 percent. For example, a foreign manufacturer offered an Indian firm a gas turbine system offered at less than 6 percent

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interest. The government, however, insisted that the loan be repaid to the government at market rates, which made the project uneconomic.

FUEL SUPPLY AND AVAILABILITY

Fuel supply will be a key issue for non-utility power generators. Currently, there are major concerns about the availability, quality, and price of indigenous fuels in India.

With regard to natural gas, the government has emphasized a policy of using this fuel primarily for petrochemical and fertilizer industries to take advantage of the full economic potential of this resource. Government permits for using gas for power generation or for raising industrial steam have come only in very selected cases. However, delays in the construction of infrastructure for gas have meant that substantial volumes of gas are going unused and must be flared. In 1984-85, for example, of the 7,200 million cubic meters of natural gas produced in India, over 3,000 million cubic meters were flared. Recently, the government has approved use of natural gas for some 1,600 MW of power generation in the country all large government plants. However, there are no indications of gas being made available for private power generation. Since natural gas is an ideal fuel for a number of power generation options (e.g., cogeneration and combined cycle), many private sector representatives would like to see a more liberal policy on natural gas distribution. While industry representatives understand the reasons behind the priorities that restrict the supplies of natural gas, they feel that the priorities need to be reconsidered in the light of the new gas discoveries, the large volume of flared gas, and the critical power shortages in the country.

There is uncertainty about exactly how much "associated" and "free" gas is available. Estimates of the supply range from 15 years of consumption to over 60 years, at consumption levels expected to be reached in the next few years when new fertilizer and power plants running on gas in Gujarat are commissioned. One reason for the government's reluctance to supply gas to industry is that it projects that the growing fertilizer industry will use all of the gas. By many accounts, however, the fertilizer plans are overoptimistic and the expected gas consumption has been overestimated. Therefore, it seems very likely that there will be enough gas to be used for power facilities.

There is also no firm agreement or understanding on the price of natural gas; rather, each customer negotiates its own price. Thus, the prices range from old contracts at Rs. 250 per 1,000 m^3 to Rs. 3,000 per 1,000 m^3 for new ones.

Similarly, the coal supply presents a variety of problems. Coal is distributed by the government, with supply priority given to the SEBs and large industries. In order to obtain a reliable supply of good quality coal at a reasonable price, facilities must employ a full time team to track their supply and shepherd the paperwork through the bureaucracy. If these efforts are not taken, it is likely that they will receive low-quality coal, late. Small power generators cannot devote such resources to their fuel supply.

An additional disincentive to using coal is the fact that much of the coal available in India is of very poor quality. Low-quality coal is very hard on equipment and increases maintenance expenses and down time for repair significantly.

EQUIPMENT AVAILABILITY AND QUALITY

In general, in order to promote development of domestic industries, India's policy has been to restrict imports of foreign equipment as much as possible. In the power sector, in some cases, domestic equipment is not competitive with equipment available from foreign suppliers. In addition, the lead time for receiving some domestic power equipment is over 3 years compared to less than 18 months for foreign equipment. Therefore, an obligation to use domestic equipment could make a project financially unfeasible.

In some cases, the decision by the government to prohibit imports of equipment has made power projects unattractive. In one fertilizer plant in Gujarat, for example, according to plant managers, imported power generation units with a capacity of 16.2 MW would have cost under $15 million and would have required a lead time of under 17 months. In comparison, the domestically available system with a generation capacity of 15 MW would have cost over $21 million and would have required a lead time of over 2 years. The government did not approve the importation of the equipment even though the purchase could have been arranged with supplier's credit. The higher cost of the domestic equipment has made the power project in this plant unattractive.

In addition, the domestical equipment for some industries that have a sizable potential for power generation is very energy-inefficient. This is especially true in the sugar industry where systems have been standardized using equipment with very low efficiencies. This has effectively eliminated the likelihood of significant additional power generation without a major investment.

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TERMS OF INTERCONNECTION TO THE GRID

Independent electricity generators will, in most cases, need to rely on existing electric utilities or the SEBs to sell their power, either directly to utilities or indirectly to other customers through the utilities' distribution network. Cogeneration systems will also need to rely on utilities for backup power during system failure or maintenance. Therefore, the terms of interaction between utilities and independent generators play a key role in the feasibility and viability of non-utility power generation projects. There are two components to such interactions: technical and financial.

To facilitate the interaction between utility and independent generator, the technical requirements by the utility should be clearly specified. These include: metering requirements, protective and control requirements, performance requirements covering power factor limitations, harmonic requirements, and operating and maintenance requirements. Such specifications are not clearly defined in India. In addition, because of large variations in the frequency of the grid electricity, which make parallel operation more difficult, many captive plants prefer not to interconnect with the grid to avoid possible damage to their systems. Furthermore, the industry and utilities have very little experience in parallel operation. Some industries especially in Gujarat, have had difficulty operating in parallel with the grid.

Financial issues of interconnection to the grid will, to a large extent, determine the financial attractiveness of a power project. The cost of back-up power and the buy-back rate -- the price a utility pays for independently generated power -- are the two most important components of the financial transactions between utilities and independent generators.

Even if an industrial facility installs a captive power plant, it will still have to rely on the grid supply for backup purposes. According to Indian industry representatives, the utilities often tend to charge high prices for backup power, while they tend to purchase this power at low rates. In one case where GEB purchase electricity from an industry, for example, the purchase price is based only on the variable generation cost to the industry regardless of the utility's generation cost and its electricity prices. Determination of a fair price for non-utility electricity is a complicated issue that will require analysis of the marginal cost of power supply to the utility and the value of a marginal unit of electricity to customers. The common methodology used for calculating the purchase price for electricity based on the utility's avoided costs is described in Appendix E.

The existing uncertainty with terms of interconnection has kept some industries from supplying power to the grid. In one industry in Gujarat, for example, an additional 5 MW could be made available from the existing on-

site power system. But industry finds no incentives to sell power in the current arrangements with the utility.

SUMMARY

The primary barrier to the development of private power generation systems in India is the lack of concrete national and state policies establishing a framework for selling power to the grid and permitting private power generation. This lack creates uncertainty in the market that inhibits the development of private power generation, even though there is a need for such power. Industry and private investors are hesitant to commit resources to private generation, not knowing if the central government and state electricity boards will look favorably on their efforts. As part of the policy framework, legal and regulatory guidelines should be established to govern the purchase of power from the private sector. Procedures for establishing fair purchase prices and defining secure purchase contracts should be defined.

Several other factors combine to create a barrier by making private power projects uneconomical (either in fact or in appearance). Import duties and restrictions on the importation of power equipment, together with foreign exchange restrictions, raise the costs of installing power generation equipment and reduce a power project's value as an investment. In addition, government policies limit profits on power projects to 2 percentage points above the prevailing interest rates, resulting in a lower rate of return on equity than that available on many other types of projects.

Even if the risks of power projects are reduced and the benefits are increased, funds may still not be available to finance projects. Private sector projects have to compete with non-power projects for investment funds. Loans are available through development banks, but bureaucratic red tape and delays limit the usefulness and desirability of these funds.

The inability of potential private generators to secure reliable supplies of good-quality fuel represents another significant barrier to the development of non-utility power systems. The supply of natural gas has been limited by the government to fertilizer and petrochemical plants and recently to a few power plants. Very little gas is made available to other prospective customers. Poor quality of coal and the elaborate effort required to insure its adequate supply makes this fuel not very attractive to non-utility power generators.

