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Thailand: ... and Options in the Energy Sector

A Joint Report of IBRD and NESDB Thailand

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Report of the Joint UNDP/World Bank Energy Sector Assessment Program

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Report No. 5793-TH

THAILAND

ISSUES AND OPTIONS IN THE ENERGY SECTOR

SEPTEMBER 1985

This is one of a series of reports of the Joint UNDP/World Bank Energy Sector Assessment Program. Finance for this work has been provided, in part, by the UNDP Energy Account, and the work has been carried out by an assessment team from the World Bank in association with the National Economic and Social Development Board (NESDB) of Thailand. In addition, the Canadian International Development Agency (CIDA) provided concurrent indirect support to the assessment team through the funding of an energy policy adviser to the NESDB.

ABSTRACT

An effective energy development program is well within the capacity of the government of Thailand if it is carried out efficiently in cooperation with the private sector. The strategy proposed in this report recommends an expanded role for the private sector not only in the exploration and production of energy but also in its transportation, refining and marketing. To bring this about, the regulatory process governing private involvement in energy activities will need to be improved and a pricing system established that more accurately reflects the opportunity costs of energy resources. In addition, the report recommends (a) expanding the uses for natural gas; (b) formulating a program to expand exploration and development of lignite for power, industry and domestic uses; (c) increasing electricity tariffs to augment internal cash generation at the utilities; (d) deregulating petroleum product prices to allow them to adjust more freely to changes in international prices and the value of the Baht; (e) making institutional reforms to clarify responsibilities and improve long-term planning in the public sector; and (f) formulating new policies to ensure adequate rural energy supplies of both traditional and commercial fuels at competitive and economic prices.

ABBREVIATIONS AND ACRONYMS

BMTA	Bangkok Mass Transit Authority
DED	Defense Energy Department
DMR	Department of Mineral Resources
EGAT	Electricity Generating Authority of Thailand
E&P	Exploration and Production
ICB	International Competitive Bidding
IOC	International Oil Companies
LPG	Liquefied Petroleum Gas
MEA	Metropolitan Electricity Authority
NEA	National Energy Administration
NESDB	National Economic and Social Development Board
OMO	Oil Marketing Operations (PTT)
ONG	Natural Gas Operations Unit (PTT)
PEA	Provincial Electricity Authority
PTT	Petroleum Authority of Thailand
RTG	Royal Thai Government
SRT	State Railways of Thailand
TP	Texas Pacific Oil Company

CURRENCY EQUIVALENTS
(As of December 1984)

1 Baht	=	US$0.037
27 Baht	=	US$1.00

FISCAL YEAR
October 1 to September 30

WEIGHTS AND MEASURES

bbl	Barrels (approximately 6.6 barrels per tonne fuel oil)
bpd	Barrels per day
Bcf	Billion cubic feet (10^9)
BTU	British Thermal Unit - a unit of heat equal to 0.25 k calories
cif	Cost, insurance and freight
mm	Million
mmbbl	Million Barrels
MW	Megawatts
MMCFD	Million cubic feet per day
tcf	Trillion cubic feet (10^{12})
toe	Tonnes oil equivalent (10.415 x 10^6 kcals)
km	kilometers

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MAPS

IBRD 19199: Thailand Ports
IBRD 19200: Provincial Electricity Authority
IBRD 19201: Electricity Generating Authority of Thailand

PREFACE

This report is one in the series undertaken by the Joint UNDP/World Bank Energy Assessment Program. To carry out this work on Thailand, a joint energy assessment team was established between the World Bank and the National Economic and Social Development Board (NESDB) of Thailand. The team executed its work through a series of missions in Thailand between 1983-1985 and a wrap-up mission in Washington, D.C. The team also, through three working groups (related to energy supply and demand), undertook an extensive evaluation of the Thai energy sector with the specific objective of providing support to the formulation of the energy strategy being developed for Thailand's 6th Five Year Plan (1987-91). Members of the working groups were drawn from the private sector, the Thai government and state enterprises, plus NESDB's advisors financed by CIDA World Bank staff and its consultants financed under the UNDP/World Bank Energy Assessment Program met on a number of occasions with these groups to discuss specially prepared working papers.

The following persons formed the World Bank Team at various points in time during the course of this study: Robert Sadove (Team Leader), Trevor Byer, John Tillman, Gary Gaskin, L. Wijetilleke, E. Deffern, T. Fitzgerald, Colin Warren, Ms. Swee-Kheng Koh, J. Boroumand, D.K. Kumar, Y. Albouy, Ms. Helena Ribe, Ernesto Terredo, Fred Temple, and D. Fallen-Bailey.

The NESDB team consisted of Dr. Phisit Pakkasem (Team Leader and Deputy Secretary-General of the NESDB), Anuparb Sunananta (Director, Infrastructure Projects Div.), Piromsakdi Laparojkit (Chief, Energy Planning Section), Piyasvasti Amranand (Chief, Technical Planning Section), Praipol Koomsup (Associate Prof. of Economics, Thammasat Univ.).

The team also was supported by Canadian energy consultants provided through the NESDB and financed by CIDA. These were: Peter Eglington (Chairman, Ottawa Energy Group Ltd.), John Foster (President, EDPRA Consulting Inc.) and Susan Bogach (President, Bogach Associates Ltd.).

The report was written by Robert Sadove and Trevor Byer with contributions made by John Tillman and D. Fallen-Bailey. The report was edited by Maryellen Buchanan.

I. OVERVIEW AND RECOMMENDATIONS

Introduction

1.1 This report outlines the key issues and options to be addressed in formulating a five-year energy strategy for Thailand and the recommended policies and investment program to implement that strategy.

1.2 Over the last two decades, Thailand has been almost totally dependent on imported petroleum for its primary energy requirements. In 1980, imported petroleum accounted for about 70% of the country's total energy needs: hydro providing 3%; coal/lignite, 3%; fuelwood and charcoal, 11%, and bagasse, 7%. The availability of increasing quantities of natural gas since 1981, as well as the rise in the use of lignite in the power and cement sectors, is already having a major structural impact on the energy supply mix and use patterns in the country. Natural gas use has already lowered the share of primary energy supplied by petroleum from 82% in 1970 to some 56% in 1983. This declining trend should continue over the short to medium term as gas and lignite production increase during the rest of this decade. Despite this progress, however, the bill associated with importing some 210,000 bbls/day of petroleum amounted in 1984 to some US$2.5 billion and remains a significant drain on the economy given that it absorbed over one-third of the country's export earnings. In this context, the economy of Thailand has reached the point where an economically sound energy program over the five-year period 1987-91 will be essential to maintain high economic growth rates. This implies continued development of domestic energy resources and expansion of production policies that would ensure the efficient exploitation and use of energy resources. This report proposes policy changes that would make Thailand's economy more efficient and less dependent on imports of energy than under present policies.

1.3 Energy demand for the next five to seven years is projected to grow at about the same rate as GDP (5-6% p.a.), this growth is dependent on a continuation of the current structural adjustment program which encompasses suitable exchange rate policies, promotion of exports, increased domestic energy production, a realignment and reform of domestic energy prices, and reasonable stability in international fuel prices. With appropriate policies, the share of imports in overall energy consumption could decline from 54% in 1982 to 33% in 1991. However, any failure to sustain exploration and development for gas, oil and lignite thereafter could create a need for imported energy again to supply almost 60% of domestic demand, causing a deterioration in the balance of payments and slowing economic growth in the second half of the 1990s.

1.4 An effective energy development program is well within the capacity of the Government of Thailand, if it is carried out effectively in cooperation with the private sector. As far as the public sector is concerned, certain institutional reforms are desirable. Among the numerous agencies and departments responsible for various phases of the government's energy activities, there is a compelling need to clarify responsibilities, eliminate overlapping jurisdictions, improve long-term planning and coordination and establish improved procedures for setting overall sector policies. While most agencies require some strengthening and efficiency improvement, especially on the planning side, none is a bottleneck for implementation of the policies and investment programs being proposed.

1.5 The strategy proposed in this assessment report will require an increased role for the private sector, both local and foreign, in the exploration, production, transportation, refining and marketing of energy. To stimulate such an expansion of the private sector role, the report discusses the following steps in detail:

(a) establishment by government of policy guidelines concerning the areas where increased private sector participation is desired;

(b) improvement of government's private sector regulatory mechanisms; and

(c) deregulation of energy prices.

1.6 Emphasis is placed on the adequacy of incentives to foster private sector investment in the desired areas by modifying relevant policies including royalties, taxes, prices, leasing arrangements, and the legal requirements for establishing joint ventures. Expanded exploration and development of oil, gas and lignite can be encouraged only if greater incentives for the private sector and a more effective regulatory process are established. Better energy demand management in the form of appropriate pricing and proper fuel selection measures also can help in this process; these studies are discussed in specific chapters of the report.

1.7 Essential components of the strategy that needs to be formulated for discussion purposes include:

(a) developing more natural gas by attracting additional private sector participants, improving the regulatory process and establishing a pricing system that more closely reflects opportunity costs;

(b) expanding the uses for natural gas;

(c) formulating program to expand exploration and development of both low quality lignite for power and high quality lignite for industry and domestic use;

(d) increasing electric power tariffs to augment the utilities' internal cash generation; focusing on the expansion program for the next five to ten years in a flexible manner which is more directly related to indigenous resource development programs;

(e) continuing to base the choice of imported petroleum products versus domestic refining on competitive pricing while encouraging private sector investment in any refinery expansion that may be needed at the end of the decade;

(f) deregulating petroleum product prices, thereby ensuring more automatic adjustment of these prices at both the retail and ex-refinery levels as international prices or the value of the Baht undergo change. As a means of achieving this, the elimination of the Oil Stabilization Fund is desirable;

(g) encouraging the more efficient use of the major transport fuels (diesel, gasoline and LPG) by modifying the structure of petroleum product prices at the retail level should be modified to reflect more closely that at the border price level; and

(h) formulating new policies and programs to ensure adequate rural energy supplies by improving the supply and efficiency of using traditional fuels while also more effectively providing rural consumers with access to commercial fuels at competitive and economic prices.

Resources, Institutional Background and Planning

Resources

1.8 In practice it should be possible to increase domestic energy production in a way to sustain economic growth over the next two to three decades. Thailand has a somewhat diversified e- gy resource base, consisting of lignite, hydropower, natural gas, and limited quantities of oil and natural gas liquids. The rural sector still has access to substantial forest resources, although the future of these resources is threatened by continuing rural population increases and pressures to develop agricultural holdings. The lignite potential, although clearly substantial, so far appears to be of average quality and competitive in cost. Hydro resources are substantial, but most are located in border rivers and are not likely to be developed before the end of the century. Thailand has a substantial potential for oil and gas; some 180 million barrels of liquids (crude oil and condensate) and 12,900 billion cubic feet of gas already have been identified to date, out of an ultimate recoverable reserve (URR) estimated at 1,100 million barrels of liquids and 19,000 billion cubic feet of gas. The task of the future therefore is to develop these resources quickly, economically and efficiently so that they can provide an adequate energy base for a rapidly growing modern economy.

Institutions and Planning

1.9 Energy sector institutions in Thailand appear to function adequately in terms of agency-by-agency operations, maintenance and implementation of projects. However, there is some lack of coordination among sector agencies and some areas of overlapping responsibilities. Except for the five-year planning exercise, long-term plans for individual agencies are seldom coordinated, and in many subsectors no one agency has been designated to have overall planning responsibility.

1.10 Although energy institutions can and should be strengthened, they are not the bottleneck which would hold up an expanded energy program. The greatest need is to make them more efficient in planning future programs in a more integrated manner. In oil and gas, the Petroleum Authority of Thailand (PTT) is the dominant public sector body since it is responsible for transporting, processing, purchasing and selling natural gas, but the Department of Mineral Resources (DMR) has responsibility for regulating the oil and gas licensing, exploration and production industry. Its long-term plans are rarely made in coordination with those prepared for the rest of the energy sector except when the Five Year Plan is under preparation.

1.11 In the case of electricity, somewhat better coordination is achieved amongst the three agencies -- EGAT (responsible for most generation and transmission facilities), MEA (for distribution in the Bangkok area) and PEA throughout the rest of the country. For example, despite the involvement of seven government agencies/committees in decision-making on power sector issues, a reasonably good degree of co-ordiniation is achieved within the sector. These agencies/committees are: the Committee for Power Policy and Development; the Budget Bureau; the Tariff Rate Committee; NESDB; the Ministry of Finance; NEA; and the National Debt Committee. These agencies review a large number of issues from tariffs to capital project proposals, budgets for submission to the Council of Ministers, annual financial performance, and requests for government equity and loans. Though none of these bodies has overall policy responsibility for power sector issues, decisions are made to a great extent by the agencies and the three utilities reaching a concensus.

1.12 Energy sector policy and planning functions involve the Cabinet, the National Economic and Social Development Board (NESDB) -- which is under the Office of the Prime Minister -- and NEA. From an administrative standpoint EGAT reports to the Prime Minister's Office, PTT and DMR to the Ministry of Industry, while NEA is under the Ministry of Science, Technology and Energy. Despite this, the energy system works reasonably well in terms of implementing projects, as well as operations and maintenance. Its main weakness is at the overall energy sector policy and planning level, while at the sub-sectoral level these capabilities are much stronger. Sound investment reviews take place in an integrated way on an annual basis, but the one-year horizons for investment review appear too short for overall sectoral planning purposes, particularly in a period when financial and technical constraints have become so severe. Effective energy sector planning and strengthened program coordination within the sector also need to focus on the role of the private sector. There clearly is room for an expanded private sector role in the exploration, production, transport, refining and marketing of energy in Thailand, and to some extent in electric power generation and lignite mining. The private sector's involvement is already strong in the petroleum industry, particularly in oil and gas exploration and production, the import and distribution of oil products, and to a lesser extent, in refining. The private sector has begun to play an increasing role in lignite mining, which is dominated by EGAT's operation of large captive mines of low quality lignite for power use. The private sector also plays a dominant role in the small scale mining of high quality lignite for industrial use as well as in overburden removal at EGAT's Mae Moh mining on a subcontractor basis.

1.13 Opportunities for expanding private participation in energy development and associated changes in state energy roles must be approached carefully so that clear guidelines are formulated to encourage a gradual integration of private activity without unduly disrupting existing patterns of operation. In this process there is a need for the private sector to appraise government more of its views and perspectives. There also is a need to strengthen government machinery in regulating private sector activities in the energy sector and improve coordination between public and private sector activities.

1.14 Possible changes in the state agency roles must be approached cautiously. Energy issues pervade all sectors of the economy and no major activity can be ignored. Too much integration by government agencies may result in domination of a supply-side orientation. Although the major thrust of the energy component of the 6th Five Year Plan emphasized in this report is for increased exploration, production and marketing of energy in Thailand, programs need to be closely related to demand prospects. Given this thrust, what appears to be required in the view of the assessment team is:

(a) better coordination and planning between public sector entities;

(b) clear guidelines regarding policy to be provided by the government, especially concerning those areas in which increased private sector activity is called for;

(c) the need for the private sector to appraise government more effectively of its views and perspectives; and

(d) improved government machinery to regulate enhanced private sector activities in the energy sector and facilitate better coordination between public and private sector entities.

1.15 The government can do much to increase the production and efficient use of energy by focusing its policy tools more specifically on production and use objectives. Energy demand management can be used more effectively to achieve greater efficiency in energy use both through appropriate pricing and conservation incentives. Expanded exploration and development of oil, gas and lignite are being examined with new approaches to production and institutional arrangements based on better incentives for the private sector and a more effective regulatory process. The uncertainties regarding gas and lignite availability and future power demand have lead to a reexamination of the planning policies used in determining least cost investment programs. Current policies are now being designed to base programs more on minimizing the cost of energy production and in turn optimizing the timing of investments.

Formulating a Government Energy Strategy

The Role of Pricing

1.16 At this time pricing should be the starting point in formulating an energy strategy in Thailand because prices are a major factor in most of the decisions that need to be taken regarding fuel supply and use, and some serious distortions already exist. The basis for pricing used in the report is that energy prices should be set at least at the level of their opportunity costs to encourage optimal investment decisions from the national standpoint. Perhaps the most critical area of pricing policy involves the level and structure of retail and ex-refinery petroleum prices. In the case of tradeable goods such as petroleum products, their opportunity costs are the import parity (c.i.f.) prices in Bangkok for those products that are in deficit (primarily diesel oil), while for those products in surplus (natural gas condensate/gasoline and increasingly fuel oil) they are their f.o.b. (export) prices. Since Singapore is the major regional trading center for petroleum products import parity prices in Bangkok are likely to reflect their f.o.b. Singapore price plus freights while for products in surplus, export prices may have to be close to or somewhat below those in Singapore to clear the market.

1.17 Petroleum Product Prices. Prior to the November 1984 devaluation the retail value of the reconstituted barrel of petroleum products consumed in Thailand was about 46% above the import price level. This retail value of the reconstituted barrel, of course, included all margins to distributors as well as government tax take. When account is taken of the former, this level of weighted average retail prices was roughly in line with general tax levels. However, as retail prices of petroleum product were not adjusted since the devaluation, the retail value of the reconstituted barrel of consumed products has declined, reaching a level of only 22% above that of the weighted average import price in February 1985. Since then world oil prices have continued their slow decline 1/, resulting in the weighted average import product price in June 1985 falling by about 9%. This meant that as of June 1985 the retail value of the reconstituted barrel of consumed products had risen to about 31% above that of the weighted average import price. Since there is, however, the need for additional government revenue, steps should be taken to adjust the overall level of retail product prices upwards so that their weighted average price would be around 40% above that at the border. This measure would increase government revenue by about 2.5 billion Baht to a total of around 19 billion Baht from petroleum product taxes.

1.18 The disproportionate level of taxation on gasoline has introduced major distortions into the structure of retail prices relative to border prices. This has resulted in an uneconomic shift to diesel oil use in transport, especially for light trucks/pick-ups. This report suggests specific ideas on how to eliminate some of the distortions in petroleum product prices. A new structure of retail petroleum product prices should be set which is closer to the structure of border prices so as to ensure a more economic pattern of use especially for the major transport fuels -- diesel oil, gasoline and CPG. In effecting these changes, the following are of relevance:

(a) retail prices for automotive diesel oil are low relative to gasoline -- the differential between retail premium gasoline and automotive diesel prices should be reduced from its present level of 5 Baht/liter to about 3 Baht/liter.

(b) retail prices of LPG are low relative to those of gasoline -- the differential between the retail prices of premium gasoline and LPG should be reduced from its current level of 6.3 Baht/liter to about 4.6 Baht/liter.

The current retail price structure of petroleum products along with that proposed by the Assessment Team and their relevant border prices are shown below:

1/ This being more pronounced for diesel oil and fuel oil.

Product	Border Prices as of Feb. 1985 a/	Present Retail Price Structure	Recommended Retail Prices
	---------------Baht/liter---------------		
LPG	4.674	5.38	6.4
Premium Gasoline	6.245	11.70	11.0
Regular Gasoline	5.706	10.80	10.1
Kerosene	6.073	6.12	7.9
Auto. Diesel Oil	5.808	6.70	8.1
Resid. Fuel Oil	4.853	4.09	5.5

a/ As of June 1985 gasoline border prices had declined by about 2% relative to February 1985 and kerosene, diesel oil and fuel oil border prices by between 7-12%.

To effect such a change in the structure of retail prices would require raising the level of taxes on diesel, kerosene, LPG and fuel oil. At the same time an effort needs to be made to ensure that imported "boiler" fuels such as fuel oil and coal are taxed equally. The cumulative effect of adopting the above retail price structure would be to lower the foreign exchange cost of supplying LPG, diesel oil and gasoline by about US$1.2 billion between 1986-95 or about 5-10% of the estimated balance of payments current account deficit.

1.19 The Oil Fund. The Fund initially was established to stabilize the domestic effects of large short-run movements in international oil prices. This now appears to be a secondary role, as the Fund has become a discretionary mechanism to delay retail price adjustments to devaluations or changes in international oil prices as well as a mechanism to cross-subsidize petroleum products. The result has been further encouragement of uneconomic fuel substitution. The Fund also has become costly in terms of government expenditure in that cross subsidies currently exist for LPG, kerosene, diesel oil and fuel oil which, if sustained through 1985, could amount to about 1/2% of GDP (5 billion Baht). The assessment team recommends that the government adopt a policy objective to abolish the Fund and in its place establish a mechanism to link retail prices to international border prices while automatically reflecting changes in exchange rates.

1.20 Ex-Refinery Prices. Appropriate ex-refinery prices are a critical instrument for maintaining a competitive environment for refinery operators. Before the November 1984 devaluation, ex-refinery prices were consistently below or equal to the c.i.f. level of directly imported products. However, since then ex-refinery prices for most products have been higher than those of direct imports. The assessment team recommends that ex-refinery prices be set at levels competitive with those of directly imported products even if this leads to temporary financial losses in the refinery sector because of the prevailing level of international product prices relative to crude prices. Adherence to this policy at present and over the medium term would ensure:

(a) that the country enjoys the benefits of very competitively priced internationally traded products which have resulted from excess refining capacity in the region and worldwide; and

(b) decisions made in the late 1980s concerning investments in refineries would result in a more economically efficient and competitive industrv.

Natural Gas Prices and Development of the Gas Industry

1.21 Pricing is one of the most important tools for fostering the exploration and development of natural gas. In fact, the absence of any accepted international reference point for determining gas prices to the producers in Thailand is a major deterrent to further exploration and has caused protracted delays in negotiations. Clear guidelines on the pricing of gas to producers and consumers need to be established immediately. One possible option for such a system could contain the following key features:

(a) a clear signal to producers and consumers regarding current and future principles for pricing natural gas;

(b) the pricing system adopted must possess a high degree of transparency so that producers and consumers are able to determine well-head prices and plant-gate prices respectively, given a Basing Point Price for gas in Bangkok;

(c) the gas price at the Basing Point must be directly linked to the international prices of competing fuels, expressed as a percentage (y%) of the fuel oil price in Singapore (plus freight costs to Bangkok); the report refers to this percentage as the "discount parameter";

(d) to address short term movements, the Basing Point Price should be adjusted quarterly to follow the behavior of the fuel oil price in Singapore, over the preceding 90-day period;

(e) every few years, the government should adjust the "discount parameter" in order to reflect the medium term changes in the opportunity cost of gas between fuel oil and coal parity;

(f) in order to simplify and give transparency to the system, it is important that the gas transport cost be established clearly. In establishing the cost (or price for .ommon carrier systems), the guiding principle would be a reasonable return on investment to the pipeline owner. The cost will also depend on the volume, load factor, distance and interruptibility of the gas being transmitted.

(g) that government should implement the above system concurrently with a revised tax and royalty system so that government takes its benefits through royalty and income tax on gas production based on profits measured at the well head.

1.22 The report places great emphasis on gas prices for the power sector, as the power sector is the most important user of gas in Thailand and would remain so until the end of the century. 2/ The recently negotiated gas price to EGAT (US$3.20/MMBTU) is close to the estimated equivalent value for gas used in a comparable steam unit fueled by coal at today's prices. This latter value (the so-called "coal parity") is currently calculated to be US$3.14/MMBTU and might be thought of as the floor price for gas used in the power sector (it is also currently about 90% of the fuel oil equivalent price). The assessment team recommends pricing gas to EGAT close to its current floor price over the next several years in order to make gas competitive.

Pricing Imported Coal

1.23 According to pricing projections in the world market, imported coal may be expected to play a growing role as a fuel in the cement industry and, by the mid-1990s, in the power sector. Coal's primary competitor in the cement sector is high grade lignite which, with natural gas, already has displaced most of the fuel oil consumed in this industry. Under current government policy a 10% import duty is levied on imported coal; therefore to ensure equal tax treatment with other imported "boiler" fuels, the assessment team recommends a similar import duty/excise tax be applied on fuel oil.

Pricing Electric Power

1.24 Pricing electric power is particularly important in generating sufficient resources to finance investment. The present tariff structure provides a mechanism of cross-subsidization in which higher electric rates apply in urban areas and industry subsidizes rural and household consumers. The government policy of uniform national tariffs has led to some economic distortion, but a more important problem concerns the generation of resources to finance investment. Large rate increases were introduced in 1981 and 1982 which went a long way towards restoring a relatively healthy financial situation in the subsector; however, 1983 tariff reductions caused a setback in this progress. The projected cash generation ratio and the return on revalued assets for 1985-86 is not expected to be particularly robust. A general increase in rates is warranted, and there are some serious problems with the rate structures. Cross subsidies from commercial to residential customers need to be reduced. As PEA tariffs are about the same as MEA's in spite of

2/ Power sector use of gas would account for between 70-80% of total gas utilization over this period.

substantial cost differences, regional cross subsidies also exist which are questionable, at least for the largest consumers. Apart from these major changes, some improvements in tariff design should be considered which could shift demand away from the peak period.

1.25 More generally, lessons should be drawn from peak load pricing which can quickly be put into effect for several large industrial consumers and more options involving direct control of the loads of small, medium and large consumers should be investigated since peaking costs are still high, i.e., more than US¢12/kWh for PEA low voltage service. More research into the opportunities for managing the industrial and commercial loads will be useful in shaping the high and long duration of the daily load plateau and in assessing its increasing sensitivity to climatic conditions.

Developing Indigenous Primary Energy Resources

Optimizing Future Uses of Lignite

1.26 Lignite will play an increasingly critical role in meeting base load power requirements over the next ten years. Current estimates of the opportunity cost of lignite at the Mae Moh mine 3/ show it to be close to the transfer price between EGAT's mining and generation departments. The depletion premium is estimated to be low due to the uncertainties regarding the size of reserves, future mining costs, and estimates of replacement fuel costs (essentially imported coal) at the time the reserves can no longer be committed for new capacity. Hence, the opportunity costs of lignite as now used in power generation are close to mining costs. The assessment team therefore recommends that lignite for the power sector should continue to be priced at its opportunity cost. In the case of high quality lignite used in the industrial sector (particularly that of cement), prices are set by the competition relative to fuel oil, coal and natural gas and hence are closely market related.

1.27 Unlike oil and gas exploration and development where the international oil companies play the lead role, in the case of lignite EGAT plays the major role in exploration and development activities. The local private sector has begun playing an increasingly significant role in the lignite industry. First, as a subcontractor to EGAT at the Mae Moh mine for the removal of overburden and secondly, as the supplier of high-quality lignite to industrial users, among which the cement sector has become very important.

3/ Calorific value of Mai Moh lignite of 4,900 Btu/lb.

1.28 In the assessment team's view the current level of lignite exploration activity in Thailand (about US$2 million a year) is too low for the period of the Sixth Plan and should be expanded. In addition, there should be a program:

(a) to increase the efficiency of overall mining activities and strengthen the mining industry as a whole;

(b) of measures to facilitate the penetration of high grade lignite use outside of the power sector which, inter alia, requires the identification and development of additional mines having better quality lignite than Mae Moh; and

(c) to ensure that the private sector role is enhanced where it is efficient to do so. This could have the desirable effect of limiting the scale of increases in public sector borrowing required as the sector expands over the next decade. Two specific options could be evaluated. Under the first, EGAT would maintain sole control for mining <u>low grade lignite</u> for captive use at mine-month power stations, while at the same time form a joint venture company with private mining concerns to explore for, develop and market <u>high grade lignite</u> for industrial uses. Under the second option, a single major joint venture company would be formed, using the lignite department of EGAT as a base, to undertake exploration and mining of high and low grade lignite for use in the non-power and power market.

<u>Refinery Expansion</u>

1.29 In the past Thai refineries have supplied nearly three-fourths of the country's petroleum product requirements; the rest were covered by imports. However, the refineries' product yield pattern emphasizes middle distillates and fuel oil so that product imports are heavily skewed (60%) towards diesel oil. The imbalance between product yields at the refineries and product demand is due to:

(a) the uneconomic stimulus to diesel demand in transport provided by retail pricing policies;

(b) the increasing amounts of natural gas that are substituting for fuel oil, thereby eroding the market share of an important petroleum product; and

(c) the very limited processing flexibility in the refining sector to modify product yield patterns. This flexibility is limited to an 8,800 bbls/day fluid catalytic cracker (FCC) and a 12,000 bbls/day visbreaker, both located in the TORC refinery.

