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PRIVATE-SECTOR POWER GENERATION IN THAILAND: POTENTIAL, IMPEDIMENTS, AND POLICY ISSUES

Final Report

Prepared For:

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Prepared By:

Hagler, Bailly & Company

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EXECUTIVE SUMMARY

Background

Thailand's economy is growing rapidly, as is the amount of electricity that it uses. Between 1961 and 1984, electricity demand grew from 464 GWh to over 18,500 GWh (representing an annual growth rate of over 16 percent), or from 18 kWh to over 370 kWh per capita. Moreover, demand for electricity is expected to grow by over 6 percent per year between 1985 and 2000.

To meet this growing demand, Thailand's electric power sector has absorbed over 70 percent of total government investment in the energy sector in the past 20 years. Government investment in the power sector during the Fifth Development Plan (1982-1986) was over B90 billion (U.S. $3.4 billion[1]), equivalent to over 15 percent of total government investment during this period. The amount of government investment needed to meet electricity demand during the Sixth Plan (1987-1991) is estimated at over B100 billion ($3.8 billion).

The government is very concerned about the growing public debt in Thailand. This concern makes it very difficult for the government to finance the investment needed to meet electricity demand.

In addition, although there are large resources of fossil fuels in Thailand, there are also major cost uncertainties associated with exploitation of fuels for use in new power plants. The existing power generation expansion plan projects over 5,000 MW of new capacity based on domestic gas and lignite between 1980 and 2005. However, if domestic supplies of fuel, especially natural gas, continue to be severely limited and costly, then new generation capacity beyond the early 1990s would have to use imported fuels. The result would be a substantial increase in capital investment for new generation units and a much larger fuel import bill.

To reduce the capital shortage and improve operating efficiency, the Royal Thai Government (RTG) seeks to encourage private-sector participation in those sectors of the Thai economy previously dominated by the public sector. Government policy now calls for serious consideration to be given to involving the private sector in power generation. Faced with the burden of financing the public utilities, some government agencies, such as the National Energy Administration (NEA), are exploring approaches to power generation that fall outside the current utility structure and are funded by the private sector. A

1 US$=26.5 Baht

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starting point for such approaches could be to encourage the participation of the private sector in generating electricity from indigenous energy resources such as natural gas, or from technologies and resources that have not been traditionally used by electric utilities, such as industrial cogeneration, bagasse, and sugar cane wastes. The development of such alternatives would not only reduce the generation expansion needs of electric utilities and bring private capital into the power system, but would improve overall energy utilization efficiency and increase indigenous fuel use.

This concept, in fact, is reflected in some of the current activities being pursued by the RTG. The NEA, for example, has been helping local communities in rural areas to develop, own, and operate small hydroelectric facilities. In this way, the communities can meet their own electricity needs and sell any excess power to the utility. In addition, NEA intends to encourage private-sector participation in power generation from urban waste and dendrothermal sources.

PURPOSE OF STUDY

The purpose of this study is to assess the potential for non-utility power generation by the private sector in Thailand, including such options as cogeneration and other power facilities, analyze the impediments to the development of such power options, and recommend the first steps required to design and implement a program to exploit the economically viable potential. The study was carried out by a team of consultants from Hagler, Bailly & Company during a 3-week trip to Thailand, from January 26 to February 17, 1986. The team's scope of work is presented in Appendix A.

FINDINGS

The study findings are organized in three categories: general, cogeneration, and power-only systems.

General

1. This preliminary analysis suggests that the economically attractive potential for private-sector power production in Thailand from cogeneration and small-scale generation systems (less than 50 MW) using indigenous energy resources is about 1,035 MW over the next 10 years. Of this potential, 725 MW could be developed by the private sector at costs competitive with utility electricity prices (the financial potential). The economic potential refers to that amount of the cogeneration potential that can be developed, given energy and fuel prices valued at their shadow prices -- prices that represent the true cost to the economy. The financial potential

refers to that amount of the cogeneration potential that can be developed given energy and fuel prices as they exist in the present market -- the prices paid by industry. The potential is distributed as follows:

	Economic (MW)	Financial (MW)
Cogeneration systems	545	310
Bagasse-fueled systems	260	260
Rice husk-fueled systems	155	155
Small hydropower systems	55	--
Municipal waste-fired systems	20	--
Dendrothermal systems	--	--
Small fossil-fueled systems	--	--
TOTAL (Rounded)	1,035	725

These estimates are based only on the direct and obvious economic costs and benefits of each alternative; they do not take account of socioeconomic factors such as job creation and domestic energy self-sufficiency. Power generation from municipal waste, for example, could help resolve long-term waste disposal problems of large urban areas. Similary, the development of dendrothermal plantations could bring employment opportunities to rural areas and reduce deforestation in the country. However, it is beyond the scope of this study to assign economic or cost values to such factors.

2. The potential for private power generation is substantial but there are a number of issues that must first be resolved before the private sector can make a major contribution. These include the ability of the Thai private sector to raise the necessary funds, the ability of such private projects to qualify for concessional financing from international lenders, the government's policy on foreign investment in the power sector, the ability of the Thai private sector to operate such facilities, the price that private generator would be charged for fuel, and the types of guarantees that the Thai government would need to provide for power purchases from such facilities.

3. The RTG has shown a strong interest in promoting private investment in a number of economic sectors, including the energy sector. The government recently developed a new policy to encourage private power generation but other details remain to be ironed out. Specifically, no policies have been set for the purchase of power from private generators.

4. The Electricity Generating Authority of Thailand (EGAT) will have some excess power capacity until 1989, which provides the RTG with a 3-year window of opportunity in which to define and implement its policy with respect to private-sector power generation. Before 1989, EGAT's marginal

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cost of production will be relatively low but certain private generation options may still be justifiable on a short-term economic cost basis, such as surplus generation from sugar mills. However, by 1990, EGAT's marginal cost is projected to increase substantially as new capacity is needed, making more alternative investments economically attractive.

5. There is currently no proposal on establishing guidelines for setting the price at which power could be purchased from independent producers.

6. In general, EGAT, the Provincial Electricity Authority (PEA), and the Metropolitan Electricity Authority (MEA) are receptive to the idea of purchasing power from non-utility generators. However, they seem to believe that no independent generator will be able to produce electricity at prices below existing electricity rates. In addition, the utilities are concerned about dispatching problems if small generation units are connected to the grid.

7. EGAT maintains that it would purchase power from non-utility producers if the power were cheaper than EGAT's own production cost or if it were mandated to do so by the government.

8. The private sector is generally satisfied with the quality of service it receives from the electric utilities. Therefore, it has no strong incentive to develop its own power supply options. This situation is in contrast to that in many developing countries, where the utility power supply is unreliable and the quality of service is low. Furthermore, many in the private sector in Thailand would not consider generating power for sale to the grid if they knew the utilities were opposed to such an arrangement.

9. There are no well-developed sources of long-term financing for investment in private power systems. The stock market presents some possibilities, but it is not well developed and needs greater expansion before it will present a substantial source of financing. It is thus likely that the development of these systems would be feasible only for the largest, most creditworthy private organizations.

10. Although the study team could obtain little information about the prospects of private investment in larger power plants, it found evidence that the government is interested in exploring such possibilities as a way of reducing public investment in the energy sector.

Cogeneration

11. Thailand already has a substantial industrial cogeneration capacity. The capacity, estimated at 377 MW in 1985, is private and mostly in the seasonal sugar industry (350 MW).

12. There is currently no excess power available for sale to the grid because power from existing cogeneration systems does not exceed on-site needs; in any case, there is no set price or policy for such transactions.

13. The projected financial potential for cogeneration systems through 1996 is 310 MW. Most of these systems would be sized to meet primarily on-site needs, unless purchase policies are established to provide financially attractive conditions for the sale of excess power.

14. Under current RTG policy, equal duties are charged on cogeneration and non-cogeneration systems (30-50 percent).

Power-only Systems

15. Small-scale systems based on agricultural waste fuels (bagasse and rice husks, in particular) could generate over 415 MW of power by the year 1996. The realization of this economic potential will be constrained by several factors, including the undeveloped markets for bagasse and rice husks and their erratic supply and combustion characteristics, inadequate financing schemes to attract private investors, and the lack of a policy on the purchase of bulk power.

16. No financial potential was found for small power systems using commercial fuels (oil, gas, or lignite), as these systems cannot compete economically with EGAT's larger fossil-fueled plants.

17. Large, private gas-fired systems could produce power at costs comparable to current EGAT electricity prices for large industries. The private sector could potentially finance, develop, and operate enough large power plants (over 50 MW) to offset a major portion of EGAT's 10 year power expansion plan of 4,600 MW. Other developing countries have been turning to the private sector recently for power generation. For example, the private sector is going to finance, build, and operate a 960 MW imported coal plant in Turkey, and a 120 MW imported oil plant in Pakistan.

18. A limited economic potential of 75 MW was identified for micro hydroelectric and municipal waste-to-energy systems. Wind, solar, and biogas resources were not found to have a significant economic potential over the next 10 years.

RECOMMENDATIONS

Recommendations are presented in the same categories as the findings: general, cogeneration, and power-only systems.

General

(a) Because of the medium- and long-term economic benefits of cogeneration and non-utility power production, the RTG should begin to develop and publicize policies that encourage private-sector power generation in the areas of industrial cogeneration, agricultural waste-fuel-based power generation, and large-scale power plants using domestic fossil fuels. The RTG should:

- Develop methodologies to calculate the appropriate price and conditions under which power is purchased from private producers, taking into consideration such issues as:

  (i) The projected increase in EGAT's marginal cost of power generation by 1990-1991.

  (ii) The seasonal, time-of-day, and regional values of private power to utilities.

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

  (iv) Special incentives to encourage the initial investments in private power generation.

- Publicize these policies

- Develop the institutional capability for coordinating all aspects of private-sector power generation, including the development of guidelines for preparing private-sector proposals.

(b) In order to better deal with private power generators, government staff should be trained in relevant financial issues such as estimating the true value of power used in calculating "buy back" rates. They should also be trained in technical issues of importance for connecting private power generators with the public grid, including dispatching procedures and load planning.

(c) In light of the U.S. experience with PURPA, the RTG should consider training Thai specialists at U.S. utilities, as well as transferring specialized planning models to calculate utility "avoided costs" or true economic costs.

(d) In addition, the RTG could use U.S. utility experience to draft a typical utility/small generator contract format that considers the seasonal and regional variations of various generation options.

(e) In the short term, the RTG could foster a demonstration project with EGAT and/or PEA that entails purchasing excess power from sugar mills. Such a project would provide data on the economic and technical characteristics of these kinds of transactions.

(f) The RTG could consider providing specific incentives to private power plants for the supply of power (and possibly heat) to the new industrial estates promoted by the Ministry of Industry.

(g) A study should be conducted by NEA to identify the advantages and disadvantages of allowing excess power to be wheeled from one plant to another.

Cogeneration

(h) Cogeneration should be encouraged by the RTG as an energy conservation measure. The new private-sector energy conservation center should be put in charge of policy implementation. In addition, NEA should undertake a study to identify the need, if any, for additional incentives to promote cogeneration similar to those already granted to other conservation investments.

(i) NEA and the new energy conservation center should jointly design and conduct an outreach program consisting of seminars, workshops, short courses and site visits in Thailand and the United States, as well as the publication of brochures and technical information.

(j) To encourage cogeneration, the government should guarantee a supply of backup power from utilities to cogenerators at fair prices.

Power-only Systems

(k) Because the bulk of the economic potential lies in the use of bagasse and rice husks, a more detailed assessment of the potential and problems associated with the use of these resources is needed. NEA should undertake a study on power generation from rice husks similar to the detailed study of power generation from bagasse conducted by USAID in March 1986. In particular, the use of domestic lignite with bagasse and rice husks in dual-fueled systems should be considered.

(l) On the basis of these two studies, a more detailed comparison of on-site and off-site options for private-sector power generation should be undertaken, as well as an examination of the most appropriate financing for these power plants.

(m) The government should clarify its policy on the availability and price of domestic fuels, especially natural gas, to private power generators. This information is especially important for large units running on natural gas, which have the potential to generate electricity at costs competitive with EGAT prices.

(n) A detailed analysis of the impact of private-sector financing of large power plants on the availability of capital for other sectors of the economy is needed.

(o) As a solution to the domestic capital shortage, the government should consider the possibility of power sector investment through joint ventures in building and operating large power plants. Such ventures would require a clear policy by the government on tax rates, guarantees, and repatriation of profits.

(p) In assessing the economic and financial feasibility of waste-to-energy systems, the cost evaluation should include the long-term cost of developing and establishing disposal sites when the present ones are filled, rather than considering only the short-term costs of handling and disposal at present sites.

(q) A detailed assessment of dendrothermal plants is needed that will focus on socioeconomic factors affecting their development, including the ability to gather large tracks of plantation or deforested land near the power plants. Detailed feasibility studies are needed of one or more potential plant sites.

INTRODUCTION

Thailand's economy is growing rapidly, as is the amount of electricity that it uses. Between 1961 and 1984, electricity demand grew from 464 GWh to over 18,500 GWh, or from 18 kWh to 370 kWh per capita. Before 1973, electricity demand grew by more than 20 percent per year (three times gross domestic production (GDP) growth). When GDP growth slowed and real prices rose sharply in the 1970s, electricity demand declined to 6 percent per year. When GDP growth picked up again and prices stabilized, electricity demand grew more rapidly -- at 13 percent per year, or about twice GDP growth.

Industrial electricity demand has grown especially rapidly, from 470 GWh in 1961 to over 13,000 GWh in 1980 -- an annual growth rate of 17 percent. As a result, the industrial sector's share of total electricity demand has increased from 37 percent in 1961 to over 60 percent in 1980.

To meet this growing demand, Thailand's electric power sector has absorbed over 70 percent of total government investment in the energy sector in the past 20 years. The share of investment in the power sector, as a fraction of total government investment, increased from 6.9 percent in the Second Development Plan to over 15 percent in the Fifth Plan. In absolute terms, government investment in power increased from B4.8 billion ($181.1 million) in the Second Plan to over B90 billion ($3.4 billion) in the Fifth Plan.

According to current economic forecasts, demand for electricity is expected to grow by over 6 percent per year between 1985 and 2000 (NESDB, Sixth Plan projections, base case). The amount of government investment needed to support the expansion of the electric supply system and thus satisfy this growing demand is estimated at over B100 billion ($3.8 billion) during the Sixth Plan.[1]

The public debt in Thailand, however, makes it extremely difficult for the government to undertake a high level of investment in the power sector -- or in any other economic sector. As of June 1985, Thailand's public debt was B260 billion ($9.8 billion), which is equal to 28 percent of national income and 90 percent of one year's exported goods and services. To reduce these deficits, expenditures for development activities have been subjected to a cap; as a result, they are declining compared with routine, recurring expenditures. To reduce the debt burden, the Ministry of Finance, on the advice of the International Monetary Fund (IMF), has lowered the ceiling on new loan

[1]. World Bank, Thailand: Issues and Options in the Energy Sector, September 1985.

signings -- for long-term commitments, not fiscal year obligations -- from B42.4 billion ($1.6 billion) in FY 1985 to B26.5 billion ($1 billion) in FY 1986.

In addition, there is major uncertainty with regard to the availability and production cost of domestic natural gas and lignite. Current power generation expansion plans in Thailand project the use of natural gas for an additional 3,500 MW generation capacity. These projections are based on somewhat optimistic reserve estimates. If gas supplies continue to be severely limited and alternative sources such as Texas Pacific increasingly costly, however, there appears little future for gas in the electricity program after 1992. In this case, new generation capacity beyond 1993 would be fueled with imported coal, which would mean a substantial increase in capital investment. Coal plants are on average $300-$500 per kW more expensive than oil- or gas-fired plants, and importing coal would probably place significant pressure on the balance of payments during the second half of the 1990s.

PRIVATE-SECTOR POWER GENERATION

To reduce the capital shortage and improve operating efficiency, the Royal Thai Government seeks to encourage private-sector participation in those sectors of the Thai economy previously dominated by the public sector. This approach would also spare the government the administrative and organizational burden of activities that could be done equally well or better by private-sector companies.

In the energy sector, the government proposed a policy at the Pattaya Energy Conference of 1985 to promote private-sector involvement in oil and gas exploration, transportation, and marketing. Since then, the government has been streamlining regulations to facilitate private-sector participation in these activities.

In the power sector, there is a consensus that power services are properly the domain of government-owned utilities. However, the power sector in Thailand, which is fully owned and operated by the government, absorbs over 60 percent of government investment in public enterprises. Faced with the current financial squeeze, and given the generation capacity surplus, the government has put a temporary freeze on the utilities' expansion efforts while it reevaluates the power needs of the country. In addition, some government agencies are considering alternative approaches to power generation that would reduce the utilities' financial burden on the government.

A starting point for such approaches could be to encourage the participation of the private sector in generating electricity from indigenous resources, such as natural gas, or from technologies or resources that utilities traditionally have not used, such as industrial cogeneration, dendrothermal, small hydro, urban

waste, and other renewable resources. Development of such alternatives will not only reduce the generation expansion needs of electric utilities and bring private capital into the power system, but will improve overall energy utilization efficiency and increase indigenous fuel use.

CURRENT ACTIVITIES

A number of developments in recent years point to the possibility of private-sector participation in power generation in Thailand. With initial help from the government (National Energy Administration), the private sector has become involved in an effort to build a number of small hydroelectric projects in rural areas. These projects will be owned and operated as cooperatives (with the government as a shareholder) and will sell power to the electric utility. The projects will eventually be owned and operated entirely by the private sector. In addition, two major projects by the government that call for direct investment by the private sector are under study. One is a waste-to-energy project in Bangkok that will use municipal waste to generate electricity, and the other is a project to grow trees in deforested areas to use as wood fuel in electricity generation. Furthermore, a number of industries own and operate generation units; many of them use the product waste available to them and thus incur little fuel cost.

In its moves to involve the private sector in power generation, Thailand is not alone. Over the past 10 years, various countries have recognized the need for policies that will encourage the generation of electricity outside the traditional structure of utilities, promote production alternatives, and take advantage of financially and economically rewarding power projects.

Of particular interest to Thailand is the case of the United States, which enacted the Public Utility Regulatory Policies Act (PURPA) in 1978 to promote the development of small and nonconventional power generation options. PURPA mandates that U.S. electric utilities purchase power from small power producers at their own "avoided cost," independent of the producers' cost. The avoided cost is intended to reflect the true value of electricity to the utility, and is established on the basis of utility marginal costs.

STUDY OBJECTIVES

The objectives of the study were:

(1) To identify the private-sector potential for cogeneration and power production from renewable and indigenous energy resources, particularly small hydro, biomass, lignite, and natural gas.

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(2) To identify the policy/regulatory/institutional issues associated with private-sector generation of electricity from cogeneration or renewable/indigenous resources for sale to the grid.

(3) To recommend measures to encourage the private-sector development of cogeneration and other non-utility power options, where economically viable.

This study coincides with the emerging interest and initiative taken by the Royal Thai Government to facilitate private-sector investment in the Sixth Plan as a way of reducing the financial, administrative, and organizational burden on the government. In particular, it has occurred at a time when the National Energy Administration (NEA) is involved in a number of power generation projects using domestic renewable resources that are to be implemented by Thai private sector.

The study was carried out in Thailand between January 27 and February 17, 1986, by a team of consultants from Hagler, Bailly & Company.

STUDY APPROACH

The study team visited Thailand for 3 weeks, collecting data through a review of the literature and interviews with key representatives of the private and public sectors, donor agencies, and USAID. The list of organizations contacted is presented in Appendix B and includes: electric utilities, government ministries involved in energy issues, government and commercial banks, energy and electricity research institutions, and a number of large industrial firms. The team also visited a number of potential sites for power generation, including a hydroplant, a rice mill, and a sugar mill.

The collected information was used to develop estimates of the technical, economic, and financial potential for private-sector power generation from each of the options considered. To estimate the potential for power generation from industrial cogeneration, the team used a proprietary model developed at Hagler, Bailly & Company. This model has been successfully used in the United States and a number of developing countries.

REPORT ORGANIZATION

The study report consists of four chapters:

In Chapter 1, an initial estimate of the technical, economic, and financial potential of private-sector power production from industrial cogeneration and other non-utility power generation options is presented.

In Chapter 2, the existing power sector institutions in Thailand are described and the major issues and impediments associated with private-sector development of cogeneration and other non-utility power options are identified and discussed.

In Chapter 3, based on U.S. experience with the development of non-utility power options, possible approaches to establishing the price of electricity from non-utility generators are described and preliminary estimates of the range of avoided costs in Thailand are determined.

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

A glossary precedes the appendices and a bibliography follows them. Appendices A through F provide additional information to support the main text of the report.

CHAPTER 1: POTENTIAL FOR PRIVATE-SECTOR POWER GENERATION

This chapter evaluates the potential for private-sector power generation in Thailand. First, the available non-utility power generation options are identified. Then the existing non-utility generation activities in the country are reviewed. And finally the technical, economic, and financial potential of each option is estimated.

NON-UTILITY POWER GENERATION OPTIONS

There are two major options for private-sector power generation in Thailand outside the traditional structure of electric utilties: industrial cogeneration and power-only systems.

Industrial Cogeneration

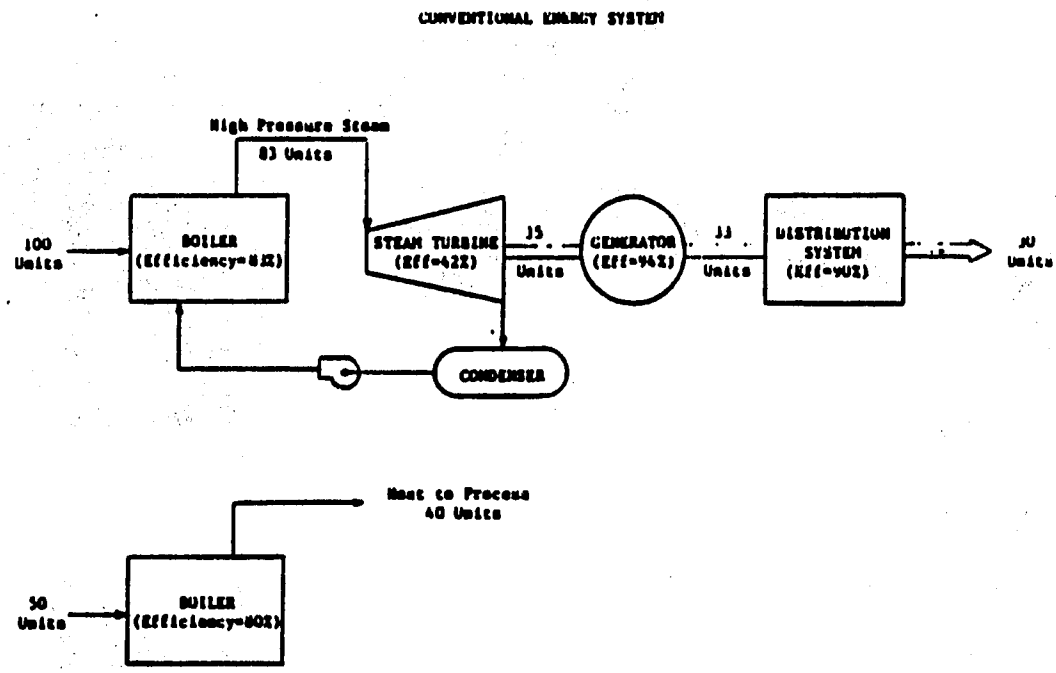
Cogeneration refers to the sequential production of electricity and useful thermal energy (usually in the form of hot liquids or gases) as an integral part of an industrial process. Traditionally, industrial thermal energy is produced by boilers and furnaces that typically have efficiencies of 50 to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

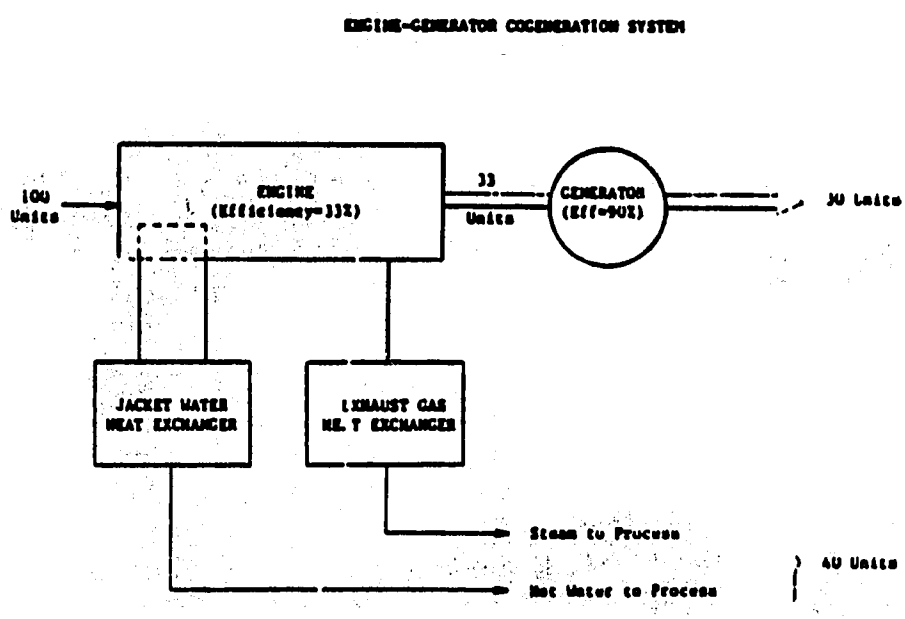
The following example illustrates the energy savings possible with cogeneration. Generating 30 units of electricity and 40 units of heat in conventional energy systems requires 150 units of fuel input (see Exhibit 1.1). Producing the same amount and mix of energy in a cogeneration system, however, requires only 100 units of fuel input.

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 amount of fuel used to generate a given amount of energy translates directly into a reduction in thermal and other types of pollution.

EXHIBIT 1.1

Energy Input and Output Comparison
Between Conventional and Cogeneration Systems





Source: Adopted from Orlando (1984)

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. Small-scale power in this study refers to the generation of electricity by private non-utility organizations or individuals for their own needs, for sale to the grid, or for sale to other customers. Typically these systems are less than 50 MW in size. Several indigenous resources are available for such systems, including fossil fuels (e.g., natural gas, lignite), municipal or agroindustrial waste (e.g., bagasse, rice husks), small-scale hydro, and dendrothermal plantations on which trees are harvested as fuel for power generation. In addition, these resources include other renewable options, such as photovoltaics and wind systems, which have limited potential at this time but may be more important in the future. However, time and resources did not permit a detailed analysis of these last two options.

For the purposes of this study, large-scale power includes utility-sized power generation systems (generally greater than 50 MW) that are financed, owned, or operated by private non-utility entities and that sell their power output primarily to Electricity Generation Authority of Thailand (EGAT), Metropolitan Electricity Authority (MEA), or Provincial Electricity Authority (PEA). The technologies that appear most attractive for such systems are combined cycle plants fired by natural gas from the Gulf of Thailand, boiler/steam turbine plants fired by domestic lignite, and medium-sized hydroelectric facilities. For these systems, investments that would normally be made by EGAT would be made instead by private investors. This option might be attractive if the Thai government finds it difficult to raise capital (as at present, because of caps on the total amount of government or government-guaranteed loans) for power-sector investments.

EXISTING PRIVATE POWER GENERATION

According to NEA,[1] there are 614 MW of small, privately owned power generating systems, most of them located at industrial sites and used for cogeneration, power-only generation, or as a backup for emergencies. Of these 614 MW, 378 MW or 62 percent are generated by steam systems (engines and turbines) and 236 MW are produced by diesel engine generators. Most of these diesel generators are small (i.e., below 1,000 kW) and are used only as back-up units, except in some remote small-scale rice and other agroindustrial activities, including sawmills. The fuel cost for power generation from these diesel engines is estimated at about 3 B/kWh, which is

[1] NEA biannual survey of privately owned electricity generation.

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much higher than the energy charge of electricity purchased by the industry from the grid at 1.4 B/kWh.

The NEA survey, which provides good information on each generator by company, region, size, fuel type, and Thai Standard Industrial Code (TSIC) group, does not indicate actual electricity generation nor the number of hours of operation per year (see Exhibit 1.2). To estimate the electricity generation from these systems, NEA begins with old data on generation levels and increases them by 10 percent per year to estimate current generation levels. NEA estimates that the steam units generate an average of 2,123 kWh/kW/year (i.e., they operate 2,123 hours per year). This operating level translates into a low capacity utilization factor (24.2 percent); the capacity factor is low because most steam turbines and engines (305 MW or 81 percent of the total) are used in the seasonal sugar industry. According to the interviews conducted during the course of this study, most of the steam systems are operated in a cogeneration mode, with low pressure steam being used in the process. The exact quantity of fuel used by these systems is not known, although estimates are available for the quantity of bagasse used in sugar mills and rice husks used in rice mills. These estimates can be used to approximate fuel use.