Technical issues also create barriers to developing private power generation systems. Lack of experience, standards, and technologies impede efforts to encourage private power generation. Specifically, both industry and utilities lack experience with connecting private generation systems to the utility grid. Standards on metering requirements, protective and control devises,

performance requirements, and other technical factors vital to successfully interconnecting power systems need to be defined.

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

The study conclusions are organized in two categories: power generation potential and major impediments.

Power Generation Potential

The preliminary analyses conducted in this study reveal that the financially attractive non-utility power generation potential in Gujarat and Maharashtra could exceed 2,600 MW during the 1986-1996 period. The private sector could potentially finance, build, own, and operate enough capacity to significantly reduce the current and projected power shortages in the western region.

Industrial cogeneration accounts for the vast majority of this potential, perhaps exceeding 2,000 MW by itself (see Exhibit 4.1). The estimate of the potential could be lower or higher depending on the availability and cost of natural gas, the purchase price for power, regulations governing interconnection with the utility, and the cost for backup power, among other things. This estimate may be on the conservative side since no calculation of the cost of load shedding is included in the analysis. The financial and managerial problems caused by load shedding are one of the major incentives for cogeneration investment in India.

The industries with the highest potential are the fertilizer, basic chemicals, refinery, and pharmaceutical industries. About one-third of the cogeneration potential lies in existing plants (retrofit or replacement of existing steam generating equipment), and almost all the potential comes from topping cycle cogeneration systems, where steam is used first for power generation and then for industrial processes. Over two-thirds of this potential lies in government-owned industries. In the analysis of cogeneration potential, it is assumed that natural gas is available only to fertilizer and petrochemical industries. However, if natural gas is made available to all industries, the analysis indicates that the cogeneration potential could be over 3,000 MW over the 1986-1996 period. The potential for bottoming cogeneration is estimated

Exhibit 4.1

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

Technology	Economic: Generation Costs[1] (Ps/kWh)	Economic: Potential (MW)	Financial: Generation Costs[2] (Ps/kWh)	Financial: Potential (MW)
A. Small Scale				
Cogeneration				
Industrial Topping Systems	Under 80	2,550	Under 130	2,150
Industrial Bottoming Systems	55-77	50	70-120	50
Commercial Systems[3]	Under 80	30	Under 160	30
Power Only				
Sugar Cane Residue-Fired Systems	40-49	425	49-66	425
Other Agrowaste-Fired Systems	40-49	nil	49-66	nil
Coal Fired Systems	60-99	(4)	92-169	(4)
Gas Fired Systems	78-117	(4)	120-189	(4)
Municipal Waste-Fired Systems[1]	148	--	195	--
Hydroelectric Systems	N.A.	N.A.	N.A.	N.A.
Dendrothermal Systems	1.54	--	2.83	--
B. Large Scale				
Coal-Fired Systems	76-103	(4)	95-145	(4)
Diesel Generators	88	(2)	93-94	(2)
Combined Cycle	64-97	(4)	67-114	(4)

1 Systems with electricity costs of under Ps. 80/kWh are considered economically attractive. This figure reflects the avoided cost to utilities from power supplied by non-utility generators and is estimated based on the long-run marginal cost of electricity generation to GEB and MSEB.

2 Systems with electricity costs of under Ps.130/kWh are considered financially attractive. This figure reflects the current price of electricity to industry in Gujarat and Maharashtra.

3 Analysis was done only for Bombay.

4 There is no resource limitation for these systems. Therefore the total potential could, in theory, replace a major portion of expansion needs in Gujarat and Maharashtra during 1986 - 1996.

Source: Hagler, Bailly & Company

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

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

The potential for power generation from bagasse and cane residue over the next 10 years is estimated at about 425 MW -- 75 MW in Gujarat and 350 MW in Maharashtra. This resource represents the least expensive power option of those studied. Power can be generated from sugar cane wastes during the dry season, from November to April. Since this is the period of peak agricultural electricity demand and minimum hydroelectric power availability, developing power systems using bagasse and cane waste could reduce the peak generation expansion requirements of utilities substantially, at the same time reducing the use of oil for peaking units

The potential from other agrowastes is very limited. It is estimated to be only 30 MW, solely in Gujarat.

Small-scale power generation from domestic fossil fuels, i.e., natural gas and coal, is 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 and priced at concessionary rates. The actual size of the potential for these options depends 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 financial generation potential as their costs are considerably higher than the cost of electricity from the grid.

Finally, large scale conventional power systems fueled by domestic fossil fuels, e.g. coal, natural gas, and fuel oil, have generation costs that are competitive with those of the electric utilities. They not only can reduce the cost of power to industry but also present a valuable addition to state-owned power plants by bringing new private capital and manpower into the power sector. Based on the existing private utility performance in India, it is likely that private sector large-scale power plants will be operated more efficiently and reliably, thus increasing the efficiency of the nation's electricity supply.

Major Impediments

The potential for non-utility power generation in India is substantial and is just beginning to be realized. The study team found that the prime motivation for non-utility entities to venture into power generation activities has been their concern about the unreliability of the power supply from the grid. The team found that there are 5 major impediments keeping non-utility entities from investing in power projects. These impediments are explained in the following paragraphs.

Lack of Clear Government Policy

The primary barrier to the development of non-utility power systems in India is the lack of concrete national and state policies permitting private power generation and establishing a framework for selling power to the grid or other customers. Although some government policies are designed to facilitate licensing of captive power projects, in practice almost all facilities must go through the extensive permitting process. Specifically, the licensing process for private power plants of 25 MW or less is greatly simplified, but so many exceptions exist that most plants, regardless of their size, must follow the more time-consuming licensing process. The central government's position, as expressed to the study team, is that policies defining the terms of interaction between private generators and the SEBs should be developed by the state governments. Policies in state governments are not well formulated and there is little precedent and few established procedures for selling power to the grid. This situation creates uncertainty in the market that inhibits the development of private power generation. Industry and private investors are hesitant to commit resources to private generation not knowing if the central government and state electricity boards will look favorably on their efforts.

Difficulty in Financing Power Projects

Financing problems also inhibit the private sector from investing in power generation systems. Obtaining funds to finance power projects can be very difficult. In the first place, these projects face competition for the limited investment funds from private-sector non-power projects. In the second place, even where funds are available from development banks, it can take a long time and great effort to obtain such funds, which limits their usefulness and desirability.

Industries and private investors other hesitate to invest in private power projects since they can often earn higher rates of return on other projects for several reasons. Government regulations limit profits on power projects to 2 percentage points above the prevailing interest rate. Investors typically expect a return of 20 to 25 percent on equity, but since prevailing interest

rates are around 12 percent, power projects will yield a much lower rate of return. In addition, import duties, restrictions on the importation of power equipment, and foreign exchange restrictions add further limitations that reduce the expected rate of return on many power projects. Import duties are 40 percent on equipment for power projects in new facilities and they can be over 100 percent on equipment for retrofit projects. Finally, investments in plant equipment to increase production often appear to be the most attractive use of funds in many Indian industries and decision-makers would rather invest their limited funds in expanding output than in improving energy efficiency.