1.30 If current plans to expand Esso's hydroskimming refinery and rehabilitate the Bangchak refinery are implemented and the TORC refinery retains its current capacity and complexity, by 1990 net product imports should have declined to about three-fourths of their 1984 level, although diesel oil imports would be about the same as in 1984. At the same time the government would need to restructure the retail prices of petroleum products, as recommended above, to stimulate economic fuel choices, and have the three refineries run on light feedstocks, including condensates and allow the Bangchak refinery access to very competitively priced Sirikit crude.

Oil and Gas Exploration and Development

1.31 Because the oil and gas fields that have been discovered so far in Thailand are geologically complex and much broken up by geological faults, larger numbers of wells are needed to develop any one discovery, and individual well recoveries are relatively low. Furthermore, the fields themselves are subject to relatively rapid declines once they have reached peak production, and over time, many small oil and gas fields are likely to be found rather than a few large ones. All of this means that in order to maintain a given level of production, a steady, continual pace of exploration is needed, and the investment per unit of production will be higher in Thailand than in other countries. The legal and fiscal system governing the oil industry must take account of these factors if the stop-and-go character of past exploration activity is to be replaced with steady progress in producing oil and gas.

1.32 Appropriate government policies are needed to encourage more rapid conclusion of the contracting process governing the exploration and development activities of the private oil companies. Unless the contracting process can be simplified and speeded up, there is an imminent danger that exploration activity will decline (especially when combined with weak international oil prices) and that discoveries will not be brought on stream fast enough, leading to:

(a) a serious underutilization of downstream investments in pipelines and gas recovery facilities;

(b) significant financial and economic losses to government due to delayed or foregone revenues and economic benefits (in terms of oil import displacement); and

(c) severe financial penalties for the private operators who would be unable to quickly recover their exploration costs.

1.33 To avoid the anticipated declines in gas and condensate production capability levels from existing contracts, the team recommends that the government satisfactorily conclude current negotiations with companies regarding the development of discoveries already made. This would address the short- to medium-term problem. Second, in order to accelerate exploration activity, incentives and policies will have to be improved and better focused.

1.34 The legislation/regulations governing oil and gas activity need to reflect the high costs of production in Thailand relative to major oil/gas producing areas of the world. In addition, there is a need to reassess incentives for the oil industry while keeping them consistent with national interests, particularly if the current period of weak oil prices persists over the medium term. The assessment team recommends the following modifications to the legislative/fiscal regime:

(a) Royalty - payments should be graduated according to the size of fields, with smaller fields paying a lower rate;

(b) U.S. Tax Compatibility - minor changes are needed in the current taxation to ensure compatibility with US tax regimes;

(c) Abandonment of the 1982 DMR Requirements - these should cease to be applied as they provide severe limits on the costs which can be offset against income, such that taxable profits in the early years are higher than in most countries. In addition, the regulations provide for steep increases in royalties unrelated to likely profits;

(d) Joint Ventures and Participation - DMR regulations should specify inclusion of a joint venture option for a Thai oil company for all new concessions, which would become effective upon establishment of a commercial discovery;

(e) Other Legal Aspects - these include obligations to produce; the length of exploration and promotion periods; relinquishments; and confidentiality provisions, which are extreme by international standards.

Power System Development

1.35 The development of the power system has been closely related to the expansion in primary energy. It has also been particularly capital intensive and a major burden on the financial resources available to the country. The power system has sustained very rapid growth for more than twenty-five years, averaging more than 15% a year. During this time installed capacity has increased from 176 MW in 1960 to 6155 MW in 1985. Since 1980 there has been a substantial substitution away from fuel oil with consumption declining from a peak of 2,500,000 toe to 1,800,000 toe. Natural gas consumption in the power sector reached 149 MMCFD in 1983 and lignite consumption increased from 93,000 tons in 1960 to 1.6 million tons. The future, however, is clouded by pending shortages of these domestically produced resources. Unless the gas or lignite programs can be further expedited to produce more fuel for power generation, substantial imports of coal and fuel oil will be required for power use by the mid to late 1990s.

1.36 The official electricity demand projections for Thailand prepared by the Working Group in September 1984 show a long run average growth rate of about 6.8% p.a. through the year 2001. NESDB projections based on the Siam II Model indicate likely growth in demand of 11.1% p.a. during the fifth plan period (1982-86), 6.9% between 1987-1991, 5.7% between 1991 and 1966, and 5.2% between 1996 and 2001. Upward changes in this load forecast are not unlikely and would require significant adjustments in EGAT's future program. As in the assessment team's high demand scenario, a 1% difference in the demand growth rate could translate into a peak generation requirement difference of 1500 MW in 1996 -- 15% higher than with the EGAT projection. Coping with demand uncertainty will be one of the most difficult issues facing the sector. It requires reducing construction lead times for all plants through site study/preparation and design standardization. It may also influence the fuel choices.

1.37 According to EGAT planning, by the end of the sixth plan period gas and lignite 4/ available for power will be fully developed. However, it is dangerous to rule out the gas option completely for the period after 1992/93 since it is recognized that more gas supply than now projected could be available if large reserves are rapidly proven and developed. Therefore, flexibility must be incorporated into EGAT's planning decisions and commitments so that, if and when gas becomes available around current price levels, it could be used for power generation. Since analysis shows that EGAT will need to build over 2000 MW of capacity additions between 1993 and 1996 and alternatives to gas are available, decisions can be taken in stages.

1.38 Gas is ruled out of the first decision stage, around 1985-86. Plants for 1994 and after, -- the second decision stage around 1987-88 -- could reopen this issue. In case a higher gas supply variant materializes, perhaps an additional 300 MW combined cycle unit could be commissioned. Such a plant would represent a small addition to the system so it could be inserted almost at any time and no opportunity would be lost in deferring this additional commitment until more is known about gas development.

1.39 The choice of combined cycle units is not only dictated by its short construction lead time but also by its higher efficiency and lower investment cost which maximize the netback value of gas in the expansion of power generation. This preference for combined cycle units extends naturally to the development of a core program based on firmly available resources and a lower demand scenario.

4/ Unless the 200 million tons of lignite reserves at Mae Moh currently sterilized by Units 1-3 were to be developed following de-commissioning of these units. This reserve would provide about 1700 MW of additional capacity equivalent to about four years demand growth at that time.

1.40 The use of dual-fired (fuel oil/gas) steam capacity in the power system was valuable at the beginning in accelerating the development of a gas market at its infancy. It also provided flexibility to burn fuel oil in the event that gas did not become available. This has resulted in EGAT having, by end 1986, some 2400 MW of dual fired fuel oil/gas steam capacity which will remain in the system for another 10-20 years. The leap to triple-fired (oil/gas/coal) units is only exceptionally justified, as is the case for Bank Pakong #3 and 4, because the site is convenient for both coal and gas supply and the commissioning dates (1991-93) at a stage when gas production could either enter its decline or its renaissance.

1.41 The issue in the development of coal-fired capacity is to defer this massive investment as much as possible. The use of efficient combined cycles commissioned at short notice, for the major part of the incremental gas available for power is a good strategy. Triple-fired units also exceptionally will achieve that purpose if some heavy coal related investments can be deferred at the plant site.

1.42 Reserve capacity margins are also a source of investment costs. Whether the present EGAT's reserve criteria are too cautious depends very much on the performance of the plants to be commissioned and generally on the quality of EGAT's operation planning and maintenance. This subject deserves more attention and so does the optimization of the reserve criteria based on a study of the economic cost of power outages.

Rural Energy Issues and the Role of Modern Fuels

1.43 Rural life in Thailand has been undergoing dramatic changes over the past two decades involving a shift away from a self-sufficient, subsistence agrarian economy based on renewable energy to one which is becoming technologically, economically and culturally focused on commercial production for larger markets. The high rate of increase in rural incomes associated with this growth has unleashed new expenditure patterns and life styles, which in turn have increased the demand for commercial energy sources in transport and residential uses. The growth in electricity and LPG use in rural households therefore can be expected to accelerate in the future. By the year 2000, 35-45% of rural households are expected to be using LPG.

1.44 Fuelwood shortages and serious environmental problems are beginning to occur in certain areas, although the fuelwood supply problem is not yet critical, and substantial areas of natural forests are still accessible in many parts of the country. Forest depletion rates have exceeded sustainable levels and give cause for concern for the future. Continued demand for fuelwood at current rates already has put a strain on the accessible forests and resulted in deforestation in large areas, such as Central Thailand. The combination of fuelwood collection, agricultural expansion, commercial fellings, shifting cultivation, and the effects of urbanization have reduced the country's forested land area from 27 to 16 million hectares over the last 25 years. By 2001 the area is likely to be less than 11 million hectares if current trends continue. The total sustainable supply of fuelwood in 1983 is estimated to be about 15.5 million m^3, which compares with the 1983 consumption level of about 39 million m^3, including urban demand (Table 8.2). The nearly 23 million m^3 deficit is met by overcutting of the forests. By 2001 potential demand could increase to a level of 50 million cubic meters while the sustainable supply would decline to about 13.9 million m^3 leaving a deficit of about 36 million m^3. Although these numbers have a margin of uncertainty, there can be no disagreement on the direction of the trend and the nature of its potential impact. If unchecked, the excessive exploitation of natural forests could quickly lead to environmental damage, fuelwood shortages and a decline of agricultural productivity in many areas.

1.45 Over the next twenty years, the various economic factors affecting rural energy demand and the decline in natural forest resources will result in a growing deficit of fuelwood. Whether the situation will lead to a faster shift to modern fuels than assumed is a question that has an impact on the supply strategy that needs to be adopted. The present structure of prices (Table 8.4) shows clearly that fuelwood-derived energy is in some cases a less expensive option to consumers and that the process of large-scale switching to modern fuels in rural areas would involve a high cost to rural households. Since as much as 25% of rural income may be spent for energy, maintaining fuelwood supplies may be the least cost approach to meeting many of the rural household cooking needs whenever fuelwood supplies can be planted close to consumers. Charcoal produced from wood from a nearby plantation can provide cooking energy, allowing for differing end use efficiencies, at Baht 1.0 per useful Kcal compared with Baht 2.2-3.3 for LPG and a LRMC of Baht 5.0 for electric rice cookers. The essence of the rural energy strategy needs to combine two objectives -- that of improving the supply and efficiency of using traditional cooking fuels while at the same time efficiently providing rural consumers with access to commercial fuels at competitive and economic prices.

Energy Efficiency Programs

1.46 Increases in petroleum and electricity prices between 1979-82 have encouraged the Thai manufacturing sector to undertake important initiatives to use energy more efficiently: for example, in the non-metallic minerals subsector (in particular, cement) a major switch from fuel oil to cheaper lignite, coal and gas use began in this period. Added to this total, energy intensity also fell between 1979-82 by about 14%, indicating that some significant operational improvements had been made by cement operators. The need for these improvements is driven by the fact that energy accounts for 30% of production costs in this industry.

1.47 In addition to pricing policies, government action also is needed to implement an effective energy efficiency strategy for the manufacturing sector:

(a) to identify and eliminate fiscal and financial constraints to private sector adoption of higher efficiency measures; and

(b) to assist in ensuring that the private sector is fully aware of the opportunities for cost effective measures (housekeeping, retrofitting and new equipment). Publicly sponsored demonstration projects in selected subsectors would go a long way towards removing any remaining apprehensions about the commercial viability of investments to increase energy efficiency. Specific short and long term measures which should form the core of government's energy efficiency program are detailed in this report.

1.48 As transport consumed about 60% of petroleum products in 1983, it is clear that improving the efficiency of petroleum use is primarily a transport issue in Thailand. Here again the pricing policy for petroleum products is a key issue. Past policies have stimulated an uneconomic substitution of diesel fuel for gasoline in light trucks/pick-ups and the team has recommended modifications to this policy. There also is the perennial problem of traffic congestion in Bangkok leading to low fuel use efficiencies. Most measures undertaken to relieve this problem have had limited impact due to the continued rapid growth in vehicular traffic. The team considers that further, efficiency-conscious investment in roads and public transport will be imperative as will be tighter management of traffic demand.

Investment Strategy

1.49 As the level of public sector investment in the energy sector has been rising substantially in recent years, it will be important to keep it both under control and in line with the country's growth objectives during the Sixth Plan. The programs suggested in the various chapters imply a level of investment to develop, produce and distribute energy which is probably higher than for any previous five-year period in the country's history. Except for oil company activities in oil and gas, most of the responsibility for this rising investment has been with the public sector energy enterprises. A primary concern of the government will have to be to find ways to reduce this level and establish the highest priorities consistent with the national economic framework. Determining the priorities is made complex by the fact that responsibility for energy investments is shared among several agencies, namely, PTT, EGAT, MEA, PEA, BCP and DED, as well as a number of joint companies such as TORC. Judgments regarding priorities are also difficult in that investment priorities often have been determined by the availability of funds. Furthermore, as government policy is strongly encouraging investment by the private sector, priorities must be weighed more effectively within in the context of total investment.

1.50 The overall energy investment strategy will not change substantially. The current strategy emphasizes minimizing public sector investment and operating cost levels, particularly by maximizing the use of gas and employing capital-intensive technologies. In practice this has proven especially difficult because of uncertainties about the timing and amount of gas which might be available on the one hand, and the amount of alternative resources that might be developed on the other. Uncertainties regarding the price and availability of imported fuels also have complicated matters. For the next few years this situation probably will not change. However, by expanding the private sector role and given the projected continuation of relative ease in the world energy picture, the level of public sector investment can be lowered (Chapter V).

1.51 The economic environment in which the Sixth Plan is being formulated places severe constraints on financing public investment and this factor is reinforcing a review of the role of each public sector energy agency. For example, substantial attention is being given to redefining and focusing the large role of PTT in investments related to upstream and downstream activities in oil and gas. Similarly, the role of the public sector in future refinery investments should be assessed. Suggestions have been put forth which might promote lignite activities in the private sector as well as foster additional contributions of private equity for EGAT. Joint ventures already have begun as a promising means of expanding private sector participation in oil and gas, and in lignite.

1.52 The burden of imported energy supplies and the discovery of new domestic gas resources undoubtedly will continue to justify large capital spending for the energy sector. Energy will continue to be the single most important sector for public spending. Energy sector capital spending already weighs particularly heavily in total public investment, averaging 24% during the fifth plan period. Energy sector enterprises in recent years have accounted for more than 50% of state enterprise investment. The power sector agencies have contributed the bulk of these investments. In the past, large amounts of this capital investment have been financed by foreign borrowing. Increasing the internal generation of cash by the various energy enterprises will be an absolute requirement of any energy strategy.

1.53 Since the Sixth Plan has not yet been formulated, it is too early to judge the size of proposed energy investments or their share of macroeconomic requirements. Preliminary estimates in Table 1.1 show that with a modest change in growth assumptions, investment requirements could increase by nearly $3 billion. Additional variations in potential investment levels by the private sector are indicated below (para. 1.56). Variations attributable to changes in relative priorities over the decade could add to or subtract from these figures.

Table 1.1: PROJECTED PUBLIC SECTOR ENERGY INVESTMENT, 1987 - 1991
(US$ Million)

Sector/Program	Currently Proposed Projects	Increases Due to Projects Based on High Growth Scenario a/
Electric Power		
Hydro Electric Projects	369	-
Thermal Power Plants	2,406	1,500
EGAT Transmissions	495	345
MEA	465	325
PEA	275	125
	4,010	2,295
PTT Projects		
Pipelines	365	160
Exploration and Development	154	345
Marketing	63	-
Gas Separation	60	-
Refineries	234	-
Misc.	30	45
	906	550
Lignite Mining	578	125
Rural Energy Programs	100	-
Energy Efficiency Program	25	-
Total	5,620	2,970

a/ Assume additional 1500 MW power required as outlined in Chapter V. TORC refinery investment based on latest figures available. Lignite mining investment based on EGAT, July 15, 1985 reports. It is assumed a significant part of the increase could be financed by private equity.

1.54 The approach to public sector investment followed in this report, starts with a "core" investment strategy, based on that level which must be met to satisfy the needs of the projected GNP but will not be so low as to constrain growth in energy in the period following the Sixth Plan. A micro-economic review of the current investment proposals submitted by the individual energy agencies indicates that most of the projects these agencies are considering would need to appear in some form in any core program (Table 1.1). However, some might be in the private sector. Furthermore, since many of these investments represent longer term programs, they have not yet been formally evaluated by NESDB and represent only a list of promising projects from which the responsible agencies will need to carry out feasibility studies, evaluate resource requirements and relate the projects to national priorities. The core program, at this time, is still a collection of projects at varying stages of identification and preparation. Summing up these lists of projects provides a core investment program varying from as low as $4.5 billion to as high as $5.6 billion.

1.55 The government's strategy of making greater use of the private sector in developing indigenous energy resources could succeed not only in keeping the level down but also tailoring the priority of public investments more closely to scarce resources. The fact that the projects in the public sector that now appear most favored by the agencies involved would total close to $5.6 billion should give a clear signal that careful control of public sector expenditures will be at the heart of the energy strategy.

1.56 In quantitative terms the potential of the private sector can be very large. If a higher gas scenario can be achieved, for example, then the cost of the future power program can be reduced considerably. If proper incentives are created, the private sector could provide about $1.3 billion during the years 1987-91, of which about 20% would be for exploration (medium case scenario). Higher figures have been proposed by various members of the study group. Once the process of privatization begins in earnest, there is a consensus in the group that much higher investment expenditure levels over the decade of the 1990s will be possible -- around $6 billion in an optimistic scenario, or $3.5 billion in a medium scenario.

II. AN ENERGY PERSPECTIVE FOR THE SIXTH PLAN PERIOD

Introduction

2.1 These are difficult times to put into effect an expansive energy strategy, particularly one that is dependent upon rapid development of indigenous resources. Long-term price and supply uncertainties have hardly diminished despite the recent decline in world energy prices. The financial outlook for the world economy is still not particularly optimistic.

2.2 Exploration and development of oil, gas and lignite is such a costly and risky operation that the role of the State in this effort in Thailand is being reassessed for the sixth plan period. It is proposed that greater use might be made of private sector resources and market-oriented decision-making. Many of the policy options discussed in this report are intended to create an environment which would allow the private sector to supplement better the activities that the public sector has monopolized in the past. If equity investments are to become a more important factor in the energy sector in Thailand, and this is the government's stated goal, a more realistic incentive system will need to be created; the burden of an outdated legislative and regulatory process alleviated; price distortions eliminated; and the demand management system liberalized. It is possible that domestic energy production could be raised substantially, energy could be used more efficiently, and the level of public investment could be kept to a modest level that would be sustainable for the rest of this decade. The success of the energy strategy that is being formulated for the sixth plan period will depend on how these issues are addressed. If the plan is successful, it may be possible to avoid another energy crisis and associated high levels of imports that appear to to be on the horizon for the mid-1990s.

Macroeconomic Background

2.3 The economic background for the sixth plan period is an outlook of somewhat slower growth, with a greater emphasis on exports. Energy imports are to be held in check. The economy, which sustained one of the highest growth rates in per capita incomes among developing countries between 1960 and 1980, probably will grow more slowly. Although its reliance on traditional agriculture would still continue, the expansion would be led by additional intensification and mechanization in agriculture, a modest growth in modern industrial and service sector activities, and a broad strengthening of transport and communication facilities throughout the country. GDP growth would continue at about 5.5% a year, which is well below the 7-8% achieved during the 1960s and 1970s.

2.4 In this atmosphere energy consumption, which was stalled at the beginning of this decade, would begin to grow again, although not at the rapid pace of the 1970s. For nearly 25 years rapid GNP growth was accompanied by an even faster growth in energy consumption, increasing from about 1.6 million tons of oil equivalent (toe) in 1960 to around 18 million toe in 1983. 5/ During the seventies the share of energy imports in commercial energy averaged about 90%. Only since 1982 has this dependence on oil imports declined somewhat as a result of modest increases in the domestic production of natural gas, lignite and crude oil. In 1983, imported petroleum still accounted for nearly 75% of commercial energy. The import bill for petroleum that year represented 25% of total imports and absorbed 39% of the economy's export earnings.

2.5 Because of this heavy reliance on imported oil, the Thai economy suffered severely from the two oil price shocks of the 1970s and the ensuing international economic upheavals. The effects of the first oil shock were partially hidden for several years because world inflation in commodity prices temporarily offset the impact of the oil price increase on the balance of payments. Furthermore, the government's conservative fiscal policies at that time helped to keep domestic inflationary pressures under control.

2.6 In the second half of the 1970s, expansionary policies encouraged continued high rates of economic growth but resulted in accelerating inflation, a quickly deteriorating external balance, a rapidly growing savings-investment gap -- particularly in the public sector -- and increased reliance on foreign borrowing. In order to limit domestic inflation and reduce the external imbalances, the government imposed price controls on selected items. By failing to adjust domestic energy prices to the sharp increases in oil costs, the transition to an energy scarcity situation was delayed. The second oil price shock and the effects of the severe worldwide recession that followed therefore hit Thailand at a time when its economy was already deteriorating. The government at first was slow in responding to these adverse external conditions but by late 1980, several policy adjustments were made which effected substantial increases in electricity tariffs and in the price of most petroleum products by early 1982. At this time, growth in petroleum product consumption ceased, both as a response to these price increases and to the increasing availability of natural gas. The average growth rate of GDP continued to fall short of historical growth (about 5% p.a. during 1982-84) due the high interest rates at home and abroad, the continuing worldwide recession, and weak exports.

5/ Per capita energy consumption rose from 59 kgoe in 1960 to 296 kgoe in 1983.

Evolution of the Energy Sector

2.7 The social and economic transformation of the Thai economy over the past 25 years has resulted in higher per capita incomes. This in turn led to increased use of energy intensive appliances such as automobiles and air conditioners, which account for much of the rapid growth in energy consumption during the 1960s and 1970s. How much of this growth in energy consumption can be attributed to the low domestic energy prices is difficult to measure. However, it is clear that most of this growth was met by rapidly expanding energy imports which, by 1978, accounted for 21% of total imports. After the second oil shock, the share of energy in Thailand's total imports increased to 31%, while 45% of the economy's export earnings were required to finance energy imports (1980 data). This level has been reduced only slightly in recent years.

2.8 The role of traditional fuels in the energy supply picture has been declining. Estimates prepared for the World Bank Rural Energy Assessment 6/ indicate that in 1982 traditional fuels provided only about one-third of the final energy consumed in Thailand. One fourth of the traditional fuels consumed is attributed to industry -- principally bagasse used in sugar mills. Most of the rest is consumed by households. Charcoal accounts for about 16%, followed by fuelwood (12%), bagasse (7%), and paddy husk (4%).

2.9 Until 1981, almost all crude and petroleum products consumed in Thailand were imported. In that year indigenous resources met only 11% of commercial energy demand, with hydroelectric power and lignite accounting for three quarters of domestic supplies. With the advent of natural gas production, by 1983 the share of petroleum products in commercial energy consumption fell to 75%. Domestic resources (25% of commercial energy) came mostly from natural gas (10%) and hydropower (7%), and the rest from crude oil (5%) and lignite (3%). Electricity generation absorbed the bulk (98%) of natural gas production. With respect to final consumption of commercial energy, petroleum products accounted for 85% (diesel 44%; gasoline 19%; fuel oil 16%, jet fuel 11%; LPG 6% and kerosene 5%), electricity 13%, and coal/lignite 2%. (Annex 1).

Economic Projections for Energy and the Economy

2.10 If government policies are properly structured, prospects are favorable for developing indigenous energy during the remaining years of this decade. The most likely scenario for domestic crude and natural gas

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6/ World Bank Rural Energy Assessment, Report No. 044/85, September 1985.

production indicates the share of imports in overall energy consumption would decline from 54% in 1982 to 33% in 1991. However, after 1995 the volume of energy imports may start to rise again -- at first moderately, but the pace quickens towards the end of the 1990s. If nothing is done to sustain exploration for gas, oil and lignite by the year 2001, imported energy is expected to again provide almost 60% of domestic energy requirements (base case scenario). In light of the relatively low price outlook for coal in international markets and the lower than expected potential supply of natural gas and lignite, imported coal has become an attractive option for use in power generation and in the cement industry in Thailand. Hence, the share of imported coal in commercial energy use in Thailand by the late 1990s could be 15% (Table 2.1).

Table 2.1: PROJECTED ENERGY CONSUMPTION, 1982-2001
(THOUSAND TOE)

	1982	1991	1996	2001	Annual Growth (%)
Petroleum Products	9,436	13,427	16,663	20,033	4.0
Natural Gas	1,119	6,103	8,255	5,602	8.9
Hydro Electricity	1,118	1,533	1,926	1,988	3.1
Coal	98	299	412	5,034	23.0
Lignite	596	2,988	3,188	3,270	9.4
Commercial	12,367	24,350	30,444	35,927	5.8
Non-commercial	5,707	6,348	6,781	7,357	1.4
TOTAL	18,074	30,698	37,225	43,284	4.7

Source: Based on Energy Demand and Macroeconomic Situation 1985-2001, NESDB, June 1985.

2.11 The prognosis for the overall economy during the same period is encouraging, assuming that the government continues to adopt the stabilization policies now under way. External factors such as an economic recovery in industrialized countries and weak international oil prices have already contributed to a favorable outlook for economic growth in the near future. The most likely scenario for the Thai economy would be growth at about 5.4% p.a. through the end of the decade. As a result of the recent devaluation of the Baht and reforms in the exchange rate system, Thailand's net trade position is improving. The combination of weaker oil prices and increased substitution of gas and lignite for oil imports is effectively reducing the level of imports. Future improvements in the balance of payments will be contingent on the continuation of current exchange rate policies, the promotion of exports and increased domestic energy production, plus a decline in international fuel prices.

2.12 To analyze the interaction between the energy sector and the economy and prepare energy demand forecasts, NESDB, with support from the World Bank, has developed an economy-wide multisectoral, multi-household equilibrium model of the economy of Thailand. The model is an adaptation of the SIAM2 model which uses a Social Accounting Matrix (SAM) as the data base. SAM includes an input-output table which specifies the amount of each type of energy used in the production process of every sector. Changes in output over time generate associated changes in the demand for each type of energy from each sector. The sum of individual demands across sectors gives the total demand for each type of energy. Econometric specifications of changes in the input-output coefficients are incorporated whenever possible to account for improvements in energy efficiency over time. Details of the model, data base, and scenarios used are provided in Annex 2. The results of the projections through 2001 for the consumption of different forms of energy are shown in Table 2.1. These results are reasonably consistent with similar projections prepared by the assessment team for each subsector as discussed in the various chapters of this report.

2.13 As the macroeconomic projections indicate, even if a stabilization program of restrictive fiscal and monetary policies is adopted and external factors such as international oil prices and worldwide economic activity are favorable, failure to maintain domestic oil and gas production (at least at the levels now projected for the mid-late 1980s) will result in a deterioration of the Thai balance of payments and GDP growth during the nineties. Even in the scenario where real oil prices remain constant up to 2001, the current account deficit would widen rapidly in the nineties and lower economic growth would be unavoidable.

2.14 To maintain a healthy balance of payments and steady growth after 1990, several key policy decisions are required:

(a) Structural adjustment policies including a cautious fiscal and monetary policy; maintenance of the current exchange rate system and export promotion are essential.

(b) Demand management intended to achieve greater efficiency in energy use through the provision of appropriate pricing and conservation incentives will be necessary.

(c) An expanded program of exploration and development of oil, gas and lignite is needed to at least maintain, or increase, the levels of indigenous energy production from the late 1980s through the 1990s. This would require the adoption of appropriate institutional and production arrangements based on greater incentives for the private sector and a more effective regulatory process.

(d) Careful investment planning will be required to minimize the costs of energy production and optimize the timing of investments.

Projected Energy Use By Sector

2.15 Current end-use energy consumption in Thailand, as derived from the SIAM model exercise, is shown in Table 2.2. Households and industry accounted for most of traditional energy consumption (62% and 38%, respectively), and transport and industry dominated commercial energy consumption (at 52% and 24%). Transport accounts for two-thirds of petroleum products consumption, including virtually all gasoline and about two-thirds of diesel consumption. Transportation also absorbed 45% of LPG, 34% of kerosene and all the jet fuel. The industrial sector consumed 50% of the electricity provided, 80% of fuel oil and the bulk of coal and lignite. The outlook for energy consumption in each of these main sectors, as summarized from the assessment team's subsector analyses, is presented below.