POTENTIAL FOR ADDITIONAL PRIVATE-SECTOR POWER GENERATION: DEFINITIONS AND ASSUMPTIONS

To determine the relative attractiveness of the various private-sector power generation options, three sets of numbers were developed: the technical potential, economic potential, and financial potential (see Appendix C for a detailed discussion). For each power generation option, the technical potential is the amount of generation capacity that can be developed given the current and expected state of the technology and the availability of the natural resource. This is largely a resource-limited number. The economic potential is that portion of the technical potential that can be developed with resulting electricity costs lower than the utilities marginal production cost. In determining the production cost of electricity, this analysis uses only the true economic costs and benefits, and factors out the "transfer payments" such as taxes, duties, and profits that do not represent actual costs but rather shifts of resources from one sector to another. Similarly, the financial potential is the generation capacity that can be developed with costs below the financial cost of power provided by utilities. The financial analysis looks at the project from the viewpoint of the investor. It determines the actual 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.

Exhibit 1.2

Existing Cogeneration Capacity (1984)

TSIC Code	Industry	Installed Capacity (MW)	Type of System	Fuel Used
3118	Sugar	305.00	Steam Turbine	Bagasse
3116	Rice Mills	2.90	"	Rice Husks
3211	Textiles	9.00	"	Oil
3311	Sawmills	0.60	"	Wooc
3411	Pulp & Paper	13.24	"	Oil/wastes
3530	Refineries	5.50	"	Oil
3511	Basic Chemicals	1.25	"	Bagasse
3692	Cement	7.40	"	Oil
	Total (rounded)	345.00		
	Other Activities	33.00		
	Grand Total	378.00		

Source: NEA

The economic and financial costs (or value) of power from electric utilities, and other key economic and financial assumptions used in these analyses, are summarized in Exhibits 1.3.A and 1.3.B. The derivations of these values are discussed in more detail in Appendix C. Generally, the values were based on studies by NEA, NESDB, and Thai utilities and by international organizations such as the World Bank and the Asian Development Bank. 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 B/kWh or $/kWh.

For the economic cost of electricity, the study team used the long-run marginal cost of supply for each utility, as presented in a recent NEA study.[2] To simplify cost comparisons, the marginal demand and energy costs were converted into an average marginal cost in B/kWh, assuming annual utilization of 6,000 hours (see Exhibit 1.3.A). These figures represent the average marginal cost of medium-voltage power to each utility.

For the financial cost of electricity, the team used EGAT's current tariffs to large industries, MEA and PEA. It assumed that non-utility power would replace the power generated by EGAT. Again, the demand and energy charges were converted to an equivalent cost in B/kWh.

For the technologies that do not provide firm capacity, such as cogeneration and hydro, cost comparisons were based on the energy cost only and not on the demand (or capacity) cost.

Care must be taken in interpreting the results of the analyses in this report. For example, for a number of years, NEA has been studying the potential of small-scale hydropower and dendrothermal systems to supply energy to the more remote villages, particularly those not yet connected to the PEA grid. The justification for such systems must include not only a comparison of their power generation costs with EGAT's or PEA's, but also their contribution to social equity and rural development.

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 Thai government could stimulate investment by the private sector in power systems to supplement resource-constrained 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

[2] National Energy Administrtation, Thailand Power Tariff Structure Study, September 1984.

Exhibit 1.3.A

Key Economic Assumptions

Marginal Productivity of Capital: 12 percent, real terms
Estimated Economic Eletricity Cost:*

Utility	Demand Charge B/KW/yr	Energy Charge B/kWh	Average Cost B/kWh
EGAT	600	0.95	1.05
MEA	1,715	0.97	1.26
PEA	835	1.01	1.15

* Generation and medium voltage distribution

Source: Hagler, Bailly & Company and NEA.

Exhibit 1.3.B

Key Financial Assumptions

After-tax return on equity:	25 percent, real
Cost of debt:	15 percent, real
Debt/equity ratio:	3:1
Marginal tax rate:	30 percent
Deperciation:	10 years, straight line
Tax concessions:	None

Financial Electricity Cost*

Utility	Demand Charge B/KW/yr	Energy Charge B/kWh	Average Cost B/kWh
EGAT to Industry	1,044	1.4100	1.58
EGAT to MEA	960	1.3853	1.55
EGAT to PEA	804	1.0298	1.16

* Based on the tariffs that EGAT charges large industries, MEA, and PEA

Source: Hagler, Bailly & Company and EGAT.

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

In addition, where a particular technology is deemed only marginally economic or not economic at all, that does not mean the technology is not worthy of development. Rather, it means that, on the basis of the project's most direct and obvious economic costs and benefits but without consideration of other socioeconomic factors, a private-sector individual or firm is not willing to undertake it without significant government subsidies.

A final consideration for systems in remote areas is that they may also compete with the planned extension of the PEA power grid. By the end of 1986, PEA expects approximately 80 percent of the rural settlements in its service territory to be connected to its grid; this figure is expected to increase to 95 percent by 1991 and to nearly 100 percent by 1997. Thus, the economic life of a remote power generating project will probably be less than 10 years, after which it will operate in a "fuel-saver" mode, reducing the need for gas and oil generation by EGAT. In this case, the high initial capital cost must be recovered in 5 or 10 years, rather than in the 20 years assumed in many of the economic analyses.

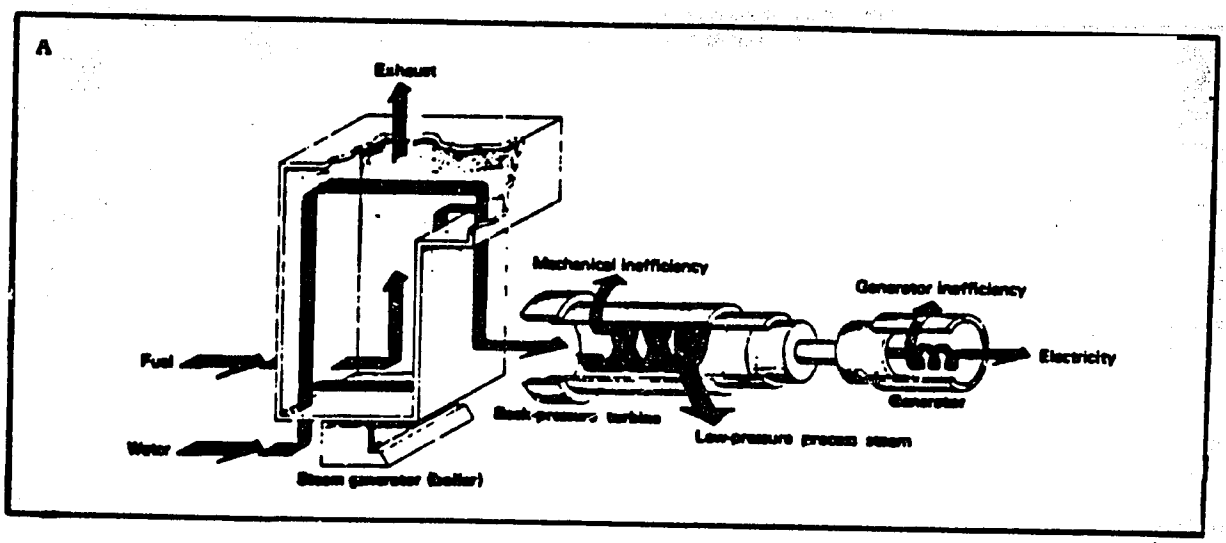
POTENTIAL FOR ADDITIONAL COGENERATION

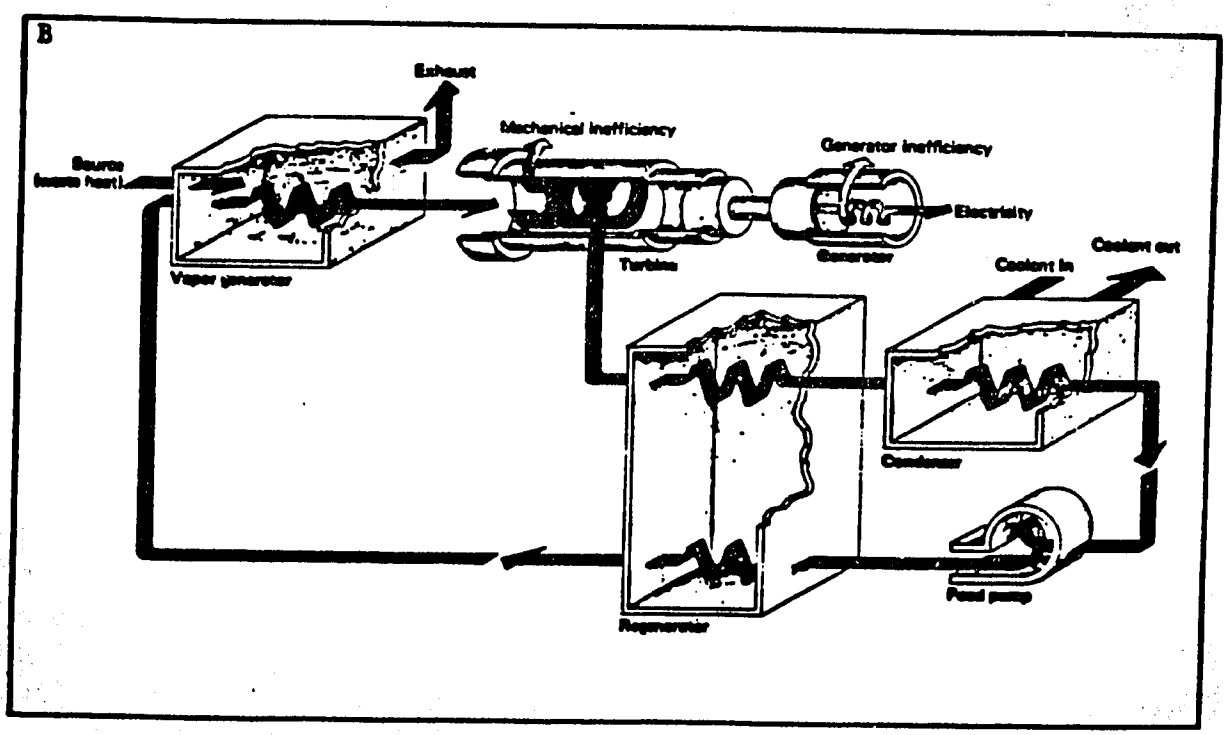
In this section, the potential for additional cogeneration in the industrial sector in Thailand is estimated[3]. Cogeneration systems fall into two categories: topping systems and bottoming systems. In a topping system, thermal energy exhausted in the production of electrical or mechanical energy is used in industrial processes (see Exhibit 1.4A). 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 a 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

[3] This study does not cover the cogeneration potential in the commercial sector because that market is estimated to be very small.

Exhibit 1.4.A Steam-Turbine Topping System

1.4.B Rankine Bottoming System





Source: U.S. Department of Energy, Cogeneration: Technical Concepts, Trends, Prospects; 1978

located in industrial sites may 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 heat released from the combustion of commercial fuels. Basically, a bottoming cycle system consists of a waste heat boiler used to vaporize water or organic fluids and a turbine generator with condenser, unless low-pressure exhaust steam extracted from the turbine can be used directly in the process (see Exhibit 1.4B). Such systems are used in processes generating large waste heat streams at temperatures of 250°C and higher.

In Thailand, the following industries are possible candidates for bottoming systems:

- Cement
- Chemical, including petroleum refineries
- Steel, including smelting
- Glass

The cogeneration potential in the Thai industry is estimated, first for topping and then for bottoming applications, in the following sections. Since most of the cogenerated electricity is used on site by industry, the financial potential is estimated by comparing the cost of power from cogeneration systems with the price of electricity purchased from utilities. To be conservative, the team assumed that no firm generation capacity would be available from cogeneration systems, so it took into account only the energy charge component of electricity tariffs (0.95-1.01 B/kWh for the economic analysis and 1.02-1.41 for the financial analysis as shown in Exhibits 1.3.A and 1.3.B)

Topping Systems Using Commercial Fuels

To identify the technical potential for topping cogeneration, the team first identified the current requirements for low-pressure steam in each industry. To do this, energy consumption statistics by 4-digit TSIC code were used, as was the detailed process energy information available in the energy audit reports prepared by United Nations International Development Organization (UNIDO), Japan International Cooperation Agency (JICA), Asian Development Bank (ADB) and NEA during the 1981-1985 period. These detailed audits provide excellent information on steam demand, plant capacity factor, electric-to-steam demand ratios, type of fuel used, and annual hours of operation (see Appendix D for details). This information provided the basis for estimating the technical potential under current conditions and up to 1996. The detailed computations were carried out using Hagler, Bailly's proprietary model, which

is described in Appendix D. The results of the model show that the technical potential for topping cogeneration systems using commercial fuels between 1986 and 1996 is 433 MW, of which more than two-thirds is in the food and textile industries (see Exhibit 1.5).

The economic potential for topping cogeneration was estimated for a base case scenario, where economic assumptions followed government estimates and projections for energy costs to the year 2000. The results indicate that the economic potential is very close to the technical potential, 420 MW (see Appendix D).

The estimates of the financial potential, using system technical performance data similar to U.S. and Thai financial parameters, show that 184 MW could be economically developed during the 1986-1996 period, of which 80 MW are in new industries (see Appendix D for more detail on the distribution of the cogeneration potential).

Topping Systems Using Waste Fuels

Because all industries that now use waste fuels -- sugar mills, sawmills, and rice parboiling mills -- will continue using back-pressure cogeneration systems, the economic potential of additional topping systems depends on the growth of these industries. Using growth rate projections from NESDB and steam conservation rates estimated by NEA, the team estimated the total incremental technical potential for topping cogeneration systems using waste fuels at 50 MW. Based on a capital cost of $500/MW, 3,000 hours of operation per year, and no fuel cost, the economic cost of electricity from such systems is about 0.8 B/kWh, and the financial cost is 0.6 B/kWh. The economic potential for these systems is expected to be 46.1 MW (see Exhibit 1.6). Because these systems have low fuel costs, the entire economic potential is also financially viable.

Bottoming Systems

Based on a review of the detailed energy audits performed by ADB, JICA and NEA, the study team identified a sample of plants with exhaust streams of 300°C or more that were candidates for cogeneration bottoming systems. Because bottoming systems generating less than 100 kW of electrical output are not readily available, and are not usually economically viable, the estimate of the bottoming system potential includes only those applications having waste heat streams of 2 GJ/hr (2 mmBtu/hr) or more, which corresponds to a power output of 100 kW or more.

Using data from ADB audit reports on the cement industry, where an estimate of potential power generation was made for each of the seven kilns operating

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Exhibit 1.5

Technical Potential of Topping Cogeneration in Thai Industry Using Commercial Fuels (1986-1996)

TSIC Code	Industry	Cogeneration Potential (MW)
31	Food	148
32	Textiles	154
33	Wood	10
34	Pulp & Paper	46
35	Chemicals	65
36	Non Metals	0
37	Basic Metals	6
38	Fabricated Metals	4
	TOTAL	433

Source: Hagler, Bailly & Company

Exhibit 1.6

Economic Potential of Additional Topping Cogeneration Systems Using Waste Fuels (1986-1996)

Industry	Type of Waste	1986 Cogeneration Capacity (MW)a	Projected Annual Growth Rate (%) (1985-2000)b	Projected Cogeneration Capacity In 1996 (MW)	Increment 1986-1996 (MW)
Cane Sugar Mills	Bagasse	305.0	1.2	345.0	40.0
Rice Mills (parboiling)	Husks	3.0	2.0	3.7	0.7
Sawmills	Sawdust	0.6	5.4	1.1	0.3
Pulp and Paper Mills	Black Liquor(c)	6.6	5.4	11.8	2.7
Refineries	Off-gas(c)	2.8	1.1	3.2	0.4
Other	Misc.	3.0	4.6	4.9	2.0
	TOTAL	321.0		369.7	46.1

(a) From Exhibit 1.2

(b) NESDB, Adjusted for energy conservation (-1.0%/year) - Vol. II p. 36, 91-93

(c) Assumed to be half total fuel consumption.

Source: Hagler, Bailly & Company.

in Thailand, the team estimated that 25.5 MW of power could be technically generated in this industry.

For the chemicals, petroleum refining, steel, and glass industries, the net output of the waste heat streams was computed in GJ/hour from the data available in audit reports. Using a standard system efficiency of 22 percent for waste heat stream temperatures higher than 800°C, 20 percent for temperatures between 500°C and 800°C, and 15 percent for temperatures between 300°C and 500°C, the team estimated the bottoming system potential at 43 MW in 17 plants (see Exhibit 1.7). Because the audits cover only about 70 percent of Thai industry, the total national potential is estimated at around 62 MW in 1982 conditions. With energy use in these industries expected to grow an average 4.5 percent per year for the 1982-2001 period, after conservation[4], the potential is projected to grow to 125 MW by the year 1996.

Using U.S. capital costs and annual O & M costs that are 5 percent of capital costs, the team estimated that levelized annual costs of power would range from 1.17 to 2.9 B/kWh (see Exhibit 1.8). Similarly, the financial cost of power from these systems is expected to range between 1.38 and 3.45 B/kWh. Only systems sized at 2 MW and more can be competitive with the price of electricity purchased from EGAT, by MEA and large industries, at 1.55-1.58 B/kWh. The cumulative potential of such systems is 38 MW in 1982 conditions, or 78 MW in the year 1996.

The cost of electricity from these systems would be higher than the 1.15 B/kWh that EGAT charges PEA.

SMALL-SCALE POWER GENERATION FOR SALE TO THE GRID

One set of options for power generation by the private sector is the investment in small dedicated power units selling power to the grid. These systems include:

- Small fossil-fueled systems
- Municipal waste-fired systems
- Bagasse-fired systems
- Rice husk-fired systems
- Small-scale hydropower
- Dendrothermal systems

These systems differ significantly in their investment requirements, operating costs, and potential for implementation by the private sector. In the following

[4] See Hagler, Bailly & Company report "Kingdom of Thailand: The National Energy Saving Goals for Industry, 1986-1991," Draft Final Report, March 25, 1986.

Exhibit 1.7

Estimate of Technical Potential of Bottoming Cogeneration - 1982

Industry	Plant Name	Waste Heat Characteristics			otential
		(ºC)	GJ/hr	hr/year	(MW)
1. Cement[1)]					
a	Siam Cement	350-460	-	3,200	10.70
b	"	"	"	"	4.00
c	"	"	"	"	2.63
d	"	"	"	"	2.10
e	"	"	"	"	2.63
f	"	"	"	"	1.61
g	"	"	"	"	1.80
h	"	"	"	"	
				Total	25.50
2. Refineries[2)]	Bangkok	540-1,000	95.0	8,000	5.60
	TORC	"	100.0	"	6.00
	ESSO	"	70.0	"	4.10
				Total	15.70
3. Steel[3)]	Bangkok	415	6.9	5,000	0.30
	Sahaviriya	810	7.6	4,000	0.40
	Union Metal	800	2.8	5,400	0.20
				Total	0.90
4. Chemicals[4)]	Siam Chemicals			Total	0.15
5. Glass[5)]	Bangkok Glass	540	5.6	8,000	0.30
	Samutprakarn Glass	480	3.5	8,600	0.20
					0.50
				Grand Total (rounded)	=43.00

Notes:
1) from ADB report, Vol. 3-B
2) " " " "
3) from JICA report, Vol. 2
4) from ADB report, Vol. 3-C
5) from JICA report, Vol. 1

Source Hagler, Bailly & Company

Exhibit 1.8

Economic Cost of Producing Power From Bottoming Cycle Systems

System Size (MW)	Investment Cost 1985 U.S.$/kWe	Levelized Annual Cost of Power Baht/kWh (U.S. cents/kWh)			
		5,000hr/year		8,000hr/year	
4+	1,800	1.90	(7.09)	1.17	(4.4)
2.4	2,100	2.2	(8.27)	1.37	(5.2)
1.2	2,500	2.61	(9.85)	1.63	(6.2)
0.1	2,800	2.9	(11.0)	1.83	(6.9)

Assumptions:

- System operating life = 15 years
- Capital recovery factor = 0.147
- O&M costs = 5 precent of initial capital cost

SOURCE: Hagler, Bailly & Company

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

Small Fossil-Fueled Systems

These systems include diesel engines, gas turbines, and boilers with condensing steam turbines that run on domestic natural gas or lignite. As far as the study team was able to determine in its discussions with private- and public-sector individuals and organizations, there are no privately owned systems of this type now operating. In addition, there appears to be no discernible interest on the part of the private sector in investing in such systems. This lack of interest is based on the private sector's perception of EGAT as a reasonably efficient utility that can generally meet all reasonable power demands and has lower power generation costs than a privately financed plant would have.

These lower production costs are based on several factors: EGAT's economies of scale (owing to its ability to construct and operate power generation units of several hundred megawatts of capacity); EGAT's access to sources of relatively low-cost capital (from the RTG and other sources, including international organizations such as the World Bank and suppliers' credit), which a private Thai investor probably cannot duplicate; and EGAT's access to low-cost fossil fuel resources, including natural gas and lignite.

Technical Potential

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

Economic Potential

The estimated production cost for an economic delivered natural gas price of $2.50/mcf ranges from 1.04 B/kWh to 1.49 B/kWh (see Exhibit 1.9). This cost is at best marginally competitive with the utilities' estimated economic marginal cost of 1.05 to 1.26 B/kWh. In addition, the marginal natural gas price is the price at the point where the pipeline comes ashore at Bangkok, near EGAT's combined-cycle generating plants. Locations elsewhere in the country would require a pipeline that does not yet exist, adding significantly to this cost. With gas at $3.00/mcf to $3.50/mcf, which represents Thai natural gas costs with reasonable pipeline charges, the power generation costs range from 1.19 B/kWh to 1.80 B/kWh, which is more expensive than the

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Exhibit 1.9

Economic Cost of Small Power Generation from Natural Gas-Fired Simple Cycle Gas Turbines (Baht/kWh)

	Natural Gas Price (Delivered, $/mcf)			
System Size		$2.50	$3.00	$3.50
50 MW	1.04	1.19	1.34	
20 MW	1.19	1.34	1.49	
5 MW	1.49	1.64	1.80	

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%
- System operating life = 20 years
- Capital recovery factor = 0.134

Source: Hagler, Bailly & Company

utilities' estimated economic marginal cost, except for large units with gas prices of under $3.00/mcf.

Similarly, the economic production cost of lignite-fired boilers with condensing steam turbines -- 1.52 to 2.08 B/kWh -- is not competitive for the expected ranges of delivered lignite costs -- 400 to 700 B/ton delivered (see Exhibit 1.10). This non-competitiveness is mainly the result of the relatively high costs ($1,500/kW) of lignite-fired boiler and steam turbine systems in such relatively small sizes.

Financial Potential

At the current industry gas price of $3.50/mcf, the largest turbines (20 MW to 50 MW) may be marginally competitive with the the price that EGAT charges the industry and MEA (1.58 and 1.55 B/kWh respectively), but smaller systems with generating costs up to 2.14 B/kWh will not be competitive (see Exhibit 1.11). These costs imply that the private sector may invest in large systems, with the aim of selling electricity to MEA or to industry. Small gas turbine systems (5 MW) do not appear financially attractive, however, even if the gas price were reduced to $2.50/mcf.

If industry received gas at the same price as that EGAT currently pays ($3.20/mcf), 50 MW systems would be financially attractive, and 20 MW systems might also be. To receive this price, however, these systems would probably need to be sited near the point where the natural gas pipelines come ashore. Thus, they would probably be equivalent, for power generation purposes (e.g., in dispatching), to EGAT-owned systems. Therefore, these systems are discussed in more detail in the section on large-scale power generation.

The financial costs of small lignite power plants are estimated in Exhibit 1.12. These costs are higher than the prices at which industry, MEA, and PEA can buy electricity.

Municipal Waste-Fired Systems

The potential for burning municipal waste in Bangkok to generate power has been explored several times in the last 15 years. A major feasibility study will soon begin, funded by the U.S. Trade and Development Program (TDP). The TDP funded a prefeasibility study that estimated the costs and benefits of such a project; the information presented in that report forms the basis of this analysis.

The Bangkok metropolitan area has a population of approximately 5 million, inhabiting an area of 1,568 square kilometers. Each year approximately 1

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Exhibit 1.10

Economic Cost of Small Lignite-fired Boiler/Steam Turbine System (Baht/kWh)

Lignite Cost (Baht/metric ton delivered)	Electricity Cost (Baht/kWh)
400	1.52 - 1.73
500	1.59 - 1.85
700	1.71 - 2.08

Assumptions:

- Total installed capital cost = $1,500/kW
- Annual O&M cost = 1 cent/kWh
- Capital recovery factor = 0.134
- Annual capacity factor = 0.60
- Overall plant efficiency = 25%
- Lignite heat value = 3,000 - 5,500 kcal/kg

Source: Hagler, Bailly & Company

Exhibit 1.11

Financial Cost of Small Power Generation from Natural Gas-fired Simple Cycle Gas Turbines (Baht/kWh)

	Natural Gas Price (Delivered, $/mcf)		
System Size	$3.00	$3.50	$4.00
50 MW	1.28	1.43	1.53
20 MW	1.46	1.61	1.76
5 MW	1.84	1.99	2.14

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 = 0.183
- Marginal Tax Rate = 30%
- Depreciation: Straight Line, 10 years

Source: Hagler, Bailly & Company

Exhibit 1.12

Financial Cost of Small Lignite-Fired Boiler/Steam Turbine System (Baht/kWh)

Lignite Cost (Baht/metric ton delivered)	Electricity Cost (Baht/kWh)
400	1.62 - 1.83
500	1.69 - 1.95
700	1.81 - 2.18

Assumptions:

- Total installed capital cost = $1500/kW
- Annual O&M cost = 1 cent/kWh
- Capital recovery factor = 0.183
- Annual capacity factor = 0.60
- Overall plant efficiency = 25%
- Lignite heat value = 3000 - 5500 kcal/kg
- Marginal tax rate = 30%
- Depreciation = straight line, 15 years

Source: Hagler, Bailly & Company

million tons of municipal waste are generated; this amount is expected to double in the next decade. The Bangkok Municipal Authority is charged with collection and disposal of this waste. It now has three disposal sites -- at Ram Intra, On Nooch, and Nong Khaem. Ram Intra has a small incinerator that has not been operable for several years because of a lack of parts. In addition, there are compost plants at each of the disposal sites to process waste for sale.

In 1981, the total amount of waste delivered to the three sites was 3,059 tons per day. Of this total, 1,120 tons were composted. Composting reduced the amount of waste by 25 percent (or 280 tons), leaving 2,779 tons of waste per day to be burned for power generation. The characteristics of this waste are summarized in Exhibit 1.13. Compared with municipal waste in the United States and Western European countries, Bangkok waste generally has a higher moisture content and lower flammable (i.e., paper) content, and thus has less potential for power generation.

Technical Potential

Bangkok's approximately 2,779 tons of waste per day represent a potential power output of 36 MW, and an annual generation of 237 million kWh. At present there are no estimates of municipal waste-to-energy potential in other Thai cities. However, the second largest city, Chang Mai, has a population of approximately 1 million. If its waste characteristics are similar to Bangkok's, then it is likely to have a potential power output of 7 MW. No other Thai cities are likely to have significant potential for power generation from municipal waste.

Economic Potential

The TDP prefeasibility study recommended that waste-to-energy systems totalling 20 MW be installed at the three sites, for a total output of 130 million kWh per year at production costs ranging from 2.2 to 3.8 B/kWh (see Exhibit 1.14). While these costs do not appear competitive with the utilities' marginal costs of 1.05 to 1.26 B/kWh (see Exhibits 1.3.a and 1.3.b), several factors make them seem higher than they might actually be. First, the tipping fee may be much higher than the 276 B/ton assumed in the study. Discussions with Bangkok Municipal Authority officials indicate that estimates for this fee range from 200 B/ton to 1,200 B/ton. The Authority is undertaking a study to determine this cost more accurately. If the estimate for this fee were to double to 550 B/ton, for example, the power production costs become 1.0, 2.6, and 2.2 B/kWh at Ram Intra, On Nooch, and Nong Khaem, respectively. Ram Intra then appears competitive with the utility supply.

Exhibit 1.13

Composition of Bangkok Municipal Solid Waste

Moisture content:		57.1%
Ash content:		15.7%
Chemical composition:		
Carbon	15.0%	
Hydrogen	2.3%	
Nitrogen	0.4%	
Oxygen	9.3%	
Sulphur	0.1%	
Chlorine	0.2%	
Lower heating value wet basis	1,130 kcal/kg (2,036 Btu/lb)	

Source: Trade and Development Program, "Municipal Solid Waste to Electricity in Bangkok," Prefeasibility Study, 1985.

Exhibit 1.14

Summary of Operating Characteristics and Economic Costs for Bangkok Municipal Waste-to-Energy Sites

	Ram Intra	On Nooch	Nong Khaem
• Waste delivered (tons/day)	423	1445	1151
• Waste available for power (tons/day)	343	1285	1151
• Waste used in power production (tons/day)	303	612	612
• Power output (MW)	4	8	8
• Generation (million kWh/yr)	26	52	52
• Capital cost (million $)	12.8	25.7	25.7
• O&M cost (million $/yr)	1.7	6.3	5.6
• Tipping fees (million $/yr)	1.2	2.3	2.3
• Net economic cost for power (million $/yr)	2.2	7.4	6.7
• Economic power Cost (Baht/kWh)	2.2	3.8	3.4

Assumptions:

- Average capital cost = $3200/kW
- O&M cost = $13.6/ton available for power
- System operating life = 20 years
- Power generation capacity factor = 0.75
- Capital recovery factor = 0.134
- Tipping fee = 276 Baht/ton

Source: Hagler, Bailly & Company

Trade and Development Program, "Municipal Solid Waste to Electricity in Bangkok," Prefeasibility Study, 1985.