However, these financing difficulties appear to be surmountable. In at least one case of private power development in India -- the Faridabad project --the developers have had very little difficulty obtaining a mixture of private and public financing.

Uncertainty of Fuel Supplies and Availability

The private sector also hesitates to invest in power projects fearing that they will not be able to obtain reliable supplies of good-quality fuel. The current government policy limits access to natural gas, complicated licensing procedures hamper access to coal, and the expense of using oil add together to create a significant disincentive to private power generation. The supply of natural gas is essentially limited by the government of fertilizer and petrochemical plants. A few gas-turbine power plants have been given access to natural gas recently, but under current policy industry cannot expect to receive supplies for power generation. Coal is distributed by the government and supply priority is given to the SEBs and large industries. Coal supplies are available to potential power generators, but obtaining good quality coal at a reasonable price requires a major effort to track supplies and push the required paperwork through the extensive bureaucracy. Few industries can afford to devote such resources to their fuel supply. The problem of railway wagon shortages and the substantial cost difference between coal transport by rail and by road add to supply uncertainty of this fuel.

Uncertainty of Equipment Availability and Quality

The private sector also hesitates to invest in power generation because government regulations intended to protect domestic manufacturers of power equipment often require the use of equipment that in some cases is more expensive and of lower quality than imported equipment. This can eliminate any financial and energy-efficiency benefits that power projects offer. In addition, it often takes longer to obtain domestic equipment than imported equipment. A typical lead time for obtaining domestic power equipment is

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over 3 years, while foreign equipment can be delivered in less than 18 months.

Uncertainty About the Terms of Interconnection to the Grid

A final reason that the potential for private power is not being met is that the ill-defined state of the terms of interconnection to the grid gives the private sector no assurance that it will be treated fairly when it installs power generation equipment. Independent electricity generators will, in most cases, need to rely on existing electric utilities or the SEBs to sell their power, either directly to the utilities or indirectly to other customers through the utilities' distribution network. Cogeneration systems will also need to rely on utilities for backup power during system failure or maintenance. Many of the issues that need to be defined to govern this interaction have not been spelled out in regulations and policies. Standards on metering requirements, protective and control devises, performance requirements, and other technical factors vital to successfully interconnecting power systems need to be clearly defined. In the absence of well-defined terms of interconnection, industry will face high technical risks as it installs generation equipment.

Financial interconnection issues are also not clearly defined in India. Procedures for determining the cost of back-up power and the buy-back rate -- the price a utility pays for independently generated power -- need to be established. In their absence, utilities often charge unreasonably high rates for backup power and pay low rates to purchase power. The existing uncertainty is discouraging industry from supplying power to the grid.

RECOMMENDATIONS

Based on the findings of this study, several measures are recommended to increase the participation of non-utility entities in power generation in India in general, and in Gujarat and Maharashtra in particular. The recommendations are divided into two categories: general and specific.

General

1. It is necessary to define and publicize a clear policy on non-utility power generation, covering cogeneration and power-only systems. The primary policy issues are:

   (i) Permission for independent generators to operate in parallel with, and sell electricity to, the grid.

(ii) The establishment of a straightforward procedure for licensing independent generation systems. This procedure should cover construction and operation permits, import licenses, financing, and fuel supplies.

(iii) Definition of the terms of interaction between the SEBs and non-utility generators. These terms should spell out the technical requirements for interconnection and parallel operation.

(iv) Definition of a price that utilities will pay to independent power generators for electricity and the cost of backup power.

In defining this policy, the following should be taken into account:

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

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

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

2. An important issue for non-utility power generators is the purchase price that the SEBs pay for power. Guidelines should be established for defining this price. A price policy based on the avoided costs of the SEBs offers a fair value for non-utility-generated power and has proven to be an effective incentive for the development of non-utility power generation in other countries, e.g., the United States. This policy will lead to the efficient allocation of resources and expanded generation capacity. In defining a fair purchase price, the following issues should be taken into account:

(i) The SEB's relatively high generation costs that will result from future plants

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

(iii) The increased value of private power to utilities based on the season, time of day, and region

(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 systems.

Specific

In addition to the general recommendations presented above, a number of more specific measures could be taken to speed up the development of non-utility power development.

1. In light of the importance to industry of an adequate supply of electricity, the large industrial cogeneration potential, and the high efficiency of cogeneration systems, the policy on limiting the natural gas supply to industry should be revisited. Gas-fired cogeneration systems are relatively simple to operate and have low operation and maintenance costs compared to coal-fired systems. Allowing the industry to use natural gas could greatly expand the cogeneration capacity in the country and result in a highly efficient use of the valuable natural gas resource. Similarly, access to natural gas could draw investors into the development of large scale simple or combined cycle power systems to generate electricity for sale of the grid.

2. Similarly, in light of the inadequate supply of power in the country, the policy of limiting the rate of return on power investments to 2 percent above the interest rate should be reevaluated as an incentive to bring more capital into power activities.

3. Leasing and third-party financing of power plants could alleviate some of the financing difficulties associated with non-utility power options. In light of the cogeneration potential in government-owned industries, the government should consider implementing such financing schemes in its facilities.

4. Since industrialists and other perspective non-utility generators in India are very concerned about the quality and cost of domestic power equipment, international competitive bids for private power systems should be encouraged.

5. Since there is a considerable potential for power generation in the sugar industry that is constrained by the unavailability of proper equipment (small but efficient steam turbines), avenues for developing the capability for manufacturing such power systems should be identified and pursued. Joint venture efforts with foreign manufacturers should be considered to develop and locally manufacture proper power systems based on waste fuels for the sugar industry.

6. Training should be provided for utility and energy planning personnel in defining the purchase price for electricity (according to SEBs' avoided costs). In addition, technical assistance should be provided to industrial cogenerators and independent power generators on interconnection technologies and requirements and on operating in parallel with the grid. In light of the extensive experience of U.S. utilities and cogenerators in such activities, opportunities should be explored for transferring this technical know-how to India.

7. Publicizing local non-utility power generation activities and proposals should be supported, in particular those projects that involve the interaction between SEBs and non-utility generators.

8. Additional demonstration projects should be undertaken to reduce uncertainty about interconnecting with the grid.

9. Studies should be undertaken in other parts of India by local consultants to verify the potential for non-utility power generation to provide a solution to the country's power shortage. Other industrial states with chronic power shortages, in particular, should be early targets of such studies.

10. The feasibility of private power generation dedicated to large industrial complexes or industrial parks should be assessed.

11. If not already available, a detailed analysis of the cost of load shedding should be done so that a more accurate estimate of the economic value of the incremental non-utility power generation can be developed.

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.