Table 2.2: PROJECTION OF FINAL ENERGY DEMAND (IN THOUSAND TOE)
1982-1991

Commercial Energy	1982	1991	Annual Growth (%)
Agriculture & Fishery	793	1,194	5.3
Industry	2,783	5,347	8.5
Transportation	4,447	7,295	6.4
Households	646	1,403	10.2
Services	749	1,328	7.4
Total Commercial	9,418	15,567	7.3
Traditional Energy	5,707	6,348	1.3
Total	15,125	22,915	5.3

Source: Based on Energy Demand and Macroeconomic Situation, 1985-2001, NESDB, June 1985.

Agriculture

2.16 Agriculture 7/ accounts for about 20% of GDP but only 13% of energy consumed. Rice and sugar milling consume more than 80% of the energy used in agriculture. The agricultural growth which took place between 1960 and 1980 has been associated with a rapid increase in mechanization which is reflected in an increased use of petroleum products and electricity. Between 1960 and 1983, the consumption of

7/ Agriculture includes crops, livestock, forestry and the processing of rice and sugar, as well as fishing.

energy in agriculture (excluding rice and sugar milling) is estimated to have risen by 24.3% per year, reaching about 400,000 toe by 1983. More than three-fourths of this was diesel consumed by tractors and other field operations. Since the rapid expansion in area under irrigation and related multiple cropping observed in the past is not likely to continue much further, growth in mechanization and in energy demand is expected to slow down.

2.17 The demand for diesel is expected to grow about 7.7% p.a. until 1986 and fall to 4.4% p.a. during 1987-2001. For the agriculture sector as a whole, energy consumption would continue to grow steadily at 2.7% between now and 2001. A modest shift away from traditional fuels to commercial fuels is anticipated, with the share of non-commercial energy expected to fall from about 86% in 1982 to about 81% in 2001.

2.18 Fishing, which has been included under agriculture, is one of the most energy intensive industries in Thailand, with energy accounting for about 18% of the industry's total production cost. In 1983, the fishing industry consumed about 500,000 toe, or 4% of total end-use energy consumption -- most of it diesel fuel, which amounted to 14% of the country's total diesel consumption.

2.19 Growth in the consumption of energy in fishing will be determined primarily by growth in the industry's output -- which is expected to remain steady and uninterrupted. However, a decline in the fish catch in the Gulf may force fishermen to travel greater distances which will increase the consumption of energy. If the present petroleum price structure is maintained and international oil prices remain stable, the demand for diesel by the fishing industry should grow at an annual rate of 6.7% through 1986 and 3.6% during 1987-2001.

Industry

2.20 This sector, which includes manufacturing, mining, and construction, made up about 30% of total energy consumption in 1983, two-thirds in the form of commercial energy. In the same year, oil made up 47% of the commercial energy used in industry, followed by diesel with 24%, and electricity most of the remainder. Within industry, most of the fuel oil consumed is in cement, iron and steel, and textiles; cement alone accounted for about 25% of national fuel oil consumption in 1983.

2.21 The demand for energy in industry in the next decade or so will depend on the growth of the sector itself, the degree of interfuel substitution, and the limited adoption of more energy efficient technologies. Several heavy industries -- fertilizer and petrochemical plants -- based on natural gas as a feedstock are likely to be built during the next five to six years. These plants are projected to consume about 30 MMCFD and 43 MMCFD of gas, respectively, by 1990. Meanwhile, the demand for fuel oil in industry is expected to decline through the late 1980s as greater use is made of lignite, natural gas and coal in cement production. After 1990, however, the demand for fuel oil would grow again at 5-6% per year if there is no major gas discovery or if limited amounts of coal and lignite can be used in the cement industry.

2.22 In 1983, the total demand for electricity in the industrial sector amounted to 676,000 toe, approximately 30% of which was used in heavy and intermediate industry (mostly cement, iron and steel), 25% in light industry, and 15% in food processing. In fact, industry used two-thirds of all electricity consumed in the country and a significant share of this was consumed by a relatively few industries, such as metals, cement and textiles. On the basis of the expected growth in these industries, the industrial demand for electricity is projected to grow at an annual rate of 7.2% up to 1991 and 5.7% during 1992-2001.

2.23 Industry also makes extensive use of traditional fuels; both fuelwood and charcoal are used by the brickmaking and ceramics sectors, and agricultural wastes are used in food processing. Bagasse is used as a boiler fuel in the sugar mills -- about 5 million tons or 1,035,000 toe actually were utilized in 1983. Since the sugar industry has undergone tremendous growth during the past two decades, the use of bagasse has grown rapidly. Given the present low price of sugar in international markets, growth in sugarcane production is expected to be modest during 1987-2001 -- around 3% per year -- and the consumption of bagasse is expected to rise at the same rate.

2.24 Paddy husk is mainly used by rice mills; about 2.5 million tons (535,000 toe) of rice husks were produced in rice milling operations in 1982. Its largest use was in the rice mills themselves, to drive steam engines and raise process steam for parboiling and drying purposes. Rice production and the consumption of paddy husks in the agricultural sector are expected to grow at about 1.5% per year.

Transport

2.25 Transport facilities have been growing rapidly over the past 25 years. The highway network has expanded nearly threefold, while the motor vehicle fleet nearly doubled over the last five or six years. During the 1970s the consumption of gasoline, diesel and jet fuel in transport grew at annual rates of 6.4%, 6.6%, and 8%, respectively. This trend slowed after 1979 with the decline in economic activity. Gasoline consumption declined by 2.7% per year between 1979 and 1984, mostly due to absolute and relative price increases and the slowdown in economic activity. During the same period diesel consumption increased by 15% a year. Similarly, LPG consumption in transport increased by roughly 50% a year over the same period. To a large extent the growth in consumption of these two fuels is due to the price structure which provides incentives to substitute them for gasoline. In 1983, the transport sector accounted for 52% of total commercial energy consumption and 62% of petroleum product consumption. Approximately 90% of gasoline and 64% of diesel was used in transport. In 1985, about 4,500,000 toe is being consumed in transport and consumption is growing at an annual rate of 6.4%. By 1991, nearly 7,300,000 toe a year is expected to be consumed in this sector.

Power Generation

2.26 The choice of fuels used in electricity generation is likely to have a substantial effect on the energy picture over the next 15 years. To meet the rapidly growing demand for electricity over the past 25 years, inputs of commercial fuel increased at more than 10% a year. In 1960, diesel provided the fuel for two-thirds of the capacity. The subsequent expansion in capacity was provided mostly by oil-fired steam thermal plants and, to a lesser degree, by hydro-based plant. Until the early 1980s, hydro provided 21-25% and fuel oil most of the rest. In the last few years, the share of hydro has remained about the same, but the shares of natural gas and lignite have risen to 30% and 10%, respectively. Natural gas consumption in the power sector reached 54,462 MMSCF in 1983 and lignite consumption increased from 93,000 tons in 1960 to 1.6 million tons. Fuel oil consumption used in electricity generation rose to a peak of 2,580,000 toe. The substitution away from fuel oil around 1983 reduced fuel oil consumption to 1,550,000 toe. However, the projection to the 1990s shows a reversal of the substitution process so that by the latter part of the next decade over 50% of the fuel used in generating electricity would be imported coal. By the end of the 1990s 9,000,000 tons of coal may have to be imported unless there is a major increase in hydro imports or in generation from additional discoveries of lignite or gas reserves.

Households

2.27 Household demand for energy has changed substantially during the past 25 years. In urban areas there has been a shift towards using modern fuels for lighting and cooking, and the use of air-conditioning and household appliances is now becoming widespread. In 1980, charcoal and fuelwood were used as cooking fuel in 42% of households, compared to about 90% of the households in the early 1960s. LPG and electricity are now used in place of traditional fuels for cooking by more than 70% of urban households. Overall, electricity has become the most important commercial energy used in urban households (about 45% of the total), followed by kerosene (33%), which is used for cooking in restaurants and hotels. About one-half of the electricity consumed in commerce and service establishments is for air-conditioning; the other half is used for lighting and operating other electrical equipment and appliances.

2.28 The consumption of energy by the service sector is projected to grow by 5.6% through 1986, and 5.3% per year to 2001. The service sector demand for electricity is expected to rise by 7.1% per year through 1991, and 5.4% per year during 1992-2001. Due to shortages of fuelwood and charcoal and consequent higher prices that will develop, the demand for those fuels by the service sector is projected to rise by less than 1.0% per year through 2001. LPG use is expected to substitute partially for these fuels and it is estimated to grow at an annual rate of 10%.

2.29 Overall, between 1982 and 1991 final energy demand is expected to grow at about the same rate as GDP (5.3% and 5.4%, respectively).

The use of traditional energy is expected to grow very slowly, at 1.3% p.a., although commercial energy consumption will grow faster than GDP at about 7.3% p.a. This will result in an energy-GDP elasticity of 1.3%, which is comparable to that observed in countries at a similar stage of development. The highest growth (10.2% p.a.) will take place in the househould sector, which will account for 9% of commercial energy consumption in 1991, compared to 7% in 1982. Although the industrial sector is anticipated to grow at 8.5% p.a., its share in consumption is expected to grow more than that of any other sector -- from 29% to 34%. The shares of transport, agriculture and fisheries, and services will remain stable, at about 47%, 8%, and 7%, respectively.

III. ENERGY RESOURCES - LIGNITE, HYDRO, BIOMASS

Introduction

3.1 Thailand's commercial energy resource base is somewhat diversified, consisting principally of lignite, hydropower, natural gas, and more limited quantities of oil and natural gas liquids. The rural sector formerly was supplied by the ample forest resources, but continuing rural population increases and pressures to develop agricultural holdings have put sufficient strain on these to jeopardize their long-term availability. Known lignite reserves are around 1,700 million metric tons (MMt), 865 MMt of which are regarded as proven. The total reserves may be greater, since only 23 of 79 potential coal-bearing basins have been investigated in detail or systematically explored and only 5 of the 79 potential basins are being mined. The rest of the potential coal-bearing areas have been subjected only to geological reconnaissance. Of the total proven and probable reserves, 86% are located in the Mae Moh deposit in northwestern Thailand. 8/ The total hydropower potential in Thailand itself is estimated to be about 8,300 MW, with an annual generation potential of 14,330 GWh. A much larger potential exists on border rivers with Laos and Burma -- estimated to be around 14,000 MW, with an annual generating capacity of 90,000 GWh. Development of these sites would require international agreements with other riparian states, which in the present disturbed political environment of Southeast Asia seems unlikely to occur before the end of the century. Of the oil and gas reserves, some 180 million barrels of liquids (crude oil and condensate) and 12,900 billion cubic feet of gas have been identified to date as proven, probable and possible 9/, while the ultimate recoverable reserves (URR) including both discovered and as yet undiscovered are estimated to be around 1.1 billion barrels of liquids and 19,000 billion cubic feet of gas. To put the above resource figures into perspective, Thailand's commercial energy consumption in 1983 was 14.3 million tons of oil equivalent and has been growing at 10% a year for the last ten years. The total of presently known proven and possible energy reserves (excluding hydropower) amounts to approximately 57 years of supply at present consumption levels. This reserve base should by no means be considered comfortable for four reasons:

(a) it obscures the fact that 57% of the total represents lignite, only 3% oil and condensates, and 40% natural gas;

(b) the lignite reserve data are for mineable reserves with present technology, as distinct from reserves which are economically mineable at present levels of costs and competing fuel prices;

8/ EGAT Power Development Plan (1985-2001), May 1985.

9/ About 3.72 billion cubic feet of this gas is considered proven.

(c) if one assumes that the growth rate of demand for commercial energy in Thailand up to the year 2,000 declines to 5% per year and to 2.5% per year between 2000 and 2010, commercial energy resources will be depleted by 2015, or within 30 years; and

(d) with oil only providing 3% of the reserve base, it is clear that the country's energy resources would not be able even to meet the transport sector demand, which represented some 45% of commercial energy demand in 1983.

3.2 Although the country has energy resources which can be used by industry and the power sector, these resources clearly do not provide an adequate energy base for a rapidly growing modern economy, particularly one in which transport sector consumption will continue to dominate.

Institutional Issues

3.3 The institutional aspects of energy resource management in Thailand are complex and include a large number of government bodies which in some cases appear to have overlapping jurisdictions. In the case of coal (lignite) there are three: the Department of Mineral Resources (DMR), the National Energy Administration (NEA), and the Electricity Generating Authority of Thailand (EGAT). In oil and gas, the Petroleum Authority of Thailand (PTT) is the dominant public entity, since it is responsible for transporting, processing, purchasing and selling natural gas (para. 4.40), but the DMR has the responsibility for regulating the oil and gas exploration and production industry. EGAT is responsible for hydroelectric development but must coordinate this with the Royal Irrigation Department to ensure the optimum use of water resources. Energy sector policy and planning functions involve the Cabinet, the National Economic and Social Development Board (NESDB) (which is under the office of the Prime Minister), and NEA. The situation is further complicated by the fact that EGAT reports to the Prime Minister's office, PTT and DMR to the Ministry of Industry, while NEA is under the Ministry of Science, Technology and Energy. There is a lack of effective coordination between these official bodies.

3.4 Private sector involvement is strong in the petroleum industry, particularly in oil and gas exploration and production, the import and distribution of oil products and, to a lesser extent, in refining. The private sector has only played a small role so far in lignite mining, which is dominated by EGAT's operation of large captive mines to supply thermal power stations; the NEA operates two lignite mines to supply small industrial consumers. The private sector participates little in generation and not at all in the distribution of electric power. Generation is principally the responsibility of EGAT, although there is some captive generating capacity in the sugar and cement industries.

3.5 The institutional aspects of the energy sector in Thailand are complex and need to be clarified in light of a new thrust in government energy policy towards a greater private sector role. To do this it is not necessary to have all entities with operational and/or planning responsibilities reporting to a single Ministry of Energy, as was common in many countries a few years ago. Energy issues pervade all sectors of the economy and such a Ministry could easily become all-powerful and far too supply-side oriented. The major thrust of the energy component of the 6th Five Year Plan calls for an increased role for the private sector (local and foreign) in the exploitation, production, transport, refining and marketing of energy in Thailand. This is a direction which the assessment team fully endorses but which will certainly require, in the assessment team's view:

(a) clear guidelines regarding the government's policy toward areas in which increased private sector activity is called for;

(b) better coordination and planning between public sector entities; and

(c) improved government machinery to regulate and enhance private sector activities in the energy sector and facilitate better coordination between public and private sector entities.

Lignite/Coal

3.6 Thailand's coal resources are all relatively low grade, of the quality generally categorized as lignite, although some deposits verge on being sub-bituminous. The characteristics of lignite include a relatively low calorific value due to its high water content, and, in several of the Thai deposits, a high proportion of mineral ash. Table 3.1 gives estimated reserves and average calorific values for Thai lignites. For comparative purposes, the heat value of imported Australian steam coal is 6,700-7,100 kcal/kg, or double that of most Thai lignites except for the reserves at Li, which are of reasonably good quality. Information about reserves is sketchy and inadequate, especially in view of the need to formulate longer-term energy policy. There is considerable evidence to show that lignite could be a major long-term energy source in Thailand, but the lack of definite information regarding the quality, location, and economic mineability of reserves makes firm planning difficult.

Occurrence of Lignite and Exploration

3.7 Lignite in Thailand occurs in a series of small disconnected areas, known in geological terms as "basins", which are scattered the length of the country, mainly in the western part. A total of 79 such basins have been identified, of which 37 are known to have either workable deposits or verified occurrences of lignite and the remainder await geological exploration. Only five basins contain active mines at

Table 3.1: SUMMARY OF COAL RESERVES AND QUALITY IN MAJOR DEPOSITS
(Reserves in million metric tons)

Location	Mine or Deposit	Operator Owner	Year Prod. Started	Reserves Proven	Reserves Probable	Moisture	Ash	Volatiles	Fixed Carbon	Sulphur	Heat Value
						(percent)	(percent)	(percent)	(percent)	(percent)	(kcal/kg)
LAMPANG	MAE MOH	EGAT	1955	802	661	30-35	10-28	20	13-26	0.8-1.5	2500-3000
KRABI	Khlong Khu Nan) Khlong Thom)	EGAT	1964	25	28	30	32-47	n.a.	n.a.	1.5-2.4	2850-3000
LAMPHUN	Pa Kha, Li	NEA	1969	12.0	15.0	21	8	n.a.	n.a.	< 1 }	5500-6000
	Ban Pu, Li	World Fuels Co.	1979	8.0	15.0	20.7	8.1	n.a.	37.3	4 }	
NGAO LAMPHUN	Mae Teeb	Phrae Lignite Co.	1976	1.1	11.0	19	6.2	30	40.5	6.5	4980
MAE RAMAT, TAK	Mae Tuen	Thai Lignite Co.	1980	1.3	2.3	7.75	1.06	39.5	51.7	0.71	3275
LOEI	Na Duang	Siam Graphite Co.	1982	0.05		n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
KRABI	Sin Pun				16.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
LAMPANG	Jae Khon	NEA		15.5	32.0	4.6-23.6	n.a.	20.3-41.5	37.6	1.6-9.7	1527-502
LAMPANG	Ngao				24.5	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
	Chae Hom				26.3	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
				865	831						

n.a. - data not available.

Source: Monenco Report on Lignite, 1984, and EGAT Power Development Plant (1985-2001), May 1985.

present and two others have old abandoned mines. By the end of 1983 EGAT had mapped and drilled in ten basins, and other government agencies or private concerns had conducted limited exploration in about six basins.

3.8 According to available information the basins were classified on the basis of their lignite potential and the extent to which they have been explored. Table 3.2 summarizes this classification scheme.

Table 3.2: STATUS OF LIGNITE EXPLORATION

	----Lignite Potential----			
	I Good	II Fair	III Poor	Total
1. Unexplored	16	19	24	59
2. Partially explored	5	5	5	15
3. Fully explored	-	-	-	-
4. Basins with lignite mining	5	-	-	5
Total	26	24	29	79

The 21 basins rated as having good lignite potential but which are unexplored or only partially explored have been designated as high priority targets for EGAT's exploration program; the six prime targets are:

Northern Region	Southern Region
Wiang Haeng	Thung Yoi (Sin Pun)
Mae Taoi	Khian Sa
Serm Ngam	Sa Pan Sai

3.9 In the second phase of the 1983 exploration exercise, three basins were drilled in detail. Only the exploration at Wiang Haeng resulted in any discovery of a significant lignite reserve -- between 40 and 50 MMt of 3500 kcal/kg lignite, which is sufficient to fuel a 300-MW power plant for about 30 years. However, the overall stripping ratio was 15.4 bank cubic meters per ton of lignite, which is too high to make the lignite economically mineable under present conditions.

3.10 Lignite exploration has been carried out in at least 20 of the 79 tertiary basins, although in most of these the effort has not been systematic. Some basins are small and the lignite bearing area would be limited to a few square kilometers; others cover several thousand square kilometers. Consequently, the ultimate lignite potential will only be revealed as systematic exploration proceeds. The number and thickness of lignite seams vary within a basin and from basin to basin. Mae Moh has four seams; only the two middle seams, each 5 m to 15 m thick, are mined. The top seam is also thin and the bottom too deep. In the Li basin two seams, each up to 7 m thick, are mined and at Krabi a 15 m thick seam is mined. Lignite seams typically dip towards the center of the basins at about 10°, but dips of up to 40° also occur. There are also numerous minor geological faults which displace the lignite seams so that estimating reliable stripping ratios and economically mineable reserves is difficult.

3.11 One of the anomalous aspects of lignite exploration and development in Thailand is that the most active and important entity in this field is EGAT. Some exploration is undertaken by the NEA, and small private mining companies to a more limited extent. Though information on these activities is limited they are definitely at a level significantly below that of EGAT.

3.12 Table 3.3 details EGAT's exploration activities in 1982 and 1983. In both these years about 70% of the effort had been concentrated on detailed drilling of Mae Moh and Krabi, with the remaining 30% spread over several other basins. Its annual lignite exploration budget is about US$2.0 million. Given the prospects, this level of activity may be appropriate for EGAT in terms of power sector requirements, though it should ensure that priorities are continually reviewed and efforts directed at the most promising prospects.

Table 3.3: EGAT'S 1982 AND 1983 EXPLORATION ACTIVITIES

	FY82		FY83		
	Holes	Meters	Holes	Meters	1000 Baht
Mae Moh	124	23,407	116	13,294	7,600 a/
Krabi	116	32,610	224	51,243	30,000 a/
Mae Tha-KhoKa	5	705	44	8,184	2,571
Thai/Malaysian Border	-	-	5	1,179	840
Chiang Muan	-	-	21	3,613	949
Wiang Haeng	-	-	31	5,510	1,921
San Pa Tong	-	-	18	3,357	916
Chaiburi	-	-	33	2,288	1470
Chai Hom	16	1,084	-	-	-
Wang Nua	89	7,264	-	-	-
Li	53	9,617	-	-	-
Ngao	12	2,015	-	-	-
Total	415	76,702	492	88,668	46,267
US$ thousand					2,007 b/

a/ Preliminary estimate.
b/ 23.05 Baht/US$.

3.13 It is not necessarily in the national interest that the major exploration and development effort of one of Thailand's important energy resources should be left only to a public electric utility, which is bound to have its own internal priorities and will allocate funds for lignite exploration and development only insofar as its own needs are concerned, regardless of whether other industrial consumers have need of or could use lignite as a fuel. This is not to say that EGAT has not performed an excellent task so far in the development of economic lignite resources for use in the power sector. This issue is wider than EGAT and the power sector. It involves:

(a) the future role of high quality lignite as an important fuel outside of the power sector, in particular, in the cement sector competing with imported coal, fuel oil and natural gas. This industry in 1984 used some 330,000 tons/lignite (or about 14% of total lignite production); and

(b) the most effective institutional arrangements to accelerate the exploration, production, transport and use of such lignite in non-power sector markets. In this context, high grade deposits (such as at Li) are of special significance once lignite is to be transported for use by industry, while lower grade resources can still be economically exploited for mine-mouth power generation.

3.14 Regardless of the eventual arrangements decided upon for lignite development in the 6th Five Year Plan, the assessment team believes that the scale of activity in lignite exploration between 1986 and 1991 should be at least twice as high as that of EGAT in 1983 or should increase to at least US$4 million annually (paras. 3.27-3.34).

Lignite Reserves and Production

3.15 Presently known reserves of lignite in Thailand are estimated at 1700 MMt (Table 3.1), 1460 MMt (86%) of which are in the Mae Moh basin. However, most of the reserves outside Mae Moh occur at depths too great, or consist of seams too thin, to make them economically mineable. Currently known mineable reserves total 465 MMt; 452 MMt are at Mae Moh. Another 10 MMt are at Krabi, where EGAT has plans to exploit them to fuel a 75-MW power station. There is little available information on privately held reserves. Of the basins where lignite is known to occur but which have not been drilled sufficiently to enable reasonably accurate total reserve estimates to be made, Sin Pun (Krabi province) is the most promising. The stripping ratio here is between 2.7 and 5.1 bank cubic meters per ton of lignite (BCM/ton), lower than at Mae Moh (7.1 BCM/ton average), and lignite quality is slightly higher. Another basin where exploration is currently under way is Wiang Haeng (Chiang Mai province), where estimated total reserves are 40-50 MMt; however, the higher average stripping ratio (15.4 BCM/ton) of this deposit makes it look less attractive than Sin Pun at this stage. EGAT's current strategy is to concentrate exploration efforts in the southern (peninsula) region (Region 3) due to the more urgent need for expanded electricity generation there as compared to the central and northern regions.

3.16 The current operators and production of lignite are shown in Table 3.4. Output in 1983 totaled 2.2 million tons, of which 1.8 million tons was produced by EGAT.

Lignite Production Potential

3.17 Over the next decade, lignite production will expand in the Mae Moh and Krabi basins, with the Mae Moh basin making the largest contribution to national primary energy supply. Even if significant additional reserves were discovered in other basins, the time requirements for exploring, measuring and developing reserves would mean that exploitation could not begin until the mid 1990s, at the earliest. The following sections describe the development now under way at Mae Moh and Krabi and indicate their likely future production potential.

Mae-Moh - Currrent Situation and Reserves

3.18 The Mae Moh mine and associated power station is located approximately 650 km north of Bangkok in an area of low population density where most of the land is used to cultivate of teak wood and tobacco. The mine is connected to the national road system by paved roads and to the national rail system by a 5-km spur. In the past, this spur has been used to deliver lignite to the North Bangk power plant (see Table 3.4). Extensive exploration has established total proven and probable reserves at 802 and 661 MMt, respectively. Consideration of lignite ash content and other figures considerably reduces the volume of reserves that is economically mineable. The costs of mining a unit of heat are reduced as the percentage of ash in the lignite decreases; in addition, lower ash content means lower power plant operating costs in the areas of milling, slagging, ash disposal, etc. The lignite reserves at Mae Moh which have ash content below 45% are considered economically mineable; using this criterion, Mae Moh measured and indicated reserves totaled 814.2 MMt at the end of 1982, from which a total 437 MMt run-of-mine production is expected between 1987 and 2024, as follows:

	MMt
Total measured and indicated reserves with ash content below 45%	814.2
Less: reserves considered uneconomic	74.6
reserves sterilized power units 1-3	237.8
reserves mined to 1987 (14.2 Mt run-of-mine)	15.8
Indicated reserves available for mining after 1987	486.0
Indicated run-of-mine reserves at 90% recovery	437.4

Source: World Bank Second Mae Moh Lignite Project. Appraisal Report (March, 1984).

These reserves have an average stripping ratio of 7.2 bank cubic meters/ton, an average run-of-mine ash content of 26%, and an average calorific value of 2700 kcal/kg. Their sulphur content is high, ranging from 2.5% to 4.0%.

Table 3.4: OPERATING LIGNITE MINES AND PRODUCTION, 1977-83

Province Location	Operator	Mineable Reserves (Mt)	Destination of Output	Output ('000 tons) a/ 1977	1978	1979	1980	1981	1982	1983	Est.1984
Mae Moh (Lampang)	EGAT	452	Mae Moh Power Plant	47.1	103.9	823.3	875.3	1184.8	1195.7	1291.9	1640
			North Bangkok Power Plant	115.6	75.9	51.8	0.1	0.1	0.1	-	-
			Sub-total	162.7	179.8	875.1	875.4	1195.7	1291.9	1640	
Krabi (Krabi)	EGAT	10	Krabi Power Plant	294.6	268.2	283.1	363.8	362.4	372.3	351.7	350
Li (Lamphun)	NEA	6	Industries, households								
Li (Lamphun)	World Fuels Co. Ltd.	2	Industries, households								
Li (Lamphun)	Dharmumaprida Co. Ltd.	1.1	Industries, households								
			Sub-total	85.7	106.7	94.1	110.5	99.6	131.6		
Ngao (Lampang)	Phrae Lignite Co, Ltd.	0.79							102.3		
Mae Ramat (Tak)	Thai Lignite Co. Ltd.	1.0							83.5		
Na Duang (Loci)	Siam Graphite Co. Ltd.	1.0							5.9		
Totals		473.9									

a/ On a Thai fiscal year basis (Oct. 1-Sept. 30).

Sources: EGAT data and Li sub-totals - Second Mae Moh Lignite Project SAR; other: - data provided to a December 1983 IMF assessment team.

3.19 Future Production. The magnitude of the Mae Moh reserve base is sufficient to maintain an annual production level of 14.6 Mt a year for 30 years -- the maximum economic lifetime of any power facilities installed at Mae Moh. This level of output could support 2,090 MW of installed base load capacity at Mae Moh. 10/ Current installed capacity at Mae Moh is 375 MW (3 x 75 MW, 1 x 150 MW) and a further three units of 150 MW each are now under construction. 11/ By March 1986, a total of 825 MW will have been commissioned, consuming some 5.7 Mt a year of lignite.