In addition, since the amount of waste is expected to double within a decade, it is quite likely that the existing waste sites will be filled in the foreseeable future, necessitating new sites that are likely to have much higher costs. The need for new sites can be delayed for a number of years by installing waste-to-energy systems at the existing sites, since burning will significantly reduce the volume of waste. The Authority's study of disposal costs and allowable tipping fees should be expanded to include an estimate of when existing sites will be filled and what the costs of developing new sites will be. These estimates should then be used in the feasibility study to determine whether the waste-to-energy system is cost-effective using long-term costs of waste disposal rather than short-term costs.

Financial Potential

The financial potential of municipal waste-to-energy systems does not appear promising. The estimated financial costs for these systems, assuming a tipping fee of 276 B/ton, are shown in Exhibit 1.15. If the tipping fee is doubled, the financial power cost becomes 1.7, 3.2, and 2.8 B/kWh at Ram Intra, On Nooch, and Nong Khaem, respectively. These costs are still substantially higher than the prices that EGAT charges PEA, MEA, and large industries (1.16, 1.55, and 1.58 B/kWh, respectively). If these cost estimates are borne out by the feasibility study, it will be difficult to attract private investors for a waste-to-energy system without significant government subsidies. However, it is likely that the long-term costs of waste disposal will be significantly greater than the short-term costs at existing facilities, and may make municipal waste-to-energy systems attractive.

Bagasse- and Cane Residue-Fired Systems

The cane sugar industry -- one of the major industries of Thailand -- produced approximately 2.46 million metric tons (mt) of sugar during the 1983/84 season. The amount of cane crushed was 25.05 mt, creating about 7.27 mt of bagasse, the fiber residue. The Office of the Cane and Sugar Board (OCSB) estimates that 90 percent of the bagasse is now burned on-site in boilers that generate medium-pressure steam (300-350 psig). The steam is used to run the crushing mills and to generate electricity through back pressure turbines, with the low-pressure exhaust steam used in the process. The remaining 10 percent of the bagasse is either sold, mostly to the paper and particle board industries or for compost, or is disposed of in a variety of ways, including incineration. This small quantity of bagasse -- less than 1 million tons -- may thus be considered excess and available for other use, including power generation.

In addition to bagasse, cane residues can be used as a fuel in existing boilers to generate power. These residues, which consist mainly of cane tops and

Exhibit 1.15

Summary of Operating Characteristics and Financial Costs for Bangkok Municipal Waste-to-Energy Sites

	Ram Intra	On Nooch	Nong Khaem
• Waste delivered (tons/day)	423	1445	1151
• Waste available for power (tons/day)	343	1285	1151
• Waste used in power production (tons/day)	303	612	612
• Power output (MW)	4	8	8
• Generation (million kWh/yr)	26	52	52
• Capital cost (million $)	12.8	25.7	25.7
• O&M cost (million $/yr)	1.7	6.3	5.6
• Tipping fees (million $/yr)	1.2	2.3	2.3
• Net financial cost for power (million $/yr)	2.9	8.7	8.0
• Financial power costs (Baht/kWh)	2.9	4.4	4.0

Assumptions:

- Average capital cost = $3200/kW
- O&M cost = $13.6/ton available for power
- System operating life = 20 years
- Power generation capacity factor = 0.75
- Capital recovery factor = 0.183
- Marginal tax rate = 30%
- Depreciation = straight line, 10 years
- Tipping fee = 276 Baht/ton

Source: Hagler, Bailly & Company

Trade and Development Program, "Municipal Solid Waste to Electricity in Bangkok," Prefeasibility Study, 1985.

leaves, can represent an even more attractive energy source than bagasse because they have little value for other uses, except cattle feed, and they are available in large quantities. A study on their potential was recently conducted under funding from USAID[5] and is summarized below, together with the potential from bagasse.

Technical Potential

From Bagasse

The OCSB expects sugar cane production to decline from the current 25 mt/year to 23 mt/year in 1987 and 1988, thereafter rising to regain its current level by 1990 and reaching 28 mt by 1996. On the basis of this projection, 7.27 mt of bagasse will be available in 1990 and 8.1 mt in 1996, assuming the ratio of bagasse-to-cane remains the same.

However, the amount of excess bagasse is likely to increase over this period owing to technical improvements in the refining process that will increase energy efficiency. These improvements include bagasse drying using flue gases, dried bagasse pelletizing, thermo/turbo compression in the evaporation stage, and replacement of low pressure boilers and turbines. They will result in savings of 10 percent of the bagasse used by 1990, and savings of 19 percent by 1996.

On the basis of these improvements, sufficient excess bagasse would be available to generate up to 371 MW during the sugar season by 1990 and 610 MW by 1996 (see Exhibit 1.16).

If the technical potential is defined as the quantity of power that could be produced according to the best international performance (i.e., Hawaii, where 70 kWh excess can be produced from each ton of cane processed), the technical potential would be 875 MW in 1990 and about 980 MW in 1996 (see Exhibit 1.16).

From Cane Residue

The study on electric power from cane residues estimates that 270-715 MW of generating capacity can be developed from cane tops and leaves -- roughly the same capacity as bagasse. This estimate suggests that about 300 MW of generating power could come on line between 1986 and 1995 using excess bagasse as a fuel during the crushing season and conditioned -- dried and baled -- residues during the interseason (April to November).

[5] Electric Power from Cane Residues in Thailand: A Technical and Economicl Analysis. May 1986, prepared by Ronco Consulting Corporation, Arlington, Va.

Exhibit 1.16

Projected Bagasse Balances and Technical Potential for Power Generation (1984-2000)

	1984	1990	1996
a) Cane Grown (million tons)[1]	25.00	25.00	28.00
b) Sugar produced (mt)[1]	2.46	2.50	3.00
c) Bagasse produced (mt)	7.27	7.27	8.10
Current Technology			
d) Burnt in on-site boilers (mt)[2]	6.54	6.21	6.90
e) Sold (paper industry, compost, etc.)[3]	0.30	0.50	0.60
f) Excess (f= c-d-e)	0.42	0.56	0.60
Modified Technology and Conservation			
g) Energy conservation rate (%)	0.00	10.00	19.00
h) Additional bagasse available (mt)	0.00	0.62	1.34
i) Excess (i= f+h)	0.42	1.18	1.94
j) Potential excess electricity generated (GWh/yr)	-	741.00	1,218.00
(MW)	-	371.00	610.00
Maximum Potential			
70 kWh/tonne of cane (GWh/year)[4]	1,750.00	1,750.00	1,960.00
(MW)	875.00	875.00	980.00

Source: Hagler, Bailly & Company

1) Source: OCSB

2) Source: Energy Master plan, taking units account 5% steam savings between 1990-2000

3) Study team estimate

4) Source: World Bank report - 70/kWh excess per ton of cane processed

Economic and Financial Potential

Bagasse

Surplus bagasse can be used to generate excess electricity for sale to the grid by installating new condensing turbine units. Depending on the system size, the economic cost of power would be between 1.18 and 1.32 B/kWh (see Exhibit 1.17). For plants with a capacity of more than 5,000 tons/day, the electricity production costs are competitive with the marginal cost of electric utilities (1.05 to 1.26 B/kWh).

The financial cost of power generated from bagasse would be between 1.45 and 1.63 B/kWh (see Exhibit 1.7). For units over 5,000 MW in capacity, this cost is competitive with the prices that EGAT charges its large industrial customers (1.56 B/kWh). These mills would have a combined capacity of 260 MW (see Exhibit 1.17).

Residues

Based on the results of the study mentioned earlier, sugar mills of 5,000 tons per day or more could produce electricity at a cost of 1 B/kWh or less, which is significantly lower than the cost of power from EGAT. Therefore, the lower bound of the technical potential -- 270 MW, -- constitutes a good estimate of the economic and financial potential.

Given the economic potential from bagasse (260 MW during the crushing season) and from cane residues (270 MW during the interseason), the study team concluded that 260 MW of excess power would be economically produced from sugar mills year-round.

Rice Husk-Fired Systems

Rice husks, a product of rice milling, are a major agroindustrial and biomass waste in Thailand. There are about 40,000 rice mills producing more than 12 million tons of rice annually from 18.3 million tons of paddy. The corresponding amount of rice husks is estimated at 4.1 million tons. NESDB estimates that this amount of husks was produced in 1982, of which 23 percent, or 935,000 tons, was consumed as fuel. For 1984, NEA puts the figure for husks used as fuel at 1.32 million tons. An NEA study has estimated that the amount of rice husks produced in 1980 was 4.54 million tons, of which about 20 percent, or 900,000 tons, was used on-site.[6].

[6] "Feasibility Study on Rice Husk Pyrolysis Technology for Rice Mill Applications in Thailand." NEA/USAID 1984, p46 and fol.

Exhibit 1.17

Economic Potential for Generating Surplus Electricity for Excess Bagasse - 1991 Conditions

Plant size(a) (tons of cane/day)	Number of Mills(a)	Total Capacity in Plant Size Range (t/d),(%)(a)	Technical Potential MW(b)	Technical Potential GWh/year(b)	Power Generation Costs: Capital cost ($/kW)(c)	Economic Non-Fuel (Baht/kWh)(d)	Financial Non-Fuel (Baht/kWh)(d)	Fuel Cost (Baht/kWh)(e)	Economic Cost (Baht/kWh)	Financial Cost (Baht/kWh)
3,000	12	20,600 (7.1)	26.3	52.6	460	1.08	1.39	0.24	1.32	1.63
3,000-5,000	10	42,600 (14.6)	54.2	108.4	440	1.03	1.33	0.24	1.27	1.57
5,000-10,000	14	113,500 (39.0)	114.7	289.0	420	0.99	1.27	0.24	1.72	1.51
10,000+	9	114,600 (39.3)	145.8	291.2	400	0.94	1.21	0.24	1.18	1.45

(a) Source: Office of the Cane and Sugar Board - 1984-85 statistics

(b) Using size distribution of previous column

(c) From World Bank report: "Identifying the basis conditions for economic generation of public electricity from bagasse in Sugar Mills - Appendix V. Economics and Financial costs are assumed to be the same.

(d) Using economic CRF of 0.147 for a system of 15 years, a financial CRF of 0.198, annual O&M costs of 3% of capital cost, and 2,000 hours per year of operation.

(e) Fuel cost: based on Baht 150/tonne or $.71/mmBtu; 27% efficiency (12,640 Btu/kWh). Economic and financial fuel costs are assumed to be the same.

Source: Hagler, Bailly & Company.

Drawing on information from these various sources, a balance of rice husk availability and use can be estimated. This estimate indicates that in 1984 about 2.8 million tons of husks would have been available for other uses (see Exhibit 1.18). Theoretically, all this amount could have been available for power generation. However, only large rice mills can use the husks on-site for power generation, and less than 3 percent of them have more than 60 hp installed. Thus, these 2.8 million tons of husks could be used on-site in the largest rice mills and used off-site in dedicated power plants to generate power for sale to the grid. As a result, all electricity would be generated from boilers with condensing (or extraction condensing) steam turbines, or from steam engine/generators.

Using U.S. data, the study team estimates that 90,000 tons of husk can generate 10.6 MW of power, or that roughly 1 MW can be generated from 8,500 tons of husk per year. This ratio corresponds to an overall plant efficiency of 28 percent, which is very high. Using this ratio, the maximum potential from rice husks used as a power plant fuel is estimated at 300 MW.

Economic and Financial Potential

The economic potential depends primarily on two key factors: the value of the rice husks and the power system cost.

No good estimate of the economic value of the husks is available in Thailand apart from sketchy data on market prices, which range from 100 to 250 B/ton. Because there is generally no demand for this by-product, the economic value of the husks was estimated on the low side of the market price at 150 B/ton.

Efficient rice husk-fired power plants with boilers ranging from 2 to 10 tons of steam per hour output with condensing steam turbines could cost $1,200-1,600/kW installed if all components were imported. Annual operation and maintenance costs would be around 5-7 percent of system investment costs, and overall system efficiency around 26-28 percent. If local boilers/steam or engine/generators were used, however, capital costs would be much lower, at $450-500/kW installed, for overall system efficiencies of about 20 percent.[7]

In estimating the economic potential, two categories of rice mills must be considered:

a) Large (100 tons/day or more) rice mills using only dry milling (no heat requirements).

[7] ADB audits, Vol 2-A.

Exhibit 1.18

Rice Husk Availability and Use (1984)

	Million Metric Tons
Paddy production	18.3
Rice husk production:	4.1
for on-site power and heat	0.93
sold to other industries	0.40
Available	2.77

Source: Hagler, Bailly & Company.

b) Large rice mills using parboiling (need for steam); there are about 30 such mills.

Small and medium-sized rice mills would not be candidates for the economic generation of power if they process less than 100 tons/day since their power requirements would be less than 100 kW.

The economic potential in dry milling, using on-site noncogenerating power plants or off-site power plants of locally made boilers at 10 bar pressure and steam engine/generators, is substantial. It is estimated at 151 MW, for an average economic cost of generation of 0.6 B/kWh (see Exhibit 1.19). The corresponding potential and cost using imported equipment are estimated at 204 MW and 1.3 B/kWh. At this price, the electricity generated is not competitive with marginal cost of power to utilities, 1.05 to 1.26 B/kWh. The economic potential in parboiling is small -- 3-5 MW.

The financial potential is the same as the economic potential, with the systems using local equipment being competitive with PEA power, and those using imported equipment not being competitive.

Small-Scale Hydropower

Hydropower has always been a major source of power for Thailand. The economics of hydropower systems, however, depend on their scale. In assessing the potential of such systems, therefore, the study team has differentiated among large, mini-, and micro-hydropower systems.

Technical Potential

One estimate puts the large-scale hydropower potential from rivers within Thailand at 8,300 MW. In addition, an additional 14,000 MW are available from the rivers on its borders (the Mekong and Salween), although their development is unlikely in the immediate future because of major political, environmental, and social impediments. At present, there are approximately 1,800 MW of large hydropower generating capacity, with 429 MW under construction and 2,500 MW (in 25 projects) under study.

Thailand currently has eight mini-hydropower sites (here defined as sites with a generating capacity of 200 kW to 6,000 kW) with a total capacity of 16,265 kW. In addition, 3,290 MW of potential has been identified at another 103 sites.

Exhibit 1.19

Economic Cost of Producing Power from Rice Husks (Mills processing 100 tons per day and more)

1985 Dollars -

	Total Annual Throughout (mmt)			Power Generation Costs						
	Paddy	Husks(c) Total	Husks(c) Excess(d)	Capital Cost ($/kW)	Economic Non-Fuel (Baht/kWh)(g)	Financial Non-Fuel (Baht/kWh)(g)	Fuel Cost (Baht/kWh)(h)	Economic Cost (Baht/kWh)(i)	Financial Cost (Baht/kWh)(j)	Potential (MW)
A. Dry milling	9.0(a)	2.0	1.3	local 500(e)	0.44	0.55	0.20	0.64	0.75	151
				imported 1,300(f)	1.13	1.42	0.15	1.28	1.67	204
B. Parboiling (Cogeneration)	1.0(b)	0.22	0.1	local 400	0.35	0.44	0.20	0.55	0.64	5

(a) Assuming half total paddy processed by these mills (source: consultant interview).

(b) Assuming 20-25 of total exports (source: consultant interview).

(c) Based on 22 percent of paddy processed.

(d) Same ratio as Exhibit 1.18.

(e) ADB audit reports, Volume 2-A.

(f) Estimate.

(g) Using economic CRF of 0.147, financial CRF of 0.198, and annual costs of 5 percent of capital costs, and 6,000 hours of operation/year.

(h) Based on Baht 150/tonne or $0.45/mmBtu. 20 and 27 percent efficiencies on local and imported systems, respectively.

(i) Economic Power Cost from PEA is 1.15 Baht/kWh (=(835 + 1.01 * 6000)/6000).

(j) Financial Power Cost from PEA is 1.60 Baht/kWh (=(12 * 95 + 1.41 * 6000)/6000).

Source: Hagler, Bailly & Company.

Economic Potential

Of these 103 potential sites for mini-hydropower development, 25 of the most attractive ones have been studied in detail by NEA. These 25 have a total capacity of 55.4 MW and an annual generation potential of 217.5 million kWh per year. Four of these sites (Nam Mae Sa-Nga, Nam Mae Sap, Nam Mae Mao, and Nam Mae Tun) were constructed during the Fifth Five-Year Plan. Another one, Huai Mae Hat, is under construction with financing provided by USAID, and another, Lam Phra Plerng, is under construction with the dam already built with a grant from the Belgium Government, and the electricity generating equipment to be financed by USAID. For the economic cost estimates, the team assumed the foreign currency portion of the costs to be approximately equal to the value of the electromechanical equipment. The economic cost of producing power from these sites ranges from 2.4 to 8.4 B/kWh. The financial costs range from 3.1 to 11.1 B/kWh (see Exhibits 1.20 and 1.21).

These estimates tend to be optimistic, for three reasons. First, the output of these projects is highly seasonal, with the rainy season output twice the dry season output. Normally, mini-hydropower projects have only minimal storage capability, so it is usually not feasible to attempt long-term storage to even out this pattern. Second, it is difficult to match the daily demand patterns, so a site will usually require supplemental power -- such as a diesel generator or a grid connection -- to meet peak demand. In addition, there may be surplus power available that cannot be stored to meet peak demands (e.g., the dam is too small). If the site is connected to the PEA grid, the surplus power can perhaps be sold to PEA; if not, the power is lost.

Finally, the economic life of the project may be short owing to the extension of the power grid under PEA's vigorous rural electrification program. At the end of 1984, 62 percent of the villages in Thailand were electrified. The program is expected to reach 80 percent by the end of 1986, 95 percent by the end of 1991, and essentially all villages by 2001.[8] Thus, even if the cost of the hydropower system is competitive with diesel generation for remote villages that will not be connected to the grid for several years, it may be more economical to supply power to the village with a diesel-generator set until the grid reaches the area.

The direct economic costs do not appear competitive with the cost of power produced by utilities. To be justified, therefore, these sites must have significant additional benefits. Such benefits can include stimulation of rural economies by providing jobs and making it possible for light industry to be established, improving the quality of life of rural villages, and assisting

[8] NESDB, Energy Issues and Policy Directions in the Sixth National Economic and Social Development Plan (1987-1991), Vol. 1, Oct. 1985, p.72.

Exhibit 1.20

Estimated Economic Costs of Power from Selected Mini-hydropower Sites in Thailand

Project Name	Domestic Capital Expenses (1985 $000)	Foreign Capital Expenses (1985 $000)	O&M Costs (000 $/yr)	Capacity (kW)	Output (10E6 kWh/yr)	Economic Power Cost (1985 B/kWh)
Pitsanulok (e)	3093	1994	746	3530	15.44	2.40
Nam Mae Wang	7507	2570	1403	6000	27.85	2.49
Phranburi Dam (e)	2401	1413	622	2500	11.59	2.40
Lam Takong Dam (e)	3250	1413	780	2500	11.56	3.04
Nam Mae Rim	3439	1590	705	2800	11.02	3.09
Huai Mae Tho	2611	1620	603	2200	9.05	3.14
Huai Wang Kiang (i)	2210	916	440	1000	6.46	3.31
Nam Mae Klang	4007	1709	801	3000	11.28	3.45
Nam Mae Ya	2306	1150	486	1500	6.22	3.76
Nam Mae Tun (i)	1289	273	217	400	2.70	4.06
Mae Kuang Dam (e)	3390	2712	1022	4800	12.02	3.69
Nam Mae Sa-Nga (i)	3514	1175	658	2000	8.20	3.95
Khlong Ae	4196	2077	890	2700	11.12	3.84
Khlong La-Un (i)	1834	445	382	500	4.15	4.26
Huai Mae Suk (i)	1353	393	244	400	2.46	4.93
Khlong Ra (i)	2075	1010	425	1040	4.37	4.72
Nam Mae Sap (i)	2420	1727	637	2100	6.10	4.73
Nam Un Dam (e)	2766	633	570	1120	4.91	5.38
Nam Mac Surin (i)	1254	170	192	275	1.80	5.55
Lam Phraplerng Dam (e)	2494	525	506	930	4.07	5.78
Nam Mae Mao	12167	3049	2093	6000	17.30	6.10
Khlong Nai	3052	775	533	970	4.08	6.54
Nam Mae Suai	14222	3121	2368	5600	16.16	7.45
Nam Mae Khong(i)	2269	581	393	400	2.58	7.66
Nam Mae Ngat (i)	5989	644	840	1120	5.00	9.07
TOTAL	95109	33685		55385	217.49	

(e) - existing dam site
(i) - isolated site (no connection to grid)

Capital Recovery Factors:
CRF(12%, 20 years) = 0.1339
CRF(12%, 10 years) = 0.177

Source: National Energy Administration
Hagler, Bailly, and Company

Assumptions:
E-M Equipment Operating Life = 10 years
Civil/Other Works Operating Life = 20 years
1985 Costs = 1.13*1980 Costs
Standard Conversion Factor = 0.9

Exhibit 1.21

Estimated Financial Costs of Power from Selected Mini-hydropower Sites in Thailand

Project Name	Total Capital Cost (1985 $000)	Electro-Mechanical Equipment (1985 $000)	O&M Costs (000 $/yr)	Generating Capacity (kW)	Output (10E6 kWh/yr)	Financial Power Cost (1985 B/kWh)
Pitsanulok (e)	5087	1994	746	3530	15.44	3.05
Nam Mae Wang	10076	2570	1403	6000	27.85	3.21
Phranburi Dam (e)	3814	1413	622	2500	11.59	3.18
Lam Takong Dam (e)	4662	1413	780	2500	11.56	3.90
Nam Mae Rim	5029	1590	705	2800	11.02	4.10
Huai Mae Tho	4232	1620	603	2200	9.05	4.27
Huai Wang Kiang (i)	3127	916	44[illegible]	1000	6.46	4.33
Nam Mae Klang	5716	1709	801	3000	11.28	4.54
Nam Mae Ya	3457	1150	486	1500	6.22	5.01
Nam Mae Tun (i)	1563	273	217	400	2.70	5.07
Mae Kuang Dam (e)	6102	2712	1022	4800	12.02	5.01
Nam Mae Sa-Nga (i)	4690	1175	658	2000	8.20	5.08
Khlong Ae	6273	2077	890	2700	11.12	5.10
Khlong La-Un (i)	2279	445	382	500	4.15	5.24
Huai Mae Suk (i)	1746	393	244	400	2.46	6.28
Khlong Ra (i)	3085	1010	425	1040	4.37	6.30
Nam Mae Sap (i)	4147	1727	637	2100	6.10	6.43
Nam Un Dam (e)	3399	633	570	1120	4.91	6.60
Nam Mac Surin (i)	1424	170	192	275	1.80	6.79
Lam Phraplerng Dam (e)	3019	525	506	930	4.07	7.06
Nam Mae Mao	15215	3049	2093	6000	17.30	7.70
Khlong Nai	3827	775	533	970	4.08	8.26
Nam Mae Suai	17343	3121	2368	5600	16.16	9.34
Nam Mae Khong(i)	2850	581	393	400	2.58	9.69
Nam Mae Ngat (i)	6633	644	840	1120	5.00	11.05
TOTAL	128794	33685		55385	217.49	

(e) - existing dam site
(i) - isolated site (no connection to grid)

Capital Recovery Factors:
CRF(20 years) = 0.183
CRF(10 years) = 0.232

Source: National Energy Administration
Hagler, Bailly, and Company

Assumptions:
E-M Equipment Operating Life = 10 years
Civil/Other Works Operating Life = 20 years
1985 Costs = 1.13*1980 Costs

national security by demonstrating the concern of the central government. In addition, there can be technical benefits such as stabilization of the PEA grid by providing a power source at the end of a long distribution line. Unfortunately, it is difficult to quantify the economic value of these benefits and thus determine their value to the Thai economy.

Thailand also has many micro-hydropower sites (here defined as those under 200 kW). There are now 25 such sites in operation with a capacity of 1,387.5 kW, and 13 more are under construction with a capacity of 361 kW. Economically, these sites are difficult to justify because their costs of 24,000 to 73,000 B/kW make the power very expensive compared with that of small diesel-generator sets. Thus, ancillary benefits must be considered in any justification of these investments.

NEA has recently begun an innovative project to promote the development of attractive micro-hydropower sites. In this effort, the rural populace will participate directly in the construction and operation of the system, and will have an opportunity to acquire full ownership of it. NEA will supply the material for civil works and the electromechanical systems. To keep costs low, these materials will be procured locally. When completed, the site will be operated by the villagers, possibly through some form of cooperative. The ownership will be split, with the villagers initially owning 30 to 40 percent of the project and NEA owning the remainder. The villagers will be allowed to purchase NEA's portion of the project out of project revenue. In addition, "soft" loans or loan guarantees may be available, with NEA assuming the financial risks. NEA envisions the implementation of 10 to 12 such projects each year.

Dendrothermal Systems

Dendrothermal systems are wood-fired power generation systems using wood supplied from nearby "plantations" that are managed and selectively harvested to provide a constantly renewing fuel supply. NEA is currently studying systems based on eucalyptus trees using existing cassava plantations or deforested land.

The technical potential from existing cassava plantations is estimated by NEA to be 400-500 MW. The potential from deforested land is much more difficult to estimate; NEA estimates this potential to be five to ten times as large as the potential from cassava plantations, or 2,000 to 5,000 MW. However, it will be difficult and time-consuming to aggregate deforested land into economical plantations. In addition, the yield from this deforested land will probably be less per acre than that from cassava plantations, owing to factors such as soil erosion.

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Economic Potential

The important characteristics and estimated economic costs of a 25-MW dendrothermal plant are summarized in Exhibit 1.22. More recent estimates by NEA indicate that 50-MW power plants may be more economical to operate (by approximately 5-10 percent).

In estimating the economic potential, two costs for wood were considered -- 148 and 473 Baht per cubic meter. These costs fall within the range of estimates in two dendrothermal studies performed for NEA. The economic cost of electricity from dendrothermal plants is estimated between 1.97 and 5.43 B/kWh (see Exhibit 1.22). Both the large capital investments needed and the relatively high cost of growing and collecting wood fuel makes these systems appear economically unattractive, compared with the marginal electricity production costs of utilities (1.05 to 1.26 B/kWh). These dendrothermal systems will be economically attractive only if the raising, collection, and delivery of the wood fuel can be performed at essentially no cost.

Financial Potential

The financial costs of dendrothermal systems are estimated to be between 2.4 and 6.3 B/kWh, depending on the wood cost (see Exhibit 1.23). These estimates make dendrothermal plants uncompetitive with EGAT power generation, which costs 1.16 to 1.58 B/kWh, at least until EGAT's cost of natural gas and oil increase significantly. If the government wishes to have the private sector invest in dendrothermal systems, it will probably have to provide significant incentives such as subsidies and tax concessions.

LARGE-SCALE POWER GENERATION FOR SALE TO THE GRID

It is also possible for private investors to finance large-scale utility-sized power plants (>50 MW). The objective of this type of investment is to displace the funds needed by EGAT to finance new generating plants. The current EGAT generation expansion plan, which represents the technical potential, is summarized in Exhibit 1.24. This potential is approximately 4,626 MW by 1996, of which 3,075 MW are lignite- or coal-fired boiler/steam turbine systems, 600 MW are natural gas-fired combined cycle systems, and 951 MW are large-scale hydropower systems. These represent a total investment of B 111,863 million (or approximately U.S. $4.1 billion).