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: J.V. Raghuraman, Director,
K.C. Mahaan, 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: 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: P.J. Manohar Rao, Managing Director,
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: R.K. Pauchari, Director,
S. Ramesh, Senior Fellow,
Ashok Gadgi, Fellow,
V.V. N. Kishore, Fellow
AS, JS, PS

3:00 P.M.
Organization: Bharat Heavy Electricals Ltd.
Main Topic: Power Generation Equipment
Present: N.K. Dutta, General Manager,
A.K. Chakrabarti, General Manager (CEC),
K.C. 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: P.K. Goel, General Manager,
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: J. Gururaja, Advisor,
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: O. P. Vimal, Director
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

Tuesday, August 12, 1986

11:00 A.M.
Organization: Department of Power
Main Topic: Private Power Generation
Present: Mrs. Chandra
David Jhirad, USAID
AS

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: Vijay L. Kalkar, Adviser, Economic Policy & Planning
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: N. Balasundaram, Director,
K.C. Mahajan, NPC
PS

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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 Development Enterprise,
S. Padmanaban, 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: S.K. Aggarwal, Member (Planning)
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: 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 Performance of Renewable Energy Systems in India
Present: 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: H.R. Patankar, Principal Secretary to Government
H.B. Bhatt, Adviser,
R. Kapoor, NPC
AS, PS

3:00 P.M.
Organization: Ahmedabad Electricity Company (AEC)
Main Topic: Private Utility Operation in India
Present: Lldayan K. Sheth, General Manager (Commercial)
Shashi Kant Shari, General Manager (Finance)
J.J. Rana, Company Secretary,
S. Datta, Advisor/Consultant,
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: S.K. Grover, General Manager,
V. Charandas, Executive Director,
C.G. Patel, Executive Director, Operations,
R.cKapoor, NPC
AS, PS

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

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

Friday, August 8, 1986.

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

Saturday, August 9, 1986.

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

Sunday, August 10, 1986.

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

Monday, August 11, 1986.

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

Tuesday, August 12, 1986.

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

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MAHARASHTRA

Thursday, July 31, 1986.

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

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

Saturday, August 2, 1986.

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

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Monday, August 4, 1986.

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

2:30 P.M.
Organization: Thermax Private Limited
Main Topic: Availability of Power Equipment in India
Present: Shyam Shankaran, Deputy Manager
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: R.V. Rao, General Manager-Projects
P.C. Ghosal, Manager
D.S. Talwai, NPC
AS, PS

3:00 P.M.
Organization: Industrial Credit & Investment Corp. Ltd.
Main Topic: Financing Energy Projects
Present: Shri R.V. Bhargava, General Manager
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
D.S. Talwai, NPC
JS

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
D.S. Talwai, NPC
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)
D.S. Talwai, NPC
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
Giadre, Technical Director
Kagalkar, Chief Engineer, Dispatch
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)
D.S. Talwai, NPC
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)
D.S. Talwai, NPC
JS

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
D.S. Talwai, NPC
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
D.S. Talwai, NPC
JS

2:00 P.M.
Organization: Thermax Private Ltd.
Main Topic: Markets for Power Equipment
Present: Sudhir Mohan, Product Mgr. Heat Recovery
D.S. Talwai, NPC
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

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

11:00 A.M.
Organization: Indian Chemical Manufacturers Association
Main Topic: Industrial Power Generation
Present: K.R.V. Subramanian, Managing Director Colour - Chem Limited
K. Narayanan, President Chemical and Plastics India Ltd.
S.P. Daksny, Manager, National Organic Chemical Industries Ltd.
B.K. Gupta, Chief Engineer, Herdillia Chemicals Limited
H.N. Chakrabarti, Hindustan Lener Ltd.
G.G. Nayak, Executive Secretary, Indian Chemicals Manufacturers Association
M.S. Marathe, Managing Director, SAKHAR Karkahana Sangh Ltd.
AS

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 national economic viewpoint. 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.

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)

[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.

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 Rs./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 that 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.

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:

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

where:

CRF_e = the economic CRF

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 CRF

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

f_d = fraction of debt in project financing

r_d = 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 team during their in-country visit. The key values for the economic analysis 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 capital 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 opportunity cost of gas has been estimated, by reference to international fuel oil party. 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. 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 and 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

- Fuel Costs:

	Unit Cost	Heat Content	$/mmBtu
Natural Gas	1.85 Rs./m3	36,850 Btu/m3	4.0
Diesel Oil	1.8 Rs./lit	36,478 Btu/lit	4.0
Furnace Oil	1.8 Rs./kg	40,474 Btu/kg	3.5
Coal	260-600 Rs./ton	19,840 Btu/kg	1.05-2.42

- Value of Electricity: 0.80 Rs./kWh

- Marginal Productivity of Capital: 12 percent

- Standard Conversion Factor: 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

- U.S. $1.00 = Rs. 12.5

Source: Hagler, Bailly & Company

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: 10 years
- Energy Prices:

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

- U.S. $1.00 = Rs. 12.5

Source: Hagler, Bailly & Company

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 D.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

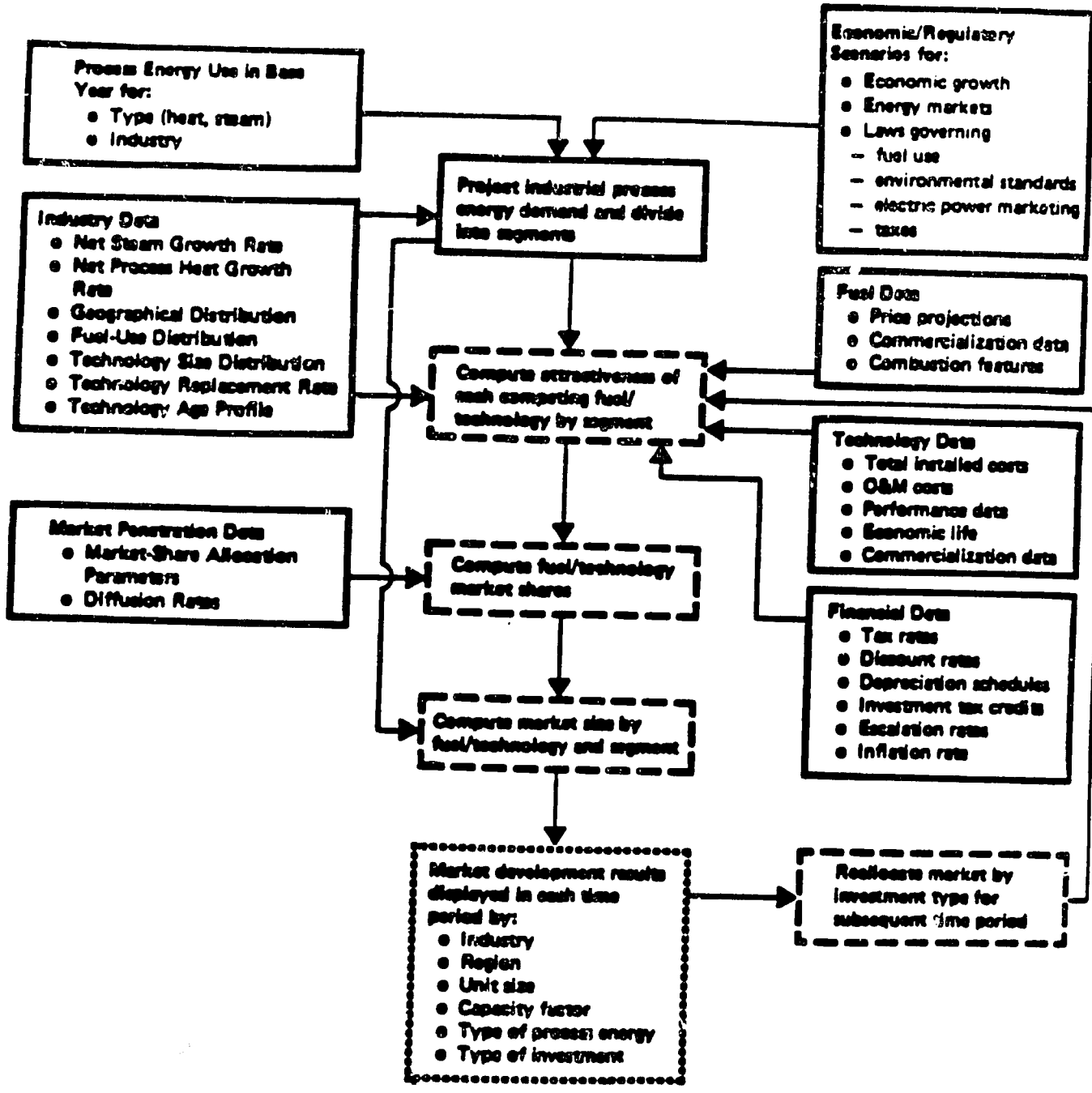
First, we divide the market for industrial steam-generating equipment into segments to examine more accurately the effect of various factors on the selection of steam-generating and cogenerating technology. The total market for industrial steam-generating equipment is disaggregated by the following categories:

- 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 3.1

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 per 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.

Exhibit D.2a

COGENERATION SYSTEM CAPITAL AND O&M COSTS
(Millions of Dollars)

System Size: 60 mmBtu/hr (Fuel Input) Capacity Factor: 0.80

	CAPITAL COST	O&M COST
Fuel Oil Steam Turbine	7.0	0.85
Coal Steam Turbine	11.1	1.34
Natural Gas Steam Turbine	4.8	0.60
Advanced Fluidized Bed	17.3	1.16
Natural Gas GT/WHRB*	6.3	0.38
Fuel Oil GT/WHRB	6.3	0.49
Natural Gas Combined Cycle	14.5	0.69
Fuel Oil Combined Cycle	14.5	0.93
Diesel WHRB	11.8	0.69

Exhibit D.2b

System Size: 150 mmBtu/hr (Fuel Input) Capacity Factor: 0.80

	CAPITAL COST	O&M COST
Fuel Oil Steam Turbine	12.9	1.57
Coal Steam Turbine	24.1	2.84
Natural Gas Steam Turbine	8.7	1.11
Advanced Fluidized Bed	39.2	2.32
Natural Gas GT/WHRB	11.7	0.58
Fuel Oil GT/WHRB	11.7	0.77
Natural Gas Combined Cycle	27.2	1.05
Fuel Oil Combined Cycle	27.2	1.49

Exhibit D.2c

System Size: 345 mmBtu/hr (Fuel Input) Capacity Factor: 0.80

	CAPITAL COST	O&M COST
Fuel Oil Steam Turbine	22.5	2.72
Coal Steam Turbine	48.7	5.66
Natural Gas Steam Turbine	15.1	1.91
Advanced Fluidized Bed	82.7	4.40
Natural Gas GT/WHRB	20.7	0.87
Fuel Oil GT/WHRB	20.7	1.21
Natural Gas Combined Cycle	47.9	1.57
Fuel Oil Combined Cycle	47.9	2.35

Source: Hagler, Bailly & Company

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* Gas turbine with waste heat recovery boiler.

Exhibit D.3a

Economic Potential for Industrial Cogeneration in Private and Public Industries, 1986-1996 (MW)

Industry	Gujarat		Maharashtra	
	Private	Public	Private	Public
Textile	43	0	36	0
Rayons	23	0	31	0
Pulp & Paper	21	0	36	0
Refineries	0	104	0	48
Fertilizer	0	433	29	250
Basic Chemicals	361	400	133	24
Dyes	18	0	58	0
Food	0	12	29	0
Pharmaceuticals	250	0	0	53
Tyres	0	0	13	0
Soaps	0	0	41	0
Total	**716**	**949**	**406**	**375**

Source: Hagler, Bailly & Company

Exhibit D.3b

Financial Potential for Industrial Cogeneration in Private and Public Industries, 1986-1996 (MW)

Industry	Gujarat		Maharashtra	
	Private	Public	Private	Public
Textile	26	0	22	0
Rayons	14	0	21	0
Pulp & Paper	13	0	24	0
Refineries	0	140	0	199
Fertilizer	0	474	31	279
Basic Chemicals	235	251	90	15
Dyes	11	0	40	0
Food	0	7	20	0
Pharmaceuticals	164	0	0	37
Tyres	0	0	9	0
Soaps	0	0	28	0
Total	**463**	**872**	**285**	**530**

Source: Hagler, Bailly & Company

Exhibit D.4a

Economic Potential for Cogeneration in Textile Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Textile
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	2	1	1	1	0	0	5
COAL STEAM TURB	1	1	1	1	1	0	5
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	1	2	3	2	8
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	2	4	5	3	14
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	3	10	17	11	41
DIESEL WHRB	0	0	0	1	1	1	3
	3	2	8	19	27	17	76

Source: Hagler, Bailly & Company

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Exhibit D.4b

Financial Potential for Cogeneration in Textile Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Textile
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	1	1	1	1	0	0	4
COAL STEAM TURB	2	1	1	1	1	1	7
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	1	2	3	2	8
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	1	2	4	2	9
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	1	5	9	6	21
DIESEL WHRB	0	0	0	0	1	1	2
	3	2	5	11	18	12	51

Source: Hagler, Bailly & Company

Exhibit D.5a

Economic Potential for Cogeneration in Rayon Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Rayon
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	1	1	1	0	0	0	3
COAL STEAM TURB	1	1	1	0	0	0	3
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	1	2	2	1	6
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	1	3	3	2	9
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	3	7	13	8	31
DIESEL WHRB	0	0	0	1	1	1	3
	2	2	7	13	19	12	55

Source: Hagler, Bailly & Company

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Exhibit D.5b

Financial Potential for Cogeneration in Rayon Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Rayon
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	1	1	0	0	0	0	2
COAL STEAM TURB	1	1	0	0	0	0	2
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	0	1	2	1	4
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	1	2	2	1	6
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	1	4	7	5	17
DIESEL WHRB	0	0	0	0	1	1	2
	2	2	2	7	12	8	33

Source: Hagler, Bailly & Company

Exhibit D.6a

Economic Potential for Cogeneration in Pulp & Paper Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Pulp & Paper
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	1	1	1	1	1	0	5
COAL STEAM TURB	1	1	1	1	1	1	6
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	1	2	3	2	8
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	1	3	4	2	10
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	2	6	12	8	28
DIESEL WHRB	0	0	0	1	1	1	3
	2	2	6	14	22	14	60

Source: Hagler, Bailly & Company

Exhibit D.6b

Financial Potential for Cogeneration in Pulp & Paper Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Pulp & Paper
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	1	1	1	1	0	0	4
COAL STEAM TURB	1	1	1	1	1	1	6
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	0	1	3	2	6
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	1	2	3	2	8
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	1	3	6	5	15
DIESEL WHRB	0	0	0	0	1	1	2
	2	2	4	8	14	11	41