3.20 EGAT is currently preparing plans for further expansion of the Mae Moh mine to fuel an additional 3 x 300 MW of generating capacity, and its May 1985 Power Development Plan (1985-2001) shows the following commissioning dates for these three units:

Unit 8	300 MW	July 1989
Unit 9	300 MW	June 1990
Unit 10	300 MW	December 1990

3.21 A significant fraction (29%) of Mae Moh reserves are unavailable for mining at present because generating Units 1-3 and some associated buildings are located on top of them. When these units are retired in the mid- to late-1990s an additional 238 MMt of reserves will become available for mining, or 214 MMt of run-of-mine reserves (90% recovery). At this time, the feed requirements of units 4-10 will be approximately 10.5 MMt/year, and run-of-mine reserves, including the released portion, will stand at 550 MMt. This level of reserves would be sufficient to support an additional 1500 MW of generating capacity over and above the already committed or planned 1725 MW so that reserves would be depleted by the year 2025. This would require an expansion of mine capacity to about 21 MMt/year -- a very large mine by any standard. The crucial question facing Thailand is, in the absence of other known sizeable lignite reserves for base load power generation, what is the optimal pattern of use of the Mae Moh reserve. Related to this is the environmental problem at Mae Moh which could become significant in a mine of 21 million tons/year production (para. 3.35). The entire issue of the optimal development of Mae Moh's resources will depend on the price and availability of natural gas in the mid-1990s, the movement of international coal prices and the shadow price of foreign exchange. The latter is of significance since a power plant based on imported coal will be more foreign exchange intensive over its lifetime than its lignite competitor. Furthermore, the present high value of the US dollar relative to the Australian dollar and other currencies of coal exporting countries tends to underrate the long-term cost of imported coal -- an

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10/ Assuming a 75% annual load factor and an overall plant efficiency of 30%, net of auxiliary equipment requirements.

11/ In March 1984, these were 65%, 19% and 12% completed, respectively.

effect intensified by the current depressed state of the international coal market and the shipping industry. All these factors tend to make imported coal appear much cheaper at present and over the short term than its probable long-term cost, the net effect of which possibly might be to slow the rate of lignite development in the early 1990s unless these signals change over the next couple of years.

Krabi Basin - Reserves and Exploration

3.22 The tertiary basin at Krabi, as defined to date, is 30 km long by 12 km wide and is topographically flat, containing large areas of mangrove swamp in the southern portion. The western edge of the basin subcrops to the west of a major river, the Pakasai, and the seam extends under the river. About 8.5 km of the subcrop has been drilled to date and three potential mining areas identified in addition to the two areas of the subcrop that are already being mined. The lignite seam is typically 10 to 15 meters thick. Reserve estimates of coal quantity and quality at Krabi are still tentative, pending completion of the full exploration program. Moreover, given the steep dip of the seam, economically mineable reserves will be less than the technically proven reserves. At present, economically mineable reserves are estimated at about 10 million tons.

3.23 EGAT operates a 60 MW (3 x 20 MW) lignite-fired power station at Krabi (Chapter V) with lignite supplied from two nearby open cast mines, Wai Lek and Bang Pu Dam. Together these mines produce about 360,000 tons of lignite per year averaging about 3,000 kcal/kg and 35% ash. The power units were commissioned between 1964 and 1969 and current plans are to decommission them in August 1990. The Krabi power plant is the largest single base load plant in the southern region and depends on energy transmitted approximately 800 km from the central region for much of its supply (Chapter 5).

Sin Pun Area

3.24 This is the most promising of the lignite deposits discovered by EGAT in the course of its recent exploration program. The location is about 70 km east- northeast of Krabi. So far, about 3,000 meters of very shallow subcrop have been delineated by trenching and 90 boreholes. Coal quality appears to be superior to Krabi and Mae Moh (3,000 kcal/kg). Even with limited drilling, measured reserves total 5 million tons, and another 5 million are indicated, which could support a 75-MW power plant for 25 years. The deposit is still open at both ends, so there are expectations that the extent of known reserves will increase during 1984-85 as EGAT continues its drilling program. It is reasonable to expect that a power generating and lignite mining project will develop in Sin Pun by the early 1990s.

Coal and Lignite Consumption in Thailand

3.25 Table 3.5 shows the actual reported consumption of lignite and imported coal from 1975 to 1983.

Table 3.5: THAILAND - LIGNITE AND COAL CONSUMPTION (1973-1983)
('000 tons)

	1975	1976	1977	1978	1979	1980	1981	1982	1983
Lignite									
Mae Moh - Power a/	103	163	102	225	941	935	1204	1300	1408
Krabi - Power	330	326	268	262	312	386	331	387	384
Fertilizer Plant	39	46	47	42	-	-	-	-	-
Cement b/	33	56	68	71	83	88	24	280	290
Tobacco b/	5	13	16	19	30	22	115	125	126
Other Industry	-	-	-	-	-	-	3	24	20
Total Lignite	510	604	501	619	1366	1431	1677	2116	2228
Other Coal (Imports)									
Steam Coal c/	4	4	4	1	4	16	12	95	102
Anthracite	-	-	1	9	4	13	2	5	11
Coke	30	33	30	35	43	70	32	52	37
Briquettes	-	1	1	-	-	4	13	9	9
Total Other Coal	34	38	36	45	51	103	59	161	159
Total Consumption	544	642	537	664	1417	1534	1736	2277	2387

a/ Approximately 60,000 tpa used at North Bangkok power plant to 1978.
b/ High quality lignites (caloric value more than 4500 kcal/kg).
c/ Steam coal mainly for Siam City Cement Plant in 1982 and 1983.

3.26 What is important to note in this table is the rise in the use of lignite by the cement and tobacco industries since 1981. The potential for strong growth in lignite use in such industries over the next decade is very likely provided the lignite mining industry is equipped to face this challenge in non-power sector uses of lignite (paras. 3.27-3.34). It is also worth noting that 9000 tons of coal briquettes were imported in 1983, although it is not known for what purpose they were used. Briquettes are widely used as domestic fuel in both Eastern and Western Europe, and there is no reason why some of the lower ash content Thai lignites could not be processed to make an acceptable smokeless fuel for use in domestic cooking stoves and for cottage industry use. In rural areas the availability of such material might alleviate the fuel shortage and help to arrest the rapid rate of deforestation. It is recommended that briquetting tests should be undertaken on the various grades and types of Thai lignites to determine whether a marketable product can be produced. Dependent on these results the possibility of establishing a briquetting plant in Thailand could then be investigated.

Opportunities for Strengthening the Lignite Mining Industry

3.27 The scale of lignite mining in Thailand in 1983 was about 2.2 million metric tonnes, of which 1.8 MMt were produced in EGAT for use in power stations; 0.1 MMt were produced by NEA, and 0.3 MMt were produced by three private mining companies. Thus, 85% of the 1983 production was generated by the public sector, essentially by EGAT, and 82% of production was used for power generation. Given the major expansion in lignite use for power generation under way, production for the power sector could rise to about 12 million tons a year by the early 1990s. In addition, the cement industry is expected to increase its capacity from about 9.5 million tons in 1984 to about 17.5 million tons in 1995. By that time lignite could meet about 35% (2 million tons/year) of this industry's energy needs (para. 6.54) if it is competitive with imported coal and/or natural gas in such end-uses. Other industrial uses of lignite could consume another 0.5-1.0 million tons a year by that time.

3.28 Most private lignite mining operations in Thailand are small and undercapitalized. These characteristics appear to prevail for much of the national mining industry in addition to the lignite part of it. These companies are involved in mining higher grade lignite ores for use outside of the power sector. The key issues therefore that need to be addressed are:

(a) how to strengthen the role and activities of the private sector in lignite mining, especially with the objective of increasing the exploration, production, transport and use of high grade lignite in non-power sector activities over the next decade; and

(b) how to harness the financial strength of EGAT's mining activities for power sector use to achieve these objectives.

3.29 Under current arrangements, EGAT mines exclusively for the large, secure and rapidly growing power sector market, and the private sector operators attempt to increase exploration and production for, and use of, high quality lignite in the more difficult industrial market. These arrangements may not be optimal and could limit penetration of lignite as an energy source in the economy outside of the power market. 12/ A healthy mining industry in Thailand needs the support of a stable long-term market such as that provided by the power sector if it is to attract the additional capital, professional expertise and industrial user commitment to lignite which are needed to provide for the possible increase in demand by industry. Penetration of the industrial market, particularly cement, is more complex than mining lignite for mine-mouth power generation because of:

(a) the small current size of the market, which makes it difficult for small operators to undertake the level of improvements needed to achieve significant growth;

12/ Current World Bank covenants covering its first and second Mae Moh lignite projects limit the use of lignite produced under these projects to power generation by EGAT.

(b) the need to identify and develop more high quality lignite mines (low in ash and water content and high in calorific 13/ value) to allow the mineral to be transported to users competitively and to partly sustain the high temperatures needed in cement kilns; and

(c) the requirement to improve the transport infrastructure from mine to end-user so that costs are further reduced.

3.30 In assessing the roles of the private sector and EGAT in future lignite mining operations the issue of the efficiency of some private mining interests needs to be addressed. Presently EGAT sub-contracts to a Thai joint venture contractor (selected through local competitive bidding) for the removal of 60% of overburden at Mae Moh for the 1984-1990 period. The local contractor is to remove some 90 million bank cubic meters (BCM) of overburden while EGAT would remove 60 million BCM of material (25 million BCM of lignite and 35 million BCM of overburden) with its own personnel and equipment. At Mae Moh, in 1984 the private contractor moved 5.5 million BCM at an average cost of US$1.47/BCM, while EGAT moved 12.1 million BCM at an average cost of US$2.38/BCM. Though EGAT's task may be complicated because it consists of removing material between the lignite seams and from deeper levels than those worked by the contractor, the difference still is sufficient to make it appear that the private contractor can excavate the lignite at a substantially lower cost than EGAT. Apart from the direct cost comparison cited above, a comparison of the relative efficiency of private sector and EGAT mining operations should consider that the latter has benefited from a number of indirect subsidies, such as the government's waiver on customs duties for imported equipment, and access to capital on favorable terms in the form of World Bank loans backed by government guarantees. Such loans have amounted to US$131 million. The government contribution to EGAT's mining operations through remission of customs duties in 1984 is estimated to have been equivalent to 9% of total investment, or US$3.9 million. During the same period, EGAT earned about 12% return on its revalued mining assets of about US$180 million, or $21.6 million. This means that nearly 18% of EGAT's return on mining assets was due to an indirect government "subsidy." If, with these advantages, EGAT's costs of overburden removal are about 60% above those of the private mining contractor, there would appear to be a strong case for either further improving EGAT's mining efficiency or for EGAT to continue increased reliance on private contractors for overburden removed. It would appear that the contractor's productivity is higher, enabling him to mine at lower cost with higher equipment utilization rates and lower labor costs. The key issue therefore becomes to improve the efficiency of the lignite mining industry as a whole while building on the areas of strength in EGAT's operations.

3.31 This objective could be achieved through various options, one of which is the full privatization of the industry. The government is

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13/ In the region of at least 4,500 kcal/kg.

increasingly concerned about the level of the country's foreign debt, especially the public sector foreign debt service, which is limited by law not to exceed 9% of foreign exchange earnings. The Mae Moh mine had about US$180 million of assets at the end of 1984, much of it representing foreign exchange costs. To raise the level of lignite production at Mae Moh and other deposits above 12-13 million tons/year by the early 1990s, further major purchases of new mining equipment (much of it in foreign exchange) will be called for. It is in seeking to relieve some of this burden while concurrently improving efficiency, that some degree of privatization (involving local and/or foreign private companies) of mining operations should be assessed.

3.32 The method and extent of further private participation in the industry may be limited by practical considerations. Full private ownership of all lignite mining operations is unlikely (even if foreign participation is contemplated) given the size of the investment and the fact that EGAT is the only large buyer of lignite and is likely to remain so even if major penetration of the non-power market occurs in the next decade. Another possible mechanism includes leasing the mining assets to a private operator of the mine. Care has to be exercised in such arrangements to ensure that the operator does not skimp on equipment maintenance resulting in breakdowns and production interruptions. Contracts would also have to be concluded between EGAT and the operator regarding grades and quantities of lignite to be delivered with penalties for failure to perform.

3.33 One of the arguments put forth in favour of maintaining the present arrangements in the lignite mining industry is that, with EGAT controlling both Mae Moh mining and power generation, it is unlikely that the level of coordination this allows between the two functions could be duplicated if there were two separate operators. Although this is valid, there is still:

(a) a desire to increase the efficiency of overall mining activities and strengthen the mining industry as a whole;

(b) the need for measures to facilitate the penetration of lignite use outside of the power sector and to identify and develop additional mines with better quality lignite than Mae Moh; and

(c) a concern about somewhat limiting the scale of increases in public foreign indebtness as the sector expands over the next decade.

3.34 Most of these objectives could be met by forming a joint venture mining company between EGAT, local and foreign private mining partners, with EGAT holding majority interest. This suggestion was considered by the joint Bank/NESDB Energy assessment team as a valid and useful option worthy of further analysis. Such a company could be established by starting with the lignite department of EGAT and its assets, while the private sector partners would acquire minority interest in the new company through cash contributions for equity. One option would be for this new joint venture company to take over EGAT's mining leases and be issued with leases to explore for, produce, and market lignite for power and non-power uses. The possibility of foreign equity participating in such a joint venture operation is not clear, since lignite is not internationally traded and the expected dividends, in foreign exchange, would have to be higher than the opportunity cost of capital to the private investor. Another option could involve leaving operations as they currently are for low quality lignite for power sector use, while putting more incentives in place to encourage private sector activity in the exploration and production of high quality lignites for industrial uses. What appears desireable is that the issues and options of strengthening the lignite mining industry further need to be analyzed in greater depth to provide the basis for a new policy thrust.

Environmental Issues

3.35 A final issue to be addressed concerns the environment at Mae Moh in the mid-1990s. At the scale of mining anticipated, issues regarding disposal of overburden and ash, and backfilling of mined out areas are likely to assume serious proportions. If planned beforehand, the cost of remedial measures is not generally excessive. It could be argued that a joint venture company in which EGAT had majority interest would be more likely to undertake this duty in a more conscientious manner than a private mining company which wishes solely to maximize profits.

Lignite Costs and Value

3.36 Since lignite mined at Mae Moh is produced by EGAT exclusively to supply its mine-head power plants, operations at this largest mine in Thailand do not reflect a market price for lignite nor its relative worth. Studies undertaken in 1983 14/ determined the opportunity cost of lignite at Mae Moh to be about US$18/ton (US$1.70/MMBTU).15/ This was close to the transfer price of lignite between EGAT's mining and generation departments of US$19.22/ton in 1983. It was also estimated that the economic rent, or depletion premium, of lignite is small due to the economic size of the Mae Moh reserves, future mining costs, and uncertain estimates of replacement fuel costs (essentially imported coal) at the time the reserve is depleted. As such, the opportunity cost of lignite at Mae Moh is close to its mining costs which are estimated to remain fairly constant in real terms over the next several years. The degree to which lignite can be competitive with imported coal, fuel oil, and natural gas is discussed below (paras. 5.38 and 6.57).

3.37 The sector of lignite use which most closely reflects market prices is cement, where high grade lignite is involved. As noted below (para. 6.54), lignite currently is moved considerable distances (about

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14/ Lignite Pricing Study by Meta Systems, Inc. (1983).

550 km) by private operators at highly competitive transport costs (US¢2/km). The delivered prices 16/ of lignite in the Saraburi area (center of the cement industry) in 1984 were US$30-33/ton (US$1.68-1.84/MMBTU), 17/ of which roughly one-third of the price represents the transport cost element. This implies a mine-head price of some US$22/ton (US$1.23/MMBTU) for a private operator.

Hydropower

3.38 The total hydropower potential of rivers in Thailand (i.e. completely under Thai control) is estimated to be 8,300 MW, offering an annual energy generation potential of 14,330 GWh/year; of the latter, installed capacity was 1,809 MW in April 1985. The average load factor for hydro generating plants is only 32% because the majority of the plants are used for intermediate and peaking purposes.

3.39 Apart from the installed capacity, a further 429 MW is already under construction, and EGAT's development plan calls for an additional 840 MW of hydro capacity to be installed by 1995, when the total should be 3,078 MW with an energy generating potential of 6,600 GWh/year. This would represent about 37% of the estimated indigenous hydro capacity and 46% of its hydro energy generation potential. Most of the remaining sites are small and apparently have limited economic potential despite their high aggregate amount. It is possible that many of the smaller sites could be exploited for local use outside the interconnected grid system (mini-hydro).

3.40 NEA has been in charge of the development of mini-hydro plants outside the integrated EGAT system, although the management of many of these is turned over to EGAT management upon completion of construction. The principal potential for this development is in the northern provinces of Thailand. By the end of 1984, NEA had completed five mini-hydro projects and had seven more under construction or planned, for a total of 75 MW of installed capacity. "Micro-hydro" projects of 5 kW to 200 kW capacity have been installed at twelve sites, and ten more are under construction or planned, for a total installed capacity of 1 MW. The installed cost of these projects is high, around $3,500 per kW, including transmission and distribution. Thus, the construction of such projects must be justified more on social grounds than economic ones.

3.41 The hydro capacity of rivers within Thailand is dwarfed by the potential of rivers forming the Thai frontier with Laos and Burma. Ten

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15/ Based on an average Mae Moh calorific value of 2,700 kcal/kg.

16/ Monenco Study (1984) of Potential Coal Demand.

17/ Based on high grade, more than 4,500 Kcal/kg lignites.

possible sites on these rivers would have an installed capacity of 14,000 MW and an energy generation of 90,000 GWh/year. The Pa Mong site on the Mekong River alone could have an installed capacity of 4,800 MW and the Salawin Project on the Burmese border could have another 3,000 MW. Problems impeding the development of these projects are as much political as technical. Their development would require agreement between the riparian powers. Since neither Burma nor Laos is likely to be in a position to absorb the energy provided by such projects, any such agreement would have to include acceptable terms for Thailand to use the other countries' shares of the energy generated. Given the long lead time required for constructing such large projects, it is probably not too soon for Thailand to initiate preliminary negotiations with the two neighboring countries, although it is unlikely that any energy will be available from these sources until some time early in the next century. Unless there are further major increases in gas, oil and/or lignite discoveries in Thailand over the next decade, by the beginning of the next century imported energy will again play a significant role in meeting the power sector's requirement. Within this context, international hydro would become an important alternate option. Thailand currently imports power generated at the 150 MW Nam Ngum hydro installation in Laos. These imports have been transmitted to the Thai grid without any non-technical break since the initial Nam Ngum units were commissioned in December 1971. Many other hydro sites which could be developed exist within northern Laos. Six of the largest of these sites have a total capacity in excess of 4,000 MW with an estimated energy generation of 17,500 GWh/year. Desk top studies have suggested that probably all six of these would be economic to develop with a view to exporting the power to Thailand. The most favorable of these sites is on the Nam Theun with a potential of 1,200 MW. A recently completed prefeasibility study of this site indicates that 5,000 GWh/year could be delivered to the Thai grid at a very competitive price. The study suggests that, given favorable encouragement by Thailand, the first 600-MW phase of the project could be commissioned in 1996 and the second 600-MW phase in 1997. The early involvement by Thailand during the predevelopment stage would help ensure that the development of such sites would be timed to fit in with Thailand's energy and power requirements.

Table 3.6: THAILAND: INDIGENOUS HYDRO POWER

	Capacity		Energy		Load
	Installed	Dependable	Average	Firm	Factor
	(MW)		(GWh)		(%)
1. Installed	1,809	1,533	5,007	3,346	32
2. Under Construction	429	358	528	217	14
3. Planned for Completion 1988-95 a/	840	-	-	-	-
Total	3,078	?	6,600	?	25
4. Additional Identified Site	1,750				
5. Mini-Hydro	800	800			
Total	5,628				
Theoretical Potential	8,300		14,330		20

a/ Includes Nam Choan with capacity of 580 MW.

Source: Items 1-2 EGAT Power Development Plan (1985-2001), May 1985, other items mission estimates.

Biomass

3.42 The residential sector in Thailand has traditionally relied on wood and charcoal for cooking fuel. However, population pressure on the land and constantly increased felling of trees have placed the long-term future of this fuel resource in jeopardy. At present some 36 million people (75% of the population) reside in rural areas. In 1980, about 40% and 55% of rural households used wood and charcoal, respectively, as their principal cooking fuel. The combination of fuelwood collection, agricultural expansion, commercial fellings and the effects of urbanization have reduced the country's forested land area from 27 to 16 million hectares over the last 25 years. It is further estimated that, by the turn of the century, the forested land area is likely to have decreased to 11 million hectares if current trends continue (para. 8.25). The sustainable yield for all of Thailand's forests is estimated to be about 37.5 million m^3 (9.6 million TOE) a year relative to current demand of 39 million m^3. However, as only about 20% (around 8 million m^3) of the forests are economically accessible, there is a very high level of overcutting near inhabited areas, which reduces the sustainable yield from this source in future years. The net effect is that forests near inhabited localities are being heavily overcut, thus requiring the transport of woodfuels from greater distances each year. This in turn implies that the cost of wood and charcoal will increase steadily in the future.

3.43 In addition to wood, substantial quantities of bagasse and paddy husk are consumed as fuel in the sugar and rice industries. These fuels are utilized by the industries producing them and do not generally find their way into domestic consumption in large quantities. The quantities produced and used are directly proportional to the level of activity in the industry involved, i.e., bagasse in the sugar industry and rice hulls in rice mills. There is a substantial surplus of rice husks and bagasse not required by their processing industries to meet captive energy demand. Research is in progress to see if these can be turned into usable domestic or industrial fuels in order to relieve the pressure on fuelwood supplies (paras. 8.34-8.35).

Oil Shale Resources

3.44 It has been well known for several years that Thailand has reserves of oil shale in the Tak Province. The area of the sedimentary basin of tertiary deposits in Thai territory is about 500 kms^2. The reserves of oil shale are estimated at about 6 billion barrels. The Department of Mineral Resources (DMR) has been conducting an exploration drilling program in this region since February 1974. Through a chemical analysis of the oil shale samples from drilling data, the quality and quantity of oil shale have been evaluated. The results indicated that oil shale quantity ranges from 1% to 26% by weight or 10 to 330 liters per ton of oil shale. The specific gravity of oil shale was about 0.9 at 60°F. At the 1985 level of oil prices and given the prospects for these prices over the next several years, the exploitation of shale oil in Thailand would not be competitive. As such, this area of resource exploration and development should be given low priority in the assessment team's view.

IV. ENERGY RESOURCES - OIL AND GAS

Background and Occurrences

4.1 Small quantities of oil have been produced from the Fang area of Northern Thailand for many years but the modern phase of the industry began with the discovery by Union Oil of the Erawan gas-condensate field in the Gulf of Thailand in 1974. Another large gas field was discovered further south in the Gulf by Texas Pacific. Subsequently, Shell discovered oil at Sirikit, north of Bangkok in 1981, and Esso discovered gas in the Khorat Plateau of northeast Thailand. With the exception of the Khorat gas, which is produced from relatively old rocks, the oil and gas fields of Thailand produce from five sedimentary basins containing rocks of relatively young geological age, mainly sands and shales, located along the axis of the central valley and extending south into the Gulf of Thailand. There is another sedimentary basin off the west coast of Thailand which is relatively unexplored and its petroleum potential cannot be evaluated with any precision at this time.

4.2 Most of the fields which have been discovered so far are geologically complex, much broken up by geological faults, and have reservoirs which are laterally discontinuous. This is the case with the Erawan field, where experience has shown that it is in effect an agglomeration of small discrete accumulations rather than the large individual field it was originally thought to be. The corollary of this is that larger numbers of wells are needed to develop any discovery, and individual well recoveries are relatively low, while the fields themselves are subject to relatively rapid declines once they have reached peak production. There is also the likelihood that over time many small oil and gas fields rather than a few large ones will be found. All of this has consequences of major importance for the future of the oil and gas industry in Thailand, and, in particular, government policy (paras. 4.40-4.48). One of the most important of these is that, in order to maintain a given level of production, a steady, continual pace of exploration is needed. Another consequence is that the investment per unit of production will be higher in Thailand than it would be in, for example, Indonesia or Malaysia. The legal and fiscal system governing the oil industry must take account of these factors if steady progress is to be made in producing oil and gas, as opposed to the stop-and-go regime which has characterized exploration activity so far.

4.3 The reasons for the lack of continuity in exploration are many. Some are based on international oil industry factors beyond the control of the Thai government; others are the results of gaps or deficiencies in the existing petroleum legislation, and of actions taken unilaterally by RTG with regard to the fiscal treatment of oil and gas development by private companies which the latter regarded as financially detrimental to their interests. The initial disappointment to the private concession holders in the Gulf of Thailand was the failure to discover sizeable oil accumulations. The only significant discoveries were those made by Union Oil and Texas Pacific which consisted of gas/-condensate fields that could not be produced until there was a market for the gas. This resulted in all but these two companies relinquishing their concessions. The prolonged negotiations over the price to be paid by the government for gas produced from the offshore fields (which still have not been concluded in the case of Texas Pacific) and the associated uncertainty for explorers about that price, and the disillusionment resulting from the realization that the producible reserves and production rate of Union Oil's Erawan field were much less than had been forecast, all had a discouraging effect on further exploration offshore. The discovery of oil at Sirikit by Shell in 1981 was very encouraging for future oil exploration in Thailand as a whole, but its effect was largely negated by DMR's publication in 1982 of additional tax requirements, on the eve of a general weakening in international oil prices.

Oil and Gas Reserves

4.4 To date oil and/or gas has been found in five basins: Fang Basin in northern Thailand, Sukhotai in north-central Thailand, Khorat in eastern Thailand, the northern Gulf of Thailand, and the central and southern Gulf of Thailand. In northern Thailand the Defense Energy Department has been producing small amounts of oil from Miocene sandstone reservoirs associated with a lacustrine shale source; between 300-500 bbl/day of medium gravity high paraffin oil have been produced in the Fang Basin over the past 20 years. There are several discoveries, the most important of which is Mai Soon. Additional discoveries in the Fang Basin are likely and at least six other similar basins -- several considerably larger than the Fang Basin -- exist in northern Thailand but have not yet been tested by the drill. Shell has found at least four oil accumulations in the Sukhotai Basin, of which the Sirikit Field is the principal discovery. Sirikit produces from lacustrine/fluvial Miocene sandstone with a probable Miocene lacustrine shale source. The structure appears to be a remnant of a collapsed anticline. Additional finds on the Shell Block are likely, and a discovery in an adjacent block was reported recently. Esso has tested two gas discoveries on its Khorat Blocks and encountered a strong indication on a third feature (Channobot). Gas is reservoired in upper Paleozoic carbonates which have low matrix porosity caused by fractures below the mid-Triassic unconformity. Amoco tested oil and gas in Block 5/27 (now PTT) in the upper Gulf of Thailand from L. Miocene sandstones. Union has eleven discoveries (several may be combined for production), and Texas Pacific made three discoveries in the central and southern Gulf of Thailand (Pattani Trough, an arm of the Malay Basin). These fields produce from lenticular fluvial sandstones of Miocene/ Oligocene age. Structures are north/south oriented collapsed features with a high density of faulting. Table 4.1 indicates present estimates of proven oil and gas reserves.

Table 4.1: THAILAND OIL AND GAS RESERVES
(as of February 1985)

Field	Proven Reserves Oil/Condensate (million barrels)	Gas (BCF)	Operator	Location
Erawan	25.6	628	Union	Offshore
Baanput	8.2	165	Union	Offshore
Platong	4.5	144	Union	Offshore
Satun	10.0	580	Union	Offshore
Kaphong	-	-	Union	Offshore
Pladang	-	-	Union	Offshore
Funan	-	-	Union	Offshore
Jakrawan	-	-	Union	Offshore
Pakarang	-	-	Union	Offshore
Trat	-	-	Union	Offshore
"B" b/	10.6	1,799	Texas Pacific	Offshore
"E" b/	2.4	125	Texas Pacific	Offshore
Sirikit c/	36.3	-	Thai Shell	Onshore
Sirikit-West c/	1.4	-	Thai Shell	Onshore
Nam Phong	-	280 a/	Esso Khorat	Onshore
Total	99.0	3,721		

a/ Estimate by Department of Mineral Resources (DMR).
b/ Estimates of the Texas, Pacific Band E structures have not been revised downwards to take into account the Erawan experience.
c/ A small amount of associated gas exists at t;he Sinkit field, though it is not shown here.