No estimates were made of the economic or financial potential because the team's discussions with Thai public- and private-sector organizations indicated that the economic performance of these plants would be approximately the same for private financing as for public financing (through EGAT). The

Exhibit 1.22

Economic Cost Estimates for Dendrothermal Power Plants

Wood Market Price (B/cu-m)	Fuel Cost (B/kWh)	Total Electricity Cost (B/kWh)
473	4.51	5.43
148	1.41	2.33
110	1.05	1.97

Assumptions:

Plant power output = 25 MW
Annual plant capacity factor = 0.6
Land requirements = 85-155 sq km
Eucalyptus lower heating value = 405,720 kcal/cu-m
Plant lifetime = 20 years
Plant efficiency = 20.0% (17,000 Btu/kWh, 4,300 kcal/kWh)
Net heat rate = 94.4 kWh/cu-m
Plant capacity factor = 0.60
Plant output = 131,400,000 kWh/yr
Total capital cost = 31,800 B/kW
Foreign exchange portion of capital cost = 70%
Powerplant cost = 30,850 B/kW
Annualized capital cost = 0.786 B/kWh
O&M costs = 0.133 B/kWh
Total non-fuel costs = 0.92 B/kWh
Capital recovery factor = 0.134 for power plant; 0.12 for land

Sources:

Thailand Energy Master Plan Project: Volume 7, Rural Energy Demands and Renewable Supply Options; Robert R. Nathan Associates, Inc.; February, 1982

Improvement of EMP Electricity Subsystem Study: Final Report; Technical Applications Universal Ltd.; December, 1985

Thailand National Energy Administration

Hagler, Bailly & Company

Exhibit 1.23

Financial Cost Estimates for Dendrothermal Power Plants

Wood Market Price (B/cu-m)	Energy Cost (B/kWh)	Total Electricity Cost (B/kWh)
473	3.50	4.82
143	1.00	2.32
97.5	0.69	2.01

Assumptions:

Plant power output = 25 MW
Annual plant capacity factor = 0.6
Land requirements = 85-155 sq km
Eucalyptus lower heating value = 405,720 kcal/cu-m
Plant lifetime = 20 years
Plant efficiency = 20.0% (17,000 Btu/kWh, 4,300 kcal/kWh)
Net heat rate = 94.4 kWh/cu-m
Plant output = 131,400,000 kWh/yr
Annualized Capital Cost = 1.21 B/kWh
O&M Cost = 0.11 B/kWh
Capital recovery factor = 0.134 for power plant; 0.12 for land
Depreciation = 15 years straight line on power plant; none on land
Marginal tax rate = 30%
Return on equity = 25%, after tax
Debt cost = 17%, pre-tax
Debt/equity = 3/1

Sources:

Thailand Energy Master Plan Project: Volume 7, Rural Energy Demands and Renewable Supply Options; Robert R. Nathan Associates, Inc.; February, 1982

Improvement of EMP Electricity Subsystem Study: Final Report; Technical Applications Universal Ltd.; December, 1985

Hagler, Bailly & Company

Exhibit 1.24

Planned EGAT Generating Capacity

Name	Fuel	Commissioning Date	Capacity (MW)	Investment (Million Baht)
Srinakarind	Hydro	Jul 1988	180	1,070
Nam Chon	Hydro	Apr 1992	580	13,106
Kaeng Krung	Hydro	Jan 1991	80	2,900
Sai Buri	Hydro	Jul 1992	46	3,070
Kaeng Sua Ten	Hydro	Nov 1991	65	5,735
Ao Phai #1	Coal	Sep 1992	600	9,798
Ao Phai #2	Coal	Mar 1994	600	9,798
Ao Phai #3	Coal	Oct 1995	600	9,798
Krabi #1	Lignite	Sep 1988	75	4,374
Krabi #2	Lignite	Jan 1992	150	4,851
Krabi #3	Lignite	Jan 1993	150	3,843
Mae Moh #8	Lignite	Jun 1989	300	11,319
Mae Moh #9	Lignite	Jun 1990	300	10,309
Mae Moh #10	Lignite	Jun 1991	300	10,309
Nam Phong CC	N. Gas	Nov 1990	300	5,670
Nam Phong CC	N. Gas	Jan 1993	300	5,670
TOTAL			4,626	111,863

Assumptions:

- 1983 Baht
- 1 US$ = 26.5 Baht

Note: In addition to the projects listed here EGAT has planned 5 miscellaneous hydro projects from 2.8 to 58 MW in size having a total investment of 6,684 Baht, which would be commissioned in late 1995, and another 1,051 MW of hydropower in 12 sites, which are now under investigation.

Sources:

Improvement of EMP Electricity Subsystem Study: Final Report

Techapun Ltd. for National Energy Administration; December, 1985

Thailand: Issues and Options in the Energy Sector; World Bank Report No. 5973-TH; September, 1985

financial cash flows cannot be estimated because the large size of such investments means the tax and other factors affecting the project cash flows would be negotiated individually between the investors and the government, and their terms cannot now be determined.

To put the financing requirements of these power projects in perspective, the largest private firm in Thailand, the Siam Cement Group, made capital investments in 1984 of approximately B1.6 billion. All but one of the 16 power projects in EGAT's expansion plan are larger than this, with the largest eight times as large and the average sized project more than four times as large. Thus, it is unlikely that any private Thai organization would have the resources to finance a large-scale power project, and such projects will most likely rely on joint ventures or foreign financing. Because of the large size of the investment and the fact that government utilities are the only customers, foreign investors will require some kind of government guarantee or support, such as a guaranteed power purchase price and amount or a guaranteed return on investment. However, it is beyond the scope of this study to make assumptions on such government measures to estimate generation costs. Chapter 2 contains a more detailed discussion of financing issues associated with the development of large-scale power projects by the private sector.

SUMMARY

Even though the public utilities in Thailand have adequate reserves and reliably provide power at reasonable rates, there is still a sizable potential for private-sector power generation (see Exhibit 1.25). The technical potential for small power systems, cogeneration and power-only, is over 29,000 MW. Most of this potential comes from small hydropower and dendrothermal systems.

The estimated economic and financial costs of electricity from these resources and technologies are presented in Exhibit 1.26. Based on the comparison of the economic cost of power from each technology and the utilities' long-run marginal cost of medium voltage electricity, the economic potential is estimated at over 1,000 MW, of which 544 MW comes from cogeneration systems -- 466 MW from topping cycle systems and the remainder from bottoming cycle systems. Small hydropower and municipal waste represent about 75 MW of economic capacity.

The financial potential is approximately 723 MW. Power generation from bagasse and rice husks, in particular, provide about 60 percent of this potential. The remaining 40 percent comes from industrial cogeneration.

Lignite-fired systems do not represent a financial potential, since their generation cost is much higher than current EGAT prices. Large natural

Exhibit 1.25

Potential Generating Capacity

	Technical (MW)	Economic (MW)	Financial (MW)
Small Power Systems			
Topping cogeneration	483	466	230
Bottoming cogeneneration	125	78	78
Small fossil fueled system	--	--	--
Municipal waste systems	40	20	--
Bagasse systems	980	260	260
Rice husk systems	300	155	155
Small hydropower systems	22,300	55	--
Dendrothermal systems	5,000	--	--
Total, small	29,228	1,034	723
Large Power Systems			
Large hydropower	951	*	*
Large lignite	3,075	*	*
Large natural gas	600	*	*
Total, large	4,626		
TOTAL (Rounded)	33,314	1,034 **	723 **

* The economic and financial potential of large utility-sized systems depend on government policies that have not been defined.

** Does not include the potential for large power plants.

Source: Hagler, Bailly & Company

Exhibit 1.26

Comparison of Economic and Financial Costs of Electricity

System/Resource	Economic Cost (B/kWh)	Financial Cost B/kWh)
Utility Supply	1.05-1.26	1.16-1.58
Topping Cogeneration		
with Commercial Fuels	under 0.97	under 1.03
with Waste Fuels	.08	.06
Bottoming Congeneration	1.17-290	1.38-3.45
Small Fossil Fueled Systems		
Natural Gas	1.04-1.80	1.28-2.14
Lignite	1.52-2.08	1.62-2.18
Municipal Waste Systems	2.2-3.8	2.9-4.4
Bagasse Systems	1.18-1.32	1.45-1.63
Rice Husk Systems	0.64	0.55
Small Hydro Systems	2.4-8.4	3.1-11.1
Dendrothermal Systems	1.97-5.43	2.4-6.3

Source: Hagler, Bailly & Company

gas-fired units (over 50 MW) could generate power at financially attractive costs. However, major issues of financing and gas availability need to be resolved before the private sector invests in such projects.

The other small power systems (waste, hydro, and dendrothermal systems) do not represent any financial potential at present. However, if the RTG attaches social values to the development of such resources, and chooses to provide direct or indirect support, such systems may well prove to be financially competitive with utility-generated power.

Private investors could also finance large-scale utility-sized power plants (>50 MW). The objective of this type of investment would be to displace the funds otherwise needed by EGAT to finance new generating plants. EGAT is planning to add over 4,600 MW of new generation capacity by 1996. However, because of the size of investment required, some kind of foreign financing is needed. Joint ventures with foreign investors, equipment supplier financing, and direct foreign loans are among the various ways of financing large-scale power projects. Such transactions will require a direct government role, in the form of various guarantees, which is beyond the scope of this study to define therefore, no attempt was made to estimate the financial potential of such power options.

CHAPTER 2: IMPEDIMENTS TO PRIVATE-SECTOR POWER GENERATION

The potential for private-sector power generation is unlikely to be fully realized in the near future because of a number of institutional, financial, and policy issues. In this chapter, these issues are identified and discussed. Since any new generation system should interact with the existing power system in the country, this chapter starts with a brief description of the power sector structure and the current policy and regulatory framework governing the generation, transmission, and distribution of power in Thailand.

To identify major issues associated with the private-sector development of cogeneration and other nonutility power options, the study team conducted a number of interviews with key representatives of electric utilities, private-sector entities, the financial community, and government agencies involved in power sector planning. This chapter addresses the issues raised during the course of the interviews.

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

POWER SECTOR STRUCTURE

The Thailand power sector is composed of three electric organizations: the Electricity Generating Authority of Thailand (EGAT), the Metropolitan Electricity Authority (MEA), and the Provincial Electricity Authority (PEA). EGAT is responsible for most generation and transmission facilities, while MEA and PEA are responsible for distribution activities.

EGAT was created by the 1968 Merger Act, which combined the Yanhee Electricity Authority, the Lignite Authority, and the Northeast Electricity Authority into one body. EGAT's responsibilities are:

(i) To generate, acquire, transmit, or distribute electric energy to the Metropolitan Electricity Authority (MEA), the Provincial Electricity Authority (PEA), other electricity distribution authorities as prescribed, consumers as directed by the Royal Decree, and neighboring countries

(ii) To undertake activities related to the production of electric energy (such as development of electric energy from natural resources, including water, wind, natural heat, sunlight, oil, and coal) and other activities that promote the objectives of EGAT.

(iii) To produce and sell, individually or jointly with other bodies, lignite or lignite by-products.

MEA was first founded in 1900 as a private agency for generating electricity in some areas of Bangkok. Later it was converted to a government-owned enterprise by the Metropolitan Electricity Authority Act in 1958. MEA is responsible for acquiring and supplying electric energy for three provinces in the metropolitan area.

PEA was established under a 1960 Act by Royal Decree executed on September 20, 1960, as a successor to the Provincial Electricity Organization. PEA's principal duty is to supply electricity for the public in all provinces of the country, except the three in the metropolitan area for which MEA is responsible. PEA is also in charge of providing electricity to unelectrified areas of the country.

The three electricity authorities are directed and supervised by different government agencies. EGAT is controlled by the Electricity Development Committee, which is chaired by the prime minister, and is directed by a board of directors appointed by the cabinet. MEA reports to the Ministry of Interior and the chairman of its board of directors is the Under-secretary of the Ministry of Interior. PEA reports to the PEA board, chaired by the Permanent Secretary of the Ministry of Interior, who in turn reports to the Minister of Interior.

Seven government agencies are involved in power sector issues: the Committee for Power Policy and Development, the Tariff Rate Committee, the Budget Bureau, the National Economic and Social Development Board (NESDB), the Ministry of Finance, NEA, and the Foreign Loan Committee. These agencies review tariffs, capital project proposals, budgets for submission to the council of ministers, annual financial performance, and requests for government equity and loans. No single agency has overall policy responsibility, and many decisions are made by the consensus of all agencies, including the state utilities.

Power sector coordination is facilitated through two arrangements. The first is the Load Forecast Working Group, composed of representatives from NESDB, EGAT, PEA, and MEA. This group is responsible for forecasting power demand. The second arrangement is the rate adjustment procedures, which require coordination between EGAT, PEA, and MEA to ensure that each utility generates an adequate proportion of its investment while preventing cash imbalances.

Generating Capacity

To meet the rapidly growing demand for electricity in the country, both during peak demand and other times, the power utilities have pursued an ambitious power generation, transmission, and investment program over the past 25 years. Under this program, installed capacity has risen from 176 MW in 1960 to 6,155 MW at the end of April 1985. The current generation mix of EGAT is shown in Exhibit 2.1.

Total electricity generation from EGAT units in 1984 amounted to over 21,000 GWh. In addition, EGAT imports some electricity from neighboring Laos. Net imports in 1984 amounted to about 700 GWh, less than 4 percent of domestic generation.

EGAT's efforts to reduce the use of imported oil for power generation have been remarkably successful. The total percentage of electricity generated using imported heavy fuel oil and diesel oil declined from over 80 percent in 1978 to 30 percent in 1984 (see Exhibit 2.2). To reduce the amount of imported oil used to generate electricity, between 1978 and 1984 EGAT increased the percentage of electricity generated from natural gas from 0 to 39.3 percent; the percentage from hydro, from 3.9 percent to 19.4 percent; and the percentage from lignite, from 3.9 percent to 11 percent.

Currently, EGAT is experiencing a generation surplus. As of 1984, EGAT's generation capacity was about 5,650 MW, while the peak generation was only 3,550 MW. A World Bank study[1] estimates the average energy generation capacity of the entire EGAT system at over 31,000 GWh, while actual generation in 1984 was about 30 percent below this average. The current overcapacity, which is expected to continue until the late 1980s, adds to system reliability and availability but is costly to the utility and the government.

The current expansion plan of EGAT calls for an additional 1,700 MW of generation capacity by the end of 1990. This includes 900 MW of lignite-fueled thermal plants (Mae Moh units 8, 9, and 10), 420 MW of hydro plants (Srinagarind unit 5 and Chiew Larn units 1-3), and 300 MW of combined cycle (Nam Phong). In addition, for the 1991 to 2001 period, EGAT is planning an additional 7,000 MW of generation capacity.

A crucial uncertainty with regard to EGAT's current expansion plan is the availability and real cost of natural gas and lignite. The World Bank and NESDB envision gas production rising from less than 400 mmcfd in 1986 to 760 mmcfd by 1990 and 840 mmcfd by 1995. Given this supply picture, gas availability to the power sector is estimated at 520 mmcfd in 1990 and around

[1] World Bank, Thailand: Issues and Options in the Energy Sector, September 1985.

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Exhibit 2.1

The Electricity Generation Mix of EGAT

Type	Fuel	Installed Capacity	Dependable Capacity
		MW	MW
Hydro	Hydro	1,809.9	1,533.1
Thermal		3,327.5	3,158.3
	Lignite	585.0	552.9
	Oil	742.5	705.4
	Gas Oil	2,000.0	1,900.0
Combined Cycle			
	Gas	740.0	684.0
Turbines		265.0	218.5
	Gas	70.0	60.5
	Gas/Diesel	75.0	60.5
	Diesel	120.0	98.0
Internal Combustion			
	Diesel	33.6	26.9
Total		6,155.0	5,260.8

Source: EGAT

Exhibit 2.2

EGAT's Electricity Production by Energy Sources (percent)

Year	Hydro	Fuel Oil	Diesel Oil	Lignite	Natural Gas	Total %	Total GWh
1978	16.7	60.1	2.5	3.9	-	100	12,636
1979	24.3	63.2	3.0	9.5	-	100	13,442
1980	8.8	78.7	2.7	9.7	-	100	14,425
1981	20.6	58.4	1.4	10.9	9.9	100	15,369
1982	23.1	35.2	9.3	11.2	30.1	100	16,619
1983	19.4	37.6	9.6	11.0	32.3	100	18,856
1984	19.4	30.1	1.3	11.0	39.3	100	21,024

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

570-600 mmcfd between 1993 and 1995[2]. On the basis of such supply prospects, EGAT has built, is building or plans to build over 3,000 MW of gas-fired units. If the gas supply ultimately proves to be much larger than that projected, but its cost levels do not rise, the future of gas-generated electricity would be substantial. On the other hand, if supply continues to be severely limited and alternative sources (such as Texas Pacific) become increasingly costly, there appears little future for gas in the electricity program after 1992. In this case, the gas-fired plants coming on line in the early 1990s, such as the Nam Phong #1 and #2 combined cycle units, would have to be run on gas oil in the late 1990s.

The supply of lignite is also uncertain. Lignite reserves are currently estimated at about 857 million tons, with 815 million tons at Mae Moh. Of this total, about 350 million tons are proven and probable, and are sufficient to sustain a generation capacity of about 1,700 MW. This capacity matches the projected lignite-fired generation capacity of EGAT by the early 1990s. New capacity beyond 1993-1994, however, would be fueled with imported coal. Coal plants would represent a substantial increase in capital investment, because they are on average $300-$500 per kW more expensive then oil- or gas-fired plants. In addition, importing coal would probably place significant pressure on the country's balance of the payments during the second half of the 1990s[3].

Thailand does not have any major hydro schemes suitable for baseload operation, apart from those involving international agreements, which would be economic if they were feasible.

Fuel supplies aside, the immediate uncertainty surrounding the power sector's expansion plans stem from the current generation overcapacity and the financial constraints of the government. The development budget for the power sector during the Five-Year Plan is expected to be cut by the government from about $4 billion to $2 billion. Although it is certain that these budget cuts will take place, there are no clear indications of which plans will be changed and how it will affect EGAT's long-term prospects for supplying adequate power to the country.

Electricity Demand

EGAT's main customers are MEA and PEA. EGAT also has about ten direct customers that are large-scale or specialized users prescribed by the 1969 Royal Decree.

[2]World Bank, op. cit. p. 45.

[3]World Bank, op. cit. p. 97.

MEA's share of the country's total demand declined from 80 percent in 1965 to 54 percent in 1984. By the end of the 1970s, MEA served a well-established, developed market in the Bangkok area. Largely because of the high income levels in Bangkok, the annual consumption per household connection in the MEA area increased from 695 kWh in 1963 to 2,600 kWh in 1980. The intensity of industrial use of electricity also increased, from 120 watt hours per Baht of value added in 1968 to 156 in 1978.

Consumption in the PEA area has also increased rapidly, with PEA's sales growing from 2,551 GWh in 1966 to 8,400 GWh in 1984. Consumption per household connection (urban) increased from about 290 kWh per year in 1966 to 1,130 kWh in 1983, while consumption in provincial areas increased even faster -- from 17 watt hours per Baht of industrial value added in 1968 to 105 in 1978. By 1983, about 88 percent of PEA sales were made to urban areas and 12 percent to rural areas. To accelerate the process of rural electrification, in 1973 the government adopted a national plan that called for the electrification of all villages in about 25 years. As a result of these intensified efforts, the annual rate of village connections increased from 940 in 1974 to over 5,000 in 1981, and the proportion of villages electrified increased from 23 percent in 1978 to 62 percent in 1984.

This rapid growth in rural areas has played an important part in shaping electricity demand in the national system. Peak demand is increasing more rapidly than overall consumption, up from 2,255 MW in 1979 to 3,547 MW by 1984, and the daily load curves at EGAT are rather sharply defined, with the peak running from 6 p.m. to 10 p.m., a shoulder from 9 a.m. to 6 p.m. at about 85 percent of the peak, and off-peak hours for the remainder averaging about 70 percent of the peak (see Exhibit 2.3).

Current Policies and Issues on Private Power Generation

Within the current structure of the electric utilities in Thailand, there are no provisions for the purchase of power by any of the three utilities from independent generators. In practice, EGAT is the only generation utility and therefore the only supplier of power. However, there is no statement in the body of the EGAT, PEA, and MEA laws that keeps them from purchasing power from other suppliers.

Regulations require that any independent generation unit with a capacity of over 500 kW obtain an operating license from EGAT. The application for such units must be submitted to EGAT through the National Energy Administration. The purpose of this requirement is to allow EGAT to plan for back-up power for these units. Since there has been no sale of power from such units to the grid, there are no provisions for pricing.

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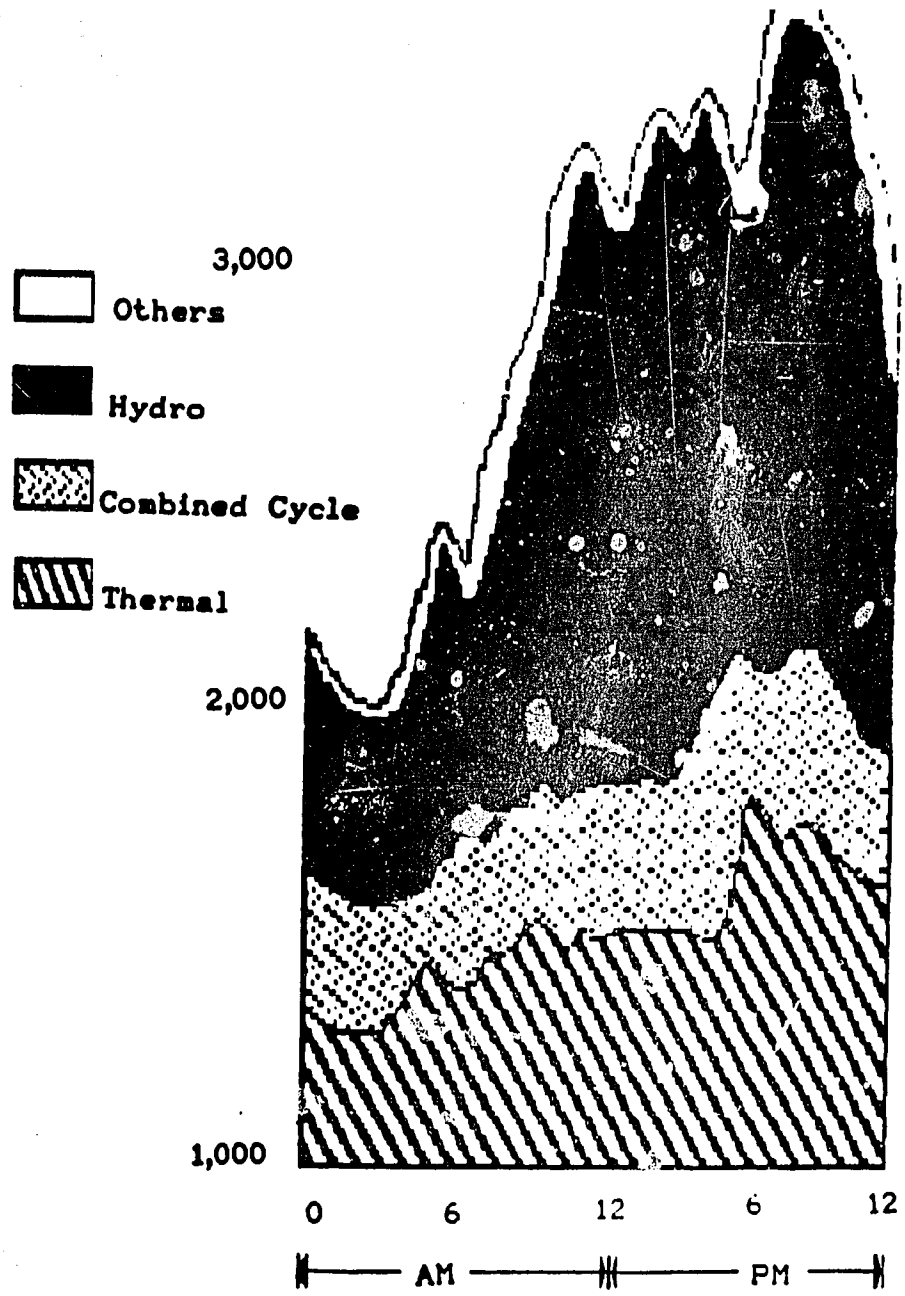
Exhibit 2.3 EGAT's Daily Load Curve, March 28, 1984

Daily System Gross Peak Generation: 3,547.30 MW
Daily System Gross Energy Generation: 87.04 million kWh
Daily Load Factor: 78.75%



Source: EGAT

There are a few exceptions to EGAT's generation monopoly. PEA owns and operates a few small generation units, mostly diesels in remote areas and small hydroelectric facilities built by NEA and then owned and operated by PEA. In addition, there are several micro-hydroelectric facilities that have been built with financial and technical help from NEA in rural areas. These facilities are partially owned by the surrounding communities, which supported their construction by contributing manpower and material and which pay for the operating expenses. In addition, EGAT purchases power from neighboring Laos at fixed prices that are renegotiated periodically.

VIEWS AND PERCEPTIONS ON PRIVATE INVESTMENT

To identify the major issues associated with the private-sector development of cogeneration and small power systems in Thailand (as perceived by various Thai organizations), the study team conducted over 50 interviews with representatives of the government, electric utilities, the private sector, commercial and government banks, other financial institutions, and international donor agencies. A complete list of the team's meetings is presented in Appendix B. In this section, the views expressed to the team are discussed.

The Government

The Thai government, faced with a financial and capital squeeze, has a genuine interest in private investment in the energy sector in general. There is now a stated government policy favoring such investment. However, at the present time there is no specific policy for encouraging private-sector investment in the electric power sector.

The government views private investment in electric power (particularly for large units of greater than 50 MW) primarily as a long-term objective that has little or no urgency in the immediate future. It thinks that the electric utilities operate efficiently compared with international standards, and can meet projected demands at least until the late 1980s. This view does not mean, however, that the government is not interested in private-sector development; rather, such development is not needed to meet the expected near-term growth in demand. The government thus has time to evaluate a number of possible ways to integrate private-sector power generation in the existing structure (e.g., by requesting private-sector proposals to install and operate relatively small generators (less than 50 MW)), and it has time to assess the problems and develop policies for private investment in large units when they become necessary.

The government is also interested in the ancillary benefits of small power production using indigenous fuels. These benefits include decreased reliance

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on imported fuels for power generation, increased employment, and rural area electrification and development. As a result, the government is willing to consider not only requiring utilities to purchase power from independent generators, but requiring utilities to pay a price greater than their direct avoided costs. However, it has never developed specific guidelines to set the premium it is willing to pay for this power.

NEA in particular is interested in developing indigenous power sources, particularly if they can be owned and operated by non-government entities. It is active in developing mini- and micro-hydropower systems in rural areas and developing innovative financing mechanisms. For example, it is setting up joint ventures between Thai government agencies and rural villages to develop micro-hydropower sites. The government's share will gradually be sold to the local communities, which will use their project revenues to buy the share. NEA is also interested in stimulating private investment in waste-to-energy and dendrothermal projects.

Electric Utilities

Because the electric utilities in Thailand have a monopoly on generation, transmission, and distribution of electricity, they are key players in any attempt to promote private-sector power generation. An independent power producer would have to sell its power directly to utilities or use the utilities' network to wheel power to other utility customers.

In general, EGAT, MEA, and PEA seemed open to the idea of purchasing power from non-utility generators. In the absence of a precedent, however, none had a precise notion of how such transactions should be handled. The utility representatives did raise several issues in connection with such purchases. Those most frequently mentioned are discussed briefly below:

Noncompetitive prices. There is a widespread view shared by all interviewed utility representatives that no independent generator will be able to provide electricity, even for its own use, at prices lower than existing utility prices. The representatives point out that the current monopoly of utilities is a rational response to the existence of a large number of comparatively inefficient private generators in the past, and that this monopoly is responsible for the high reliability and quality of today's service. They cite a number of alternative power generation options, such as waste-to-energy and dendrothermal, which have been under consideration for many years but because of lack of financial or economic merit have not materialized. Furthermore, they note that many industrial plants own back-up units for which the capital costs are already paid, but add that these plants rely on utilities for their power supply because of the relatively low cost of such power.

Lack of qualified power specialists. Utility administrators believe there are no power experts outside the three utilities, and that the private sector will not be able to install, operate, manage, and maintain large generating systems. They say the public utilities have had a monopoly for so long that all Thai power specialists now work for them.

Interconnection to the grid. The interconnection of small-scale generation systems to the grid does not seem to be a problem for the utilities. They are familiar with operating and installing the necessary control devices and do not foresee any technical problems associated with interconnection to independent generators.

Dispatching capability. The utilities raised some concern about dispatching problems associated with small generators. In most cases, the power from such systems is not dispatchable, so the value of that power to the grid is probably less than avoided costs calculated on the assumption that all units are centrally dispatched.

Lack of clear direction. The study team was told many times that there is no clear policy on the government or utility level that specifies how private generators should be treated. Thus, there is no understanding of how much potential there is for private-sector generation nor what technical and legal requirements are needed to realize this potential.

No set purchase price. Utilities have not set a purchase price for private power generation, an issue that was raised many times. PEA and MEA indicated that if independent power does become available, they would expect to pay less for it than they pay EGAT, since it would probably be of lower quality -- in terms of its, reliability, availability, dispatchability -- than EGAT's. One utility representative suggested that the price should allow utilities to make some profit, which would reduce their opposition to purchasing this power.

Direct government role. Utilities think that a government policy requiring them to buy power from independent generators will be one way of eliminating the existing regulatory ambiguity.

Private Sector

As part of this effort, the study team held discussions with over 30 senior representatives of Thai industry and the financial community. These individuals offered their candid views of the problems and potential of private-sector involvement in small power generation in Thailand. There was a surprising degree of consensus. In the following sections, their comments on private-sector power generation in general, and on financing, government policies, and large power generating systems are summarized.

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Attitudes on Power Generation

Overall, the private-sector representatives did not display strong interest in generating power, especially for sale to EGAT, MEA, or PEA. This lack of strong interest stems primarily from the almost universal perception that EGAT is an efficient and reliable source of power for their facilities. While they would like power costs to be reduced, they felt it unlikely they could match EGAT's costs because of EGAT's economies of scale, access to less expensive fuels (owing to its operation of lignite mines and the large size of its purchases), and access to sources of relatively cheap capital, e.g., concessionary loans from foreign organizations. Thus, they felt they would be able to compete only in special cases. These special cases include instances when they can use energy more efficiently, such as industrial cogeneration, or when they have access to lower cost fuels, such as agro-industrial waste (bagasse and rice husks). Otherwise, they would require clear government policies to ensure they had equal access to fuel and financing.