Source: Hagler, Bailly & Company

Exhibit D.7a

Economic Potential for Cogeneration in Refineries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Refinery
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	3	2	2	1	1	1	10
COAL STEAM TURB	2	2	2	1	1	1	9
NG STEAM TURB	3	2	2	1	1	1	10
ADV. FLUID. BED	0	0	2	4	6	4	16
NG GT/WHRB	0	0	2	4	6	3	15
FO GT/WHRB	0	1	3	7	9	4	24
NG COMBINED CYCLE	0	0	5	13	21	13	52
FO COMBINED CYCLE	0	0	9	27	48	33	117
DIESEL WHRB	0	0	0	0	0	0	0
	8	7	27	58	93	60	253

Source: Hagler, Bailly & Company

Exhibit D.7b

Financial Potential for Cogeneration in Refineries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Refinery
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	2	1	1	1	0	0	5
COAL STEAM TURB	2	2	1	1	0	0	6
NG STEAM TURB	4	3	2	1	1	0	11
ADV. FLUID. BED	0	0	1	2	3	1	7
NG GT/WHRB	0	1	4	8	8	2	23
FO GT/WHRB	0	0	1	3	3	1	8
NG COMBINED CYCLE	0	0	19	53	101	76	249
FO COMBINED CYCLE	0	0	4	8	10	3	25
DIESEL WHRB	0	0	0	0	0	0	0
	8	7	33	77	126	83	334

Source: Hagler, Bailly & Company

Exhibit D.8a

Economic Potential for Cogeneration in Fertilizer Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Fertilizer
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	7	5	3	2	1	1	19
COAL STEAM TURB	5	4	3	2	1	1	16
NG STEAM TURB	7	5	4	2	1	1	20
ADV. FLUID. BED	0	1	4	9	12	6	32
NG GT/WHRB	0	2	6	10	11	5	34
FO GT/WHRB	0	3	11	18	19	8	59
NG COMBINED CYCLE	0	0	20	40	50	25	135
FO COMBINED CYCLE	0	0	43	97	152	100	392
DIESEL WHRB	0	0	0	0	1	1	2
	19	20	94	180	248	148	709

Source: Hagler, Bailly & Company

Exhibit D.8b

Financial Potential for Cogeneration in Fertilizer Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Fertilizer
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	5	3	2	1	1	0	12
COAL STEAM TURB	5	4	2	1	1	0	13
NG STEAM TURB	10	6	4	2	1	1	24
ADV. FLUID. BED	0	1	2	4	5	2	14
NG GT/WHRB	0	7	21	29	25	7	89
FO GT/WHRB	0	1	4	6	6	2	19
NG COMBINED CYCLE	0	0	58	126	209	151	544
FO COMBINED CYCLE	0	0	13	24	27	9	73
DIESEL WHRB	0	0	0	0	0	0	0
	20	22	106	193	275	172	788

Source: Hagler, Bailly & Company

Exhibit D.9a

Economic Potential for Cogeneration in Basic Chemicals (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Basic Chemicals
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	13	9	8	7	5	2	44
COAL STEAM TURB	11	8	8	7	6	2	42
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	1	8	23	37	23	92
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	4	18	41	57	30	150
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	37	117	235	180	569
DIESEL WHRB	0	0	2	5	9	5	21
	24	22	81	200	349	242	918

Source: Hagler, Bailly & Company

Exhibit D.9b

Financial Potential for Cogeneration in Basic Chemicals (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Basic Chemicals
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	12	7	6	6	5	2	38
COAL STEAM TURB	12	8	7	7	7	3	44
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	1	6	19	38	28	92
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	2	9	25	42	26	104
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	16	57	127	100	300
DIESEL WHRB	0	0	1	3	6	4	14
	24	18	45	117	225	163	592

Source: Hagler, Bailly & Company

Exhibit D.10a

Economic Potential for Cogeneration in Dyes Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Dyes
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	1	1	1	1	1	0	5
COAL STEAM TURB	1	1	1	1	1	1	6
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	1	2	4	2	9
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	2	4	6	3	15
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	2	8	17	13	40
DIESEL WHRB	0	0	0	1	1	1	3
	2	2	7	17	30	20	78

Source: Hagler, Bailly & Company

Exhibit D.10b

Financial Potential for Cogeneration in Dyes Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Dyes
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	1	1	1	1	0	0	4
COAL STEAM TURB	1	1	1	1	1	1	6
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	1	2	4	3	10
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	1	2	4	3	10
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	1	4	9	7	21
DIESEL WHRB	0	0	0	0	1	1	2
	2	2	5	10	19	15	53

Source: Hagler, Bailly & Company

Exhibit D.11a

Economic Potential for Cogeneration in Food Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Food
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	1	1	0	0	0	0	2
COAL STEAM TURB	1	0	0	0	0	0	1
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	0	1	2	1	4
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	1	2	3	1	7
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	2	5	9	7	23
DIESEL WHRB	0	0	0	0	1	1	2
	2	1	3	8	15	10	39

Source: Hagler, Bailly & Company

Exhibit D.11b

Financial Potential for Cogeneration in Food Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Food
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	1	0	0	0	0	0	1
COAL STEAM TURB	1	0	0	0	0	0	1
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	0	1	2	2	5
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	1	1	2	1	5
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	1	2	5	4	12
DIESEL WHRB	0	0	0	0	0	0	0
	2	0	2	4	9	7	24

Source: Hagler, Bailly & Company

Exhibit D.12a

Economic Potential for Cogeneration in Pharmaceuticals Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Pharmaceutical
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	3	2	2	2	2	1	12
COAL STEAM TURB	2	2	2	2	2	2	12
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	2	7	14	10	33
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	1	4	12	20	13	50
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	8	31	75	67	181
DIESEL WHRB	0	0	1	2	4	4	11
	5	5	19	56	117	97	299

Source: Hagler, Bailly & Company

Exhibit D.12b

Financial Potential for Cogeneration in Pharmaceuticals Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Pharmaceutical
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	2	2	2	2	2	1	11
COAL STEAM TURB	3	2	2	3	3	1	14
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	2	6	13	11	32
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	2	7	14	10	33
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	4	18	46	43	111
DIESEL WHRB	0	0	0	1	3	3	7
	5	4	12	37	81	69	208

Source: Hagler, Bailly & Company

Exhibit D.13a

Economic Potential for Cogeneration in Tyres Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Tyres
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	0	0	0	0	0	0	0
COAL STEAM TURB	0	0	0	0	0	0	0
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	0	0	1	1	2
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	0	1	1	1	3
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	0	1	3	2	6
DIESEL WHRB	0	0	0	0	0	0	0
	0	0	0	2	5	4	11

Source: Hagler, Bailly & Company

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Exhibit D.13b

Financial Potential for Cogeneration in Tyres Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Tyres
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	0	0	0	0	0	0	0
COAL STEAM TURB	0	0	0	0	0	0	0
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	0	0	1	1	2
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	0	0	1	1	2
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	0	1	1	1	3
DIESEL WHRB	0	0	0	0	0	0	0
	0	0	0	1	3	3	7

Source: Hagler, Bailly & Company

Exhibit D.14a

Economic Potential for Cogeneration in Soaps Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Soaps
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	0	0	0	0	0	0	0
COAL STEAM TURB	0	0	0	0	0	0	0
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	0	1	2	1	4
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	1	2	3	2	8
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	1	4	9	7	21
DIESEL WHRB	0	0	0	0	1	1	2
	0	0	2	7	15	11	35

Source: Hagler, Bailly & Company

Exhibit D.14b

Financial Potential for Cogeneration in Soaps Industries (1986 - 1996)

COGENERATION SYSTEM MARKET

SALES PROJECTIONS
(MW - Electric): Scenario I
INDUSTRY: Soaps
REGION: All
MARKET APPLICATION: All
SIZE RANGE: All

TECHNOLOGY	86-87	88-89	90-91	92-93	94-95	96	TOTAL
FO STEAM TURB	0	0	0	0	0	0	0
COAL STEAM TURB	0	0	0	0	0	0	0
NG STEAM TURB	0	0	0	0	0	0	0
ADV. FLUID. BED	0	0	0	1	2	1	4
NG GT/WHRB	0	0	0	0	0	0	0
FO GT/WHRB	0	0	0	1	2	1	4
NG COMBINED CYCLE	0	0	0	0	0	0	0
FO COMBINED CYCLE	0	0	1	2	5	4	12
DIESEL WHRB	0	0	0	0	1	1	2
	0	0	1	4	10	7	22

Source: Hagler, Bailly & Company

APPENDIX E: 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.