Source: NESDB Working Group on Energy Supply and Investment for 6th Five Year Plan (March 1985).

4.5 The structural and stratigraphic complexities previously referred to (fragmenting reservoirs into small components - fault blocks and/or sand lenses) make the estimation of recoverable reserves, i.e., the fraction of in-place reserves that will be produced, difficult in the absence of production history and reservoir performance. This situation causes recoverable reserves and production levels to be unusually sensitive to price/cost relationships and highly dependent on well density and abandonment levels. This sensitivity of reserves to price is important in a situation where there is little margin between production cost and price/value, especially during periods of weak international oil prices which act as the ultimate marker of gas value. This is well illustrated by the dramatic reduction in estimates of recovery factors at Erawan, from 82% of in-place gas reserves -- a rather standard expected gas recovery fraction -- to approximately 35%. Clearly, if the price/cost relationship were to improve, recoverable reserves would increase through higher density of drilling, produced from more reservoir compartments, or lower abandonment levels. On the other hand, if the price/cost relationship were to deteriorate significantly, it would not be economic for the producer to develop the field at all. The Erawan lesson has been well taken and applies to most if not all of the fields discovered in Thailand to date; the reserves estimated above and the undiscovered potential estimated in the following paragraph therefore incorporate a conservative approach to the expected recoverable fraction. To maximize recoverable reserves from both past and expected future discoveries and thereby maximize government benefit, the operator must receive the highest justifiable price and keep a tight control on his costs. In this context, government benefits come directly from royalty and taxes rather than on the margin between price and costs.

4.6 The potential oil and gas resources for Thailand are estimated in Table 4.2.

Table 4.2: TOTAL ESTIMATED POTENTIAL OIL AND GAS RESOURCES IN THAILAND

Basin	Total Expected Oil/Condensate (million barrels)	Total Expected Gas (BCF)
Northern	150	250
Central	500	1,500
Khorat	5	7,500
Northern Gulf	50	200
Western Gulf	100	600
Southern Gulf	180	6,000
Total (excluding Andaman Sea)	985	16,050
Andaman Sea	165	3,200
Total	1,150	19,250

Source: Based on data from exploratory activity.

As shown, total potential oil/condensate and gas resources in Thailand (including the Andaman Sea) amount to some 1.15 billion barrels and 19.3 trillion cubic feet, respectively. However, proven reserves to date of oil and condensates only represent about 9% of total potential while in the case of gas, current proven reserves are around 19% of total estimated resources. From this it is clear that there is still considerable scope for increased discoveries of oil and gas in Thailand. Such discoveries should be forthcoming, provided government adopts the appropriate policies to encourage a higher level of exploration and development activity by the private oil companies as well as measures to ensure a key role for gas in the energy supply mix.

Cost of Gas

4.7 The assessment team estimated the economic unit cost of gas for the following fields: Erawan (Union I contract, currently producing); Baanpot, Satun and Platong (Union II contract also producing); Union III contract (not yet negotiated); Texas Pacific "B" structure (not yet negotiated), and Esso-Khorat (negotiations not completed). Based on the assessment team's estimate (para. 4.32-4.39) of gas supply under Scenario II investment costs for field exploration and development as well as delivery costs, the costs of gas supply from the various fields in Thailand were derived. The assessment team's estimate of these costs for the Union I and II supplies at late 1984 prices are shown in Table 4.3. In relation to unit costs, projected production and costs have been discounted at a rate of 12%.

Table 4.3: COST OF NATURAL GAS SUPPLY (1984)
($ per MMBTU)

	Erawan Union I	Union II
1. Exploration & production	1.7	1.5
2. Foreign remittances	0.2	0.4
3. Well head cost	1.9	1.9
4. Govt. take (Royalty/ tax/PTT profit share)	0.5	0.6
5. Well Head price	2.4	2.5
6. Pipeline cost a/	0.6	0.6
7. Delivered cost (lines 3 & 6)	2.5	2.5
8. Delivered price (lines 5 & 6)	3.0	3.1

a/ Based on gas delivered to Bangkok.

4.8 It should be noted that the costs of exploration and production are the estimates of the Bank, and the operating companies may not necessarily concur with these cost estimates. Further, as noted above, the timing and quantity of gas production are subject to substantial uncertainties. Accordingly, the unit cost of exploration and production would need to be revised in the event of changed expectations regarding investment costs and gas supply outlook.

4.9 For purposes of estimating the production costs of gas, condensates have been treated as a by-product and the income derived therefrom has been netted against the field operating costs. While Union's fields are expected to have the lowest productivity of gas on a per well basis, they are at the same time projected to produce rich gas which would yield the highest production of condensates. The opposite is expected of Esso's onshore operation at Khorat in that it would have the highest productivity of gas per well but negligible condensate production. Texas Pacific fields, when compared with those of the other two producers, are expected to have medium productivity of both gas and condensates. Detailed assumptions on gas and condensate productivity for the various fields are set out in Annex 4. In effect, the high unit cost of gas at Union's fields (which has resulted from the low productivity of gas per well) is partially offset by the income from high condensate yields. Similarly -- but to a lesser extent -- the unit cost of Texas Pacific gas may be reduced by condensate income.

4.10 In addition to the exploration and production cost, the well head cost of gas to Thailand includes a return to equity capital of the producers. It has been assumed that these profits accruing to the foreign concessionaires would be remitted abroad. While in principle the well head cost should also include a depletion premium, it is presently estimated to be small 18/ and has been treated as zero in this report. Determination of the depletion premium is dependent on:

(a) the cost of gas production;

(b) the cost of replacement fuels (additional gas from exploration, coal and/or fuel oil) when the gas runs out; and

(c) the lifetime of the gas reserves.

The cost of gas produced and delivered to Bangkok is high and is estimated to be US$2.4-2.8/MMBTU for known fields. This implies that the available rent is small. Second, because of the difficulty in estimating the cost of replacement fuels when the gas runs out, this can only be termed speculative. The major uncertainties about the evolution of these prices over the next twenty years make estimates about the cost of replacement fuels to gas that far in the future little more than educated guesses. If the reserves are assumed to have a 30-year life and replacement fuel costs assumed to be constant in real terms over this period the depletion premium is negligible. Based on the current state of knowledge of the country's gas reserves, gas production costs and the future value of fuel to replace gas when it is depleted, the assessment team has treated the depletion premium as zero.

4.11 Well head prices of gas include both well head costs and government take from the various fields. government take has been derived from royalty, income taxes paid by the foreign operators as well as PTT's profit share in case of joint ventures. A royalty of 12 ½% has

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18/ PEIDA Energy Pricing Study, 1984.

been calculated on the basis of gas and condensate revenues to the producers. Income taxes of 50% have been estimated on the basis of projected production costs and well head prices for each field.

4.12 Well-head prices for fields not covered under the existing contracts, namely Union's third contract and those of Texas Pacific and Esso, have been estimated assuming that the delivered price is equal to the adjusted price of imported coal (which is the fuel likely to be substituted at that time). The well-head price is then the imported coal price 19/ minus the cost of transporting gas. By and large, future gas supply contracts would provide for incremental gas supply over and above the demand for fuel oil replacement and generally would be substituting imported coal and/or lignite for power generation (para. 3.36). As a result, imported coal has been taken as the relevant parity 19/ for estimating the value or opportunity cost of gas from these fields. Delivery charges include the costs of pipeline and compressors (if any) and a profit margin to allow the pipeline operator a reasonable rate of return on investment. In the case of shared delivery system costs such as the submarine trunk line and offshore compressor, a cost allocation has been made on the basis of gas volume.

4.13 The delivered cost of gas to Thailand includes the well-head cost plus pipeline cost. Based on the assessment team's estimates the most expensive source of gas worth developing, depending on the future prices of fuel oil/coal, is expected to be Texas Pacific. Based on the methodology mentioned above for estimating the well-head prices for future gas supply contracts, the economic costs of gas from the various fields may vary only within a small range of about $0.4 per MMBTU. Furthermore, the well-head prices so derived may yield an adequate, though not high return to the producers of all the fields.

4.14 However, as already noted, gas reserves and development costs are subject to considerable uncertainty. If these major parameters turn out to be less favorable than the Bank estimates, the Texas Pacific (TP) field, in particular, could be of only marginal commercial interest, especially if oil/coal prices decline further. This is mainly because the delivered cost for TP gas is likely to be the highest among all the known fields, and therefore its producers could expect to receive a lower well-head price than for closer fields.

Fiscal/Legislative Regimes and Suggested Revisions

4.15 The existing petroleum legislation in Thailand provides a basic framework for petroleum exploration by private oil companies which is essential because the government has neither the risk capital nor the technical expertise to undertake this activity on its own. However,

19/ Adjusted for the additional costs of capital and operations and maintenance associated with coal use in the power sector.

certain aspects of the legislation require clarification, modification and updating if exploration activity is to be renewed and sustained.

4.16 The present fiscal regime under which oil and gas producers operate in Thailand is biased against the development of small fields because of its heavy reliance on royalty payments to the government. There are several aspects of the fiscal/legislative regime that need to be considered:

Royalty: in effect, this is a fixed tax on production irrespective of cost or production rate. As such it is regressive in respect of small marginal fields which, for geological reasons, may be more common in Thailand than larger fields. It is suggested that royalty payments be graduated according production rate, with lower production rate fields paying less royalty than the present 12½%. Under the present regime the smallest offshore oil field which could profitably be developed is around 15 million barrels. Suitable modification of the tax regime could reduce this threshold to about 10 million barrels. The economic thresholds onshore would be lower because development costs are lower, but the same general principles apply. It does not appear to be in the national interest to inhibit the development of small oil and gas fields since their aggregate contribution to total production could be significant. However, any changes to the existing fiscal regime must be approached cautiously, and only after full discussion with the private operators. Few things are as disturbing to investor confidence as sudden and arbitrary changes in the taxation system.

U.S. Tax Compatibility: minor changes are needed in the current taxation system to ensure compatibility with US tax regimes. In this context, any modifications in the petroleum industry's fiscal regime should take into account their effect on the total tax paid by operators in Thailand to RTG and to their own governments. It is important that the two tax systems be compatible in order to minimize the effect of double taxation of profits, which again would have an inhibiting effect on further exploration and development. Thailand should seek to ensure that producers are able to obtain maximum advantage from home country tax systems. This will include measures such as allowing interest as a tax reduction.

Abandonment of 1982 DMR Special Benefits: the government should cease to apply 1982 tax and royalty demands for new concessions. They provide severe limits on the costs which can be offset against income, such that taxation in the early years is high compared with the bases in most countries. The requirements also provided for a steep increase in royalties unrelated to profits. These measures are more appropriate for Malaysian-style hydrocarbon discoveries of the immediate post 1979 period and have proved unwise for Thailand. Although geologically attractive areas were offered to the industry, this action restricted the number of offers made to just a few offered by small under-capitalized companies. Several of these were accepted. Acceptance of such offers brings risks of delay in financing, and exclusion of the majors reduces the range of exploration expertise. Some offers were made by larger companies eager to initiate some exploration in Thailand. The assessment team understands, however, that many of the companies are concerned that the fiscal terms will prevent production of small discoveries.

Other Legal Aspects

4.17 Apart from the three key areas noted above, there are lesser but nevertheless important aspects that could conveniently be tidied up at the same time. The various issues noted below are of substantial importance to government but more minor importance to the companies, so that they could be addressed as part of a wider package without materially affecting the country's attractiveness as a place for exploration. They could also be implemented for existing concessions, after full consultation, in exchange for improved incentives.

4.18 Obligation to produce: currently companies can obtain 40-year production licenses (30 plus 10) giving them substantial rights but no obligation to produce. Once the pricing basis is clarified (para. 4.27-4.29) it would be reasonable to include firm production obligations in any production license.

4.19 Exploration/production periods: overall exploration (12 years) and production (40 years) periods are very long by international standards, particularly for oil, and could usefully be brought down to customary levels.

4.20 Relinquishments: in some cases exploration is aimed at optimizing relinquishment obligations rather than bringing discoveries on-stream quickly. A number of countries have built flexibility into their regulations so that government can defer the relinquishment obligations in the event of a discovery in order for the discovery to be delineated promptly. This might also be in Thailand's interest.

4.21 Confidentiality: Thailand's provisions for the treatment of oil company acquired data keep such data confidential as long as the license is in effect and for several years thereafter, which is more restrictive than most countries. Further, the confidentiality provisions are rigidly interpreted by the DMR as their sole responsibility and a Ministerial request is necessary for any other government entity to obtain access. Thus, valid uses of such data for the National Five Year Plan, gas network and railroad planning, and PTT and EGAT counterpart investments are substantially inhibited. The promotion of Thailand's hydrocarbon potential to the international industry -- a particularly important function belonging to the DMR -- is also neglected under the guise of confidentiality. Companies expect the government to use the data collected and provided by them. They do not expect that a hard copy of that data will be sold or otherwise provided to competitors during the period of confidentiality. Reductions in the confidentiality period should be incorporated in new contracts and attitudes within the government should be relaxed to permit the various agencies concerned to either use the confidential data directly or require the DMR to provide the necessary interpretations.

Joint Ventures and Participation

4.22 Present law and regulations do not provide for Thai participation or for production sharing. The present joint venture provisions in most concessions are vague and represent a disadvantage to Thailand. Either joint ventures or production sharing would have advantages over the present system in giving larger benefits to the country.

4.23 Most production sharing systems require no cash input from government; instead, in a typical arrangement a share of production is used to cover costs and the balance is shared between government and company. In general, the average cash position would be comparable in a joint venture system, but in this case government would have to provide cash in the early period, with a view to getting greater benefits later. Although carrying some financial risk, in a number of situations the joint venture system is more advantageous to Thailand at this stage. The joint venture is important to ensure that the discovery is properly proven before the joint venture is effective. It provides for a more effective transfer of technology and operating experience for Thai nationals and a more harmonious relationship between the foreign investor and the country in the financial and operating areas. The joint venture system also avoids a major and unsettling change in legislation.

4.24 The most appropriate way of clarifying and simplifying the position is for DMR regulations to specify inclusion of a joint venture option for a Thai oil company for all new concessions, to be activated for commercial developments after an adequate testing period (to minimize risks) or to provide for a production sharing system as an alternative. The parameters would need to be set out in detail in DMR regulations. The Thai share of the joint venture should be pitched at a level reflecting risks (both field and transport) and ability to obtain financing, which for some of the larger gas options may mean a fairly minor share of production.

Accelerating the Exploration and Negotiating Process and the Role of Gas/Oil Prices

4.25 The fields being developed by Shell (onshore oil) and by Union, which produces gas and condensate in the Gulf, are foreseen to be relatively shortlived -- typified by rapid production build-up with a short peak production plateau, followed by equally rapid decline. As a result, there is a clear need for continuing development of additional discoveries and intensifying exploration efforts. Unless the contracting process can be simplified and speeded up, there is an imminent danger that discoveries will not be brought on-stream fast enough, leading to:

(a) a serious under-utilization of downstream investments in pipelines and gas recovery facilities;

(b) significant financial and economic losses to government in terms of delayed or foregone revenues and economic benefits (in terms of oil import displacement); and

(c) severe financial penalties for the private operators in terms of not being able to quickly recover their exploration costs.

4.26 As discussed below (para. 4.35), significant declines in oil, condensate and gas production capability levels from existing contracts with Union Oil and Shell are expected from 1989 onwards. Given the long lead times involved in finding and developing additional reserves, it is crucial for government to satisfactorily conclude current negotiations with additional companies regarding the development of discoveries already made, as well as adjusting regulations along the lines highlighted above to accelerate exploration activity. The oil industry needs a clear signal that additional gas/oil contracts can be concluded expeditiously with the government if it is to be convinced that there is a long-term national commitment to gas utilization.

4.27 In addition, an issue in speeding up the negotiating process, and which requires early resolution is gas pricing. The lack of any accepted international reference point for gas prices to the producers in Thailand is regarded as a major deterrent to further exploration and has led to protracted negotiations and delays in the development of fields already discovered. This damages both the companies and the country's interests. Given the high probability of finding gas rather than oil, companies embarking on exploration need to know at the outset at least the basis on which gas would be valued. This currently does not exist and its absence inhibits oil exploration as well since exploration for oil and gas cannot be neatly separated.

4.28 In the assessment team's view, clear guidelines for the pricing of gas to producers and consumers need to be established immediately. Current gas contracts between PTT and Union Oil are based on a "cost-plus" approach (and therefore backward looking) with the gas price derived at the "field-gate". In terms of escalation, this price is linked <u>partially</u> to Singapore fuel oil prices (about 40%) as well as to the U.S. and Thai inflation levels and the exchange rate of the Baht. As a matter of policy, Thailand needs to move away from cost-based gas pricing for producers since it is clumsy, prone to cause extensive delays in contract conclusion, and often leads to a decline in industry exploration and production activity. It also sends confusing signals to consumers. The country should move to a market-oriented gas pricing system in which prices are closely related to the opportunity value of gas rather than to producer costs. The assessment team endorses the proposal discussed by the joint World Bank/NESDB energy assessment team for the establishment of a gas Basing Point Price in Bangkok for all future gas contracts. This would be the wholesale price of gas at the

Bangkok end of the transmission system with consumers being charged different retail prices depending on volume, load profile interruptibility, quality and distance from the basing point, etc.

4.29 One possible option for establishing a natural gas pricing system for new gas contracts in Thailand is discussed in more detail below; however, several features of such a pricing system can be set out here (existing contracts, of course, would not be affected):

(a) a clear signal must be sent to producers and consumers regarding current and future principles governing the pricing of natural gas;

(b) the pricing system adopted must have a high degree of transparency so that producers and consumers are able to determine well head prices and plant gate prices respectively, given a Basing Point Price for gas in Bangkok;

(c) the gas price at the Basing Point must be directly linked to the international prices of competing fuels, expressed as a percentage (y%) of the fuel oil price in Singapore; this percentage the assessment team terms the "discount parameter" (sub-para. (e) below);

(d) to address short term movements, the Basing Point Price will be adjusted on a quarterly basis to follow the behavior of the fuel oil price in Singapore, over the preceeding 90-day period;

(e) government will adjust every three-five years, the "discount parameter" in order to reflect the medium term changes in the opportunity cost of gas (as this varies between fuel oil and coal parity) which in turn depends on the perceived medium term balance between supply and demand for gas. Arrangements would need to be built in to limit the effect on producers and to allow them sufficient certainty for investment decision making and planning;

(f) in order to simplify and give transparency to the system, it is important that the gas transport cost be established clearly. In establishing the cost (or price for common carrier systems), the guiding principle would be a reasonable return on investment to the pipeline owner. The cost will also depend on the volume, load factor, distance and interruptibility of the gas being transmitted.

(g) that government should implement the above system concurrently with a revised tax and royalty system so that government takes its benefits through royalty and income tax on gas production based on profits measured at the well head.

4.30 There does not appear to be any problem regarding oil producer pricing in Thailand, as the current practice reflected in the contract between Shell and RTG appears adequate. Under this, the crude oil is priced relative to international prices based on the refinery net-back resulting from distilling the crude and applying Singapore refined product prices and an appropriate refinery margin.

4.31 In addition to measures dealing with modifications to the petroleum legislative/fiscal framework and adoption of new policies on gas pricing, Thailand can take other steps to encourage the interest of foreign oil companies and accelerate exploration efforts. This would involve DMR, which has vast amounts of data -- some still confidential to the government. It is important that DMR staff obtain a more thorough understanding of the petroleum potential of each basin. Most commonly this sort of understanding comes from basin studies by in-house geologists supported by consultants. This understanding would enable DMR to make future projections of oil and gas discoveries and would highlight priority areas where action would be important. In this way DMR could play an active role in the systematic promotion of promising acreage and in negotiating work commitments with interested companies.

Natural Gas/Condensate and Crude Oil Production

4.32 Natural gas and condensate production in Thailand began on a commercial scale in 1981 when Union Oil produced an average 128 MMCFD of gas and 5,600 Bbls/day of condensate. Despite the early setbacks experienced by Union with its Erawan field (para. 4.3), in 1984 its gas production reached 214 MMCFD, 14% of which came from its second contract which became effective in 1984. Present estimates are that in 1985 total gas production would rise to 485 MMCFD, 95% from Union's I & II contract and the remainder from Shell's onshore Sirikit production. This represents nearly a fourfold increase in gas production within three years and can be considered a major achievement by the oil industry, government, and PTT (owner of the underwater pipeline in the Gulf linking Union's fields to Bangkok). Added to this, condensate production is estimated to reach 14,100 Bbls/day in 1985 (all from Union's fields) while crude oil supplied from Shell's Sirikit field should average 18,100 bbls/day this year. This would represent about a sixtyfold increase in oil production relative to the 1981 level of 300 Bbls/day from the Fang fields produced by the Defense Department.

4.33 Table 4.4 shows the gas, condensate and crude oil production capabilities arising from the two Union Oil contracts for Gulf production and the Shell contract for onshore Sirikit production. These are the only production contracts in place at present and therefore represent reasonably firm estimates of likely production from these fields. Of special significance is the fairly rapid decline in production (para. 4.2) once the relatively short peak plateau has been reached. This lends added urgency to the need to accelerate the negotiation process for fields already discovered, since the long lead time for field development requires that additional significant levels of gas, oil and condensate production be brought on-stream by 1989/90 to avoid major declines in the availability of these indigenous fields.

Table 4.4: NATURAL GAS, CONDENSATE AND CRUDE OIL PRODUCTION CONTRACTED AS OF APRIL 1985

	Union Erawan a/		Union II b/ a/		Shell-Sirikit c/d/		Total		
Year	Gas MMCFD	Condensate Bbls/day	Gas MMCFD	Condensate Bbls/day	Gas MMCFD	Crude Oil Bbls/day	Gas MMCFD	Crude Oil Bbls/day d/	Condensate Bbls/day
1982	128	5,600	-	-	-	-	128	-	5,600
1983	146	6,000	3	100	5	6,100	154	6,100	6,100
1984	184	6,600	30	1,700	17	14,000	231	14,000	8,300
1985	200	6,700	262	7,400	23	18,100	485	18,100	14,100
1986	200	6,100	300	11,300	28	19,300	528	19,300	17,400
1987	180	5,300	320	11,600	25	13,400	525	13,400	16,900
1988	170	4,600	330	11,700	15	8,000	515	8,000	16,300
1989	140	3,500	360	11,900	10	7,100	510	7,100	15,400
1990	90	2,300	380	11,700	9	6,300	479	6,300	14,000
1991	60	1,500	370	11,000	7	3,900	437	3,900	12,500
1992	40	1,000	330	8,700	4	2,100	374	2,100	9,700
1993	25	700	280	6,400	2	1,200	307	1,200	7,100
1994	15	400	230	4,800	-	-	245	-	5,200
1995	5	200	150	3,200	-	-	155	-	3,400
1996	-	-	10	1,900	-	-	100	-	1,900
1997	-	-	50	700	-	-	50	-	700

a/ Offshore.
b/ Includes Baanpot, Platong, Satun, Kaphong and Pladang fields.
c/ Onshore.
d/ The Bank's Appraisal Report on Sirikit uses additional full-size Sirikit and allows for production of gas cap gas.

Source: "Thailand Natural Gas Reserves and Petroleum Production Forecast," NESDB Supply and Investment Working Group. (March, 1985)

4.34 In Annex 5 the gas, condensate and crude oil production capabilities are shown for discoveries made or indicated to date (as well as for some fields not yet discovered) but for which negotiations to develop the known fields have not yet been started or concluded. These production capabilities have been developed by the joint government/oil industry Working Group on Energy Supply and Investment of the NESDB for preparation of the 6th Five Year Plan. In the offshore domain, a third Union contract is included based on four discoveries (Funan, Jakrawan, Pakarang and Trat) but appraisal and development are still several years away. Texas Pacific's "B" structure, discovered and delineated, is included. Development of this structure awaits conclusion of a mutually satisfactory gas contract with the government. Due to its location a further 150 kms. into the Gulf than Union's discoveries, the transmission costs for this gas will be high. This, combined with the fact that this gas is low in condensate and high in carbon dioxide, makes its development more sensitive to the movement of international energy prices than other major gas discoveries in Thailand. In terms of onshore production scenarios, two cases are postulated. The first and most likely scenario includes Esso's Nam Phong discovery in the Khorat basin (two producers so far) which is awaiting the settlement of pricing and related issues before being placed on long duration tests. Also included in this scenario is oil production from several small fields in north-central Thailand, which in total are estimated by the NESDB Working Group at about half the production level of Sirikit. These fields include West Sirikit, Nong Toom, West Tan, Pradu Tao, and Bung Ya. The second scenario of onshore production is more speculative and is based on fields not yet discovered but considered likely in geological terms. The sizes of these discoveries assumed are: for oil, the same size as Sirikit; and for gas, possible reserves of 1.5 TCF likely to be discovered in the Khorat plateau.

4.35 Table 4.5 shows the gas, condensate and crude oil production capabilities between 1985-97 under four different conditions. The "base case" assumes the production capability represented by supplies currently contracted for. As noted above, by 1989/90 the production of gas, condensate and oil would begin to decline rapidly in this case. Scenario I includes:

(a) the "base case" plus;

(b) Texas Pacific and Union III production on-stream in 1990; and

(c) Esso's Nam Phong and additional Shell production equivalent to 1/2 of Sirikit. Esso's production beginning in 1986 and the additional Shell in 1987.

Under Scenario I, 20/ gas production would rise slowly from 485 MMCFD in 1985 to 783 MMCFD by 1990, peaking at 959 MMCFD in 1993 and beginning to decline in 1987. Condensate production would increase to about 17,400 Bbls/day in 1986 and slowly decline to about 11,200 Bbls/day by 1997. Oil production would peak at an average rate of 19,300 Bbls/day in 1986, decline slowly to 16,000 Bbls/day by 1990, and experience a more rapid fall-off in the 1990s (to about 2,000 Bbls/day by 1995).

4.36 Scenario II is the same as Scenario I except that it is assumed that there would be some slippage in Union III supplies becoming available. In this case, the supplies are considered to become available in 1992 and not 1990 as in Scenario I. This results in a somewhat flatter availability profile for gas in the 1990s (763 MMCFD in 1990 and 804 MMCFD in 1995). Under Scenario II, crude oil production is the same and condensate somewhat lower than Scenario I.

20/ This scenario was adopted by the NESDB Supply and Investment Working Group (March 1985) as their "Base Case".