The only cautionary note sounded in connection with the Thai utilities' perceived rosy situation came from one representative of a major international finance organization. This individual indicated that although EGAT now had a surplus of capacity, it was quite possible and even probable that this situation would change by the early 1990s, given the government's severe problems in financing its international debts. A likely result of these problems would be a delay in, and reduction of, generating capacity, transmission, and distribution expansion plans for EGAT, PEA, and MEA. If such a delay should occur, there could be brownouts and even blackouts, which would quickly stimulate the interest of private firms in power generation, if only to meet the needs of their own plants.

In addition, one interviewee indicated that even now there are some problems with meeting demand in the south, because of a lack of local generating capacity and a lack of transmission lines to the central region of Thailand where most of the generating capacity is located. This individual believed that deposits of lignite might provide a good opportunity for private-sector development of power generation. Other interviewees who were asked about this were unaware of major problems in the south, but agreed that if there were, and if they had a facility there, they might be interested in power generation.

Most of those interviewed said that they would be very concerned about the position of EGAT on private power generation. They were almost unanimous in saying that if EGAT opposed such activities, they would probably not be interested in undertaking them.

Representatives of several of the private firms indicated that they would be very interested in "wheeling" surplus power generated on-site to another site that could use it. At least one set of plants in Thailand is engaged in such power distribution, but the plants are connected by a private transmission line because there were no provisions for wheeling the power over EGAT's lines and EGAT was unwilling to do so. Another company representative indicated knowledge of at least one other set of plants that would be interested in wheeling if EGAT, PEA, or MEA had provisions for doing so and levied reasonable charges.

One interviewee indicated that private power generation may be more likely in remote areas not connected to the PEA grid, because government spending constraints may halt PEA expansion plans. However, it would be difficult to attract private capital for this purpose. An investor would be concerned about the willingness and ability of the power users to pay for the power, since these remote areas are usually pockets of poverty. In addition, such systems would probably have high operating and administrative costs because of their remote location. Finally, private systems may become uneconomical when the PEA grid does expand to that area, meaning the power system must pay for itself before that occurs. Such short payback periods may not be feasible.

A few private-sector interviewees felt that the private sector would be able to operate a plant more efficiently than the public sector, thus reducing net generating costs. However, this feeling was not shared by all private-sector interviewees.

Attitudes on Financing

The Thai private sector places stringent requirements on the financial performance of investments, including those for power generation systems. Generally, it requires a 20 to 25 percent return on equity, after tax. This return is a nominal return -- it includes general inflation. It is not very different from that required in the United States and other developed and developing countries in which the study team has experience.

The structure and operation of the Thai capital markets, however, pose a problem for financing power generation projects. In general, there is less long-term capital available than in the United States and other developed countries. Most business loans are for short terms (1 to 3 years, typically), and are at floating interest rates. Currently these rates are typically 17 percent in nominal terms or more than 14 percent in real terms. The rates are set by the Bank of Thailand, and Thai banks are generally unable to increase these yields by, for example, adding "management fees" as is done in some other developing countries. These rates are very high by any standard, and make financing difficult for power generation systems, which typically have long payback periods. Loans are available for large companies

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having solid finances, but it is usually difficult for "second-tier" medium-sized companies to obtain long-term financing at acceptable rates. In addition, commercial banks that supply the bulk of credit to private Thai firms are increasing their liquidity in these financially uncertain times, which has the net effect of reducing the loans available to all but the best credit risks.

Attitudes on Government Policies

Thai private-sector firms are generally wary of getting involved in areas such as power generation where the government has a major stake. For example, a recent proposal entailed the development of a fertilizer plant in which the government would have a major stake together with private investors. The undertaking did not materialize because the private investors were concerned that the government would not allow "market pricing" in the politically sensitive area of fertilizer, which would, in turn, pose considerable risk to the investors' return. It is likely that private investors will also hesitate to invest in power generation, for which pricing also has a high political profile.

An interesting project involving private-sector development of what is normally considered a public-sector service is currently being proposed for Bangkok. In this project, a private consortium consisting primarily of French investment banks will finance a project to sell water to the Bangkok Water Works. The international investors will receive an essentially guaranteed return (on the order of 20 percent, after Thai taxes), and the government will receive title to the facility after 20 years. It may be possible for a similar financing structure to be used for large power generation projects, with EGAT, MEA, or PEA taking over the facility after an agreed period of time.

The Thai government offers a number of incentives to both local and foreign investors to invest in sectors it wishes to promote. At present, private power generation (including industrial cogeneration) is not explicitly identified as such an area. However, discussions with the Thai Board of Investment (BOI) indicated that it is quite likely that this area would qualify for incentives if NEA, EGAT, and NESDB were to indicate to BOI that these investments are desirable. Specific incentives include a "tax holiday" for 3 to 5 years, exemption from taxes on dividends, reduction or elimination of duties on imported equipment, guarantees on foreign currency remissions, and other preferences that depend on the characteristics of the specific project. In addition, there are other incentives for facilities located in designated Investment Promotion Zones, including company income tax reductions of 50 to 75 percent for an additional 5 years, business tax reductions of 90 percent on sales (normally these taxes are 3 to 9 percent of sales), income tax deductions of double the actual costs of transport, water, and power, and

additional deductions of up to 25 percent of capital facilities in addition to normal depreciation, with tax loss carry-forward provisions for up to 10 years. Discussions with the BOI indicated that there is a large degree of flexibility in the application of the tax concessions, which can be tailored to the requirements of specific projects.

Attitudes on Large Power Generation Systems

In the course of the team's interviews with representatives of the Thai government, public power sector, and private sector, a number of issues were raised that need to be resolved before the private sector displays significant interest in large-scale (>100 MW) power generation systems. These issues fell into three categories: project risks, government policies, and the size of the required loans. The interviewees felt that specific terms for an actual project would need to be proposed before they could carry out the detailed analysis needed to address these issues.

Project risks are of three types: financing risks, construction risks, and operating risks. Financing risks include foreign exchange risks and interest fluctuation risks. Foreign exchange risks result from the large proportion of foreign currency needed to finance power system investments (typically 50 percent or more). Private investors may require the utility or government to insulate them from such risks by, for example, paying a portion of the money received by the investors in the currency in which the project loan is denominated.

Interest rate fluctuations are also a risk. While long-term fixed interest loans are usually available for these large investments from international commercial banks or development banks, the loans are usually denominated in foreign currencies and are often limited to the foreign exchange component of the project investment. The local capital markets generally do not have long-term loan vehicles available, with the result that local currency loans are available only for short terms (usually renewable yearly, with some renewable at 3- to 5- year intervals) at floating rates that fluctuate yearly or more frequently. However, it may be possible to develop long-term financing vehicles at fixed interest rates if the government is willing to guarantee them.

In addition, it is much easier for the government (or government organizations such as EGAT) to borrow the large sums of money needed for power sector projects (typically hundreds of millions of dollars) on the international capital markets than it is for the private sector. In many cases, a government organization will qualify for grants or concessionary loan terms offered by industrialized countries when a private Thai company or consortium will not.

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U.S. vendors of large power generating equipment indicated that nearly all bids from developing countries for power generating plants require the vendor to arrange financing. The United States is at a disadvantage here because its main competitors (Japan, France, and West Germany) will often provide part or all of the funding at very concessionary terms, for example, a 2-1/2 percent interest rate over 25 years with a 7 year grace period.

The second area of project risk, construction risk, includes the risks that the project will be completed within budget and on schedule. The private sector is particularly concerned with such risks, because it does not feel it has the technical and managerial capabilities to take on construction risks in large projects. Rather, it thinks that EGAT is probably the only Thai organization that can. However, it is possible to hire international engineering and construction firms to deliver a turnkey facility and operate it for a period of time (typically 3 years) while training Thai personnel.

Operating risks include power output, reliability, fuel price and availability, and power dispatching. Here, too, the private sector is concerned about its ability to marshall the necessary technical and managerial skills to maintain a high power output and reliability, regarding EGAT as the only Thai organization that now has such capability. Thus, it may be important for Thai private organizations to form joint ventures with foreign firms that have successfully operated large power plants. Fuel pricing and availability are also concerns, and will require careful negotiation regarding fuel adjustment charges. Finally, potential investors are concerned about dispatching of their facility. If load growth is less than expected, not all of the new power may be needed, which would result in lower revenues and, perhaps, major cash flow problems for the investors.

The major government policy risk that a power generation project faces relates to the price paid for the power generated. Pricing can be highly political, as indicated by the large price subsidies given to PEA by MEA. Potential private investors are concerned that the government may not be willing to raise the price paid to the project to keep up with the rise in project costs (capital, fuel, labor, maintenance), which could result in serious revenue losses. Since the government (through EGAT) is the only customer for the power, the investors have no other options if they become dissatisfied. The private sector's concern about the effects of political considerations on pricing is demonstrated by the recent government attempt to finance a large fertilizer plant using private investors. This project was delayed and will probably not be undertaken because the investors feared that the government (which would have a large equity stake) would not allow the fertilizer to be priced at market rates, but would press for lower prices to keep its rural constituents satisfied.

A final area of concern is the impact of fund-raising efforts on Thai capital markets. Several interviewees felt the large amounts needed for investment in a large generating plant would disrupt Thai capital markets. Preliminary EGAT generation plans for the 1988-2001 period indicate that additions to system generating capacity will average 685 MW per year, at an average annual cost of $796 million. (Interviewees, however, indicated that these expansion plans will be cut back substantially, perhaps by as much as 50 percent, because of current generating overcapacity and a reduction in projected growth in demand.) Historically, about 69 percent of power sector investments were borrowed from both domestic and foreign sources, with the remainder supplied by retained earnings and government subscriptions. Approximately 65 percent of power sector investment funds have been provided by foreign grants and loans. Thus, nearly all EGAT borrowings were in effect provided by foreign sources. If power sector borrowings follow previous patterns, they will range between $275 million and $550 million per year. The Gross Domestic Investment (GDI), which represents the annual investment in fixed assets and inventories in Thailand, is approximately B2.5 billion ($10 billion) per year. Total domestic credit is increasing by approximately B100 billion ($4 billion) per year. Thus, if EGAT borrowings were shifted to domestic sources, they would have a noticeable impact (for example, causing a slight rise in interest rates). However, they would be unlikely to completely disrupt these markets.

MOBILIZATION OF PRIVATE CAPITAL FOR ENERGY INVESTMENTS

In recent decades the public sector has been the primary source of energy sector investment, through EGAT, MEA, PEA, and the Petroleum Authority of Thailand (PTT). In the Fifth Five-Year Plan (1982-1986), these organizations represented 65.8 percent, 4.2 percent, 15.5 percent, and 14.5 percent, respectively, of public energy sector investment. Such investment, in turn, represented 50 percent of total state enterprise investment, 20 percent of total public investment, and 8.2 percent of Thailand's total gross investment. Because of the severe problems that the government foresees in meeting future debt servicing obligations, both domestically and worldwide, the Sixth Five-Year Plan has as a major priority the reevaluation of the role of public-sector energy investment and the encouragement of private-sector investment in the energy sector.

In this section, the Thai capital markets are briefly described and specific activities are recommended to help attract private investment in the energy field.

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The Thai Capital Markets

From the mid-19th century to the mid-1970s (with the exception of brief periods in the 1930s and 1940s), Thailand maintained an open economy governed by a market-oriented development strategy and based on a conservative financial policy that included maintaining relatively high levels of foreign currency reserves. Growth was financed primarily through domestic savings, with relatively little foreign borrowing. The success of that strategy is shown -- for the period from the mid-1950s to the mid-1970s -- in the real GDP growth rate, which averaged 7 to 8 percent per year (4 to 5 percent per capita), and in the level of investment, which rose from 20 percent to 27 percent of GDP. Beginning in the mid-1970s, however, Thailand was seriously affected by the deterioration in its terms of trade, specifically the lower prices for its chief commodity exports (rice, rubber, tapioca, tin, and sugar) and the increased prices for its imports (primarily oil). This problem was further exacerbated by an increase in external financing needs coupled with sharp increases in the cost of this debt.

To respond to these problems, the government changed its polices in the mid-1970s. These changes included: providing greater protectionism for domestic firms; intervening in domestic credit markets to control interest rates and direct the flow of funds to priority sectors (such as agriculture); imposing price controls on many items, including energy prices (keeping them below world market prices); permitting large domestic and external public deficits; spending foreign exchange reserves; rapidly increasing the growth of the domestic money supply; and increasing foreign borrowing to finance deficits and investments.

At the end of the 1970s, the government realized it could not continue these policies and maintain a healthy economy. Over the course of several years it reversed many of these policies by lifting price controls, setting energy prices to reflect world market prices (energy prices increased 2-1/2 times between the start of 1979 and mid-1981), introducing new taxes to reduce government deficits, improving the financial structure of public companies to reduce their need for subsidies, and making numerous reforms in domestic policies, including the rationalization of export and investment incentives and targeted tax reductions, particularly in the rural sector.

These actions have been reasonably successful, given the continued deterioration in prices for commodity exports. This success is the result of a deliberate policy of low barriers to trade, few restrictions on capital flows and convertibility of domestic currency, and maintenance of a relatively high foreign-exchange reserve level that precluded the speculation and capital flight plaguing many other developing countries. This success is even more remarkable given the hostility of Thailand's neighbors, the collapses in its domestic securities exchange, and the changes in government.

At present, the capital markets for private Thai firms are not too dissimilar from those of many other developing countries. They are characterized by high capital costs and a scarcity of long-term financing alternatives. A "typical" Thai company will have a capital structure similar to the following:

Paid in capital (equity):	15 percent
Institutional credit:	31 percent
Foreign debt capital:	25 percent
Trade credit:	25 percent
Foreign suppliers' credit:	2-5 percent

Equity capital is very expensive, with investors looking for annual dividends of 15 percent or more of the market value of their investment (because relatively secure debt instruments are now returning 10 to 12 percent). The emphasis is on dividends rather than capital gains resulting from stock appreciation, because Thai equity investments are relatively illiquid. This illiquidity results from the fact that major Thai companies tend to avoid listing on the Bangkok Securities Exchange because it has a poor reputation (it has had two crashes in the last 6 years because of speculation), and because many firms are family held or closely controlled and do not wish to subject their finances to public scrutiny.

Government incentives to promote Securities Exchange-listed companies (including a reduction in the top income tax rate from 35 percent to 30 percent) have been relatively ineffective. As a result, there is a lack of liquidity for equity investors, and dividends become increasingly important, because investors may not realize the capital gains they could were the shares publicly traded on a more stable exchange. However, as in the United States, dividends are subject to "double taxation," once as a part of corporate profits and again when they are distributed to shareholders. If a firm wishes to finance future growth, it cannot pay out all its earnings in dividends. Typically, Thai firms try to keep a 50-percent payout -- one-half the after-tax earnings are paid out as dividends and one-half are retained to help finance future growth. To give the investors a 15-percent return on their investment requires an after-tax return of 30 percent of equity -- a difficult standard to reach.

For these reasons, Thai firms tend to have high debt/equity ratios compared with industrialized country capital market standards: 2:1 to 4:1 are typical. This credit is disproportionately short term (less than 3 years), with short-term instruments being about double long-term ones. The credit comes from institutions, foreign lenders, foreign suppliers' credit, and trade credits. The major sources of institutional credit for private firms include commercial

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banks, finance companies, and a quasi-government body, the Industrial Finance Corporation of Thailand.

Commercial banks are the primary source of credit, supplying B462,234 million in credit to the private sector and public utilities in June 1985. There are 16 private Thai banks, which had 1,458 local branches at the end of 1980. Fourteen international banks also have branches in Thailand. About 58 percent of commercial bank loans are overdrafts, with 19 percent being discounts of trade bills (accounts receivable) and 23 percent being straight loans, usually for short terms (1 to 3 years) and at adjustable interest rates.

The extensive use of overdrafts (in which a company pre-arranges a line of credit with a bank and draws against it when needed) is an unusual feature of Thai capital markets. It has attractions for both borrowers and lenders. First, it usually has lower interest rates than a straight loan. Second, since it is pre-arranged, the administrative costs for both the borrower and lender are low. Third, there is usually no principal repayment obligation for the borrower. Finally, a rollover of the loan is almost automatic.

The main problem with this type of loan is that it is generally available only for the largest and most credit-worthy borrowers that supply personal or corporate guarantees for its repayment. Facilities and inventories cannot be used as collateral because the Thai legal and financial systems make land the only meaningful collateral. Typically, land represents 20 percent of the assets of larger firms in Thailand. With a 2:1 coverage ratio (value of collateral/value of loan), the secured lending capacity of a firm is only 10 percent of its assets. Thus, most loans have no collateral.

At present, ceilings on commercial bank loan rates are set by the Bank of Thailand, the country's central bank. There is a three-tiered system of loan rates. Priority sectors (primarily exporting sectors) can obtain loans at 15 percent. The prime rate (for the most secure borrowers) is 15.5 percent. The ceiling rate (at which most loans are made) is 17 percent. The banks have tried to boost the effective yields on loans by adding "management fees," "placement fees," and similar charges (as is done, for example, in the Philippines, where these charges raised the effective interest rates from the government-mandated ceiling of about 18 percent to 25-30 percent). However, the banks have not had much success with this.

Commercial banks can easily arrange foreign currency loans for their customers. Because of the Baht's easy convertibility, such loans are usually available at rates similar to domestic loans. In almost all cases, the borrower takes the foreign exchange risk, although the banks can usually arrange forward cover.

A second source of institutional credit is finance companies. Such companies were allowed by the Thai government in the late 1970s to provide an

alternative source of financing to the commercial banks. They are permitted more flexibility in setting lending terms (including higher allowed interest rates) than are the commercial banks. Finance company loans to the public and private sectors stood at approximately B110,000 million as of mid-1985.

Finance companies tend to be much smaller than commercial banks. In 1980, the average commercial bank had assets of $400 million. At the same time, the average finance company (excluding the top five) had assets of about $20 million. Finance companies tend to charge slightly higher rates than the commercial banks, and generally focus on short-term loans to smaller borrowers. About 19 percent of their loans are secured with post-dated checks, which severely limits the size of loan that a company can afford to obtain since there is no guarantee that the loan will be rolled over. The company could be forced into bankruptcy proceedings if it cannot honor the check when due.

The final source of credit to Thai private-sector firms is the Industrial Finance Corporation of Thailand (IFCT). This organization has a unique role in the financial sector, since it is in effect the only supplier of long-term credit and project financing. It is a private, well-managed, efficient organization that has expanded rapidly since the mid-1970s. In mid-1985, its loans to businesses were approximately B9,782.5 million.

IFCT is willing to provide project financing to smaller organizations that cannot easily borrow from commercial banks. It provides medium- to long-term loans with 5- to 15-year maturities (average maturity is 8 years, with a 3-year grace period). The loans have fixed interest rates that are currently 14.5 percent. The corporation can make these loans because the government assures it of liquidity by backing "soft" loans for projects with high socio-economic returns and by guaranteeing concessionary financing from international organizations.

IFCT seeks to expand its capabilities; it is considering accepting deposits from commercial firms, raising funds in the domestic interbank market, developing a capability for making short-term working capital loans, and increasing its equity base through private-sector financing that will not make excessive demands on government finances.

IFCT is now authorized to become involved in projects with financing requirements between B1 million and B500 million. It is trying to reduce the minimum amount to B200,000 to allow it to finance more energy conservation investments. It now has a special loan rate of 11.7 percent for export-oriented industries, which it is trying to expand to include energy conservation as "import substitution."

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Recommendations for Mobilizing Private Capital

The shortcomings of Thai capital markets, such as the high real returns required on both equity and debt, are similar to those faced by capital markets in most developing countries. It is unrealistic to expect to change them quickly, because they reflect underlying economic realities. These realities include a scarcity of capital, the relative riskiness of investments owing to factors such as the country's susceptibility to world market events beyond its control, and a lack of enforced accounting standards, particularly for small and medium-sized firms. In the following sections, options for funding both large and small private investments in the Thai power sector are discussed.

There appear to be four major options available for mobilizing power investments by the private sector. These are (in order of implementation complexity):

- Sales of bonds by EGAT to domestic and foreign lenders
- Ventures by Thai-only corporations or consortiums
- Joint ventures between Thai and foreign companies
- Investments by foreign firms alone.

Sales of bonds by EGAT to Thai and foreign investors is the simplest and most direct means of attracting private capital into the power sector for a large generating plant. It avoids many of the concerns of private investors, such as their lack of technical and managerial experience in this area, access to cheap fuels, control over dispatching, and control over pricing. However, this is primarily a "passive" investment, and will require no significant changes over current financing practices. In addition, it will not develop private-sector experience in this area and thus will not allow improvements in operating efficiencies that can arise from the private sector's drive to reduce costs and improve profits. To the extent it attracts Thai capital, (as opposed to foreign capital), it can reduce the domestic funds available for other productive investments in the Thai economy.

Ventures by Thai firms or consortiums with no foreign partners are possible for both large (greater than 50 MW) and small (less than 50 MW) systems. For large systems, Thai firms have little experience and thus will need to purchase expertise. There are many engineering firms around the world that can supply the needed skills in plant design, construction, and operation, and will train Thai personnel to take over the entire operation.

For small systems, large Thai firms will have little difficulty financing investments in power, using traditional financing channels such as overdrafts.

Small to medium-sized firms, however, will have much more difficulty financing these investments, primarily because of their relative lack of access to capital. For these firms, the most likely short-term option is to rely on IFCT for financing. Government guarantees for these loans are possible, particularly if the company can show that such loans will more than pay for themselves through savings in foreign exchange, reduction of imports, or the delay or large EGAT investments in new power generation.

The advantages of this option over sales of bonds or joint ventures with private foreign firms is that the Thai parties keep control of the project. It may result in savings in foreign exchange over the long term, depending on the costs of the technical services and training and other resources that are not domestically available. It can also result in savings if the private sector can operate more efficiently than the public sector. This option does require the government to develop clear policies and make the necessary legal and regulatory changes to ensure that private projects are treated on an equal footing with EGAT plants. These policies ensuring equal access to fuels (particularly domestic gas and lignite) at costs comparable to those EGAT would pay, implementing policies to ensure that EGAT will purchase power from the plant, setting power purchase prices at a level that will allow investors a reasonable return, and displaying a willingness to assist in obtaining foreign loans and credits, possibly through loan guarantees.

The third option for stimulating private investment in the Thai power sector is through joint ventures between Thai organizations and foreign firms, with an active Thai government role to ensure that the venture is treated fairly vis-a-vis the public utilities. The Thai partner would provide equity capital, personnel to build and operate the facility, and a local presence to handle interactions with the Thai government and utilities. The foreign partner would provide capital, technical and managerial skills not initially available to the Thai partner, training for Thai personnel in all aspects of plant design, construction, and operation, and possible access to foreign sources of funding, possibly at concessionary rates. The Thai government would develop the legal and regulatory framework necessary to ensure that the project is treated on an equal footing with EGAT power plants.

The final option is investment by foreign firms with no direct Thai investment participation. This option is particularly attractive for small to medium-sized firms that do not have the same access to capital as large Thai firms and wish to invest in small power plants such as a cogeneration system. In industrialized countries, for example, cogeneration equipment suppliers (such as General Electric) provide complete "turnkey" systems. They will design, finance, construct, operate, and guarantee performance of the entire cogeneration system. In addition, suppliers are willing to provide creative financing options such as shared savings programs, in which they receive a portion of the realized savings from the system for a specified

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period of time, after which the company owns the equipment. In effect, the realized savings pay for the equipment, and the firm need put up little or none of the investment's capital requirements. It is not clear at this time whether the Thai market is large enough to attract foreign firms for this type of investment. But it might make sense to provide this service as a joint Thai/foreign venture. In addition, a potential problem could arise from Thailand's level of taxation of investments by foreign firms, which appears to be higher than the norm. For example, there is a 20-percent tax on repartriated dividends, while most other developing countries tax these at 15 percent.

CHAPTER 3: POSSIBLE APPROACHES TO DEFINING ELECTRICITY PURCHASE PRICES

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

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

THE U.S. EXPERIENCE: PURPA

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

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

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

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

Eligibility Criteria

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

Cogeneration facilities are defined as those using energy sequentially to generate electricity and useful thermal energy. Cogenerators must meet certain operating and efficiency standards. For topping cycle cogeneration systems, the usefully employed thermal energy must constitute at least 5 percent of the total energy output. For oil- or natural gas-burning cogeneration systems, the sum of the electrical output and one-half the total useful thermal output must be at least 42.5 percent of total oil and gas input to the facility, or 45 percent if the useful thermal energy output is less than 15 percent of the total energy output of the facility. For bottoming cycle cogeneration facilities, the only requirement is that the useful power output be at least 45 percent of any oil or natural gas used for supplementary firing. There is no upper limit to the size of a qualifying cogeneration system.

Purchase Price

Independent electricity generators will usually have to rely on utilities for the sale of their power or its transmission to other customers. Therefore, the price that utilities will be willing to pay for the electricity, or the price they charge for transmitting the power, will have a direct impact on the financial

returns of such power projects. The theoretical definition of the purchase price is rather straightforward. The "avoided cost", or purchase price, is defined as the energy and capacity costs that the utility would avoid incurring as a consequence of the power provided by the independent generator -- i.e., the utility's marginal savings. Avoided costs have little relation to the utility's normal rates for sales, which are based on the utility's average costs; avoided costs may be either higher or lower than the rates for sales.

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

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

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

Implementation

Since PURPA was signed into law in 1978, investment in cogeneration and independent power production facilities has expanded dramatically. In 1980, 28 facilities were granted qualifying facility (QF) status, with a total potential

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capacity of 703 MW. In the first three quarters of 1984, 349 facilities were granted QF status, enabling them to take advantage of PURPA provisions, with a total potential capacity of 3,414 MW. Pacific Gas & Electric, a major California utility, for example, signed contracts with 273 QFs in 1984 with an estimated capacity of 4,204 MW.[1]

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

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

METHODS OF CALCULATING AVOIDED COSTS

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

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

[2]Ibid.

on actual utility operations, yielding the short-run production costs with a minimum of effort. The marginal capacity cost is estimated as the cost of a peaking unit.[3]

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 utility, and hence as an appropriate measure of marginal costs. Marginal energy and marginal generation capacity costs are calculated jointly.

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

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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 THAILAND

The detailed calculation of utility avoided costs in Thailand requires comprehensive system simulations that are beyond the scope of this study. This section, therefore, concentrates on making some preliminary estimates of the range of avoided costs for Thai utilities.

The unique structure of the power utilities in Thailand provides some simplified approaches to estimating the value of electricity to them. PEA and MEA, being primarily distribution utilities, rely on EGAT for their supply of power. To them, therefore, EGAT's schedule of tariffs represents the exact avoided costs. If an independent generator is capable of providing firm capacity and energy to MEA with the same technical specifications as EGAT's power, then it should be paid the same price. To MEA, for example, the avoided capacity cost will be 80 B/kW per month, and the avoided energy cost will be 1.3883 B/kWh for the first 100 kWh supplied, and 1.3683 B/kWh for the next 300 kWh (see Exhibit 3.1). On the other hand, if the independent generator is not providing firm capacity, its power should be valued only at the energy cost to MEA (between 1.35 and 1.38 B/kWh) (see Appendix D for a detailed description of electricity tariffs in Thailand).

This simplistic approach does not include the location of the generator. For the MEA distribution network, for example, the line loss is about 6 percent of the total power purchased from EGAT. If the independent power is close to the load center, there will be much less distribution loss and therefore higher avoided costs for MEA. For PEA, this becomes a more important item to consider. Because of PEA's widespread network, especially in rural areas, the line loss is over 10 percent (as of 1984).

There are precedents for the sale of power to PEA at EGAT rates. NEA, with the collaboration of local communities, has been generating power from small hydroelectric facilities and selling the power to PEA. The purchase price for this power is the same as EGAT tariffs to PEA. Power from the Mae Kum Luang (at Chiang Mai) and Huai Mae Phong (at Pha Yao) hydroelectric plants is sold to PEA by NEA under this arrangement. In light of PEA's high capital cost for extending the grid to new rural areas (about B 3 million per village), an independent generator that could provide reliable power and thus reduce network extension requirements could save substantial grid expansion costs for PEA.

Because most small power producers and cogenerators, produce medium voltage level power, the power is best sold to PEA and MEA not EGAT. However, it is feasible for independent generators to sell their power directly to EGAT.