In this Appendix first, the theoretical definition of purchase price is presented. 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.

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.

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, 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.[1]

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 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

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

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 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 used the "proxy unit" approach. In this approach, the capital cost of future units in each state's expansion plan determines 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 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 new units for capacity costs and old ones for energy costs. This approach applies to units that are capable of providing firm capacity. In this analysis, we treated the entire power generation system in each state as a single utility and determined the avoided cost. In addition, we estimated the avoided cost for each utility based on the specific conditions applying to it.

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, was 3,283 MW, of which 300 MW was hydro and the remaining 2,983 MW, thermal. Since the variable operation costs of hydro plants are much lower than thermal plants, utilities will run hydro plants -- when available -- at full capacity and reduce their need for thermal units. Therefore, non-utility generated power will displace electricity from thermal units and from hydro plants.

The variable operation and maintenance costs of thermal plants in Gujarat vary between 36.4 and 52.4 Ps./kWh (see Exhibit E.1). All thermal units run on coal, with fuel oil or low sulfur heavy stock (LSHS) fuel as backup fuel when available. Only one unit at the Dhuvaran plant in Kheda runs entirely on oil. The price of coal available to the GEB is Rs.380-400/tonne. In contrast, the AEC pays Rs.534/tonne for its coal needs. The price of oil available to the GEB is Rs.2,520/1,000 liters, and to the AEC is Rs.3,032.38/tonne[2]. These prices explain the higher generation costs 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 the GEB and AEC, the transmission and distribution (T&D) losses should also be considered. Currently, the T&D losses in the GEB grid are over 20 percent. T&D losses in the AEC grid are about 10-12 percent. Therefore, if the independent generator is located near major load centers, and the generated power can be distributed over a short distance, the value of this electricity to the utility

[2] National Productivity Council

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Exhibit E.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.

could be up to 20 percent higher than the marginal generation cost at thermal plants. In addition, if enough independent units are operating throughout the state, the need for transmission network extension could be drastically reduced in the long run. 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, we used the capital cost of future plants as the avoided capacity cost to the GEB or AEC. For future plants, we included those that have been submitted to the Planning Commission for approval (see Exhibit E.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. Based on the estimated avoided energy and capacity charges shown in Exhibits E.1 and E.2, we calculated the total avoided cost to utilities in Gujarat as approximately 90.5 Ps./kWh. If the savings from reduced T&D losses are considered, the avoided cost could be as high as Rs.1.0/kWh.

In the short run, there are other factors that also determine the value of non-utility power to the AEC and GEB. The AEC, for example, does not have enough generation capacity to satisfy the demand on its network, so it imports power from the GEB. The AEC's generation units operate on maximum load with very little fluctuation during the entire period, and the difference between the power generated and the demand is supplied by imports from the GEB (see Exhibit E.3). The cost of power from the GEB is, on the average, 75 Ps./kWh[3]. In the short term, this cost could be used to determine the avoided cost to the AEC. Similarly, the GEB is purchasing power from a number of suppliers at costs as high as 98 Ps./kWh (see Exhibit E.4), representing the avoided cost to the GEB.

These estimates must be viewed in light of the power shortage in Gujarat. The average price of electricity supplied to large industrial facilities is about Rs.1.3/kWh, but these facilities are the first to receive cuts during shortages. Therefore, the actual value of an additional unit of electricity during power cuts to the GEB or AEC could be said to be Rs.1.3/kWh, since this is the price they can sell it for (with adjustments for T&D losses and wheeling charges).

[3] In 1985, the AEC purchased 447 GWh of electricity from the GEB at a cost of Rs.336.2 million, as indicated in the AEC's 73rd Annual Report, 1984-85, pp. 46-47.

Exhibit E.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.