Table 4.5: NATURAL GAS, CONDENSATE AND CRUDE OIL PRODUCTION CAPABILITY SCENARIOS (1985-97)

	Currently Contracted for a/			Scenario I b/			Scenario II c/			Scenario II.A d/		
Year	Gas MMCFD	Condensate Bbls/day	Crude Oil Bbls/day	Gas MMCFD	Condensate Bbls/day	Crude Oil Bbls/day	Gas MMCFD	Condensate Bbls/day	Crude Oil Bbls/day	Gas MMCFD	Condensate Bbls/day	Crude Oil Bbls/day
1985	485	14,100	18,100	485	14,100	18,100	485	14,100	18,100	485	14,100	18,100
1986	528	17,400	19,300	548	17,400	19,300	548	17,400	19,300	548	17,400	19,300
1987	525	16,900	13,400	568	16,900	16,450	568	16,900	16,450	568	16,900	16,450
1988	515	16,300	8,000	584	16,300	15,000	594	16,300	15,000	594	16,300	15,000
1989	510	15,400	7,100	622	15,400	16,150	622	15,400	16,150	622	15,400	22,150
1990	479	14,000	6,300	783	14,900	15,950	763 f/	14,000	15,950	763 f/	14,000	29,950
1991	437	12,500	3,900	820	14,600	10,600	750 f/	12,500	10,600	750 f/	12,500	28,600
1992	374	9,700	2,100	912 e/	13,600	6,100	812 f/	10,600	6,100	812 f/	10,600	26,100
1993	307	7,100	1,200	957 e/	12,900	4,750	832 f/	9,200	4,750	832 f/	9,200	18,750
1994	245	5,200	-	954 e/	12,800	3,150	829 f/	9,100	3,150	829 f/	9,100	11,150
1995	155	3,400	-	954 e/	13,700	1,950	804 f/	10,000	1,950	804 f/	10,000	9,150
1996	100	1,900	-	934 e/	13,300	1,050	809 f/	9,500	1,050	859 f/	9,500	7,350
1997	50	700	-	854	11,200	600	849 f/	11,000	600	929 f/	11,000	4,600

a/ From Table 4.4 includes Union I and II and Shell-Sirikit.

b/ This is based on the following assumptions: (i) supplies currently contracted for plus; (ii) Union III and Texas Pacific contracts signed with supplies on-stream in 1990 according to Annex II plus; (iii) additional gas from Esso's Nam Phong field in 1986 and gas and oil from 1987 from Shell fields about 1/2 the size of Sirikit.

c/ Scenario II is based on the following assumptions: (i) currently contracted for supplies plus; (ii) Texas Pacific and Union III supplies on-stream in 1990 and 1992 respectively plus; (iii) additional gas from Esso's Nam Phong field in 1986 and gas and oil from 1987 from Shell fields about 1/2 the size of Sirikit. The Bank's Sirikit Project Report uses additional full-size Sirikit.

d/ In Scenario II.A, it is assumed that an additional oil field, the size of Sirikit would be discovered and developed by 1989 and a gas field equivalent to Esso's Nam Phong discovered and developed by 1996.

e/ Under this scenario between 1992-96 gas supplies from the Gulf would range between 700-750 MMCFD; therefore requiring investment in compressors.

f/ Under this scenario between 1990-1997 gas supplies from the Gulf range from about 600-645 MMCFD.

Source: "Thailand Natural Gas Reserves and Petroleum Production Forecast," NESDB Supply and Investment Working Group (March, 1985).

4.37 Scenario II.A is based on Scenario II plus the additional speculative assumptions that another oil field the size of Sirikit would be discovered, developed and on-stream by 1989 (Annex 4.2) and a gas field equivalent to Esso's Nam Phong discovered, developed and on-stream by 1996. The major difference with Scenario II concerns oil production, which rises to 30,000 Bbls/day by 1990 and declines to one-third by 1995.

4.38 In the assessment team's view, if the modifications to the legislative/fiscal regimes and other recommended policy measures are adopted expeditiously and contract negotiations with Union, Esso and Texas Pacific concluded in the near future, production capabilities along the lines of Scenario I could be achieved. However, if one allows for delays in government implementing the needed measures, somewhat protracted negotiations with the oil companies, and soft oil prices over the next couple of years, production profiles closer to those in Scenario II could result. It is this scenario that the assessment team considers most likely to represent production capabilities over the next ten years.

4.39 The production forecast for all cases recognizes that, as a result of geologic complexity, particularly dense faulting, the fields consist of a large number of individual reservoirs. This implies high well density and rapid depletion rates so that all fields, with the possible exception of Esso's Khorat basin, are expected to be relatively short-lived. These factors all point to the fact that energy strategy in Thailand will have to manage many uncertainties in production levels and associated costs for hydrocarbon production. Government benefits are therefore likely to fluctuate in tandem with the gas volumes in PTT's, EGAT's and other consumers' facilities.

The Role of Government, PTT and DMR in the Oil and Gas Sector

4.40 PTT was established in December 1978 by the Petroleum Authority of Thailand Act to engage in and promote the petroleum business, including related petroleum and petrochemical activities. At present, PTT operates as a single legal entity. PTT's exploration and production subsidiary was established in July 1985. The core of PTT's activities has involved gas purchases and sales, gas transmission, refining and petroleum products marketing. Its two major operational units consist of the Natural Gas Operations and Oil Marketing Operations. As PTT's role soon will be expanded to include a minority share in upstream operations -- the immediate one being a 25% share in a joint venture with Shell to develop Block S-1 -- its exploration and production (E&P) department will also become an active operational unit through the new subsidiary. Insofar as downstream operations are concerned, PTT has entered into joint venture agreements holding shares in the TORC refinery (49%) and National Petrochemical Corporation (48%), National Fertilizer Corporation (21%), Thai LNG Company (10%) and Bangkok Aviation Fuel Services (10%). In addition, PTT is a 30% shareholder of the Bangchak Petroleum Corporation (BPC).

4.41 PTT has a staff of about 2,800, of which some 400 are under the Natural Gas Operations. Taking account of the relative inexperience of the staff, under the provisions of the Natural Gas Pipeline Project, theoretical and on-the-job training has been provided for the natural gas operations and accounting and finance department. In addition, training is planned for the operation of the gas separation plant and LPG distribution, as provided under the LPG project. Further, it is also essential to build-up the strengths of the E&P Department in the specialized technical fields. This would include both recruitment of staff and training provisions. Moreover, the delegation of authority would need to be carefully monitored to ensure that the E&P Department is able to make timely decisions in a constantly changing environment as exploration and development proceeds. Indeed, this is critical for the efficient operation of the joint venture with Shell.

4.42 As PTT is expanding rapidly in both the scale of its operations and the areas of activities, there is a need to streamline as well as develop its staffing capabilities. With a view towards promoting efficiency, PTT recently commissioned a study on organizational and development planning, to be followed by the design and implementation of a management information system as provided under the LPG project.

4.43 The studies commissioned are designed to address the issues of improving PTT's organizational efficiency. However, within the context of the 6th Five Year Plan, the government's policy to encourage a greater private sector role in the energy sector and increased reliance on market forces in decision making, the following issues need to be focused on:

(a) what should be the focus of PTT's activities over the medium- and longer-term?

(b) what are the most effective mechanisms for government to regulate oil and gas activities and to formulate and implement subsector policy?

4.44 The government strategy in the oil and gas subsector to date has been to rely exclusively on the international oil companies (IOC's) in the area of exploration and production. Substantial reliance on the private sector to take these risks is appropriate and should continue to form the core of government policy. Government has the option of taking on a minority joint venture with Shell, Esso and other companies once commercial discoveries are made. This minority joint venture role is a sound way for PTT to gain production experience and, over time, should result in transfering technology to a Thai institution. PTT's 25% share of the costs and benefits in the joint venture with Shell to develop Block S-1 is the first such operation for PTT. Materially, higher proportions (e.g. in other joint ventures) would expose the public sector to potentially imprudent risks in what may be regarded as the most risky element of the industry because of Thailand's geological conditions. The assessment team fully endorses the current policy of PTT to increase its up-stream activities through the joint venture mechanism as a minority (20-25%) partner.

4.45 As one moves further downstream to the gas transmission system, PTT is the sole owner of the submarine gas pipeline in the Gulf linking the Union Oil fields to onshore. The cost of this pipeline was about US$430 million and, as the private sector expressed little interest in equity investment in this project, the state had to play the lead role in taking 100% of the risk, through PTT, in ensuring that the pipeline was built and hence that gas from the Gulf could be marketed. As additional gas fields are developed and the number of gas consumers begins to expand, the gas transmission and distribution system will have to grow. Already, a private sector consumer, Siam Cement Co., has financed and owns a 100 km line from Bangkok to Saraburi (para. 6.54) with about 60 MMCFD of capacity, which allows it to use gas in its cement plants. Both PTT and the private sector (producers and/or consumers) have major roles to play in developing the gas transmission and distribution system either through joint ventures or wholly owned elements of the system operating within a regulated framework.

4.46 When one goes further downstream to petroleum refining, PTT already holds a 49% interest in the TORC refinery, with both PTT (30%) and the government (70%) having major interests also in the Bangchak Petroleum Company (BCP) that is to undertake rehabilitation of the Bangchak refinery (para. 6.69). In the assessment team's view (para. 6.71), over the medium and longer term the private sector should be playing a significant role in the petroleum refining industry in Thailand. This is especially important given the significant risks and uncertainties that have characterized the refining industry since 1973. These risks become particularly large when conversion capacity is contemplated because of the size of investment involved and the sensitivity of its profitability to price differentials between petroleum products.

4.47 In terms of petroleum product marketing, this is a domain where the private sector should again be dominant, in the assessment team's view. The assessment team is unaware of the relative efficiencies of PTT and the private oil companies and operators in the petroleum product marketing and distribution area. Although there is reason for the state petroleum company to be involved competitively with the other oil companies and operators in domestic marketing, the rationale has not been explained for PTT's monopoly on sales of petroleum products to state enterprises such as BMTA, State Railways of Thailand (SPT), and EGAT. Indeed, much of PTT's liquidity problem has been aggravated by substantial delays in payments from some of its public sector consumers such as the BMTA and SRT.

4.48 Finally, to improve management of the petroleum subsector the assessment team recommends an approach which addresses several immediate outstanding problems:

(a) improvement of the fiscal and legislative regimes for oil and gas exploration and development;

(b) accelerating the negotiation, exploration and development process;

(c) establishing a regulated, transparent gas pricing system linked to international energy prices; and

(d) reassessing the role of the state in the oil and gas sector, placing greater emphasis on private sector participation.

To facilitate these and other changes that will be required in the future, the assessment team accepts as a valid and useful option the suggestion considered by the joint Bank/NESDB Energy Assessment team, that government establish an Oil and Gas Management Board. This Board would be regulatory but would also act as an oil and gas policy advisory board. By building on the oil and gas regulatory mandate of DMR and taking on responsibility for tariff regulation of gas and gas pipelines, such a Board would provide a mechanism for strengthening DMR's role as well as its capacity to fulfill the major tasks that lie ahead. The Board could also act as a forum for private sector and government dialogue, as well as improvement of government's regulation of "good engineering" practices in oil and gas exploration, development and transmission.

PTT's Investment Funding

4.49 PTT's governing act, taken together with its agreements with the Ministry of Finance, provide a framework that could allow PTT to achieve and maintain a sound financial position and to raise external finance without too much difficulty. PTT is a relatively new organization; it was undercapitalized when first established, and it has been in business for too short a time to accumulate adequate reserves. As discussed below there are many disquieting features about the way PTT has to operate that could leave the company in a precarious position, but PTT will have to be encouraged and allowed to act commercially for it to achieve a healthy and stable financial position. This in turn requires that government tackle problems promptly. PTT has raised (with government guarantees) significant sums from commercial banks, export credit agencies, multilateral and bilateral institutions, through loans, floating rate notes, lines of credit and other arrangements, and it has a relatively sophisticated cash management system. PTT's present and future financial position reflects its role as a state enterprise in that it suffers from a poor payment record by state agencies and enterprises, and is required to make investments not in its direct commercial interest. At the same time it can benefit from the economic rent on natural gas sales, and through its monopoly of public sector sales its petroleum products market is larger than it would be otherwise. This is a mixed picture -- at present beneficial, but probably not so in the medium term.

4.50 Investment funding comes from commercial banks, official sources such as export credits, international sources and internal cash generation. The single most important source of investment funding for PTT is its operational cash flow, estimated to finance almost 100% of future upstream joint venture investments (oil and gas exploration and production) and 30% to 35% of other investments and working capital. These funds will arise from profits on the transmission and sale of natural gas, marketing of petroleum products, and joint venture production of oil and gas. The basic structure of internal cash generation is fundamentally dependent on government permitting the immediate pass through of cost increases and the timely settlement of amounts due from other state enterprises. However, the track record has not been good. The most important customers are EGAT, Bangchak Petroleum Company, Bangkok Mass Transit Authority (BMTA) and the State Railways of Thailand (SRT) and, because of difficulties in their own cash flows over the past five years, each has at times been seriously delinquent in making payments to PTT. EGAT has been a prompt payer for some time but has strongly questioned why it should pay price increases under the supply contract; hence, PTT's margin is at risk. The Bangchak arrears were substantially settled earlier this year after three years of problems. Currently BMTA and SRT together owe PTT about $75 million, rising at $4 million per month and this is net of a major ($36 million) government-financed partial settlement in April 1985. The government has agreed to come forward with an early solution to this problem. These payment problems arise principally because PTT is a monopoly supplier to state enterprises and at the same time appears to be obligated to supply regardless of whether payments are made. Two state enterprises appear to be making little attempt to pay. Clearly, it is financially unsound for countries to allow such practices to prevail. An additional potential cash flow problem is the Oil Fund, which only three years ago accummulated $125 million in payments due to PTT, and which again is rapidly moving towards a deficit. It is worth noting that the solution to several of these problems has involved MOF funding of energy costs for state enterprise and Oil Fund deficits, which is not really appropriate for a sector meant to be a revenue earner.

4.51 The internal cash generation from gas operations and oil marketing (in both cases primarily to state enterprises), which meets 30%-35% of PTT's investment needs, represents the estimated local currency content of the investment program (including taxes). Surplus cash will be remitted to government after first recognizing PTT's cash needs and legal obligations, including specifically the payment performance of state enterprises. Government plans initially to seek a 30% remittance. The internal cash generation from exploration and production is intended to meet the major part of the cash requirements for further investment in these joint ventures, and, recognizing the risks inherent and the nature of the investments, PTT will retain its after-tax cash flow from production for joint venture financing. Taxes and royalties will, of course, be paid in the same way as payments by foreign oil companies.

4.52 PTT in the past has had little difficulty in raising money from the commercial markets using government guarantee and is in the process of seeking to raise funds without government guarantee. Given the recent experience of developing countries in commercial funding this lack of a formal guarantee may not be worth achieving. More importantly, PTT's under-capitalization makes it vulnerable to experiences such as the present one concerning non-payment of debts. It will be some years before accummulated profits put PTT into a mature and sound financial position. Moreover, the move into more risky activities such as exploration and development calls for a stronger debt/equity position. While pipeline companies in the developed countries traditionally have a high debt/equity ratio, most exploration companies have low (conservative) ratios. The substantial uncertainty introduced by government involvement (e.g., in pricing and investments) calls for a much stronger ratio, such that PTT should be aiming for an overall 50/50 ratio.

4.53 It is important at this stage to consider more closely the funding of Thai oil and gas investments, taking into account the financial risks of the various projects and the possibility of sharing these risks. Progress has been very mixed. PTT's investment in Bangchak was dictated more by Bangchak's needs (and the cash position between the two) than by prudent PTT investment. PTT's share of the investments in the proposed ethylene cracker and fertilizer plants appears to be determined more by government requirements and broader national interests than by strictly commercial criteria. Such requirements are not compatible with a commercial orientation.

4.54 A positive step has been made in the government's insistence that the TORC refinery expansion take place on a non-recourse basis, without government/PTT guarantee either of the loans or the profitability. In this way the private sector is being invited to take private sector risks. This should also apply to petrochemicals and fertilizers. In the longer term, the next major project where similar considerations should apply is the development of the Texas Pacific gas field, which, from a risk viewpoint should include the pipeline from the field to the nearest market or existing pipeline. In current terms, the total cost of developing the field could be around $700 million, with a further $300 million for a pipeline. Given the uncertainties regarding the potential performance of this field, it would be appropriate for PTT to accept no more than about 25% of the $1000 million involved, principally focusing on the less risky pipeline component, and to seek private sector partners and limited or non-recourse financing for the balance. This aspect of limiting risk has already been adopted in the (draft) joint venture agreement with Shell and the possible joint ventures with Esso and in respect of the Block 5/27 prospect.

V. THE POWER SECTOR

Organization

5.1 The organization of the power sector has been quite efficient during the past decade. The sector consists of three state enterprises: 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, and MEA is responsible for distribution in the Bangkok area and PEA throughout the rest of the country. Coordination is sometimes a problem in that seven government agencies are involved in power sector issues: the Committee for Power Policy and Development; the Budget Bureau; the Tariff Rate Committee; NESDB; Ministry of Finance; NEA; and the Foreign Loan Committee. These agencies review a large number of issues including tariffs, capital project proposals, budgets for submission to the council of Ministers, annual financial performance, and requests for government equity and loans. No one agency has overall policy responsibility and many decisions are made by consensus of all the agencies, including the state utilities. The system, which generally has been successful, is designed to ensure that sector capital expenditures are controlled without overly centralizing the decision making authority in any one governmental body. Most of the agencies involved have a substantial amount of autonomy but perhaps could be better coordinated with respect to planning and carrying out their programs.

5.2 Power sector coordination is facilitated through two arrangements. The first is the Load Forecast Working Group, made up of representatives from the NESDB, NEA, EGAT, PEA and MEA. This group is responsible for forecasting power demand. The second arrangement is reflected in 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 at the same time preventing cash imbalances. In general, the overall financial targets established for the sector have been reasonable although the mechanism of cross-subsidization with higher electric rates in urban areas and in industry has l d to subsidizing rural and household consumers. Furthermore, the policy of uniform national tariffs has undoubtedly led to some economic distortions. Although the power sector has functioned fairly effectively, there have been some years in which financial returns have been inadequate. Also, improvement in investment programming and planning appears necessary if the large programs that are contemplated in the future are to be cost effective.

Past System Development

Demand Growth

5.3 The power system in Thailand has grown at an unusually rapid rate over the past two decades. Between 1961 and 1983, electricity demand grew from 464 GWh to 17,563 GWh, increasing from 18 kWh to 365 kWh per capita. Prior to 1973, electricity demand had been growing by more than 20% per year (three times GDP growth). When GDP growth slowed and real prices rose sharply in 1974 and 1979-82, growth declined to 6% p.a. When GDP growth picked up in 1974-79 and again in 1983 and prices stabilized, electricity demand again grew at 13% p.a. or at about twice the rate of GDP growth. Industrial consumption has been growing especially rapidly.

Table 5.1: BREAKDOWN OF ELECTRIC ENERGY DEMAND

	1961	1970	1980
Electric Power Sold (GWh)	467	3,817	13,157
Percentage Share			
Industrial	37	64	63
Commercial & Misc.	24	14	14
Residential	39	22	23
Total Demand	100	100	100

5.4 MEA's share of the country's total demand declined from 80% in 1965 to 52% in 1982. By the end of the 1970s MEA served a well established, developed market in the Bangkok area; in fact, electricity supply was already available throughout most of this service area as early as 1960. With the relatively higher real incomes in Bangkok compared to the rest of Thailand, the annual consumption per household connection in the MEA service area increased from about 695 kWh in 1963 to around 2,600 kWh in 1980. By the beginning of the 1980s, residential ownership of electrical appliances in Bangkok had become widespread. For example, the proportion of households using electric fans increased from 33% in 1962 to 90% in 1980, televisions from 17% to 80%, refrigerators from 11% to 61%, and air-conditioners from 1% to 10%. 21/ The intensity of industrial use of electricity had also increased, from 120 watt hours per Baht of value added in 1968 to 156 in 1978, or an annual growth rate of 2.7%. Key growth indicators are shown in Table 5.2.

21/ MEA survey data from 1981 indicates even higher ownership rates for many appliances; 84% of households owning a rice cooker, 19% a hot plate, and the average customer having lights totaling 420 watts.

Table 5.2: ELECTRICITY INDICATORS FOR MEA SERVICE AREA
1961-1984

Year	1961	1965	1970	1975	1980	1982	1984
Average Load (MW)	N/A	153	503	968	1,647	1,897	N/A
Peak Load (MW)	N/A	311	954	1,483	2,380	3,234	3,601
Load Factor (%)	N/A	49.3	52.7	65.2	69.2	58.7	67.8
Energy Sold (GWh)	467	1,100	3,817	7,496	13,157	15,047	19,349
Consumption (kWh per cap)	17.6	360	107.4	176.8	280.2	308.0	N/A
Energy Sold in MEA	N/A	868	2,693	4,909	7,873	8,389	N/A

5.5 The provision of electricity for the rest of the country outside of Bangkok was organized into provincial areas on a planned basis in 1960 with the formation of PEA. Consumption levels since then have increased rapidly, with PEA's sales growing from 251 GWh in 1966 to 6,680 GWh in 1983. PEA focused initially on electrifying urban areas and, by the mid 1970s, most urban areas outside of Bangkok had access to electricity. Consumption per household connection increased with the growth in income from about 290 kWh per year in 1966 to 1,130 kWh in 1983, while the watt hours per Baht of industrial value added in provincial urban areas increased even faster at 20% p a. -- from 17 in 1968 to 105 in 1978. By 1983 about 88% of PEA sales were made to urban areas encompassed by municipalities and sanitary districts. (Table 5.3).

Table 5.3: PEA ELECTRICITY SALES
(GWh)

	1968	1978	1983
Urban	342	3,477	5,815
Residential/Service	210	1,603	2,858
Industry	132	1,874	2,957
Rural	20	140	865
	362	3,617	6,680

Source: Mission team estimates based on PEA data.

5.6 The widespread use of electricity was slow to get under way in rural areas; only 5% of rural households were electrified by 1970 compared to 3% in 1960. To accelerate the process, in 1973 the government adopted a National Plan for the Total Electrification of Thailand, calling for the electrification of all villages in about 25 years. The target completion date was later brought forward to the late 1980s. A variety of rural electrification programs were soon adopted and emphasis was given to electrifying villages with various kinds of partial self-help programs as well as directing attention to the less developed parts of Thailand. 22/ As a result of these intensified efforts, the annual rate of village connections increased from 940 in 1974 to 5,000 in 1981, and the proportion of villages electrified increased from 23% in 1978 to 52% in 1982. In fact, according to PEA, 20,000 villages were electrified between 1977 and 1983 and it was intended that up to 32,000 more villages were to have been electrified during the 5th Five Year Plan period (1982-6). In retrospect the number of rural households connected increased by a massive amount -- from 181,000 in 1970 to about 2.5 million in 1982. Average consumption levels in households recently connected, however, indicated that lighting was the dominant use of electrical energy by 1984, running at about 280 kWh/p.a. per rural household connected. Other uses of electricity outside the household sector still accounted for a relatively modest share of consumption in rural areas at this time although such use is beginning to expand quite rapidly into agro-industries, irrigation and other non-residential uses.

Table 5.4: RURAL ELECTRIFICATION PROGRAM

	1970	1976	1978	1980	1981	1982
Villages (thousands)						
Total	...	48.0	49.8	51.7	51.7	52.3
Electrified	...	11.0	14.0	17.5	22.6	27.1
Percent	...	(23)	(28)	(34)	(44)	(52)
Households (thousands)						
Total	...	...	...	6,565	6,706	6,848
Electrified	181	...	...	1,730	2,120	2,470
Percent	(5)	...	...	(26)	(32)	(36)

Source: PEA.

Load Management

5.7 This rapid growth into rural areas, the ·ery large expansion of residential consumption, and the recent upsurge in the use of electric rice cookers all have had an important part in shaping electricity demand in the national system. Peak demand is increasing more rapidly than overall consumption at 9.5% p.a., 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 to 10 p.m., a "shoulder" from 9 a.m. to 6 p.m. at about 85% of peak, and off-peak hours for the remainder of the time

22/ In 1978, 44% of villages in the Central Region were electrified, 39% in the North, 30% in the South and 14% in the Northeast.

averaging some 70% of peak. Daily load factors are in excess of 75% and the yearly load factor about 67%. The load is weather sensitive, but this effect is very much random and no seasonal pattern of consumption emerges clearly. A principal contributor to this growing system peak appears to be the small residential consumers, particularly those served by PEA; by comparison the MEA load curve for many years has been consistently high during shoulder hours, achieving its highest peak between 2 and 3 p.m. which reflects the much more diversified economy of Bangkok.

5.8 The marginal costs at peak are still high -- i.e., more than USȼ12 per kWh for PEA low voltage service. However, MEA and PEA are unlikely in the foreseeable future to achieve significant progress in supressing the large contribution that the small consumers' load makes to the system peak. This type of load, because of its geographical diversity and the types of appliances used, does not lend itself well to manipulation by the supplier to contain the system peak through conventional methods such as ripple control switching or domestic duo-metered time-of-day tariffs. However, significant opportunities exist for reducing the demand of the large industrial consumers at system peak time. This can be effected by increasing Time-of-Day (TOD) tariff incentives (para. 5.12) A study carried out by Kuljian Consultants in 1983 indicated that the application of TOD rates could produce substantial cost savings for both EGAT and the large consumers with high load factors on heavy pumping loads. System peak load could be reduced by some 75 MW in a first step with negligible costs. If the program effected only a 30 MW reduction in the system peak, it is estimated that this would save about $2.5 million each year in the power sector's capital expenditures. More research into the use of air conditioning by large commercial and industrial users would also identify possibilities to lower the load between 9 a.m. and 10 p.m.

Electricity Supply Trends

5.9 To meet the rapidly growing demand both at the peak and during other times Thailand has had to undertake a very substantial power generation and transmission investment program over the past 25 years, which has increased installed capacity from 176 MW in 1960 to 6,155 MW at the end of April 1985. In 1960 diesel generation provided two-thirds of the capacity but subsequent expansion has been through hydro and oil-based steam thermal plants. When the Bhumibol dam came into service in 1963 hydro and diesel oil dominated the system. In recent years hydro declined to 21%, and fuel oil accounted for 36% of energy generated by EGAT. Natural gas has risen in the past couple of years to 30%, lignite to 10%, and imported electricity to 4%. Fuel oil consumption used in electricity generation units had risen to a peak of 3 billion litres in 1980. Since 1980, however, the arrival of natural gas and lignite has encouraged a substantial substitution away from fuel oil. For example, the conversion of South Bangkok Units 3-5 to dual gas/oil around 1983 has already reduced fuel oil consumption to 1.8 billion litres. Natural gas consumption in the power sector reached 54,462 MMSCF in 1983 and consumption of lignite increased from 93,000 tons in 1960 to 1.6 million tons (Table 5.6).

Table 5.5: EGAT GENERATING MIX, END 1984

Type	Fuel	Installed Capacity	Dependable Capacity	Average Energy
		---- (MW) -----		(GWh)
Hydro	Hydro	1,809.9	1,533.1	5,006.3a/
Thermal		3,327.5	3,158.3	21,598.9
	Lignite b/	585.0	552.9	3,746.9
	Oil c/	742.5	705.4	
	Gas/Oil d/	2,000.0	1,900.0	17,852.0
Combined Cycle	Gas	740.0	684.0	3,780.0
Turbines		265.0	218.5	679.1
	Gas e/	70.0	60.5	115.0
	Gas/Diesel f/	75.0	60.5	460.1
	Diesel	120.0	98.0	104.0
Internal Combustion	Diesel	33.6	26.9	29.0
Total g/		6,155.0	5,260.8	31,093.3

a/ Firm is 3,346.6 GWh.
b/ Mae Moh 525 MW and Krabi 60 MW.
c/ North Bangkok 237.5 MW; South Bangkok units 1 & 2 x 200 MW, Surat Thani 30 MW; Barge mounted unit 75 MW.
d/ South Bangkok, units 3, 4, & 5, 3 x 300 MW; Bang Pakong Thermal 2 x 550 MW.
e/ Lan Krabu 70 MW.
f/ South Bangkok 75 MW.
g/ Maximum demand in EGAT in 1984 was 3,547 MW and EGAT supplied 21,006 GWh.

Financial Trends and Tariff Issues

5.10 During much of the 1960s the financial condition of the electric system was reasonably sound, and internally generated resources contributed substantially to the investment program. However, deterioration set in as the effect of the world energy crisis began to be felt in the 1970s. EGAT was able to generate operating surpluses after the 1973 fuel price increases until late in the 1970s despite government-imposed constraints on tariff adjustments. When possible greater efficiency was achieved through increases in hydro generation and the use of larger, more efficient steam plants. However, the surpluses were not large enough and in the end the rate of return on revalued assets declined from 10% in 1971 to 3% in 1979 and was negative by 1980. In 1980, EGAT incurred losses of Baht 1,043 million. Apart from various financial measures taken by the government to ease EGAT's liquidity problem, the electricity tariffs of EGAT had to be more than doubled between 1979 and 1982. As a result EGAT's financial position recovered and the rate of return on revalued assets increased from -2% in 1980 to 9% in 1981.

Since then EGAT has maintained a reasonable financial position, achieving a rate of return around 9-10% on revalued assets through 1983 and 8.3% in 1984. The effects of the higher tariffs, however, had been passed on to MEA and PEA and they were not able to recover as well, their rates of return still averaged only around 5-6% in 1983-84.