Currently, EGAT has an oversupply of capacity in the range of 30 percent of total demand. Therefore, the avoided cost due to purchase of power from

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Exhibit 3.1

EGAT's Basic Electricity Wholesale Tariff

April 1, 1983

1.	**Normal Rate**	
	1.1 MEA	
	Demand Charge	80.00 Baht/kW per month
	Energy Charge:	
	First 100 kWh/kW	1.3883 Baht/kWh
	Next 300 kW/kW	1.3683 Baht/kWh
	Balance	1.3583 Baht/kWh
	1.2 PEA	
	Demand Charge	67.00 Baht/kW per month
	Energy Charge:	
	First 100 kWh/kW	1.0898 Baht/kWh
	Next 300 kWh/kW	1.0598 Baht/kWh
	Balance	1.0298 Baht/kWh
2.	**Industrial Rate**	
	Demand Charge	87.00 Baht/kW per month
	Energy Charge:	
	First 100 kWh/kW	1.46 Baht/kWh
	Next 300 kWh/kW	1.44 Baht/kWh
	Balance	1.41 Baht/kWh
3.	**Social Rate**	
	Demand Charge	87.00 Baht/kW per month
	Energy Charge	1.38 Baht/kW
4.	**Special Rate (MEA, PEA)**	
	4.1 MEA	
	Demand Charge	74.00 Baht/kWh per month
	Energy Charge	1.3883 Baht/kWh
	4.2 PEA	
	Demand Charge	74.00 Baht/kWh per month
	Energy Charge	1.1998 Baht/kWh
5.	**Off-Peak**	
	Demand Charge	79.00 Baht/kW
	Energy Charge	1.42 Baht/kWh

Source: EGAT

independent generators will be only from avoided fuel and other variable operation and maintenace expenses. There is a large difference between the peak and base generation costs in EGAT system. The fuel and other variable costs for base load units vary between 0.70 B/kWh for lignite plants to 1.46 B/kWh for thermal plants using fuel oil (see Exhibit 3.2). Only 14 percent of total peak generation is currently generated by lignite plants, the rest from fuel oil, diesel oil, and natural gas. On the other hand, the peaking units, mostly gas turbines and diesels have variable costs of 2.63 to 4.13 B/kWh. Of course some of the peak and intermediate load is satisfied by the hydro plants in the generation system. However, since there is very little variable operation and maintenance costs associated with these plants, when available, they will be the last units to be replaced by independent generators. To the extent that the power from independent generators will replace fossil fueled generation of EGAT, the minimum purchase price should be the variable generation cost of the base load units (0.7 to 1.5 B/kWh). This price changes according to the region and the operating plant. In cases that the power from independent generators replaces peak generation by EGAT, the purchase price should reflect the high operation cost of these plants. In the north, EGAT is purchasing power from neighboring Laos at 1.17 B/kWh, which indicates the value of power to EGAT in this region.

Estimating the long term value of power from independent generators to the utilities requires an evaluation of the long run marginal costs (energy and capacity) of generation, transmission, and distribution. NEA has commissioned a study of electricity tariffs in Thailand. This study, to be completed in the fall of 1986, is intended to help utilities in Thailand establish a new tariff schedule more representative of their actual cost of service for each type of customer. The preliminary results of a background study[4] for this project provide some useful information on marginal costs for EGAT, PEA, and MEA.

The background study estimates the opportunity cost (marginal cost) of energy supply by types of power plant as well as the cost of electricity by user categories in regions. The calculations are based on the shadow price of power generation inputs, so the output also represents economic --not financial values. According to this study, the marginal capacity cost and energy costs of EGAT, PEA, and MEA will change very little until 1989-1990; thereafter, they will increase very rapidly (see Exhibits 3.3-3.5). For example, EGAT's cost of providing an extra unit of peak capacity in 1987 (generation and transmission) in the northern region will be over 486 B/kW/year. Its cost increases to over 570 B/kW/year in 1990, and jumps to over 1,268 B/kW/year in 1991, and to 2,408 B/kW/year in 1996. Similarly,

[4] Improvements of EMP Electricity Subsystem Study, National Energy Adminstration, December 1985.

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Exhibit 3.2

Variable Generation Cost of Selected EGAT Fossil-Fueled Power Plants

Plant	Type/Fuel	Fuel Cost (B/kWh)	Variable O&M Cost (B/kWh)	Total Variable Cost (B/kWh)
A. Base Generation				
North Bangkok	Termal/Fuel Oil	1.17	0.12	1.29
South Bangkok	Thermal/NG, Fuel Oil	1.01	0.12	1.13
Bang Pakong	Combined Cycle/NG, Deisel	0.87	0.12	0.99
Mae Moh	Thermal/Lignite	0.45	0.25	0.70
Khanom	Termal/Fuel Oil	1.04	0.12	1.16
Krabi	Termal/Fuel Oil, Lignite	0.84	0.25	1.09
Surat Thani	Thermal/Fuel Oil	1.34	0.12	1.46
B. Peak Generation				
Hat Yai	GT/Diesel	4.04	0.09	4.13
Surat Thani	GT/Diesel	3.85	0.09	3.94
Phuket	Diesel/Diesel	2.04	0.59	2.63

Source: Hagler, Bailly & Company; based on data from NEA and EGAT.

the cost of generating and transmitting an additional unit of energy in the North starts from 0.73 B/kWh in 1987, remaining flat for 4 years before jumping to 1.64 B/kWh in 1991 and to 1.85 B/kWh in 1996 (see Exhibit 3.3). Similar trends for MEA are shown graphically in Exhibit 3.4. The sudden jump in marginal costs around 1990 could be explained by the utilities' vanishing overcapacity at that time, and the need for additional generation capacity.

From a policy standpoint, it may be advisable for the government to reflect the high cost of additional utility supply during the 1990s in higher purchase prices in the late 1980s. The government could offer a higher purchase price for the rest of this decade to nonutility generators as an incentive for early entry in such investments and thus postpone the need for utility expansion in later years. From a long-term government policy prospective, this could be an effective mechanism for introducing private capital into power generation activities.

Such initiatives should be tuned to the regional needs of electric utilities. For example, PEA's marginal cost of providing an extra peak capacity kW in the south is the highest among the four regions (see Exhibit 3.5). Therefore, nonutility generators in this region should be provided with a higher purchase price.

Within the current tariff structure of utilities in Thailand, such practices could prove to be very demanding. Currently, for economic and social reasons, utilities charge uniform tariffs for the same category of customers across the country. On the average, however, PEA is faced with a more dispersed network, a sharp peak load (composed of mostly residential and commercial demand peaking around 8:00 p.m.), and higher costs of service than MEA. To compensate for this, EGAT offers lower rates to PEA than to MEA. As a result, PEA's avoided cost is kept artificially low.

To reflect the true value of independent power to the utilities, there should be a mechanism for periodic calculation of utilities' marginal costs. Since the input components of such studies -- energy cost, demand growth, load shape, and generation mix -- change constantly, the utilities or NEA should initiate a program to continually evaluate the marginal cost of supply in each region.

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Exhibit 3.3

EGAT's Marginal Cost of Electricity Generation and 230kV Transmission By Regions, 1987-1996

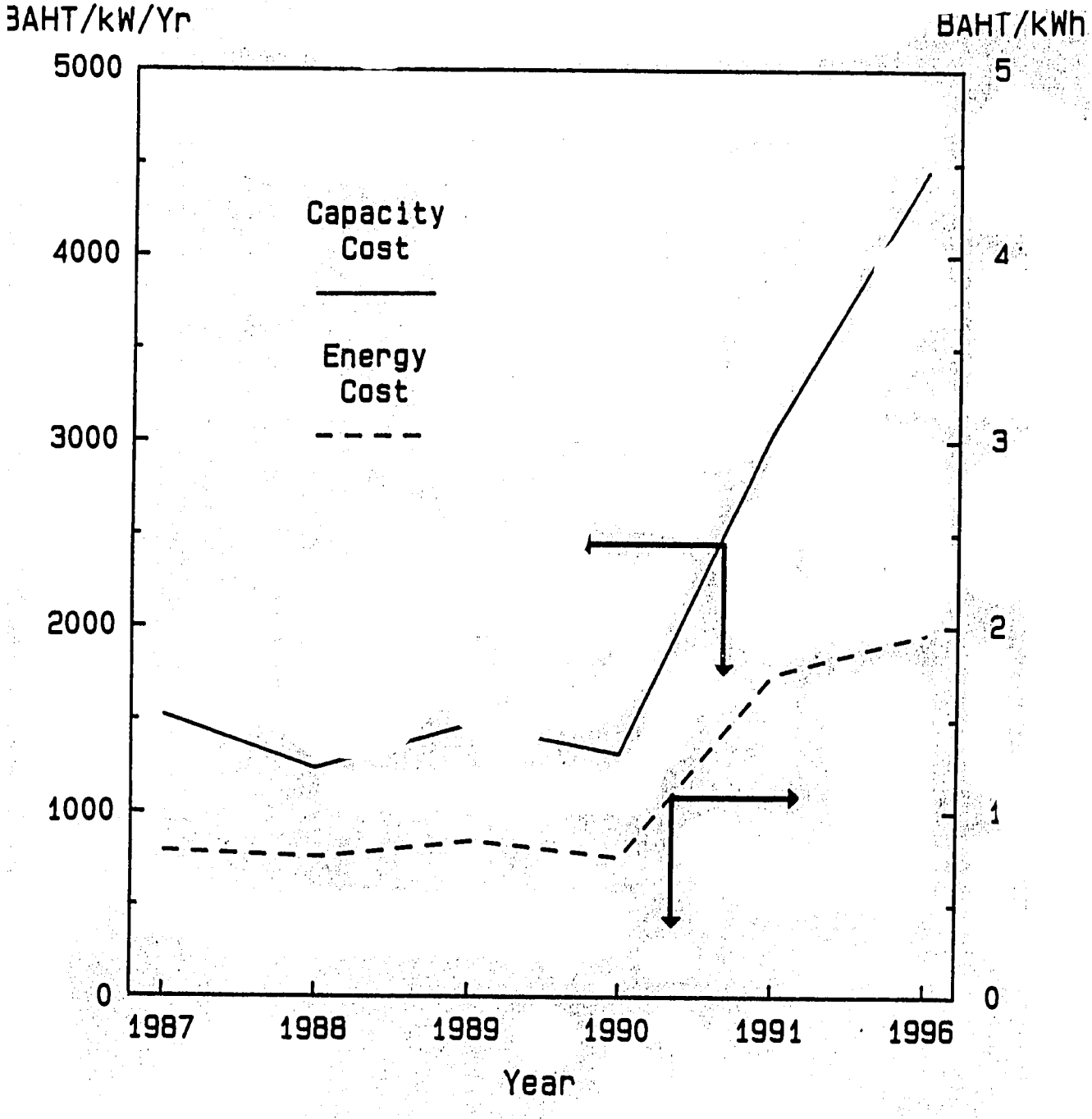
Region	1987	1988	1989	1990	1991	1996
	Peak Opportunity Cost (Baht/kW/Yr)*					
North	7.5	7.1	226.3	202.1	469.3	1502.1
Central	7.7	7.3	231.9	206.9	481.2	1538.6
Northeast	7.9	7.5	213.8	497.2	1589.2	23.5
	Energy Opportunity Cost (Baht/kWh)					
North	.72	.69	.78	.70	1.62	1.83
Central	.74	.70	80	.71	1.66	1.87
Northeast	.77	.73	.83	.74	1.71	1.83

* All values are in 1983 prices and discounted by 12% to the year 1986.

Source: NEA

Exhibit 3.4

MEA's Marginal Cost of Medium Voltage Distribution



urce: Hagler, Bailly & Company;
based on data from NEA.

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Exhibit 3.5

PEA Marginal Cost of Medium Voltage Distribution. 1987-1996

Peak Opportunity Cost (Baht/kW/Yr)*

Region	1987	1988	1989	1990	1991	1996
North	653.8	583.8	754.2	673.5	1565.9	2783.2
Central	337.8	282.0	507.9	453.5	1054.5	2235.5
Northeast	683.3	610.4	799.7	713.6	1659.8	2985.3
South	683.3	610.4	799.7	713.6	1659.8	2985.3

Energy Opportunity Cost (Baht/kWh)

North	.77	.73	.82	.74	1.71	1.93
Central	.79	.75	.85	.75	1.75	1.98
Northeast	.84	.80	.90	.81	1.87	2.11
South	.84	.79	.90	.80	1.87	2.33

* All values are in 1983 prices and discounted by 12% to the year 1986.

Source: NEA

CHAPTER 4: CONCLUSIONS AND RECOMMENDATIONS

In this chapter, conclusions from the analyses of the previous chapters are presented, and recommendations are made for short-term and longer-term actions to accelerate the development of private-sector cogeneration and small-scale power generating facilities. Preliminary conclusions and recommendations on the role of local and foreign private investment in larger power plants are also presented.

CONCLUSIONS

The study conclusions are organized in three categories: general, cogeneration, and power-only systems.

General

1. This preliminary analysis suggests that the economically attractive potential for private-sector power production in Thailand from cogeneration and small-scale generation systems (less than 50 MW) using indigenous energy resources is about 1,035 MW over the next 10 years. Of this potential, 725 MW could be developed by the private sector at costs competitive with utility electricity prices (the financial potential). The economic potential refers to that amount of the cogeneration potential that can be developed, given energy and fuel prices valued at their shadow prices -- prices that represent the true cost to the economy. The financial potential refers to that amount of the cogeneration potential that can be developed given energy and fuel prices as they exist in the present market -- the prices paid by industry. The potential is distributed as follows:

	Economic (MW)	Financial (MW)
Cogeneration systems	545	310
Bagasse-fueled systems	260	260
Rice husk-fueled systems	155	155
Small hydropower systems	55	--
Municipal waste-fired systems	20	--
Dendrothermal systems	--	--
Small fossil-fueled systems	--	--
TOTAL (Rounded)	1,035	725

These estimates are based only on the direct and obvious economic costs and benefits of each alternative; they do not take account of socioeconomic factors such as job creation and domestic energy self-sufficiency. Power generation from municipal waste, for example, could help resolve long-term waste disposal problems of large urban areas. Similary, the development of dendrothermal plantations could bring employment opportunities to rural areas and reduce deforestation in the country. However, it is beyond the scope of this study to assign economic or cost values to such factors.

2. The potential for private power generation is substantial but there are a number of issues that must first be resolved before the private sector can make a major contribution. These include the ability of the Thai private sector to raise the necessary funds, the ability of such private projects to qualify for concessional financing from international lenders, the government's policy on foreign investment in the power sector, the ability of the Thai private sector to operate such facilities, the price that private generator would be charged for fuel, and the types of guarantees that the Thai government would need to provide for power purchases from such facilities.

3. The RTG has shown a strong interest in promoting private investment in a number of economic sectors, including the energy sector. The government recently developed a new policy to encourage private power generation but other details remain to be ironed out. Specifically, no policies have been set for the purchase of power from private generators.

4. The Electricity Generating Authority of Thailand (EGAT) will have some excess power capacity until 1989, which provides the RTG with a 3-year window of opportunity in which to define and implement its policy with respect to private-sector power generation. Before 1989, EGAT's marginal cost of production will be relatively low but certain private generation options may still be justifiable on a short-term economic cost basis, such as surplus generation from sugar mills. However, by 1990, EGAT's marginal cost is projected to increase substantially as new capacity is needed, making more alternative investments economically attractive.

5. There is currently no proposal on establishing guidelines for setting the price at which power could be purchased from independent producers.

6. In general, EGAT, the Provincial Electricity Authority (PEA), and the Metropolitan Electricity Authority (MEA) are receptive to the idea of purchasing power from non-utility generators. However, they seem to believe that no independent generator will be able to produce electricity at prices below existing electricity rates. In addition, the utilities are concerned about dispatching problems if small generation units are connected to the grid.

7. EGAT maintains that it would purchase power from non-utility producers if the power were cheaper than EGAT's own production cost or if it were mandated to do so by the government.

8. The private sector is generally satisfied with the quality of service it receives from the electric utilities. Therefore, it has no strong incentive to develop its own power supply options. This situation is in contrast to that in many developing countries, where the utility power supply is unreliable and the quality of service is low. Furthermore, many in the private sector in Thailand would not consider generating power for sale to the grid if they knew the utilities were opposed to such an arrangement.

9. There are no well-developed sources of long-term financing for investment in private power systems. The stock market presents some possibilities, but it is not well developed and needs greater expansion before will present a substantial source of financing. It is thus likely that the development of these systems would be feasible only for the largest, most creditworthy private organizations.

10. Although the study team could obtain little information about the prospects of private investment in larger power plants, it found evidence that the government is interested in exploring such possibilities as a way of reducing public investment in the energy sector.

Cogeneration

11. Thailand already has a substantial industrial cogeneration capacity. The capacity, estimated at 377 MW in 1985, is private and mostly in the seasonal sugar industry (350 MW).

12. There is currently no excess power available for sale to the grid because power from existing cogeneration systems does not exceed on-site needs; in any case, there is no set price or policy for such transactions.

13. The projected financial potential for cogeneration systems through 1996 is 310 MW. Most of these systems would be sized to meet primarily on-site needs, unless purchase policies are established to provide financially attractive conditions for the sale of excess power.

14. Under current RTG policy, equal duties are charged on cogeneration and non-cogeneration systems (30-50 percent).

Power-only Systems

15. Small-scale systems based on agricultural waste fuels (bagasse and rice husks, in particular) could generate over 415 MW of power by the year 1996. The realization of this economic potential will be constrained by several

factors, including the undeveloped markets for bagasse and rice husks and their erratic supply and combustion characteristics, inadequate financing schemes to attract private investors, and the lack of a policy on the purchase of bulk power.

16. No financial potential was found for small power systems using commercial fuels (oil, gas, or lignite), as these systems cannot compete economically with EGAT's larger fossil-fueled plants.

17. Large, private gas-fired systems could produce power at costs comparable to current EGAT electricity prices for large industries. The private sector could potentially finance, develop, and operate enough large power plants (over 50 MW) to offset a major portion of EGAT's 10 year power expansion plan of 4,600 MW. Other developing countries have been turning to the private sector recently for power generation. For example, the private sector is going to finance, build, and operate a 960 MW imported coal plant in Turkey, and a 120 MW imported oil plant in Pakistan.

18. A limited economic potential of 75 MW was identified for micro hydroelectric and municipal waste-to-energy systems. Wind, solar, and biogas resources were not found to have a significant economic potential over the next 10 years.

RECOMMENDATIONS

Recommendations are presented in the same categories as the findings: general, cogeneration, and power-only systems.

General

(a) Because of the medium- and long-term economic benefits of cogeneration and non-utility power production, the RTG should begin to develop and publicize policies that encourage private-sector power generation in the areas of industrial cogeneration, agricultural waste-fuel-based power generation, and large-scale power plants using domestic fossil fuels. The RTG should:

- Develop methodologies to calculate the appropriate price and conditions under which power is purchased from private producers, taking into consideration such issues as:

  (i) The projected increase in EGAT's marginal cost of power generation by 1990-1991.

  (ii) The seasonal, time-of-day, and regional values of private power to utilities.

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

(iv) Special incentives to encourage the initial investments in private power generation.

- Publicize these policies
- Develop the institutional capability for coordinating all aspects of private-sector power generation, including the development of guidelines for preparing private-sector proposals.

(b) In order to better deal with private power generators, government staff should be trained in relevant financial issues such as estimating the true value of power used in calculating "buy back" rates. They should also e trained in technical issues of importance for connecting private power generators with the public grid, including dispatching procedures and load planning.

(c) In light of the U.S. experience with PURPA, the RTG should consider training Thai specialists at U.S. utilities, as well as transferring specialized planning models to calculate utility "avoided costs" or true economic costs.

(d) In addition, the RTG could use U.S. utility experience to draft a typical utility/small generator contract format that considers the seasonal and regional variations of various generation options.

(e) In the short term, the RTG could foster a demonstration project with EGAT and/or PEA that entails purchasing excess power from sugar mills. Such a project would provide data on the economic and technical characteristics of these kinds of transactions.

(f) The RTG could consider providing specific incentives to private power plants for the supply of power (and possibly heat) to the new industrial estates promoted by the Ministry of Industry.

(g) A study should be conducted by NEA to identify the advantages and disadvantages of allowing excess power to be wheeled from one plant to another.

Cogeneration

(h) Cogeneration should be encouraged by the RTG as an energy conservation measure. The new private-sector energy conservation center should be put in charge of policy implementation. In addition, NEA should undertake a study to identify the need, if any, for additional incentives to promote cogeneration similar to those already granted to other conservation investments.

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(i) NEA and the new energy conservation center should jointly design and conduct an outreach program consisting of seminars, workshops, short courses and site visits in Thailand and the United States, as well as the publication of brochures and technical information.

(j) To encourage cogeneration, the government should guarantee a supply of backup power from utilities to cogenerators at fair prices.

Power-only Systems

(k) Because the bulk of the economic potential lies in the use of bagasse and rice husks, a more detailed assessment of the potential and problems associated with the use of these resources is needed. NEA should undertake a study on power generation from rice husks similar to the detailed study of power generation from bagasse conducted by USAID in March 1986. In particular, the use of domestic lignite with bagasse and rice husks in dual-fueled systems should be considered.

(l) On the basis of these two studies, a more detailed comparison of on-site and off-site options for private-sector power generation should be undertaken, as well as an examination of the most appropriate financing for these power plants.

(m) The government should clarify its policy on the availability and price of domestic fuels, especially natural gas, to private power generators. This information is especially important for large units running on natural gas, which have the potential to generate electricity at costs competitive with EGAT prices.

(n) A detailed analysis of the impact of private-sector financing of large power plants on the availability of capital for other sectors of the economy is needed.

(o) As a solution to the domestic capital shortage, the government should consider the possibility of power sector investment through joint ventures in building and operating large power plants. Such ventures would require a clear policy by the government on tax rates, guarantees, and repatriation of profits.

(p) In assessing the economic and financial feasibility of waste-to-energy systems, the cost evaluation should include the long-term cost of developing and establishing disposal sites when the present ones are filled, rather than considering only the short-term costs of handling and disposal at present sites.

(q) A detailed assessment of dendrothermal plants is needed that will focus on socioeconomic factors affecting their development, including the ability to gather large tracks of plantation or deforested land near the power plants. Detailed feasibility studies are needed of one or more potential plant sites.

Avoided costs The decremental cost for an electric utility to generate or purchase electricity that is avoided through purchase of power from a cogeneration facility.

Back-up power Electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage at the facility.

Base load The minimum continuous load on a power system over a given period of time.

Biomass Any organic material not derived from fossil fuels.

Bottoming-cycle cogeneration facility A cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and then the reject heat emerging from the process is used for power production.

Bulk power Medium or high voltage power sold in large quantities.

Capacity The load for which a generator, turbine, transformer, transmission circuit, apparatus, station, or system is rated. Capacity is also used synonymously with capability.

Capacity costs Costs associated with capital investments in electricity production and delivery.

Capacity factor The ratio of the average load on a generating resource to its capacity rating during a specified period of time, expressed as a percentage.

Captive power The power produced by generation units at industrial plants primarily for on-site use.

Cogeneration The sequential production of electricity and useful thermal energy from the same fuel source.

Cogeneration facility Equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam).

Combined cycle The use of waste heat from a gas turbine

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topping cycle for the generation of electricity in a steam turbine generator system.

Dendrothermal System Wood-fired power generation in which the wood is supplied from "plantations" that are managed and selectively harvested to provide a constant reviewing fuel supply.

Dual-fuel capacity Thermal systems capable of using two different types of fuel for combustion.

EGAT Electricity Generation Authority of Thailand

Electric load following operation The operation mode of a cogeneration system that is sized to meet exactly the process electric load requirements.

Energy costs Costs associated with fuel use in electricity production.

Heat rate A measure of generating station thermal efficiency generally expressed in Btu per net kilowatthour. The average heat rate is computed by dividing the total Btu content of the fuel burned by the resulting net kilowatthours generated. The marginal heat rate is calculated as the additional (saved) Btus needed to produce (or not produce) the next kilowatthour.

IFCT Industrial Finance Coporation of Thailand

Interconnection The physical system of electrical transmission between a qualifying facility and a utility.

Interconnection costs Reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administration incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnection with a qualifying facility that are in excess of the costs the electric utility would have incurred if it had not engaged in interconnection operations. Interconnection costs are not included in the calculation of avoided costs.

Kilowatt (kW) An electrical unit of power equal to 1,000 watts.

Kilowatthour (kWh) A basic unit of electric energy equal to the use of 1 kilowatt for a period of 1 hour.

Levelization A financial arrangement whereby payments are constant over a specified period and are based on forcasted values and the value of money over time.

Line losses Losses in electricity that occur during transmission and distribution.

Load The amount of electric power delivered to a given point on a system, or the total amount of demand on the system.

Load shedding Scheduled and unscheduled but deliberate disconnecting of load from the grid by a utility because of supply shortage.

Load factor The ratio of average load to peak load during a specified period of time, expressed as a percentage.

Marginal cost The change in total cost caused by a change in output. Marginal cost can also be understood as the additional cost to produce an additional unit of output, or the savings from producing one unit less of output (i.e., avoided cost).

MEA Metropolitan Electricity Authority

Natural gas Unmixed natural gas or any mixture of natural gas and artificial gas.

NESDB National Economic and Social Development Board

Nonfirm power Electric power available as surplus only, which is supplied by the power producer at the producer's option and can be interrupted by the power producer at will.

Off-site power Power generated from systems not associated with existing industrial or commercial plants.

Oil Crude oil, residual fuel oil, liquid natural gas, or any refined petroleum product.

On-site power Power generated from systems located at industrial or commercial plants for internal use with and without sale to utilities.

Outage Interruption of electricity supply by the utility or because of faults in the utility's system.

PTT Petroleum Authority of Thailand

PEA Provincial Electricity Authority

Peak load The maximum electric load consumed or produced in a stated period of time. It may also be characterized as the minimum instantaneous load within a designated interval of a stated period of time.

Power-only system Power system constructed for the sole purpose of electricity generation (no cogeneration of thermal energy).

Purchase price The price a utility will pay for electricity purchased from a qualifying facility.

PURPA The U.S. Public Utility Regulatory Policies Act of 1978.

Qualifying facility (QF) A cogeneration facility or a small power production facility that satisfies FERC regulations.

Rate Any price, rate charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electrical energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or clarification, and any contract pertaining to the sale or purchase of electrical energy or capacity.

Renewable resources Energy resources that are not depletable, such as hydro and solar.

Reserve margins Extra power generation capacity available to (1) meet anticipated demands for power or (2) serve load in the event of a loss of generation resulting from an unscheduled outage. The reserve margin is the ratio of excess capacity to anticipated peak load, expressed as a percentage.

Simultaneous purchase and sale A regulatory convention that allows a qualifying facility to simultaneously sell its own generated power to the utility while purchasing its requirements from the utility; an

exchange of electrical flow does not necessarily occur.

Small scale Power generation facilities with a capacity under 50 MW.

Spinning reserves Reserves operated at less than the rated capacity to relieve imbalance on the system.

Thermal load following operation The operation mode of a cogeneration system that is sized to meet exactly the process thermal load requirements.

Topping-cycle cogeneration facility A cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy.

Total energy input The total energy in all forms supplied by external sources other than supplementary firing.

Total energy output of a topping-cycle cogeneration facility The sum of the useful power output and useful thermal energy output.

Useful power output of a cogeneration facility The electrical or mechanical energy made available for use, exclusive of any such energy used in the power production process.

Waste By-product materials other than biomass.

Waste heat recovery boiler A device to recover thermal energy from exhaust gases to produce steam.

Wheeling The use of transmission facilities of one utility system to transmit power to another utility system or between customer facilities within a single utility system or between utility systems.

APPENDIX A: SCOPE OF WORK

STUDY OF IMPEDIMENTS TO PRIVATE SECTOR OFF-SYSTEM POWER GENERATION IN THAILAND

This study will examine the potential for and impediments to off-system electrical generation by 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 NEA., EGAT, NESDB and the USAID Mission of their 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 NEA, EGAT, NESDB, USAID Mission and AID/W comments.

TEAM QUALIFICATIONS

A team of three experts will be in Thailand from January 27 to February 14. The team has extensive experience with private power generation both in the U.S. and in Asian developing countries, including industrial cogeneration, renewable and indigenous fossil power systems issues, economics and financing. The team also has Thailand in-country experience in the energy sector.

STUDY OBJECTIVES

(1) Identify the market and economic potential for cogeneration and, particularly, private sector small power production from renewable and indigeneous resources (particularly small hydro, biomass, lignite and natural gas).

(2) Identify the policy/regulatory/institutional and other impediments to private sector electrical generation from cogeneration or renewable/indigeneous resources (including dendrothermal) for sale to the grid.

(3) Develop recommendations and an action plan for addressing the impediments of off-system generation.

SCOPE OF WORK

(a) Background

(i) Description of Thailand energy situation: Describe briefly using existing data, the current energy situation, and the factors influencing the introduction of private sector off-system electrical generation. Such factors may be power sector constraints, e.g., capital availability, skilled manpower, inadequate generation capacity, system reliability. Other factors may be the size and type of industrial base and its capacity for cogeneration.

(ii) U.S. Experience: Briefly describe the Public Utilities Regulatory Policy Act (PURPA) and the U.S. experience in fostering private sector non-utility electrical generation.

(b) Current Off-System Generation:

- Identify any current purchase arrangements between public utilities and non-utility generators of electricity.
- Identify any projects under discussion of in the planning stage.
- Determine the amount of and trend in private (captive) diesel or fuel oil based generation.

(c) Potential for Off-System Generation:

- 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.

(i) 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 and/or oil). Develop prototypes 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.