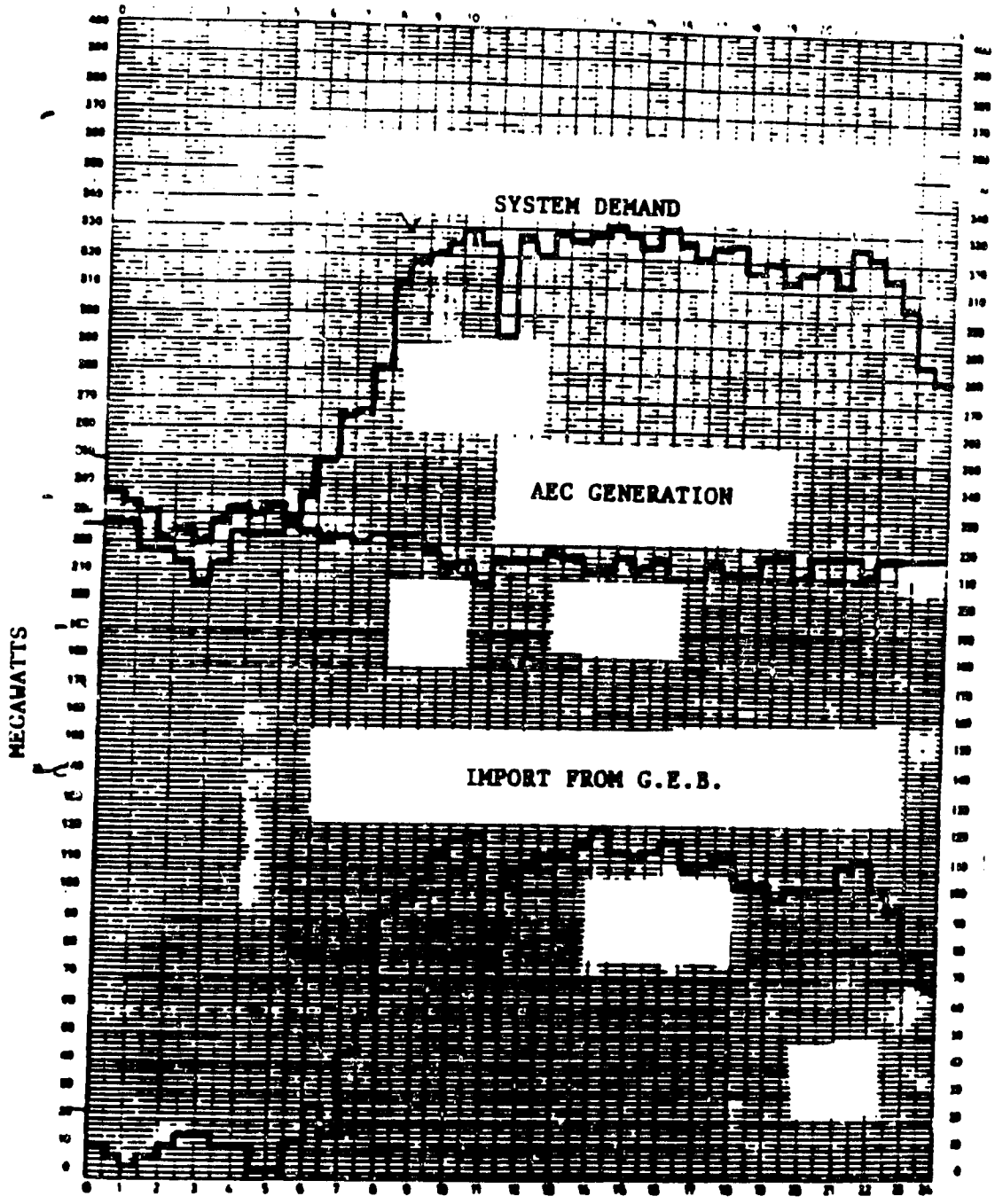
(4) NPC

Source: Hagler, Bailly & Company

Exhibit E.3

LOAD CURVE, GENERATION & IMPORT OF AHMADABAD ELECTRICITY CO.

FOR AUGUST 4, 1986



SOURCE; AHMADABAD ELECTRICITY COMPANY

Exhibit E.4

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

Maharashtra

The variable generation cost of electricity for the MSEB system is between 36.5 and 60.0 Ps./kWh (see Exhibit E.5). The price of coal available to the MSEB is Rs.300/tonne, and the price of oil is Rs.2,520/1,000 liters[4]. Only one unit in the MSEB system uses gas, the Uran plant, and the price of gas is Rs.680/1,000 cubic meters[5]. The T&D losses in the Maharashtra grid, like Gujarat, are 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. For the avoided capacity charge, we used the average cost of thermal plants commissioned during 1985, estimated at 33.4 Ps./kWh (see Exhibit E.2). We thus calculated the total avoided cost of the MSEB (energy and capacity) at between 70.0 and 94.0 Ps./kWh, approximately the same as that of the GEB.

The transactions between different suppliers in Maharashtra also give indications of the avoided cost to utilities. For example, the MSEB purchases power from Tata Electric Company at 80 Ps./kWh, which in the short run is its avoided cost. Of course, like Gujarat utilities, the MSEB supplies electricity to large industrial customers at an average price of 1.3 Ps./kWh. Therefore, at least during power cuts to industry, any electricity provided to the MSEB at prices below this figure could be profitably sold to industrial customers (with consideration for T&D losses and wheeling charges).

To summarize, in terms of generation costs, the avoided cost of electricity to Gujarat and Maharashtra utilities is between 75 Ps./kWh and 100 Ps./kWh. But in terms of the cost of power to industrial customers the avoided cost is about Rs.1.3/kWh. If one adds the cost of unreliability of supply to the industry, the actual value could go much higher.

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[4] National Productivity Council

[5] Ibid.

Exhibit E.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.

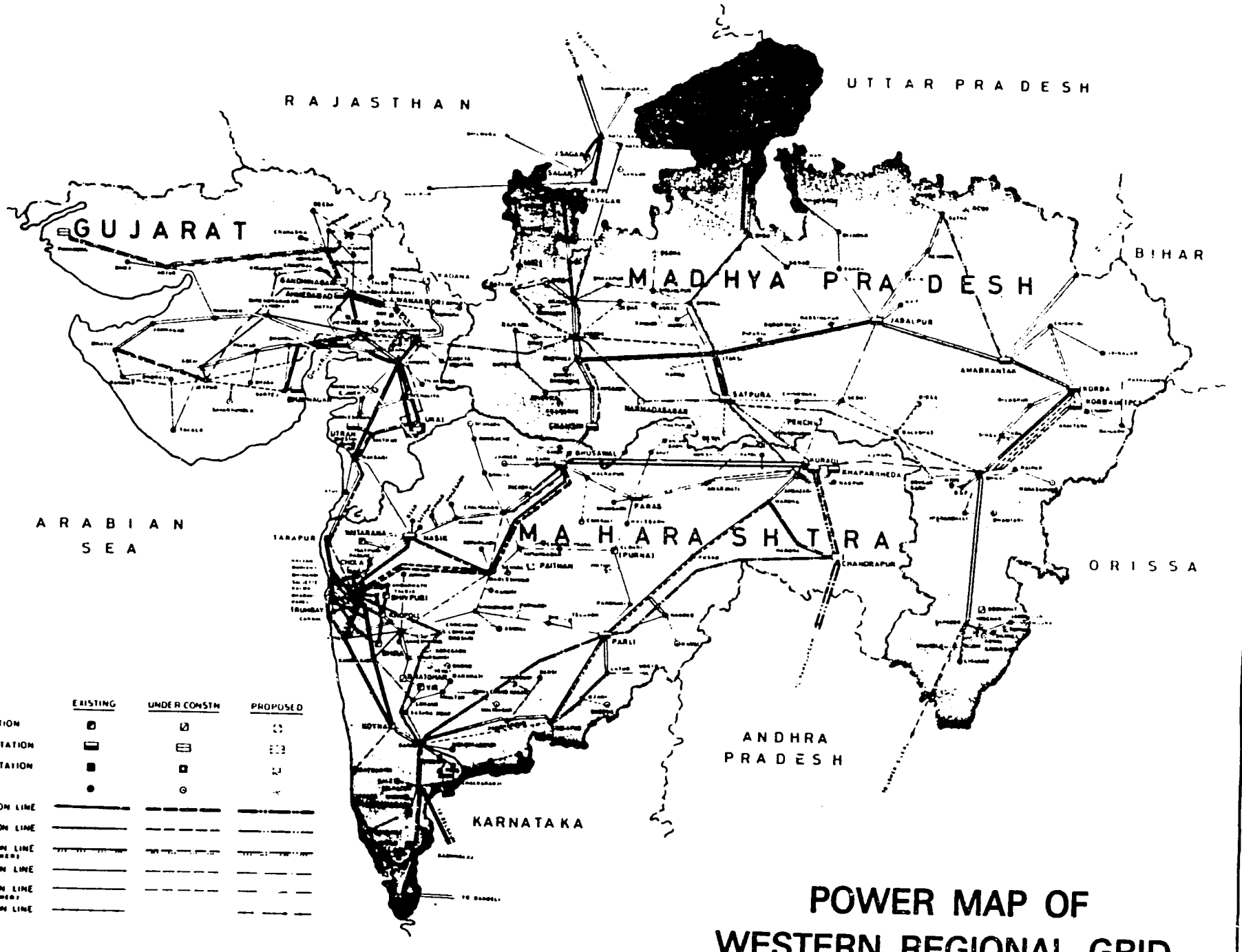
(3) Fuel consumption data from: MSEB, "1984-85 Administration Report," Appendix IV-A, pp. 12-13.

(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

APPENDIX F: POWER MAP OF GUJARAT AND MAHARASHTRA



POWER MAP OF WESTERN REGIONAL GRID

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