Table 5.6: FUEL USED IN EGAT ELECTRICITY GENERATION

Year	Fuel Oil	Lignite	Diesel Oil	Natural Gas
	(Million liters)	('000 tons)	(Million liters)	(Billion SCF)
1960 a/	89.5	93.4	79.6	--
1965	86.6	107.7	54.8	--
1970	486.7	323.4	247.7	--
1975	1,170.8	424.1	77.3	--
1979	2,229.7	1,259.0	192.3	--
1980	3,000.1	1,259.0	192.3	--
1981	2,456.9	1,534.4	99.1	9.3
1982	1,523.4	1,686.9	26.1	47.4
1983	1,832.1	1,573.4	40.8	54.5

a/ In 1960, the following quantities of additional fuels were also used:

Coal (tons)	Fuel Wood (Cu. m.)	Saw Dust (M. tons)	Paddy Husk (M. tons)
9,917	1,365	1,115	45,333

Source: "Thailand Energy Situation" for 1977 and Subsequent annual volumes through 1982. Mission estimate for 1983.

5.11 Electric rates have been a serious issue for many years. Until 1973, electricity tariffs were stable in nominal terms, i.e., declining slightly in real terms in the face of modest inflation. This did not cause many problems in these years as oil-based generation costs declined and low cost thermal steam capacity was replacing high cost diesel generation. As inflation picked up and fuel prices rose rapidly in the 1970s, EGAT's rates were raised by 50% during 1973-75 and by 259% during 1979-82 but the increase only partially offset the unavoidably higher fuel and capital costs. Besides the problem of tariff levels, however, there emerged the question of structural differences between major electricity users and the effect of uniform national tariffs. In setting tariffs for final customers, government policy has been to equalize the tariff structure in MEA and PEA areas; this probably was a reasonable policy when the Bangkok market dominated the system. However, as PEA grew rapidly and incurred higher costs, a subsidy became necessary and was effected by having EGAT charge MEA a higher wholesale tariff than PEA. However, since all of the differences were not passed on to the consumers, the financial condition of MEA and PEA deteriorated. Analyses of this situation carried out by consultants indicated that in 1982, although EGAT's and MEA's average revenues per kWh exceeded what had been estimated by the government as the proper long run marginal costs (LRMC) of producing electricity, those of PEA were far below the LRMC; the financial projections, if put into effect, would require at least that tariffs be maintained vis-a-vis inflation. The tariffs as projected by the consultants in 1982 for EGAT, PEA and MEA (Baht per kWh) are presented in Table 5.7. Average revenue per kWh already declined somewhat over the years to 1985, reflecting EGAT's actual price reduction on April 1, 1983 from B1.44 per kWh to B1.38. Similarly, PEA reduced its average rate from B1.77 per kWh to B1.68 and MEA reduced its rate from B1.82 per kWh to B1.80. The financial conditions began to deteriorate after this reduction. These regional cross-subsidies should be reconsidered in the light of their true economic impact, especially for large customers.

5.12 Cross-subsidies from commercial to residential customers are even more questionable. They should be reduced. Apart from these major changes, some improvements in tariff design should be considered to complement load control policies mentioned in para. 5.8:

(a) an increase in the capacity charge, expressed through the kWh energy charge for users with lower load factors. For these users, any modification to the present rates would then be minimal.

(b) creating for large industrial consumers who already have suitable metering a time-of day tariff, which would induce them away from the system peak.

(c) the contracting of additional demand between 12 a.m. and 6 a.m. for only a fraction of the distribution network marginal cost. This option would reduce peak and shoulder loads and could be particularly attractive for large pumping sets (and water heaters, if any).

Table 5.7: EGAT, PEA AND MEA PROJECTED TARIFFS
(B/kWh)

	FY82	FY83	FY84	FY85	FY86
Projected (in a 1982 study)					
EGAT					
Current	1.43	1.48	1.57	1.59	1.66
Real	1.43	1.38	1.37	1.30	1.28
PEA a/					
Current	1.80	1.94	2.06	2.11	2.23
Real	1.80	1.81	1.80	1.72	1.72
MEA a/					
Current	1.85	1.93	2.07	2.09	2.19
Real	1.85	1.80	1.81	1.71	1.69
Actual - EGAT - Current	1.43	1.40	1.38	1.36	N.A.

a/ MEA's average revenue per kWh is higher than PEA because MEA sales are in somewhat higher tariff categories than PEA sales.

Source: NEA Consultants. Projection of rates required to maintain sectoral rate of return of 8%.

For comparative purposes, NEA consultants estimated the following long-run marginal costs for each utility in 1982 (in b/kWh): EGAT 1.25; PEA 2.01, and MEA 1.55.

EGAT's Financial Outlook

5.13 Despite growing subsidies to make up for inadequate tariff levels during the FY77-79 period, EGAT consistently generated operating surpluses, and the issue only surfaced in FY80 when EGAT's financial position began to deteriorate (with a loss of US$50 million equivalent in FY80). The government at that point granted EGAT equity contributions of Baht 1.2 billion (US$59 million) to keep it financially solvent and also arranged a transfer of Baht 100 million (US$5 million) from MEA and PEA to EGAT. In order to finance its investment program EGAT increased its borrowings in 1980 by about 200% over the previous year. In fact, EGAT was in the midst of a long-term borrowing program growing at 33% per annum. The equity and loan funds obtained ensured that EGAT's normal operations and investment program would not be negatively affected, although EGAT was to see its working capital almost disappear, as reflected in a seriously eroded current ratio (to 0.59 in FY80).

5.14 The government instituted a Plan of Action to restore EGAT's and the sector's financial soundness and to ensure that EGAT's investment program remained intact. EGAT's income recovered to US$126 million in FY82 and US$154 million in FY83 (before the government appropriation), and its liquidity position improved substantially with the current ratio returning to 0.94. These results were better than expected mainly due to (a) the unusually high percentage of energy generated by hydro plants in place of thermal plants using heavy oil (resulting in an estimated cost savings of US$39 million); and (b) lower than expected interest rates on borrowings. EGAT's rate of return on net revalued fixed assets remained satisfactory through FY84 at 8.3%. Projections for FY85 and FY86 began to show the deteriorating effect of price reductions as well as the burden of a long term debt that had reached B42 billion (US$1.8 billion) by 1984. Debt service in FY84 had reached 80% of capital expenditures. Rates of return of 7.3% and 6.9% were recently projected by EGAT (June 24, 1985) for the years 1985-86.

5.15 A broad view of EGAT's financial situation is provided in Table 5.8. These indicators reflect two things in particular: (a) a sharp improvement in the rate of return resulting from the large increases in the average electricity prices in 1980 and 1982; and (b) an increase in the debt problem resulting from an inability to cover a large enough part of the cost of investments out of internally generated funds. The debt service coverage ratio which had declined to 0.8 in 1980 rose to 2.5 in 1983, but declined again in FY84 to 1.2. 23/ Similarly, the self-financing ratio which had been 29.2% in 1977 declined to 16.7% in FY80, rose to 28.5% in FY82 and was back to 18.3 in FY84.

Table 5.8: EGAT SELECTED INDICATORS, 1979-1984

	FY79	FY80	FY81	FY82	FY83	FY84
Profitability						
Rate of return (revalued %)	2.7	(1.9)	9.2	9.9	10.0	8.3
Average tariff (satang/kWh)	55.42	74.79	129.78	143.56	139.66	137.57
Self-financing ratio (annual %)	17.4	16.7	25.5	28.5	25.1	18.3
Operating ratio	91.9	105.2	82.4	80.6	80.6	83.0
Debt						
Debt as % of equity plus long-term debt	42.1	44.6	50.4	51.2	51.3	45.9
Debt service coverage	1.5	0.8	2.2	2.2	2.5	1.2
Liquidity						
Net working capital (B million)	(621)	(2,401)	(2,220)	(1,404)	(465)	(1,369)
Current ratio (times)	0.79	0.59	0.71	0.82	0.94	0.85
Technical						
Peak generation (MW)	2,255	2,417	2,589	2,838	3,204	3,547
Annual increase (%)	7.3	7.2	7.1	9.6	12.9	10.7
Energy generated and purchased (GWh)	13,964	14,754	15,960	16,882	19,066	21,066
Annual increase (%)	12.8	5.6	8.2	5.8	12.9	10.5
Market						
Energy sales (GWh)	12,933	13,657	14,545	15,386	17,571	19,357
Annual increase (%)	12.3	5.6	6.5	5.8	14.2	10.2
System losses (%)	7.4	7.4	8.9	8.9	7.8	8.1
Annual load factor	70.7	69.67	70.38	67.9	67.9	67.6
Number of employees	17,301	20,316	23,233	26,769	30,077	32,157
Sales per employee (MWh)	747	672	626	575	584	602
Employee per MW installed	6.0	6.3	6.1	6.6	6.0	5.5

Source: World Bank April 1985 Power Division Mission.

23 The situation in 1984 was somewhat extraordinary in that debt service was apparently very high as a result of EGAT taking out a refinancing loan of $200 million to repay two long-term loans which had higher rates of interest. During fiscal years 1981, 1982 and 1983, EGAT's debt service was about 25% of capital expenditures (excluding interest during construction). EGAT expects this percentage to rise to about 80% in FY85 and to about 100% in FY86, largely because of a substantial reduction in annual capital expenditures and the November 1984 devaluation of the Baht which has increased the debt service burden.

MEA and PEA Financial Outlook

5.16 The financial position of MEA and PEA during the 1970s resembled that of EGAT. Between 1977 and 1981, for example, PEA's revenues increased rapidly at an average annual rate of 38%, reflecting the expansion of PEA's market and the large tariff adjustments implemented in FY80 and FY81. This increase in revenues was largely offset by a substantial increase in the cost of power purchased from EGAT which grew at an average annual rate of 50%. This and the fact that PEA's yearly investment trebled during the period and the burden of carrying a debt which also tripled in financing the investment resulted in higher interest costs and reduced PEA's rate of return (Table 5.9) and its self-financing ratio. The very large increase in debt service has had a serious effect on net internal cash generation.

Table 5.9: SUMMARY OF PEA'S FINANCIAL SITUATION, FY77-81
(in millions of current Baht)

	FY77	FY78	FY79	FY80	FY81	FY82	FY83	Average Annual Growth FY77-81
Energy sales (GWh)	3,174	3,650	4,254	4,696	5,210	5,840	6,680	13.2
Revenues	2,394	3,168	3,697	5,080	8,742	NA	NA	38.2
Average tariff B/kWh	0.75	0.87	0.87	1.08	1.62	NA	NA	22.3
Operating expenditures	2,140	2,811	3,348	4,843	8,428	NA	NA	40.9
Operating income	254	357	349	237	314	NA	NA	5.4
Net income	173	354	342	146	151	NA	NA	-3.3
Rate of return (revalued) (%)	10.3	12.0	9.3	5.0	4.8	NA	NA	-
Number of connections ('000)	1,144	1,350	1,574	1,886	2,270	2,723	3,186	18.7
Energy revenue per connection (B)	1,909	2,282	2,283	2,618	3,718	NA	NA	18.1
Operating expenditures per connection (B)	1,870	2,082	2,127	2,568	3,713	NA	NA	18.7
Debt service coverage	4.2	3.8	2.8	1.9	1.6	1.6	0.8	-
Self-financing ratio	39.1	49.6	38.8	22.0	15.7	2.67	NA	-
Borrowings as % of capital expenditures	75	39	56	88	103	71	113	NA

Source: World Bank Appraisal Report 4201 TH.

PEA's operating cost per connection increased so that by 1981 they matched the revenue from electricity sales per connection. This is the result of PEA's expansion into the rural market where customers are mainly in the lower tariff brackets. In other words, during that period, in order to produce a positive net income, PEA had relied mainly on revenues from sources other than its electricity sales such as installation and inspection fees, construction for customers and interest. To complement its internally generated funds, during this period PEA made extensive use of its borrowing capacity and relied on some contributions from consumers. Equity contributions from the government were limited. Borrowings as a percent of capital expenditures even exceeded 100% in FY81. PEA has customarily relied largely on foreign loans, many of them on soft terms, from the World Bank, the Overseas Economic Cooperation Fund (OECF) of Japan, the Kreditanstalt Fur Wiederaufbau (KFW) of West Germany, the Kuwait Fund for Arab Economic Development (KFAED), the Canadian International Development Agency (CIDA), and the Organization of Petroleum Exporting Countries (OPEC) Fund for International Development. In addition, the government has subsidized the interest rate paid by PEA on domestic loans, mainly from the Ministry of Finance and the Krung Thai Bank.

5.17 Because of the availability of low interest financing, the debt service declined in this period but managed to remain above 1.6. During the period PEA's long-term debt as a percentage of its capital structure was always below 41% despite the fact that its borrowings by 1981 had slightly exceeded its capital expenditures.

5.18 As a result of tariff increases after 1981 the financial position of PEA and EGAT recovered with the PEA's rate of return on net revalued assets rising to 6.8% in FY82 and average tariff per kWh increasing from 0.84 Baht/kWh in 1978-79 to 1.80 Baht/kWh in 1982. Despite efforts to keep this tariff in line with inflation, which would have raised its level to Baht 2.10 by 1985, 24/ the level was reduced in April 1983 and significantly declined in real terms by 1985. PEA's rate of return had been expected to rise to about 7.5-8% but remained at the 5-6% level.

5.19 In its lending program covenants the World Bank required EGAT and the sector to produce rates of return on net revalued fixed assets of not less than 2% in FY81 and 8% in FY82 and thereafter, and PEA to earn rates of return consistent with the sector's requirements. In FY81 the sector rate of return was 8.8% and EGAT's was 9.2%. In FY82 the rates of return for EGAT and the sector were 9.9% and 8.9%, respectively (Table 5.8). These covenants as applicable to future years have been continued in all electric power lending in Thailand since that time. However, the modest tariff increases required just to keep PEA generating funds equivalent to a rate of return above 6% between FY83 and FY85 were not forthcoming. The financial analysis carried out assumed that some cross-funding would take place among EGAT, PEA and MEA by EGAT charging higher bulk tariffs to MEA than to PEA. This policy has been continued but apparently is not a satisfactory way to achieve a sound financial position for the whole sector. The situation is being reviewed by the government; but, with the relatively large investment programs contemplated and the desire to internally generate large cash resources within the sector, urgent action on the electric tariff is required.

24/ According to an NEA consultants' study.

Sector Investment and Internal Cash Generation

5.20 Capital investment in the power sector has been heavily financed by borrowing. In general, the goal has been to finance 30-50% out of internally generated cash resources. In fact, borrowing has been a key factor in the sector's strategy in recent years to meet the growing energy demands of the Thai economy. As much as 65% of the financing required for the sector's investments has been obtained from external grants and loans. EGAT's average level of borrowing, both foreign and domestic, has run about 70% over the period 1979-84 (see Table 5.10). Whether such a low level of internal cash generation and such a high level of borrowing should be permitted in the future is an important issue facing the government. Most important is the question of how to increase rate levels to raise internal cash generation to a level which covers a reasonable share of the investment program.

Table 5.10: EGAT CAPITAL INVESTMENT AND BORROWINGS
1979-84

FY	Investment Amount a/	Borrowing	Borrowing as % of Investment	Investment	Amount Borrowed
	- - (million B) - - -			- - (US$ millions) - - -	
1979	3,707	2,124	57	181.2	103.3
1980	8,904	6,153	69	435.2	300.3
1981	11,453	8,319	73	520.6	380.3
1982	13,797	9,819	71	599.9	425.9
1983	14,058	9,084	65	611.2	397.3
1984	10,932	8,002	73	475.3	347.0
TOTAL 1979-1984	62,851	43,501	69	2,823.4	1,953.8

a/ Including interest during construction.

Source: Adapted from April 1985 World Bank Power Mission findings.

Future Development of the System

Adequacy of the Load Forecasts

5.21 The Load Forecast Working Group has consolidated electricity load forecasts each year since 1973, with rather frequent reexamination of the results. MEA and PEA prepare forecasts for their own distribution areas, and EGAT prepares a forecast for its 13 direct customers. The load forecasts are examined by the group and changes are made as warranted. The requirements are aggregated, and provisions made for transmission losses, and these load forecasts are used in preparing EGAT's development plan. NESDB and NEA also make macro forecasts of energy requirements based on population and GDP for information and consistency purposes and for use with other economic forecasts.

5.22 MEA and PEA forecasts are prepared using quadratic trend functions based on data for 10 to 13 years. The peak load for the utilities and EGAT is calculated on the basis of actual load factor experience and expectations of variations from historic data. Comparing the forecasts for 1983 made in 1978 with the actual 1983 outcome to examine the effects of using these rather simple and pragmatic methodologies indicates that the forecasts have been higher than the actuals; the PEA forecast was about 30% above the outcome, while the MEA forecast was much closer. Mathematical trend projections for a large, long established electricity distribution system can provide reasonably satisfactory results over the short-to medium-term (1-5 years) provided there are no major interruptions to the trends in the underlying behavioral determinants of electricity demand. However, this was not the case for Thailand during 1979-82 with the second oil shock, the economic slowdown, and the sharp rise in electricity tariffs.

5.23 Substantial data are available in Thailand to permit a better understanding of the determinants of electricity demand and to enable more analytical forecasting techniques to be used. MEA has already begun to improve its projection methodology but this has not yet been incorporated into the load forecast group work. MEA carried out a load survey of all customer categories in 1980-81, detailed surveys of households to establish appliance ownership were undertaken, and individual OFF-ON peak and special rate customers were surveyed for projecting demand. MEA has also undertaken a detailed analysis of load demand and has estimated income and price elasticities of demand for major categories of customers.

5.24 PEA has not undertaken such detailed analysis but has made a number of surveys and the need for improved forecasting methods has been recognized, particularly since this may be a key factor in major changes in the future peak load forecast. PEA's present accelerated rural electrification program makes the long term forecasts derived from the parabolic extrapolation very unreliable. A PEA management study is being undertaken by Price Waterhouse/Snowy Mountain Engineering which is intended among other things to give guidance on how to improve demand forecasts for the short-, medium-, and long-term.

5.25 The methods of preparing load forecasts in Thailand must be judged in terms of the dynamic changes that are taking place in the country. The growth in electricity demand between 1970 and 1982 was particularly rapid. The average annual growth rate for the 12-year period was 12.0% for the peak and 12.5% for electrical energy. Following that period the growth in demand slowed down between 1979-82, during which time the average annual growth in peak demand and energy demands still grew at 7.7% and 8.0%, respectively. Several factors influenced the growth in this period, including sluggish growth in the economy, a power shortage in 1980 caused by a drought in 1979 which reduced hydro capacities, and the substantial increase in electricity prices. The last factor is significant. Between February 1980 and April 1981 the electricity prices to the consumers increased from about 80 Satang/kWh (3.5

cents/kWh) to about 180 Satang/kWh (7.8 cents/kWh). Little analysis is available to establish the impact that this price increase had on demand, but as indicated in NESDB work it was likely to be substantial. The Tariff Study being carried out by NEA/NIDA which will be completed this year is expected to clarify this issue.

Improving Long Term Load Forecasting

5.26 Forecasting the load growth is so important that even if there is general agreement on growth prospects during the next five years or so, the entire procedure still needs to be reexamined periodically. This is the logic behind the various load growth studies that are currently under way. The three major classes of customers -- residential, commercial, and industrial -- require different approaches. Residential consumption depends on the number of households with electricity connections and on the consumption per household connected. There is considerable demographic data available down to the province level, and population and household projections are made by the Chulalongkom University Institute of Population Studies. Since urban areas often are completely electrified, projections of the number of households will be almost sufficient to project the number of electrified households in those areas. For rural areas, the task is more complex since, in addition to projecting the number of rural households, the increase in the percentage of households electrified also needs to be forecast. Such forecasts, in the first instance, can be based on: (a) a reasonable assessment of the extent to which PEA plans for rural electrification will be carried out, and (b) the increase expected in the percentage of households being connected within an electrified village over time. According to recent experience, about 50% of households obtain electricity connections in newly electrified villages but this has been increasing over time.

5.27 The second step in such an approach would be to forecast the growth in consumption per electrified household. A major determinant is household income and information from the 1980/81 Household Expenditure Survey which is now being used to estimate the income elasticities for expenditures on electricity. Forecasts based on this approach could be used to check against estimates obtained from household ownership and use of appliances. 25/ For rural areas there is the additional problem of dealing with the growth in consumption of newly electrified households, to indicate how rural households respond to the availability of electricity. On the basis of experience in Bangkok consumption levels have been highly responsive to relatively small changes in income.

25/ Information on the ownership and use of electrical appliances is available from Population and Housing Censuses as well as the Expenditure Survey. In addition, MEA has done surveys of ownership and use of appliances.

5.28 At present, the forecasts for industrial demand are grouped into small industry, large industry, special rate, off-on peak, and agricultural pumping. These groupings reflect tariff groupings. A more useful breakdown for forecasting electricity loads would be the standard industrial classification, for example, iron and steel, mining, cement, chemical, pumping, oil and gas, and miscellaneous. Electricity loads could then be forecast on the basis of the economic growth expected in these sectors, which is the approach used in the Siam Model Planning exercises discussed in the macro analysis in Chapter II.

5.29 The electricity demand in the commercial sector is grouped into small and large business tariff categories and categories for government, hospitals and institutions. This breakdown has similar limitations for making medium- and long-term forecasts. The commercial and public service demand is related to industrial, public, and personal expenditures. Commercial power requirements in other countries frequently correlate well with the sum of industrial and residential electricity requirements, and the business load forecast would follow from the residential and industrial load. For budget purposes, the distribution of the commercial load between small business and large business tariff groups can be used in this approach on a pro rata basis using historic information.

Demand Projections

5.30 The official electricity demand projections for Thailand prepared by the working group in September 1984 show a long run average growth rate of about 6.8% p.a. through the year 2001. More specifically, NESDB projections based on the Siam II Model indicate consistent patterns with likely growths in demand of 11.1% p.a. during the 5th plan period (1982-86), 6.9% between 1987-1991, 5.7% between 1991 and 1966, and 5.2% between 1996 and 2001. The forecast of the official working group was based on regression models which include the effect of changes in GDP, population and the price of electricity. The constants for the regression equation, however, were derived from the historical data. The load forecasting group has avoided major mistakes by updating the forecasts rather frequently. The value of this procedure is apparent in that each successive updating since 1978 has resulted in reducing demand projections and has been translated effectively into several major investment reductions during the 5th Five Year Plan period: initially in November 1981, again in 1982, and a final reduction in February 1983. Forecasts of the group prepared in June 1982 and used until a year ago by EGAT for system planning were projected to increase by about 10.5% in 1983-86 and then gradually reduce to about 6.7% by 1991, giving an average growth of 9.1% p.a. for the nine-year period 1982-91. The 10.5% growth rate is still being used through 1987 but from there until the end of the century the latest projection is slightly under 6% p.a. This compares with a similarly low forecast by NESDB. The nature of the macroeconomic exercise used in the NESDB work is discussed in Chapter II.

5.31 A serious issue in this exercise concerns EGAT's and the government's use of a demand around 6.8% through the year 2001, which is what would be the effect if a higher demand materializes. According to the September 1984 working group, energy demand is projected to grow by 10.5% per annum during 1984-1987 but the growth rate declines to only 5.7% in 1993, averaging 7.9% from 1984-1993. However, if economic growth and development in Thailand exceeds the current outlook, it would then be unlikely for electricity demand to have begun to decline as early as 1989. If most of this demand growth is due to PEA residential customers, then an improvement in the load factor becomes less likely. A forecast along these lines would be related to a GDP growth rate of 6% per year, still significantly lower than the growth rate of 7.6% achieved during 1960-1980 and electricity demand would grow at 8.2% in the period to 1996 with a 67% load factor (Table 5.11).

Table 5.11: MISSION'S HIGH GNP SCENARIO
GROWTH RATE OF ELECTRICITY DEMAND

	1983 (GWh)	Projected Growth Rate a/ (percent)
Residential	4,091	7.5
Urban	3,156	7.0 b/
Rural	935	9.2 c/
Industrial	7,554	8.4 d/
Commercial	5,918	8.4 d/
TOTAL	17,563	8.2 e/

a/ Based on GDP growth of 6% (3% in agriculture, 7% in non-agriculture).
b/ 3.5% growth in urban population and income elasticity of 1.
c/ Estimated from Rural Assessment Report.
d/ Elasticity of 1.2 and sector of GDP growth rates of 7%.
e/ Weighted average growth rate.

Source: Assessment team estimated high demand variant based on calculations outlined in the paragraphs above and the assumptions indicated below.

5.32 The effect of a serious change in the load forecasts discussed above in the next few years may require significant adjustments to EGAT's future program. The load forecast prepared by the Working Group in September 1984, as compared to the high demand scenario for 1989-1996, would result in energy requirements of 57,400 GWh in 1996 compared to only 50,000 GWh in the scenario accepted by EGAT. The peak generation requirement would be 9,780 MW, or 1500 MW (15%) higher than with the EGAT projection, as shown in the bottom section of Table 5.12.

Table 5.12: EGAT's TOTAL GENERATION REQUIREMENT
WITH TWO DEMAND Variants, 1979 - 1996

Fiscal Year	Peak Generation LFWG	Peak Generation High D.	Energy Generation LFWG	Energy Generation High D.	Annual Load Factor LFWG	Annual Load Factor High D.
	(MW)		(GWh)		(percent)	
Actual						
1979	----2255----		----13965----		70.69	
1980	----2417----		----14754----		69.48	
1981	----2589----		-----5960----		70.38	
1982	----2838----		----16882----		67.91	
1983	----3204----		----19006----		67.92	
Forecast						
1984	----3601----		----21272----		67.43	
1985	----4026----		----23770----		67.40	
1986	----4413----		----26055----		67.40	
1987	----4860----		----28696----		67.40	
1988	----5285----		----31016----		66.99	
1989	5604	+ 100	33245	33497	66.72	67
1990	5958	+ 200	35463	36117	67.95	67
1991	6295	+ 360	37605	39071	68.19	67
1992	6640	+ 550	39809	42197	68.44	67
1993	6994	+ 770	42093	45573	68.70	67
1994	7409	+ 976	44649	49218	68.79	67
1995	7839	+ 1220	47294	53156	68.87	67
1996	8282	+ 1500	50029	57408	68.96	67
			Annual Growth Rate(%)			
1979-82	-----8.0----		-----6.5-----			
1983	----12.9----		----12.9-----			
1984-88	----10.5----		----10.2-----			
1989-96	5.8		6.2	8.0		

Source: Load Forecast Working Group, September 1984; assessment team adjustments after 1988 based on assumption indicated above in text.

Reliability and Reserve Margins

5.33 The comparison of demand and capacity should not be oversimplified. EGAT has a rule of thumb to approximate the future capacity requirements. The total dependable capacity of the system less the dependable capacity of the first and second largest units, current Bang Pakong thermal plants (2 x 550 MW), is defined as the firm capacity required to meet the forecast peak demand at least cost. 26/ EGAT's 1985 Power Development Plan provided for a substantial margin of firm capacity over peak demand, 14% in 1985, declining to 2% in 1989 but increasing to 18% by 1995. EGAT has also aimed to have the firm energy generation potential close to the actual requirement where firm energy is based on firm capacity and applying factors of 0.24 for peaking units (hydro, peaking turbines and diesel generators) and 0.70 for base load (thermal). At first sight, this approach appears rather cautious in a system with so much hydropower capable of delivering more than the output taken by EGAT as the dependable capacity. This will apply all the more so in the 1990s when firm energy requirements will cease to prevail and hydro will be called mostly to meet peak demand.

5.34 On the other hand, EGAT is now engaged in commissioning year after year rather large and complex units, the "teething" problems of which always result in lower performance levels in the three years following start-up. Computer-based assessments of loss of load probabilities (LOLP) and expected power curtailments provide a basis for reliability evaluation, but the results greatly depend on the quality of operating policies and their modeling and on the assumptions about plant outages.