(ii) Identify other decentralized private sector generation options and based on existing information. Estimate the potential electricity that could be provided to the grid. Identify the energy resource, the energy conversion technology options, and the institutional arrangements for generating the electricity. For example:

- bagasse or rice husks and hulls, steam boilers and mill owners,

- small hydro, low heads turbines and local cooperatives

- coal, steam boilers and coal mine owners.

(iii) For the major generation options, indicate the financial viability of the ststems and the utility payment for the surplus generation that makes the system financially viable.

(d) Utility System Description:
- Briefly describe the Thai electrical systems,ownership, fuel use, marginal cost of generatin, load projections, and system expansion projects, tariffs (EGAT. PEA, MEA).

(i) Determine EGAT's, PEA's and MEA's technical concerns about off-system generation such as system protection, metering, reliability, etc., and any related concerns about the purchase of off-system generation.

(ii) Identify the factors affecting EGAT's marginal costs. Derive an estimated "avoided cost" and the price EGAT might reasonably be expected to pay for intermittent power during peak and off-peak.

(iii) Discuss the basis for the calculation, whether fuel cost should be used in establishing the price to be paid by the utility for intermittent power or whether some capacity cost should also be included in the price.

(e) Power Sector Policies:
- 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.

(f) Impediments to Off-System Generation:
- Analyze the policy, legal, regulatory, institutional or other problems and impediments to off-system generation,
- Determine the positions of key institutions, industries and individuals concerning the impediments to, and potential for, private sector off-system generation including, but not limited to, the utilities, government ministries or commissions responsible for energy and utilities, key industrial and private sector entities, and policy- and law-makers.

(g) Costs and Benefits of Off-System Generation:
- Identify the costs and benefits of the indigeneous/renewable-based off-system electrical generation from the utility, user and national perspective.

(h) Recommendations:
-Provide policy/legal/regulatory and other recommendations that will foster introduction of private indigenous/renewable energy-based generation and cogeneration for sale to the grid,
-Describe AID's options to foster such generation.

(i) Prepare a draft report before departure from the country and provide 40 copies of the final report including a complete draft from NEA, EGAT, NESDB, USAID/Thailand and AID/W/ANE/TR/EFE.

APPENDIX B: LIST OF CONTACTS

Monday, January 27, 1986

9:00 AM
Organization: National Energy Adminstration (NEA)
Main Topic: Kick off meeting
Present: Mr. Amorn Phandhu-Fung, Head, Standard and Regulatory Branch
Mr. Pravit Teetakeaw, Chief, Energy Conservation Center
AS, PS, JS

2:00 PM
Organization: National Economic and Social Development Board (NESDB)
Main Topic: Kick off Meeting
Present: Mr. Piromsakdi Laparojkit
Mr. Kiatisak Madhyamankura
Mr. Chatchai Boonbawornratanakul
AS, PS, JS.

Tuesday, January 28, 1986

2:00 PM
Organization: Industrial Finance Corporation of Thailand (IFTC)
Main Topic: Private Sector Capital Mobilization
Present: Mr. Vorayuth Charoenloet
Mr. Apichat Khanobdee
Mr. Siengchart Limpisuree
AS, PS, JS.

4:00 PM
Organization: U.S. Agency for International Development (USAID)
Main Topic: USAID Activities in Private Sector Development in Thailand
Present: Mr. John Neave
AS, PS, JS.

Wednesday, January 29, 1986

9:00 AM
Organization: Ministry of Interior
Main Topic: Rural Electrification
Present: Mr. Hirun
Mr. Rajatin Syamananda
AS, Ps, JS.

11:00 AM
Organization: National Energy Adminstration
Main Topic: Overview of NEA's Small Scale Power Activities
Present: Mr. Mohan Singh Monga
AS, PS, JS.

3:00 PM
Organization: Boonyium & Associates Ltd. (Boiler Representatives for Cleaver-Brooks)
Main Topic: Potential for Power Generation from Rice Husk
Present: Mr. Pote Sujjavanich
AS.

Thursday, January 30, 1986

9:30 AM
Organization: Electricity Generating Authority of Thailand (EGAT)
Main Topic: EGAT's Attitude toward Private Sector Power Generation
Present: Mr. Chinda Vathananai
AS, PS, JS.

1:30 PM
Organization: Provincial Electricity Authority (PEA)
Main Topic: PEA's Attitude towards Private Sector Power Generation
Present: Mr. Surasukdi Senavongse
Mr. Sakoi Wongbuddha
AS, PS, JS.

3:00 PM
Organization: EGAT
Main Topic: Economic and Financial Picture of EGAT's Operation
Present: Mr. Viroj Nopkhun
AS, PS, JS.

Friday, January 31, 1986

9:30 AM
Organization: Metropolitan Electricity Authority (MEA)
Main Topic: MEA's Attitude toeard Private Sector Power Generation
Present: Mr. Ratree Chantarasiri, Inspector General
Mr. Varun Chariyasuth, Deputy Manager, Power Economics Division
Mr. Chaovalert Dachakaisaya, Chief, Energy Forecasting and Analysis Section, Power Economics Division
Mr. Anantchai Aksoramat, Customer Service Department
AS, PS, JS.

11:30 AM
Organization: NEA
Main Topic: Small Hydro Projects
Present: Mr. Inthon Sapata
JS.

1:45 PM
Organization: Petroleum Authority of Thailand (PTT)
Main Topic: Natural Gas Situation in Thailand
Present: Mr. Viset Choopiban, Governor's Assistant, Technical and Planning
AS, JS.

Saturday, February 1, 1986

1:00 PM
Organization: NEA
Main Topic: Visit to Mae Kum Luang Mini-Hydro Site
Present: Klonpraneet Arintra; NEA
Anucha Anantasan;NEA
Danai Egkamol; NEA
JS

Sunday, February 2, 1986

10:00 AM
Organization: Small hydro Turbine Manufacturer; Chang Mai
Main Topic: Thai Hydro Turbine Manufacturing
Present: Mr. Pramonthe Kanlueng; Chief Engineer
JS

Monday, February 3, 1986

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9:30 AM
Organization: Ministry of Finance
Main Topic: Taxation of Energy Systems and Projects
Present: Mr. Sirote Swasdipanich
AS, JS.

11:30 AM
Organization: NEA
Main Topic: Hydro, Dendro Thermal, Geothermal, Waste-to-energy
Present: Chartdonai Chartpolrach
JS.

2:00 PM
Organization: NEA
Main Topic: Dendothermal, Waste-to-energy
Present: Mr. Oran Ruthanaprakarn
JS.

Tuesday, February 4, 1986

8:00 AM
Organization: The World Bank, Regional Mission
Main Topic: World Bank's View on Private Sector Role IN Power Generation in Thailand
Present: Dr. Karl Jechoutek, Deputy Chief, Regional Mission
Ps.

2:30 PM
Organization: National Institute of Development Adminstration (NIDA)
Main Topic: Marginal Pricing of Electricity
Present: Dr. Thiraphong Vikitset, Dean, School of Development Economics
PS.

Tuesday February 4, 1986

9:00AM
Organization: Association of Thai Industries
Main Topic: Private Sector Interest in Power Generation
Present: Mr. Pairote Gesmankit, Deputy Executive Director
AS, JS.

11:00 AM
Organization: USAID
Main Topic: Information on Traditional Fuel Supply

Present: Mr. Mintara Silawatshananai, Engineer, Office of Engineering
AS, PS, JS.

1:30 PM
Organization: Ministry of Industry
Main Topic: Privitization of Energy and Industry Activities
Present: Mr. Ta-Noo Vicharangsean, Chief, Energy Industry Development Office
AS, JS.

3:30 PM
Organization: Bangkok Bank
Main Topic: Financing
Present: Mr. Piti Sithi-Amnuai, Executive Director
Mr. Soradis Vinyaratn, Senior Vice President
Mr. Pongsathoon Siriyodhim, Assistant V.P.
Mr. Ayuth Krishnamara, Lending Officer
Mr. Pamja Senadisai, Assistant V.P.
JS.

4:00 PM
Organization: Siam Motors & Nissan Co., Ltd.
Main Topic: Interest in Investing in Power Generation
Present: Mr. Piti Vechthanakorn, Chief, Engineering Division
Mr. Srichai Srimingkwanchai, Technical Department Manager
AS.

Wednesday, February 5, 1986

9:00 AM
Organization: Ministry of Industry, Industrial Economics and Planning Division
Main Topic: Joint Public/Private Committee
Present: Mr. Chamroon Malaigrong, Head
AS, JS.

11:00 AM
Organization: NEA
Main Topic: Small Hydro, Dendrothermal, Small Lignite, etc.
Present: Mr. Chartdanai Chartpolrak
Mr. Oran Rutanaprakarn
JS.

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2:00 PM
Organization: Siam Kraft Paper Co.
Main Topic: Interest in Investing in Power Generation
Present: Mr. Uthen Phisuthiphorn, Managing Director
Mr. Vinji Ongnegnun
AS, JS.

3:30 PM
Organization: Siam Cement Co.
Main Topic: Interest in Investing in Power Generation
Present: Mr. Sirichart Tamnarnchit, Engineering Division Manager
Mr. Semyod Tangmeelarp, Energy Department Manager, Engineering Division
AS, JS.

Thursday, February 6, 1986

9:00 AM
Organization: Thai-Asahi Glass Company
Main Topic: On-site Power Generation
Present: Mr. Chainarong Srifuengfung, Executive Director
Mr. Veerasak Lekskul, Manager, Control Department
Mr. Prasart Singhapanthu, Manufacturing Division
PS.

9:00 AM
Organization: Ministry of Agriculture
Main Topic: Wood Resources for Power Generation
Present: Dr. Boonkerd Budhaka, Economist
AS.

9:00 AM
Organization: Department of Mineral Resources
Main Topic: Lignite Use
Present: Mr. Sund Rachawang, Senior Mining Expert
Mr. Araya Nakanart, Geologist
JS.

11:00 AM
Organization: SAHA Union Co.
Main Topic: Interest in Investing in Power Generation
Present: Mr. Singto Tangsujaritpunt, Director
AS.

1:30 AM
Organization: Thai Farmers Bank

Main Topic: Financing
Present: Bkhawat Kavithvathanaphong, First Vice President
JS.

11:30 PM
Organization: Bangkok Metropolitan Adminstration
Main Topic: Waste to Energy
Present: Mr. Wicha Jiwalai, Deputy Governor
Mr. Visarl Chowchuvech
JS.

2:00 PM
Organization: Ajinomoto Co. (Thailand)
Main Topic: Industrial Cogeneration
Present: Mr. Kunimitsu Sato, Assistant Factory Manager
Mr. Vichit Graisarasawasdi, Manager
Mr. Mithanawat Seatisaru, Production Manager
AS.

3:30 PM
Organization: US Department of Commerce
Main Topic: Waste to Energy
Present: Mr. Siritaj Rojanapruk, Senior Marketing Officer
JS.

Friday February 7, 1986

9:00 AM
Organization: MEA
Main Topic: Technical Aspects of Connection to Grid. Load Forecasting
Present: Mr. Wannawit Thamwanich, Deputy Executive Manager, Enginnering Department
Mr. Fusakdi Chongfeungprinya
Ms. Suvimon Kiatboonsri
PS.

10:00 AM
Organization: Thai Orient Leasing Co.
Main Topic: Tax Laws and Leasing of Major Industrial Equipment
Present: Mr. Suvit Arunanondchai, Senior Vice President
JS.

3:00 PM
Organization: Industrial Estate Authority of Thailand
Main Topic: Power Generation in Industrial Estates

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Present: Mr. Vibul Taweesup, Advisor
JS.

Saturday, February 8, 1986

3:30 PM
Organization: NEA
Main Topic: Economics of Electric Power in Thailand
Present: Dr. Itthi Bijayendrayadhin, Head, Energy Economics Division, NEA
AS, PS, JS.

Monday, February 10, 1986

10:00 AM
Organization: Office of the Board of Investment
Main Topic:
Present: Mr. Boonrat Onkor
JS.

3:00 PM
Organization: Indosuez Bank (France)
Main Topic: Stock Market
Present: Mr. Jean Mallet, Manager
AS.

Tuesday, February 11, 1986

10:00 AM
Organization: EGAT
Main Topic: Private Sector Power Generation
Present: Mr. Somboon Manenava, Assistant General Manager, Transmission System Development
PS.

Wednesday, February 12, 1986

10:00 AM
Organization: The Sugar Institute, Ministry of Industry
Main Topic: Sugar Statistics
Present: Mr. Samchai Chaitiparsana, Assistant Director General

3:30 PM
Organization: Riceland International Limited
Main Topic: Rice Mills

Present: Mr. Vichai Sriprasert, President
AS, PS.

4:30 PM
Organization: NEA
Main Topic: Energy Policy in Thailand
Present: Mr. Praphat Premmani, Secretary General
AS, PS, JS.

Thursday, February 13, 1986

9:00 AM
Organization: EGAT
Main Topic: Private Sector Participation in Power Sector
Present: Mr. Kamthon Sindhvananda, General Manager
AS, PS.

Friday, February 14, 1986

4:00 PM
Organization: USAID
Main Topic: Briefing
Present: Dr. John Ericsson, Director
Mr. John Neave
AS, PS, JS.

Monday, February 17, 1986

8:30 AM
Organization: NESDB
Main Topic: Government Interest in Privatization of Powe
Sector
Present: Dr. Phisit Pakkasem, Deputy Secretary General,
NESB
AS, PS, JS.

11:30 AM
Organization: World Bank
Main Topic: Briefing
Present: Dr. Karl Jechoutek
PS, JS.

Tuesday, February 18, 1986

10:00 AM
Organization: Technicacl Applications Universal Ltd.
Main Topic: Electric Utilities' Marginal Costs

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Present: Dr. Techapun Raengkhum
JS.

APPENDIX C: ECONOMIC AND FINANCIAL ANALYSES

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

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

If there is a wide divergence between the relative attractiveness of projects as indicated by these two types of analyses, then serious thought must be given to restructuring government policies which cause these distortions. For example, policies on energy pricing and taxation which cause the relative financial costs to depart significantly from the relative economic costs will cause investors to make non-optimal energy system choices. If these distortions are large enough they can result in a slowdown in the overall economic growth with the potential for contributing to social unrest.

Calculating the Levelized Annual Cost[1]

For both the economic and the financial analyses there are many approaches which can be used. For this study we used the Levelized Annual Cost (LAC) approach. This approach is equivalent to a Net Present Value (NPV) calculation in which each of the cash flows is determined and discounted to a present value. The LAC approach in

effect converts the discounted NPV to a constant "levelized" annual value over the life of the project. It has the advantage of allowing a simple estimate of the energy cost (e.g. in Bahts/kWh) by dividing the LAC by the annual energy output. It provides a relatively simple means of estimating the impact on the apparent relative costs of various economic and financing options by providing a single number measure for what would otherwise be a complicated set of varying cash flows over the project life. The intuitive meaning of the LAC is that it is the average price the power output of the system must obtain in order for the investors to meet their desired returns.

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 Capital Recovery Factor

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

OL = system operating life

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

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

where:

CRF_f = the financial Capital Recovery Factor

r = the after-tax cost of capital

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

f_e = fraction of equity in project financing

r_e = desired return on equity

f_d = fraction of debt in project financing

r_e = cost of debt

TR = marginal tax rate

OL = system operating life

TL = system tax life

This formulation assumes the system is depreciated for tax purposes using a straight line schedule. It is possible to modify this formulation to allow accelerated depreciation, but our discussions with private firms and banks indicated that straight line depreciation is standard practice. For cases where different parts of the system have different lifetimes or tax

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treatments, a separate CRF and LAC can be determined for each part and the results then added.

Determining the Economic LAC

To determine the economic costs and benefits of the small power system options, the true "shadow costs" of capital, labor, and material for both the specific projects and for the conventional EGAT power generation options must 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 of the World Bank and the RTG. The key values are summarized in Exhibit C.1. To simplify the analyses all values are given in constant terms (i.e., net of general inflation).

Petroleum, lignite, and natural gas costs are taken from Thailand: Issues and Options in the Energy Sector; Joint UNDP/World Bank Energy Sector Assessment Program; September, 1985. The costs estimated in that report were then adjusted to reflect lower world oil prices by reducing the cost of petroleum products by the reduction in world oil prices between February, 1985 and February, 1986. This reduction was approximately from $22/bbl to $15/bbl, or $1.20/mmBtu.

Electric power marginal costs were taken from a study performed for NEA estimating these marginal costs for EGAT, MEA, and PEA. The costs shown here are arithmetic averages of the estimates of long-term marginal costs for the four electric supply regions during the period of the Sixth Five-Year Plan (1987-1991). The impact of lower world oil prices on these marginal electricity costs were not available and therefore were not incorporated in this study.

This analysis used conversion factors to convert financial (i.e. market) costs to economic costs. These factors were provided in a World Bank report: Thailand, Managing Public Resources for Structural Adjustment.

Determining the Financial LAC

The market values used to estimate the financial LACs are given in Exhibit C.2. These were provided by NEA and by our interviewees in the course of this study.

Exhibit C.1

Key Assumptions for Performing Economic Analyses

Marginal Productivity of Capital: 12 percent, real terms

Energy Costs:

Natural Gas:	$ 2.50/mmBtu[2]
Diesel Oil:	B 5.15/liter ($5.61/mmbtu)[3]
Residual Oil:	B 3.84/liter ($3.97/mmbtu)[4]
Lignite:	$ 1.80/mmbtu
Electric Power:	Long-run marginal cost of medium voltage to the utilities, as indicated below:

	Demand Charge B/kW/yr	Energy Charge B/kW	Average Cost B/kW
EGAT	600	0.95	1.05
MEA	1,715	0.97	1.26
PEA	835	1.01	1.15

Financial/Economic Conversion Factors:[5]

Capital Goods Conversion Factor:	0.84
Construction Conversion Factor:	0.88
Labor Conversion Factor:	0.92
Standard Conversion Factor:	0.92

Capital Recovery Factors (marginal productivity of capital = 12%):

System Life = 10 years:	0.177
System Life = 15 years:	0.147
System Life = 20 years:	0.134
System Life = 25 years:	0.127

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Exhibit C.2

Key Assumptions for Performing Financial Analyses

After-Tax Return-on-Equity:	25 percent, real
Cost of Debt:	15 percent, real
Debt / Equity Ratio:	3: 1
Marginal Tax Rate:	30 percent
Depreciation:	10 years, Straight Line
Tax Concessions:	None

Energy Prices:

Natural Gas:	$ 3.50/mmBtu
Diesel Oil:	$ 6.60/mmBtu
Residual Oil:	$ 4.00/mmBtu
Lignite:	B 500/ton

Electricity Prices*:

	Demand Charge B/kW/yr	Energy Charge B/kW	Average Cost B/kW
EGAT to industry	1,044	1.41	1.58
EGAT to MEA	960	1.38	1.55
EGAT to PEA	804	1.03	1.16

Capital Recovery Factors:

System Life = 10 years:	0.232
System Life = 15 years:	0.198
System Life = 20 years:	0.183
System Life = 25 years:	0.177

* Equal to the tariffs EGAT charges to its large industrial customers, MEA, and PEA as indicated below

[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

[2] Thailand: Issues and Options in the Energy Sector; p 56

[3] Thailand: Issues and Options in the Energy Sector; p.113, equal to C.I.F. price plus Marketing Margin

[4] Thailand: Issues and Options in the Energy Sector; p 56

[5] Improvement of EMP Electricity Subsystem Study: Final Report; National Energy Administration, Ministry of Science, Technology, and Energy; December, 1985

[6] Improvement of EMP Electricity Subsystem Study: Final Report; National Energy Administration, Ministry of Science, Technology, and Energy; December, 1985

[7]. Thailand, Managing Public Resources for Structural Adjustment; World Bank; 1982

APPENDIX D: COGENERATION MODEL

The study team developed detailed estimates of the Thailand cogeneration market using a dynamic model developed by Hagler, Bailly & Company. The model develops estimates of the cogeneration market over a 12- year period, using the steam demand in the various industries and their growth rate.

The cogeneration technologies considered are:

1) oil-fired boiler with straight back pressure steam turbine
2) gas-fired boiler with straight back pressure steam turbine
3) coal-fired boiler with straight back pressure steam turbine
4) high speed diesel-fired combustion turbine with waste heat recovery boiler
5) gas-fired combustion turbine with waste heat recovery boiler
6) high speed diesel-fired diesel

The model determines the market for existing facilities and for new facilities, as well as the allocations for each technology in each market. These allocations are calculated through weighing coefficients derived from the life cycle costs of the various alternatives competing in a given market. The data on industry operation parameters are summarized in Exhibits D.1 to D.5.

The estimates for economic cogeneration potential have been developed under a set of assumptions summarized in Exhibit D.6. The market obtained are as follows:

National Market	New Facilities	Existing Facilities
204 MW	94 MW	110 MW

More detailed results of the model are presented in Exhibits D.7 to D.11.

Exhibit D.1

STEAM DISTRIBUTION BY FUEL TYPE, IN PERCENT

FUEL TYPE

TSIC	HFO	DIESEL	N.G.	LIGNITE	WASTE
31	72.3	---	---	---	27.7
32	100	---	---	---	---
33					
34	65.50	---	---	9.1	25.4
35					
36	100	---	---	---	---
37	.100	---	---	---	---
38	100	---	---	---	---

Source: Hagler, Bailly & Company

Exhibit D.2

STEAM DISTRIBUTION, BY CAPACITY FACTOR (CF) IN PERCENT

TSIC	0-50%	50-80%	80%+	TOTAL
31	0.0	29.2	70.8	100
32	0.0	35.3	64.7	100
33	25.0	75.0	0.0	100
34	0.0	39.5	60.5	100
35	0.0	62.5	37.5	100
36	---	---	---	---
37	4.0	12.7	83.3	100
38	25.0	50.0	25.0	100

Source: Hagler, Bailly & Company

Exhibit D.3

STEAM DISTRIBUTION, BY SIZE, IN PERCENT

Size Range: (MMBTU/hr)

TSIC	Total 10^6 Btu/yr	0-5	5-20	20+	Total
31	1300.9	6	40	54	100
32	732.4	20.1	45.7	34.2	100
33		35	65	0	100
34	1494.1	1.0	30.0	69.0	100
35	292.7	10.9	58.5	30.6	100
36	---	---	---	---	100
37	93.5	44.3	55.7	---	100
38	7.96	50.0	50.0	0	100

Source: Hagler, Bailly & Company

Exhibit D.4

STEAM DISTRIBUTION, BY ELECTRIC/STEAM RATIO, IN PERCENT

ELECTRIC/STEAM RATIO (BTU/BTU)

TSIC	TOTAL 10^6 Btu/yr	0.0-0.20	0.2-0.5	0.5+	Total
31	1300.9	71.0	19.0	10.0	100
32	732.4	6.7	4.7	88.6	100
33	695.0	---	---	---	---
34	1494.1	7.0	90.8	2.2	100
35	517.7	36.4	63.6	0	100
36	484.18	---	---	---	---
37	93.5	0	12.7	87.3	100
38	7.96	0	0	100.0	100

Source: Hagler, Bailly & Company

Exhibit D.5

RATIO OF STEAM TO TOTAL FUEL USED

TSIC	RATIO	INDUSTRY
31	0.920	Food (excluding sugar)
32	0.897	Textile
33	1.000	Plywood and Veneer
34	0.929	Pulp and Paper
35	0.928	Chemicals, Plastic & Rubber, Medicine, Detergent and Type & Rubber
36	0.000	Battery, Ceramics, Cement & Asbestos Cement (non-metal)
37	0.120	Iron & Steel, non-ferrous metals
38	0.152	Fabricated
39	---	Other

Source: Hagler, Bailly & Company

Exhibit D.6

INPUT DATA FOR COGENERATION MARKET ANALYSIS MODEL

Fuel Prices

	1985 Price (1985 $/MMBtu)	Shadow Price	Annual Escalation
Furnace Oil	4.00	3.97	3.4%
Natural Gas	3.50	2.50	0.4%
Electricity	17.70	14.40	3.0%
H.S. Diesel	6.60	5.60	3.4%
Lignite	1.47	1.80	2.4%

Industry

No.	Name	Current Steam Demand (10^{12} Btu)	Annual Growth Rate (%)	Captive Steam (10^{12} Btu)
1	Food	15.24	0.9	0.345
2	Textile	7.57	3.8	0.010
3	Wood	0.62	3.9	0.035
4	Paper	3.20	4.0	0.465
5	Chemicals	4.50	4.0	0
6	Basic Metals	0.28	4.5	0
7	Fab. Metals	0.14	4.5	0

Other

	Financial Market	Economic Market
Tax Rate	40%	0%
Depreciation	Linear, 10 yrs	None
Discount Rate	15%	10%
Buyback Rate	70% of retail price	90% of retail price

Source: Hagler, Bailly & Company

Exhibit D.7

COGENERATION SYSTEM MARKET
SALES PROJECTIONS (MW - ELECTRIC)
INDUSTRY: ALL
REGION: ALL
MARKET APPLICATION: ALL
SIZE RANGE: ALL

ECONOMIC MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	3	1	1	0	0	0	6
NG Boiler/ST	7	3	1	1	1	1	13
Coal Boiler/ST	5	2	1	1	0	0	9
H.S.D. GT/WHRB	11	4	2	1	1	1	20
NG GT/WHRB	124	72	40	38	41	44	360
H.S.D. Diesel	19	7	3	2	2	2	35
TOTALS	169	90	48	43	46	48	444

FINANCIAL MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	8	3	2	1	1	1	16
NG Boiler/ST	0	1	1	1	1	1	5
Coal Boiler/ST	6	4	2	2	1	1	17
H.S.D. GT/WHRB	29	12	5	4	3	2	55
NG GT/WHRB	2	6	11	19	26	31	94
H.S.D. Diesel	1	2	3	4	4	4	17
TOTALS	47	29	24	30	35	40	204

Source: Hagler, Bailly & Company

Exhibit D.8

COGENERATION SYSTEM MARKET
SALES PROJECTIONS (MW - ELECTRIC)
INDUSTRY: ALL
REGION: ALL
MARKET APPLICATION: NEW
SIZE RANGE: ALL

ECONOMIC MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	0	0	0	0	0	0	2
NG Boiler/ST	1	1	1	1	0	0	4
Coal Boiler/ST	1	0	0	0	0	0	2
H.S.D. GT/WHRB	1	1	1	1	1	1	6
NG GT/WHRB	12	17	21	25	29	32	135
H.S.D. Diesel	2	2	2	2	1	1	10
TOTALS	17	21	25	28	32	35	159

FINANCIAL MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	1	1	1	1	1	0	4
NG Boiler/ST	0	0	0	1	1	1	3
Coal Boiler/ST	1	1	1	1	1	1	6
H.S.D. GT/WHRB	3	3	3	2	2	2	15
NG GT/WHRB	0	2	5	11	17	22	57
H.S.D. Diesel	0	1	1	2	3	3	9
TOTALS	5	7	11	18	24	28	94

Source: Hagler, Bailly & Company

Exhibit D.9

COGENERATION SYSTEM MARKET
SALES PROJECTIONS (MW - ELECTRIC)
INDUSTRY: ALL
REGION: ALL
MARKET APPLICATION: REPLACEMENT
SIZE RANGE: ALL

ECONOMIC MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	0	0	0	0	0	0	1
NG Boiler/ST	1	0	0	0	0	0	2
Coal Boiler/ST	1	0	0	0	0	0	1
H.S.D. GT/WHRB	1	1	0	0	0	0	3
NG GT/WHRB	12	10	9	9	10	10	59
H.S.D. Diesel	2	1	1	1	1	0	6
TOTALS	18	13	11	11	11	11	73

FINANCIAL MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	1	1	0	0	0	0	3
NG Boiler/ST	0	0	0	0	0	0	1
Coal Boiler/ST	1	1	1	0	0	0	3
H.S.D. GT/WHRB	3	2	1	1	1	1	9
NG GT/WHRB	0	1	2	4	6	7	20
H.S.D. Diesel	0	0	1	1	1	1	4
TOTALS	5	5	5	7	8	9	39

Source: Hagler, Bailly & Company

Exhibit D.10

COGENERATION SYSTEM MARKET
SALES PROJECTIONS (MW - ELECTRIC)
INDUSTRY: ALL
REGION: ALL
MARKET APPLICATION: RETROFIT
SIZE RANGE: ALL

ECONOMIC MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	3	1	0	0	0	0	4
NG Boiler/ST	6	2	0	0	0	0	8
Coal Boiler/ST	4	1	0	0	0	0	5
H.S.D. GT/WHRB	8	2	0	0	0	0	11
NG GT/WHRB	100	46	10	4	3	2	165
H.S.D. Diesel	14	4	1	0	0	0	19
TOTALS	134	56	12	4	3	2	212

FINANCIAL MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	6	2	0	0	0	0	9
NG Boiler/ST	0	0	0	0	0	0	1
Coal Boiler/ST	5	3	1	0	0	0	8
H.S.D. GT/WHRB	22	7	1	0	0	0	31
NG GT/WHRB	2	4	4	4	3	2	17
H.S.D. Diesel	1	1	1	0	0	0	3
TOTALS	36	17	7	5	4	2	71

Source: Hagler, Bailly & Company

Exhibit D.11

COGENERATION SYSTEM MARKET
SALES PROJECTIONS (MW - ELECTRIC)
INDUSTRY: FOOD
REGION: ALL
MARKET APPLICATION: ALL
SIZE RANGE: ALL

ECONOMIC MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	1	1	0	0	0	0	2
NG Boiler/ST	3	1	0	0	0	0	5
Coal Boiler/ST	2	1	0	0	0	0	4
H.S.D. GT/WHRB	5	2	1	0	0	0	4
NG GT/WHRB	55	29	2	10	0	10	125
H.S.D. Diesel	8	3	1	1	1	0	13
TOTALS	74	36	14	11	11	11	157

FINANCIAL MARKET

Technology	86-87	88-89	90-91	92-93	94-95	96-97	TOTAL
FO Boiler/ST	4	1	0	0	0	0	6
NG Boiler/ST	0	0	0	0	0	0	2
Coal Boiler/ST	3	2	1	1	0	0	7
H.S.D. GT/WHRB	12	4	2	1	1	1	20
NG GT/WHRB	1	2	3	4	6	6	22
H.S.D. Diesel	0	1	1	1	1	1	5
TOTALS	19	11	7	7	8	8	61

Source: Hagler, Bailly & Company

APPENDIX E: ELECTRICITY TARIFFS IN THAILAND

EGAT's current Tariff (introduced April 1, 1983) has separate schedules for MEA, PEA and direct-supply industrial consumers. The schedules are of th two part type and include a demand (kW) charge and an energy (kW/h) charge. The tariff structure is generally appropriate for a bulk electricity supplier. The demand component is charged at a fixed rate per unit, while the energy charge is levied on a marginally declining block tariff. EGAT also has an off-peak tariff for direct supply industrial customers using electricity intensive production processes. Each of these tariffs has a demand charge and a simuple (flat rate) energy charge. A fuel cost adjustment clause was introduced in August 1977. However, adjustment to consumer charges for fuel changes incured by EGAT is not automatic as approval by the council of Ministers is required before it can be implemented. EGAT's tariff results in a degree of cross-subsidization amongst consumers. In particular, while the costs of supplying PEA are highest, PEA is charges the lowest tariff and is subsidized by EGAT's other consumers.

EGAT's schedule of tariffs is shown in Exhibit E.1. The special rate in -this Exhibit (category 3) applies to EGAT's electrolysis and blast furnace customers. The special rate to MEA and PEA (category 4) applies to MEA and PEA's purchase from EGAT to supply electrolysis and blast furnace customers.

PEA's existing tariff was introduced on April 8, 1983. It has six consumer categories, residential, small business, large business, samll industry, and water pumping. The residential tariff is of the decreasing block type with nine blocks. Tariffs for large business, small and large industry, include both demand and energy charges. However, no time-of-day or seasonal rates. PEA's tariff is shown in Exhibit E.2.

MEA introduced new tariff schedules on April 5, 1983, which are very similar to those introduced by PEA, with the exception of an off-peak tariff for large industrial consumers and the water category which is replaced by a stand-by category in MEA's tariff. Energy rates in tariffs for consumers in the residential, small business, small industrial and large industrial categories are identical to those in corresponding PEA tariffs. The demand charges in MEA's tariffs are, however, slightly different. Two important differences between MEA's and PEA's tariffs are, first that MEA's tariffs include a fuel cost adjustment clause, and second that MEA's tariffs for large businesses and small and large industrial consumers include power factor penalty clauses. MEA's tariff is shown in Exhibit E.3.

PEA and MEA also have their own special tariffs that apply to hospital and other government institutions.

In January 1986, the Petroleum Authority of Thailand reduced its gas prices to EGAT from 87.6 Baht/mmBtu to 83 Bhat/mmBtu. This fuel cost reduction is expected to be passed to some categories of commercial customers.

Exhibit E.1. EGAT's Basic Electricity Wholesale Tariff

April 1, 1983

1. Normal Rate

1.1 MEA

Demand Charge	80.00 Baht/kW per month
Energy Charge:	
First 100 kWh/kW	1.3883 Baht/kWh
Next 300 kWh/kW	1.3683 Baht/kWh
Balance	1.3583 Baht/kWh

1.2 PEA

Demand Charge	67.00 Baht/kW per month
Energy Charge:	
First 100 kWh/kW	1.0898 Baht/kWh
Next 300 kWh/kW	1.0598 Baht/kWh
Balance	1.0298 Baht/kWh

2. Industrial Rate

Demand Charge	87.00 Baht/kW per month
Energy Charge:	
First 100 kWh/kW	1.46 Baht/kWh
Next 300 kWh/kW	1.44 Baht/kWh
Balance	1.41 Baht/kWh

3. Social Rate

Demand Charge	87.00 Baht/kW per month
Energy Charge	1.38 Baht/kWh

4. Special Rate (MEA, PEA)

4.1 MEA

Demand Charge	74.00 Baht/kW per month
Energy Charge	1.3883 Baht/kWh

4.2 PEA

Demand Charge	74.00 Baht/kW per month
Energy Charge	1.1998 Baht/kWh

5. Off-Peak

Demand Charge	79.00 Baht/kW
Energy Charge	1.42 Baht/kWh.

Exhibit E.2

PROVINCIAL ELECTRICITY AUTHORITY

ELECTRICITY TARIFFS

1. Residential Service

Application

Electric service for lighting and electric appliances used in households and adjoining area, including monasteries of all faiths, by being served through a single meter.

Monthly Rate Energy charge :

First	5	kWh or less	5.00	Baht
Next	10	kWh (6 - 15)	0.70	Baht/kWh.
Next	10	kWh (16 - 25)	0.90	Baht/kWh.
Next	10	kWh (26 - 35)	1.17	Baht/kWh.
Next	65	kWh (36 - 100)	1.65	Baht/kWh.
Next	50	kWh (101 - 150)	1.75	Baht/kWh.
Next	150	kWh (151 - 300)	1.83	Baht/kWh.
Next	100	kWh (301 - 400)	2.04	Baht/kWh.
Over	400	kWh (401 up)	2.11	Baht/kWh.

Minimum Charge : 5.00 Baht/month.

Notes:

(1) For customers who have a free-of-charge privilege for a certain amount of energy, whenever consumption exceeds the amount permissible, the charge for the excess will follow this schedule.

(2) This schedule will also be applied to business, government agency or state enterprise with the total use of electrical appliances not more than 6 kW.

2. Small Business Service

Application

Electric service for power used in small business or combined business with residence, government agency or state enterprise, having a combined lighting and electrical equipment installation of 6 kW. or over, but less than 30 kW., by being served through a single meter.

Monthly Rate Energy charge :

First	40	kWh or less	89.72	Baht
Next	260	kWh (41 - 300)	1.81	Baht/kWh.
Next	700	kWh (301 - 1,000)	1.92	Baht/kWh.
Next	2,000	kWh (1,001 - 3,000)	2.04	Baht/kWh.
Over	3,000	kWh (3,001 up)	2.21	Baht/kWh.

Minimum Charge : 89.72 Baht/month.

Notes:

(1) Any customer who first registered on Schedule 2, if later on prefers to follow Schedule 1, must have electric appliances installed less than 6 kW., which is inspected by PEA's provincial office, then Schedule 1. shall be applied.

(2) This schedule is applied to industry having a maximum demand less than 30 kW.

3. Large Business Service

Application

Electric service for business, government agency or state enterprise and its adjoining area, with a maximum 15 - minute integrated demand of 30 kW. or over and supplied at a voltage of not less than 11 kV.

Monthly Rate

3.1 Demand Charge : All kW., of maximum demand 95.00 Baht/kW.
3.2 Energy Charge : For all kWh. 1.52 Baht/kWh.
Minimum Charge : The monthly charge, calculated from 3.1 plus 3.2 or calculated from Note (4) below, shall not be less than Demand Charge which calculated from 60% of the highest demand occurring in any month of the past 12 months, ending with the current month.

Notes:

(1) For below 11 kV. delivery, the Demand Charge will be increased 3 Baht/kW.
(2) For delivery at 69 or 115 kV., the Demand Charge will be reduced 2 Baht/kW
(3) If demand and energy meter is installed on the load side of the transform another 2% must be added to both total demand and energy consumption to be calculated in accordance with Schedules under 3.1 and 3.2 above, to cover the unmeasured transformer loss.
(4) In any month during which the maximum demand does not reach 30 kW. the charge will be changed to follow Schedule 2. However, the charge shall not be less than the above Minimum Charge.
(5) Applications for the use of Schedule 3 must be approved by PEA.'s Central Office and a Purchase Contract must be made.

4. Small Industrial Service

Application

Electric service for industry at a plant and its adjoining area, with a maximu 15 - minute integrated demand between 30 to 499 kW. and supplied at a voltage of not less than 11 kV.

Monthly Rate

4.1 Demand Charge: All kW. of maximum demand 95.00 Baht/kW.
4.2 Energy Charge : First 50 kWh per kW. of maximum demand 1.46 Baht/kWh.
Next 150 kWh per kW. of maximum demand 1.45 Baht/kWh.
Next 200 kWh per kW. of maximum demand 1.44 Baht/kWh.
Over 400 kWh per kW. of maximum demand 1.43 Baht/kWh.
Minimum Charge : The monthly charge, calculated from 4.1 plus 4.2 or calculated from Note (5) below, shall not be less than Demand Charg which calculated from 60% of the hihest demand occurring in any month of the past 12 months, ending with the current month.

Notes:

(1) This schedule also be applied to government agency or state enterprise, which is industrial, if the maximum demand from 30 to 499 kW.
(2) For below 11 kV. delivery, the Demand Charge will be increased 3 Baht/kW.
(3) For delivery at 69 or 115 kV., the Demand Charge will be reduced 2 Baht/kW.
(4) If demand and energy meter is installed on the load side of the transformer another 2% must be added to both total demand and energy consumption to be calculated in accordance with Schedules under 4.1 and 4.2 above, to cover the unmeasured transformer loss.
(5) In any month during which the maximum demand does not reach 30 kW. the charg will be changed to follow Schedule 2. However, the charge shall not be less than the above Minimum Charge.
(6) Applications for the use of Schedule 4 must be under the regulation of setti up the industry plant and approved by PEA.'s Central Office and a Purchase Contract must be made.

Exhibit E.2 (Continued)

5. Large Industrial Service

Application

Electric service for industry at a plant and its adjoining area, with a maximum 15 - minute integrated demand of 500 kW. or over and supplied at a voltage of not less than 11 kV.

Monthly Rate

5.1 Demand Charge :	All kW. of maximum demand	95.00	Baht/kW.
5.2 Energy Charge :	First 200 kWh per kW. of maximum demand	1.44	Baht/kWh.
	Next 280 kWh per kW. of maximum demand	1.43	Baht/kWh.
	Over 480 kWh per kW. of maximum demand	1.41	Baht/kWh.

Minimum Charge : The monthly charge, calculated from 5.1 plus 5.2 or calculated from Note (5) below, shall not be less than Demand Charge which calculated from 60% of the hihest demand occurring in any month of the past 12 months, ending with the current month.

Notes:

(1) This schedule also be applied to government agency or state enterprise which is industrial, if the maximum demand from 500 kW. or over
(2) For below 11 kV. delivery, the Demand Charge will be increased 2 Baht/kW.
(3) For delivery at 69 or 115 kV., the Demand Charge will be reduced 5 Baht/kW.
(4) If demand and energy meter is installed on the load side of the transformer, another 2% must be added to both total demand and energy consumption to be calculated in accordance with Schedules under 5.1 and 5.2 above, to cover the unmeasured transformer loss.
(5) In any month during which the maximum demand does not reach 500 kW. the charge will be changed to follow Schedule 4. However, the charge shall not be less than the above Minimum Charge.
(6) Applications for the use of Schedule 5 must be under the regulation of setting up the industry plant and approved by PEA.'s Central Office and a Purchase Contract must be made.

6. Agricultural Pumping and Public Water Pumping Service

Application

Electric service for agricultural pumping having a combined load of not less than 25 horsepower and electric service for public water pumping of all capacities which is proceed by government or agricultural group or agricultural cooperative, by being served through a single meter. Daily load during 18.00 - 21.000 hours is prohibitted.

Monthly Rate

Energy Charge :	First 100 kWh or less	117.00	Baht
	Over 100 kWh (101 up)	1.17	Baht/kWh.
Minimum Charge :	117.00 Baht/month.		

Notes:

(1) In case using the agricultural pumping during 18.00 - 21.00 hours, PEA.'s Central Office will change to the other higher rate.
(2) Application for using Schedule 6 must be first approved by PEA.'s Central Office.

These electric rate schedules effect form April 1, 1983

Provincial Electricity Authority
Bangkok, Thailand
April 8, 1983

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Exhibit E.3

NEW ELECTRIC RATE

SCHEDULE 1 RESIDENTIAL

Applicable

To the electric service through a single watt-hour meter for lighting and appliance used in a dwelling place including related grounds and buildings, monasteries and churches of all religions.

Monthly Rate

Energy Charge :	First	5 kwhr or less	Baht	5.00	
	Next	10 kwhr	Baht	0.70	per kwhr
	Next	10 kwhr	Baht	0.90	per kwhr
	Next	10 kwhr	Baht	1.17	per kwhr
	Next	65 kwhr	Baht	1.65	per kwhr
	Next	50 kwhr	Baht	1.75	per kwhr
	Next	150 kwhr	Baht	1.83	per kwhr
	Next	100 kwhr	Baht	2.04	per kwhr
	Over	400 kwhr	Baht	2.11	per kwhr

Minimum Charge : Baht 5.00 per month.

SCHEDULE 2 SMALL BUSINESS

Applicable

To the electric service through a single watt-hour meter for lighting and appliances used in business buildings, public buildings and industrial establishments including related grounds with a maximum 15-minute integrated demand of less than 30 kilowatts.

Monthly Rate

Energy Charge :	First	40 kwhr or less	Baht	89.72	
	Next	260 kwhr	Baht	1.81	per kwhr
	Next	700 kwhr	Baht	1.92	per kwhr
	Next	2,000 kwhr	Baht	2.04	per kwhr
	Over	3,000 kwhr	Baht	2.21	per kwhr

Minimum Charge : Baht 89.72 per month.

Note During the billing month any customer under Schedule 2 whose maximum demand is 30 kilowatts or more shall be classified under Schedule 3, 4 or 5 accordingly, and shall be reclassified under Schedule 2 only when customer's demand has fallen below 30 kilowatts for 12 consecutive months.

SCHEDULE 3 LARGE BUSINESS

Applicable

To the electric service through a single demand meter for lighting and appliances used in business buildings and public buildings including related grounds with a maximum 15-minute integrated demand of 30 kilowatts or over.

Monthly Rate

Demand Charge : Baht 98.00 per kw of billing demand

Energy Charge : Baht 1.52 per kwhr

Minimum Charge : The demand charge for 60% of the highest billing demand occurring during the last 12 months ended with the current month.

Billing Demand : The billing demand (determined to the nearest whole kilowatt) shall be the maximum 15-minute integrated demand during the monthly billing period.

Power Factor Charge

For lagging power factor customers, in any monthly billing period during which customer's maximum 15-minute kilovar demand is in excess of 63% of his maximum 15-minute kilowatt demand, a monthly power factor charge of Baht 15.00 for each kvar of such excess (determined to the nearest whole kvar) will be made.

Note

1. For below 12 kv delivery, the above rate is applicable.
2. For delivery at 12 or 24 kv, the demand charge in the above monthly rate will be reduced by Baht 3.00 per kilowatt.
3. For delivery at 69 or 115 kv, the demand charge in the above monthly rate will be reduced by Baht 5.00 per kilowatt.
4. Where transformers belong to customer, if deemed necessary, MEA may elect to meter on the load side of transformers, in which case meter readings shall be increased by the amount of the transformer losses to be individually determined by tests or estimate.

SCHEDULE 4 SMALL INDUSTRIAL

Applicable

To the electric service through a single demand meter for lighting and appliances used in industrial establishments including related grounds with a maximum 15-minute integrated demand of between 30 to 499 kilowatts.

Monthly Rate

Demand Charge	:	Baht 98.00 per kw of billing demand	
Energy Charge	:	First 50 kwhr per kw of billing demand	Baht 1.46 per kwhr
		Next 150 kwhr per kw of billing demand	Baht 1.45 per kwhr
		Next 200 kwhr per kw of billing demand	Baht 1.44 per kwhr
		All over 400 kwhr per kw of billing demand	Baht 1.43 per kwhr
Minimum Charge	:	The demand charge for 60% of the highest billing demand occurring during the last 12 months ended with the current month.	
Billing Demand	:	The billing demand (determined to the nearest whole kilowatt) shall be the maximum 15-minute integrated demand during the monthly billing period.	

Power Factor Charge

For lagging power factor customers, in any monthly billing period during which customer's maximum 15-minute kilovar demand is in excess of 63% of his maximum 15-minute kilowatt demand, a monthly power factor charge of Baht 15.00 for each kvar of such excess (determined to the nearest whole kvar) will be made.

Note

1. For below 12 kv delivery, the above rate is applicable.
2. For delivery at 12 or 24 kv, the demand charge in the above monthly rate will be reduced by Baht 3.00 per kilowatt.
3. For delivery at 69 or 115 kv, the demand charge in the above monthly rate will be reduced by Baht 5.00 per kilowatt.
4. Where transformers belong to customer, if deemed necessary, MEA may elect to meter on the load side of transformers, in which case meter readings shall be increased by the amount of the transformer losses to be individually determined by tests or estimate.

SCHEDULE 5 LARGE INDUSTRIAL

Applicable

To the electric service through a single demand meter for lighting and appliances used in industrial establishments including related grounds with a maximum 15-minute integrated demand of 500 kilowatts or over.

Monthly Rate

Demand Charge	:	Baht 90.00 per kw of billing demand		
Energy Charge	:	First	200 kwhr per kw of billing demand	Baht 1.44 per kwh
		Next	280 kwhr per kw of billing demand	Baht 1.43 per kwh
		All over	480 kwhr per kw of billing demand	Baht 1.41 per kwh
Minimum Charge	:	The demand charge for 60% of the highest billing demand occurring during the last 12 months ended with the current month.		
Billing Demand	:	The billing demand (determined to the nearest whole kilowatt) shall be the maximum 15-minute integrated demand during the monthly billing period.		

Power Factor Charge

For lagging power factor customers, in any monthly billing period during which customer's maximum 15-minute kilovar demand is in excess of 63% of his maximum 15-minute kilowatt demand, a monthly power factor charge of Baht 15.00 for each kvar of such excess (determined to the nearest whole kvar) will be made.

Note

1. For 69 or 115 kv delivery, the above rate is applicable.
2. For delivery at 12 or 24 kv, the demand charge in the above monthly rate will be increased by Baht 5.00 per kilowatt.
3. For below 12 kv delivery, the demand charge in the above monthly rate will be increased by Baht 7.00 per kilowatt.
4. Where transformers belong to customer, if deemed necessary, MEA may elect to meter on the load side of transformers, in which case meter readings shall be increased by the amount of the transformer losses individually determined by tests or estimate.

SCHEDULE 6 LARGE INDUSTRIAL OFF-PEAK

Applicable

To the electric service through a single demand meter for lighting and appliances used in industrial establishments including related grounds with a maximum 15-minute integrated demand of 1,000 kilowatts or over and the consumption of electricity can be interrupted or reduced during the on-peak period, currently taken during 18.30-20.30 hours each day.

Monthly Rate

Off-Peak Period

Demand Charge : Baht 65.00 per kw of off-peak billing demand

Energy Charge : Baht 1.40 per kwhr

On-Peak Period

Demand Charge : Baht 115.00 per kw of on-peak billing demand

Energy Charge : Baht 1.40 per kwhr

Minimum Charge : The off-peak period demand charge for 100% of the highest off-peak billing demand occurring during the last 12 months ended with the current month.

Off-Peak Billing Demand : The off-peak billing demand (determined to the nearest whole kilowatt) shall be the maximum 15-minute integrated demand created in the off-peak period during the billing month.

On-Peak Billing Demand : The on-peak billing demand (determined to the nearest whole kilowatt) shall be the maximum 15-minute integrated demand created in the on-peak period during the billing month.

Power Factor Charge

For lagging power factor customers, in any monthly billing period during which customer's maximum 15-minute kilovar demand is in excess of 63% of his maximum 15-minute kilowatt demand, a monthly power factor charge of Baht 15.00 for each kvar of such excess (determined to the nearest whole kvar) will be made.

Note

1. For 12 or 24 kv delivery, the above rate is applicable.
2. For below 12 kv delivery, the energy charges in both off-peak and on-peak periods will be increased by Baht 0.01 per kwhr.
3. For 69 or 115 kv delivery, the energy charges in both off-peak and on-peak periods will be decreased by Baht 0.01 per kwhr.
4. Where transformers belong to customer, if deemed necessary, MEA may elect to meter on the load side of transformers, in which case meter readings shall be increased by the amount of the transformer losses individually determined by tests or estimate.
5. Customers desiring to use Schedule 6 shall contact MEA for the necessary contract.

SCHEDULE 7 STAND-BY

Applicable

To any business and industrial customer who :

1. has power requirement of 300 kva or more,
2. normally, has all or part of his power requirement furnished by other source of supply or a privately owned plant.
3. through a single demand meter, desires a permanent connection with the MEA's system as a stand-by power source when customer's own source of supply fails or breaks down temporarily or in case of emergency.

Monthly Rate

1. In case the stand-by is not used during any billing month, the stand-by demand charge shall be :

   Baht 30.00 per kw of stand-by demand

2. In case the stand-by is used during any billing month, the charges shall be of either the regular schedule applicable or the stand-by charge, whichever is higher.

Stand-by Demand : Stand-by demand is an agreed demand in kilowatt as specified in the contract or 15-minute integrated demand as measured during any billing month if greater, then such greater demand shall become the stand-by demand for the next billing month until again exceeded; in such case the highest demand shall thereafter apply until the termination of the contract.

Note Customers desiring to use stand-by service shall contact MEA for the necessary contract.

Fuel Adjustment Clause

Should there be any changes in fuel cost, the adjustment will be made accordingly at flat rate per unit; the annoucement of which will be issued from time to time.

THESE NEW RATES WILL BE IN EFFECT FROM 1 APRIL B.E. 2526 (1983) ONWARDS
METROPOLITAN ELECTRICITY AUTHORITY
5 APRIL B.E. 2526 (1983)

Printed at M.E.A. Press Chakphet Road, Bangkok, by Nai Suchit Feangchunuch 1983

Exhibit E.3 (Continued)

NEW ELECTRIC RATE

SCHEDULE 8 AGRICULTURAL PUMPING

Applicable

To the electric service through a single watt-hour meter for agricultur pumping with total capacity of not less than 25 horse-power, used by officially recognized farmer groups or agricultural co-operatives or related government agencies or farmers to operate water pumps for agricultural purpose.

Monthly Rate

Energy Charge :	First	100 kwhr or less	Baht	117.00	
	Over	100 kwhr	Baht	1.17	per kwhr
Minimum Charge:	Baht	117.00 per month			

Note Customers desiring to use Schedule 8 shall contact MEA for the necessar contract.

Conditions

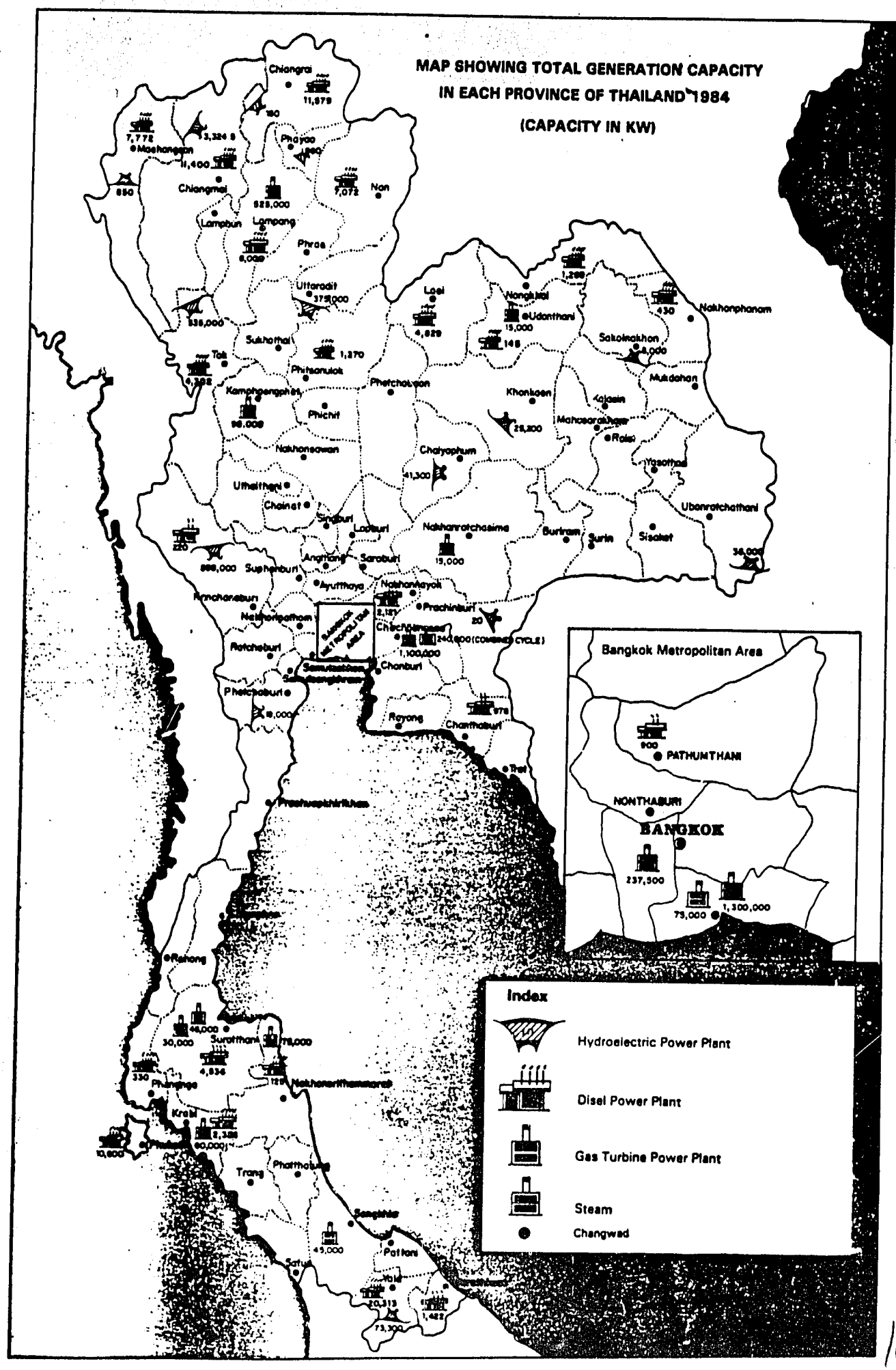
1. In applying for this schedule, customer must be head of farmer group or the one who acts on behalf of the agricultural co-operative or of government agency related to water provision for farmer groups or farmer who uses his own pump for agricultural purpose.
2. In case that customer is head of farmer group, he must submit docume issued by the government, indicating group-head's name, amount of members and cultivated area to be irrigated.
3. In applying for this schedule, customer must operate pumps with total capacity of not less than 25 horse-power.
4. Customer agrees to use electric power purchased under the contract through a single watt-hour meter for agricultural pumping only.
5. Customer agrees to follow rates, standard and regulations of service issued and to be issued by MEA.

Fuel Adjustment Clause

Should there be any changes in fuel cost, the adjustment will be made accordingly at flat rate per unit; the announcement of which will be issued from time to time.

THIS RATE WILL BE IN EFFECT FROM NOVEMBER 1, 1983 ONWARDS.
METROPOLITAN ELECTRICITY AUTHORITY
NOVEMBER 1, 1983

APPENDIX F: MAP OF THAILAND


MAP SHOWING TOTAL GENERATION CAPACITY
IN EACH PROVINCE OF THAILAND 1984
(CAPACITY IN KW)
Chiangrai
Phayao
Maehongson
Chiangmai
Lamphun
Lampang
Phrae
Nan
Uttaradit
Sukhothai
Tak
Phitsanulok
Kamphaengphet
Phichit
Phetchabun
Loei
Nongkhai
Udonthani
Nakhonphanom
Sakolnakhon
Mukdahan
Khonkaen
Kalasin
Mahasarakham
Roiet
Yasothon
Nakhonsawan
Chaiyaphum
Uthaithani
Chainat
Singburi
Lopburi
Nakhonratchasima
Buriram
Surin
Sisaket
Ubonratchathani
Suphanburi
Angthong
Saraburi
Ayutthaya
Nakhonnayok
Prachinburi
Ranchaburi
Nakhonpathom
Chachoengsao
Ratchaburi
Samutsakhon
Samutsongkhram
Chanburi
Phetchaburi
Rayong
Chanthaburi
Trat
Prachuapkhirikhan
Ranong
Surathani
Nakhonsithammarat
Phangnga
Krabi
Phuket
Trang
Phatthalung
Songkhla
Pattani
Satun
Yala
BANGKOK METROPOLITAN AREA
Bangkok Metropolitan Area
PATHUMTHANI
NONTHABURI
BANGKOK
Index
Hydroelectric Power Plant
Disel Power Plant
Gas Turbine Power Plant
Steam
Changwad

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