5.35 The next step is to determine a reliability standard which strikes a good compromise between the cost of overabundant margins and the economic cost of eventual outages. Lowering the LOLP from old US standards to 5 days/year can save 300 MW as against an economic loss of less than US$60/kW if power outages cost is about US¢50/kWh. Experience in other countries show that <u>average</u> outage costs are about this magnitude and that actual loss of load is smaller than the computer evaluation because many operating flexibilities (overloads, voltage and frequency drops) are not modeled. Considering the large investment program for the next decade, it is recommended that EGAT research into the subject of reserve margin economic optimization.

Fuel Options

5.36 According to EGAT's current analysis, the required capacity would have to increase nearly 6,000 MW between 1985 and 1996. According to its program EGAT has scheduled installation of about 5,500 MW between

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26/ Dependable capacity allows for plants not being able to generate their installed capacity. For most thermal plants, operating records indicate that dependable capacity is 95% of installed capacity. For hydro plants, long-term reservoir simulation studies using past hydrological records have been undertaken and dependable capacity averaged 84.5% for existing hydro plants and those under construction.

1986 and 1996. During the three years, October 1993 to November 1996, 40% of this capacity or 2,180 MW would be installed in three large 600-MW units, all of which would be dual-fired to burn coal. The cost of this program through 1996 would be about $5.3 billion, with the large dual-fired plants requiring an average $1100 per kW. Such a use of large coal-burning units requires an examination of what operating and maintenance problems might be encountered. Also built into this analysis are other key parameters which need careful consideration and involve major uncertainties. The price of alternative fuels is one. The price assumptions being used by EGAT were established in September 1984 but are already out of date (see Table 5.13). It is not only the current actual prices that are considerably lower, but also the expectations regarding the future prices through the year 2000. These modifications are likely to improve the competitiveness of coal while possibly causing some hydro to be reevaluated.

Table 5.13: FUEL PRICES ASSUMED IN EGAT'S POWER DEVELOPMENT PLAN
(US$ per MBTU, 1984)

Year	Lignite	Fuel Oil	Imported Coal	Natural Gas
1985	2.00	4.72	3.19	3.63
1990	2.28	5.31	3.10	3.54
1995	2.51	6.42	3.23	3.68
2000	2.86	7.76	3.39	3.83
Current Actual Price (June 1985)	1.86	3.49	2.08	3.20

Source: Based on EGAT Development Plan, May 1985.

5.37 A constant reexamination of the program is inevitable in view of the uncertainties involved. Views regarding the size and timing of the various units proposed may be changing so the latest cost outlook for the specific options available to EGAT for expanding generating capacity in the period beyond 1990 is considerably changed from what it was as recently as the Fall of 1984. For example, on the basis of rough comparisons using current fuel price relationships (Table 5.14), given the relatively low economic costs of natural gas, combined cycle (CC) plants show the lowest average generating cost of USc3.7 to USc4.3 per kWh, respectively. Lignite-fired steam plants are next, with USc5.2/kWh, followed by coal-fired steam units and gas-fired steam units at USc5.3. Fuel oil-fired steam plants at current low price levels show a rough cost of USc5.6 per kWh. The average generating cost of hydro, insofar as it is available, depends on its initial capital costs and the length of construction periods, although only detailed studies on a plant-by-plant basis can really establish its actual cost. System studies are required to determine the value and role of hydro in meeting the load. If transmission costs are added to lignite and port facilities to coal, and the current low cost of fuel oil is assumed, all three options at the present time are very closely competitive and only gas-fired combined cycle units stand out as clearly preferable for base load duty. The choices will be determined by EGAT on the basis of its view of supply availability, particularly the security of that supply and the actual cost outlook for the various options and the role that each type of supply will play in actually meeting the load, but the assumptions upon which these choices are made must be clearly understood.

Table 5.14: ESTIMATED GENERATING COSTS OF ALTERNATIVE BASE LOAD PLANTS a/
(US$ 1985)

Category	Steam-Gas	Gas Combined Cycle	Lignite b/	Imported Coal c/	Imported Fuel Oil d/
Basic Capital Costs $/KW	800	500	1,000	1,100	800
Construction Time (Years)	4	3	4	4	4
Capital Cost Incl. Interest during Const. ($/kW)	928	552	1,160	1,276	928
O.M.R./Year % of Capital Costs	4	6	5	5	4
Heat Rate (BTU/kWh)	9,500	8,000	10,000	9,500	9,500
Fuel Cost per unit ($/MMBTU) e/	$3.20	$2.50	$1.86	$2.08	$3.49
Useful Life (Years)	25	15	25	25	25
Annual Capital Costs ($/kW)	102.2	72.6	127.8	140.6	102.2
Annual O.M.R. ($/kW)	32.00	30.00	50.00	55.00	32.00
Annual Fuel Costs (¢/kWh)	3.04	2.0	1.86	1.98	3.32
Average Bus-Bar Costs (US cents/kWh)	5.3 (4.7) e/	4.3 (3.7) e/	4.9 (5.2) f/	5.3 (5.5) g/	5.6

a/ Interest rate, 10%: average load factors, all plants: 67%.
b/ Lignite at US$20/ton at Mae Moh. Calorific value taken as 4900 BTU/lb.
c/ Imported coal c.i.f. Bangkok at US$55/ton. Calorific value of 12,000 BTU/lb.
d/ Fuel oil price of US$22/bbl. Calorific value of 6.3 x 10^6 BTU/barrel.
e/ With gas at US$2.50/MMBTU, which is the estimated economic production cost (while the US$3.20/MMBTU price is the current price to EGAT).
f/ Including transmission from Mae Moh to Bangkok.
g/ Cost of port facilities for 4 x 600 MW coal plants assumed to be $200 million with capacity of 6 million tons.

Source: Mission estimates.

The Natural Gas Option

5.38 A crucial aspect of these relationships is the assessment of the gas supply and demand. As discussed earlier (para. 4.32-4.38), about 230 MMSCFD of gas were produced in 1984. Current prospects are that production will rise to about 485 MMCFD in 1985. The most likely gas supply scenario envisaged by the assessment team was that set out in Scenario II (Table 4.5), which estimates gas production to rise to 760 MMCFD by 1990 and 804 MMCFD by 1995. Within this supply picture, the assessment team considers gas availability to the power sector to rise from some 385 MMCFD in 1985 (Table 7.3), to 520 MMCFD by 1990 and around 570-600 MMCFD between 1993-95. Due to the uncertainties inherent in estimating gas supply that far into the future, a variant to the assessment team's case of gas availability is also considered. This is Scenario I (Table 4.5) and reflects the "Base Case" assumed by the NESDB and EGAT. This scenario does not differ materially from that of the assessment team's up to 1990; however, between 1991-96 its figures for gas availability are between 70-130 MMCFD higher -- all of which could be allocated to power.

5.39 Against such supply prospects EGAT has already constructed (or has under construction) generating capacity with the gas burning capability shown in Table 5.15. Based on the present prices EGAT pays for lignite (US$1.86/MMBTU), gas (US$3.20/MMBTU) and fuel oil (US$3.49/MMBTU), the energy costs of lignite plants, combined cycle gas fueled units, gas-fired steam plants and fuel oil-fired steam units are US$1.86 per million BTU, $2.56, $3.04 and $3.32, respectively. This means that in terms of energy dispatch the order is lignite, combined cycles, gas-fired steam and then fuel oil-fired steam plant. This merit order currently does not deviate from that obtained by using the present economic cost of gas (about US$2.50/MMBTU) rather than its financial price to EGAT (as $3.20/MMBTU). Based on the current prices of its main fuels to EGAT, the dispatch order is consistent with economic dispatch. This should remain true in the mid-1990s when coal capacity is added to the system and the energy cost of coal-fired generation is smaller than the energy costs of combined cycle units, with gas priced near its economic cost, which, by then, will be more than US$2.50/MMBTU.

5.40 The future of gas generated electricity relates closely to both the supply and cost of the gas. If the gas supply ultimately proves to be much larger than what has been indicated above and its cost levels no higher, of course, the future of gas generated electricity as could be inferred in Table 5.16 would be substantial. If, on the other hand, supply continues to be severely limited and alternative sources such as Texas Pacific increasingly costly, then there appears little future for gas in the electricity program after 1992 when it is assumed that Nam Phong #1 and #2 CC units would be completed. Even these additions, which will increase gas demand by about 80 MMCFD, would eventually have to be run on gasoil in the late 1990s unless the presently contemplated decline in gas production is corrected. An early switch to a fuel which is expected to be expensive at that time would jeopardize the economic viability of the last CC unit to be commissioned.

Table 5.15: PLANTS IN THE EGAT SYSTEM CAPABLE OF BURNING GAS

Plant	Retirement Capacity (MW)	Gas Demand (MMCFD)	Date
Southern Bangkok			
Units 1 and 2 a/	400	64	1995
3, 4, 5	900	144	1999
Bang Pakong Thermal			
Unit 1	550	88	2008
Unit 2	550	88	2010
Bang Pakong Combined Cycle	720	97	2007
TOTAL	3,120	481b/	

a/ To be converted to gas in 1986.
b/ This assumes all units on base load at 70% utilization factor. Economic dispatch considerations could limit the demand to 400 MMCFD.

5.41 However, it is equally dangerous to completely rule out the gas option for the period after 1992, since it is recognized that more gas supply than now projected could be available if large reserves are rapidly proven and developed. Therefore, flexibility must be incorporated into EGAT's planning decisions and commitments so that, if and when gas becomes available at or around current price levels, it could be used for power generation. Since the various analyses show that EGAT will need to build over 2000 MW of capacity additions between 1993 and 1996, and other options besides gas are available, decisions can be taken in stages. If the high gas supply variant materializes, perhaps an additional 300-MW combined cycle unit at Nam Phong could be commissioned with a reasonably short lead time and the certainty of a good netback value for the gas consumed, because of its high efficiency and low investment cost. This capacity represents a small addition to the system so it can be inserted almost at any time. No opportunity is lost in deferring this additional commitment until more is known about gas development and establishing a core expansion program based on firmly available energy sources, including lignite, hydro and imported coal. An alternative strategy would be to install dual triple oil/gas/coal-fired plants. This strategy is most valid when gas is available early on and some coal-related heavy investments can eventually be deferred. It may be a response to uncertainties about the decline of a developed field. Bay Pakong III to be commissioned in 1991 is certainly one of the best examples, since the site, which is suitable for coal-firing, is also already supplied with gas. Converting the boilers to gas, if more of it is available, will entail only negligible costs. But for most other sites new gas pipelines would be required and the triple-fired unit should remain an exception.

The Lignite Option

5.42 As discussed in Chapter III, lignite reserves currently are essentially focused on what is available at Mae Moh -- estimated at 815 million tons out of a national total of 857 million tons. Of this total about 350 million tons are proven and probable and are sufficient to sustain a generating capacity of about 1,700 MW. Three units of 75 MW are in operation and four more units of 150 MW each are under different stages of implementation. Therefore, 900 MW of additional generating capacity (3 x 300 MW) are possible at Mae Moh (Units 8, 9 and 10) and these plants have been incorporated in EGAT's May 1985 program for implementation through December 1990.

5.43 The rough analysis noted in Table 5.14 indicates that the decision to proceed with development of Mae Moh units 8-10 was sound. The transfer price of lignite was about $19.22 per ton in 1983, equivalent to $1.79 per MBTU, and has risen to about $1.90 per MBTU since then. This is close to the estimated lignite opportunity cost based on the cost of imported coal. 27/ The Meta System Study indicated that lignite is likely to remain an attractive option for base load generating capacity. The calculations prepared for this report indicate that the cost comparison with other options remains attractive, though close. However, there appears to be a general consensus that mining costs could be brought down to make the industry more competitive. Lignite therefore deserves substantial support as a potential long-term option.

Hydro Plants

5.44 Thailand does not have any major hydro schemes suitable for base load operation -- apart from those involving international agreements. These latter clearly would be economic if they were feasible. However, some 1,000 MW of peak load duty hydro schemes are still available, the largest of which is Nam Choan (580 MW), and recent calculations have shown these schemes to be economically quite competitive with other options. Again, feasibility becomes the crucial issue.

The Imported Coal Option

5.45 Because of uncertainties about natural gas and the limited reserves of lignite presently known, new capacity beyond 1993-94 according to the EGAT approach would be fueled with imported coal. This is consistent with the position taken in this report regarding the availability of gas and lignite. However, it would mean a substantial increase in capital investment as coal plants are on average $300-500 per kW more expensive and importing coal from abroad would probably place significant pressure on the balance of payments during the second half of the 1990s.

27/ Meta Systems Inc. 1983 Study on Lignite Pricing.

5.46 Because of the difference in capital cost between combined cycle and coal-fired steam units, for the small part of the power system where combined cycles are applicable, gas can be competitive for prices up to US$4.37/MMBTU (see Annex 10), that is, much higher than fuel oil parity today. The economic cost of gas, although rising over time, should not be anywhere near this figure by the mid 1990s; but it will greatly overshoot it afterwards when reserves depletion approaches. The issue here is not whether coal should be in time developed massively but how much this heavy investment can be deferred. Given the uncertainty on gas availability, the strategy in para. 5.41 provides first answers: take advantage of triple-firing and eventually delay coal-related expenditures every time site conditions permit, but since such conditions are seldom met, keep plans as flexible as possible to pitch in combined cycle units in substitution of projected single coal-fired ones; a corollary of this solution is that construction lead-times of these plants must be minimized through advance site study preparation and design standardization for reasonably sized units.

Overview of EGAT's Approach to Least Cost Planning

5.47 EGAT's planning department has developed a series of least cost sequences for the expanding generating capacity under different assumptions using the Westinghouse Interactive Generation Planning (WIGPLAN) III computer program. Various demand scenarios have been used, some of which were indicated earlier in this chapter. As noted, the focus of the EGAT program recently has been on rather modest growth rates of around 6% for the future after 1990. Similarly, main supply assumptions have been cautious assuming limited gas availability and no more lignite beyond what has already been proven. If unlimited gas supply is developed obviously the system expansion would emphasize more combined cycle gas-fired generating plants along with lignite plants if more of that fuel becomes available. With limited gas, however, the system expansion exhausts available resources for lignite-fired plants and turns to coal-fired generating plants for base load duty and hydro plants for peaking duty as the most economical. As noted above, this makes sense but only within the strict confines of what is actually known today. The key is exploration and development, both in gas, oil and lignite. Decisions taken today can only be based on what is already known, but an optimistic view must be taken about what can be accomplished in the next two or three years in exploration and development by the next stage of decision-making. The planning tools available to EGAT make it possible to minimize uncertainty without over-investing by using a staged decision-making process.

Staged Decision-Making

5.48 According to EGAT, the plan of May 1985 represents only a first step and will need fine tuning. An example of EGAT's staged decision-making is reflected in its policies toward electric supply for Region 3. Solutions for an impending shortage of supply in the southern part of the country (Region 3) have been subjected to special review and a staged decision. As an adequate link does not exist between southern Thailand (Region 3) and the rest of Thailand (Region 1, 2 & 4), optimization had been undertaken first on a two-region basis and then as an integrated national system. This separate, two-stage analysis was necessary as EGAT's work showed the likelihood of a growing energy shortage in Region 3 by 1988 with very rapid growth in demand thereafter to more than 1000 MW by the year 2000. To alleviate the 1988 shortage, EGAT in its base case had proposed at varying times (a) securing, as an interim measure, a barge mounted power plant of 75 MW rating, and linking it to the southern grid at Khanom; (b) installing a submarine gas pipeline from Erawan in the Gulf of Thailand to Khanom; and (c) setting up at Khanom, a combined cycle power plant in four stages, with a cumulative capacity of 600 MW. The uncertainty with regard to gas supplies has forced EGAT to adopt an interim approach which would speed up the installation of a new electric transmission line (originally scheduled for the mid-1990s) and delay an investment decision in favor of a gas pipeline and a combined cycle plant at Khanom in the South. Further, on account of the long lead time needed for hydroelectric projects, that alternative was not considered a viable solution for the immediate future. It appears therefore that EGAT believes they can speed up the process of strengthening the interconnection between the southern grid with the central grid and advance the investment on a 230-kV tie line, to a completion date in late 1990. This would permit the evacuation of 300 MW of additional power from the Central and Northern Regions (where there is currently an excess of generating capacity) to the southern region. Such a solution is believed to have the following advantages:

(a) Investment requirements for a transmission tie line would be significantly lower compared to a submarine pipeline (US$50 million against about US$200 million);

(b) Savings could be realized in EGAT's reserve margins;

(c) By integrating the entire system into a single grid, EGAT could choose lower cost generating options regardless of regional constraints; and

(d) The risks associated with insufficient supplies of gas could be avoided while gas-fired combined cycle plants still could be built in Region 3 in the event that the construction of a gas pipeline to Khanom subsequently proves to be economically viable.

5.49 The commissioning of the Chiew Larn (Region 3) hydro electric project (240 MW) is expected to take place in mid 1987. Further strengthening of the transmission network between Prachuap Khiri Khan and Surat Thani (about 300 km) is the proposal being considered to permit transfer of about 300 MW from the central region to the south. However, the network can be constructed by 1990 or perhaps a little sooner only if feasibility studies are carried out quickly and a decision to go ahead is taken soon. In view of this, some supply shortage in the southern region may be inevitable in the 1986-87 period. EGAT has been examining interim solutions to make up this projected shortfall. Available options consist of (a) shifting some gas turbines from South Bangkok Power Station; (b) purchasing new gas turbines; or (c) installing one more 75 MW barge plant. All these solutions could be implemented in about three years but would be costly for such a short term solution. In any event, moving towards a quick integration of the system appears to be the best approach.

5.50 Beyond this type of fine-tuning, which is permitting a delay in the Region 3 expansion program to be replaced by a strengthened interconnection, EGAT's least-cost development solutions appear to be focusing on a clear two-stage approach. The first stage would consist of completing the full utilization of proven gas and lignite resources while at the same time integrating more effectively the full system by undertaking investments necessary to strengthen several transmission lines to allow the transmission of power from north to south. The effect of integrating the system through the fine-tuning system analysis will undoubtedly reduce the level of investment. By strengthening the electrical interconnector between Region 1 and Region 3, the reserve margin for Region 3 is assumed to be approximately 25% instead of the 30% previously used in EGAT's system planning. 28/ Stage 2 planning is more complex in that it cannot be truly finalized until a better assessment of gas availability has been made. The assessment team would add lignite to this requirement. The general outline of the current least-cost development program is summarized in the list of projects indicated in Table 5.16, in which large new thermal plants are designed for dual coal/gas/oil firing and substantial use is made of imported coal or fuel oil in the later 1990s. This two-stage approach of EGAT makes large and growing fuel imports in the late 1990s and increasingly large investment program (Table 5.18) two of the most troublesome aspects of the future program as it now stands.

5.51 The absolute size of the program is a very serious problem. According to the rough estimates indicated in Table 5.18, EGAT's program will average nearly $800 million per year between 1988 and 2001. The average cost of projects to be completed between 1988 and 1995 would be about $635 million per year. The size of EGAT's investment program as with other large public sector enterprises, has been a serious problem throughout the fifth plan period. Initially (November 1981), when combined with ongoing projects, investments would have required a total capital outlay of Baht 89 billion for the period 1982-86. This investment program was later revised to conform to the revised load forecast of June 1982, reducing planned investments during the fifth plan period to Baht 78 billion. In line with its further downward revisions of power demand growth projections in February 1983, EGAT made another

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28/ The reserve margin for Regions 1, 2, and 4 remain the same, at 25%.

downward adjustment in its investment program to Baht 68 billion by postponing the construction of six major projects by one year each.

5.52 EGAT's investment programming thus has shown considerable flexibility over the last years in adjusting to a more constrained financial environment as well as a changing demand outlook by gradually phasing back investments by a total of 25% in planned capital outlays for the fifth plan period. Indeed, the program designed for the remainder of the fifth plan appears quite conservative with only 1,000 MW of plant currently under construction. However, questions remain for the program beyond 1986 which have been addressed in this report. First, the program as now planned can only foresee modest investments in gas utilizing generating capacity to cover two gas combined cycle units of 300 MW each (Nam Phong 1 & 2). As discussed above, this strategy is based on the current outlook for available gas supplies. The outlook for the availability of more gas is too uncertain to choose more gas units over other supply options, although dual-fired facilities of 600 MW are scheduled to be available at Bang Pakong 3, for 1991. EGAT thus is ready to incorporate relatively costly options in terms of capital investment, with the large investments in 900 MW of lignite fuel plant at Mae Moh (Units 8-10) amounting to roughly $11 billion and the 600 MW Bang Pakong suitable to burn coal costing $650 million. Second, more careful consideration of the elements of uncertainty in EGAT's investment planning, particularly regarding pricing, demand outlook, and gas supply prospects, will undoubtedly raise the cost of the program as dual-fired facilities relying on coal become more important.

5.53 The other major factors in the power program -- MEA and PEA -- have significantly increased their investment requirements. Six percent of total investment planned by the power utilities during the fifth plan period was scheduled for MEA, and fifteen percent for PEA. For PEA the total number of households with electricity was programmed to more than double from 2.2 million in 1981 to 4.5 million in 1986, resulting in an increase in electrification from 33% to 62%, aimed at full electrification by the late 1980s. The program has since been reduced somewhat as was that of EGAT. The PEA program, originally scheduled to cost about B19,000 million, was reduced to B15,820 million. The MEA program was estimated to be about B6,850 million in 1982 and was reduced to B4,271 million by 1984. The total electric power sector program thus was reduced from B102,000 million to B86,500 million.

5.54 Despite these reductions, power investment as a whole has been rising rapidly. From the plan period 1972-76, it has risen from US$240 million per annum to nearly US$700 million per annum during the fifth plan period measured in terms of constant 1982 Baht. It is expected to rise at a level of $920 million per annum during the sixth plan period 1987-91 in terms of current prices. Although these levels appear justified in terms of meeting the growth in power demand, it is not known yet whether sufficient internal cash resources can be generated by the power companies to finance the investment.

Table 5.16: PRELIMINARY EGAT PROGRAM (1988-2001)

Name of Project	Rating (MW)	Commissioning Date	Approximate Project Cost a/ (US$ million)
2nd PPB*	75	June 1988	82.1
Mae Moh #8	300	July 1989	380.0
Srinagarind #5	180	October 1989	33.1
Mae Moh #9	300	June 1990	380.0
Nam Phong CC #1	300	November 1990	210.0
Mae Moh #10	300	December 1990	380.0
Bang Pakong TH #3	600	October 1991	654.0
Nam Chon #1,2	290	October 1992	175.0
Nam Phong CC #2	300	January 1993	214.0
Nam Chon #3,4	290	April 1993	175.0
Bang Pakong TH #4	600	October 1993	512.0
Kaeng Krung #1,2 b/	80	October 1994	87.0
Krabi 2 #1*	150	November 1994	236.4
Ao Phai #1	600	October 1995	922.2
Ao Phai TH #2	600	October 1996	584.4
Krabi 2 #2*	150	November 1996	236.4
Ao Phai TH #3	600	October 1997	584.4
Krabi 2 #3*	150	November 1997	236.4
Ao Phai TH #4	600	October 1998	584.4
Sai Buri*	46	November 1998	77.1
Coal-Fired #1	600	October 1999	900.0
Coal-Fired #2	600	April 2000	900.0
Coal-Fired #3	600	October 2000	900.0
Coal-Fired #4	600	April 2001	900.0

Total Added Capacity 1988-2001	=	8,911.0 MW	$10,343.5
Total Net Capacity Increased	=	7,284.9 MW	
Average Cost per kW	=	US$1,161	
Average Added Capacity per annum	=	685.5 MW	
Average Cost per annum	=	US$795.7 million	

a/ Based on EGAT's approximate project costs in Table 7.1, p. 39, "EGAT Power Development Plan (1985-2001)."

b/ Generation projects in Southern Region (3).

Table 5.17: PROJECTIONS OF CAPITAL INVESTMENT FOR ELECTRIC POWER IN FIFTH AND SIXTH PLAN PERIOD, FY1970-1991 a/
(Million Baht, 1982)

	EGAT	PEA	MEA	TOTAL POWER
Fifth Plan Period				
1982	13,797	2,980	719	17,496
1983	14,058	2,280	783	17,121
1984	10,932	3,122	968	15,022
1985	9,036	3,537	1,022	13,595
1986	13,756	3,901	779	18,436
1982-1986	61,579	15,820	4,271	81,670
Sixth Plan Period				
1987	15,436	1,592	1,912	18,940
1988	18,798	2,608	2,083	23,489
1989	22,304	1,238	3,276	26,818
1990	25,705	1,080	3,408	30,193
1991	26,615	950	1,862	29,427
1987-1991	108,858	7,463	12,541	128,867

a/ Investment estimates 1982-85 for EGAT, MEA and PEA based on Bank of Thailand data. Projections 1986-91 for EGAT based on Bank Staff Appraisal Report 4799-TH, March 1984 (interest during construction included). For MEA and PEA 1986-91 based on World Bank SAR, 4201 - TH, May 1983, p. 52.

Table 5.18: PROJECTIONS OF CAPITAL INVESTMENT FOR ELECTRIC POWER IN FIFTH AND SIXTH PLAN PERIOD, 1972-1991 a/
(million Baht, US$, 1982) b/

	EGAT		PEA		MEA		TOTAL		ANNUAL AVERAGE
	Baht	US$	Baht	US$	Baht	US$	Baht	US$	US$
Fifth Plan Period									
1982-86	61,579	2,463	15,820	633	4,271	171	81,670	3,267	653
Sixth Plan Period									
1987-91	108,858	3,888	7,463	267	12,541	448	128,867	4,602	920

a/ Investment estimates 1982-85 for EGAT, MEA and PEA are based on Bank of Thailand data. Projections 1986-91 for EGAT are based on Bank SAR 4799-TH, March 1984, p. 64 (interest during construction included). For MEA and PEA 1986-91 based on World Bank SAR 4201-TH, May 1983, p. 52.

b/ Exchange rates used are:
1982-1984 = 22.5 Baht/US$
1985-1991 = 28 Baht/US$

Reducing the Level of Investment

5.55 Based on the components of the indicated expansion in the electric power system, investment costs for generating facilities were estimated in Table 5.18. A total of US$10.3 billion would be required over the 13-year period after 1988. In the sixth plan period an average of nearly $700 million a year (excluding price escalation) would be required for the sector including transmission and the MEA and PEA programs. Major efforts will be required to ensure that this program does not become so large as to seriously jeopardize the availability of investment funds for other equally important activities both in the public and private sectors. The program as presented in this chapter represents a least-cost solution on the basis of EGAT's latest projections of demand, the most recent estimates of gas and lignite availability and the current outlook for imported fuels. Although the level of consumption may be able to be reduced in the future, as noted in Chapter IX, this may prove difficult in the short run. Nonetheless, the assessment team believes that high priority should be attached to conservation efforts which might lead to a savings in the proposed expenditures and make possible a reworking of the programs. Key assumptions such as prices, GDP forecast, supply projections, need frequent updating and also might result in investment savings. There are several additional issues which may affect the size of the investment program and were addressed previously, such as the size of the reserve criteria, the lesser use of capital intensive fuel options, and the greater use of combined cycle plants in the system.

5.56 The need for flexibility in the expansion program can be best achieved by planning a plant mix emphasizing those units that are both low cost and have short lead times -- combined cycles. This is especially true in the face of major uncertainties in the growth of residential consumption with its low load factor. An expansion program combining improved load management policies with additional gas-fired combined cycle units, and which would constantly be fed with new information about demand could help to minimize investments. Its main cost would be to accelerate slightly the depletion of gas reserves.

5.57 For the longer term and what this report considers the second point of decision around 1988, EGAT may have to turn to coal-burning plants. As early as October 1991, the Bang Pakong No. 3 unit is scheduled to come on stream with a multi-fired facility capable of burning coal. The strategy apparently is to include dual-fired capacity in all large steam units scheduled for installation beyond 1991. These plants (e.g., 2400 MW Ao Phai No. 1-4) are intended to operate on gas as long as gas supply is available but would have the equipment available to switch to coal or oil as gas fields near depletion. The large units that would follow would be designed for burning only coal under the current plan. As noted earlier the projected levels of investment may pose a serious constraint and need to be reexamined most carefully. The implications for future investment levels cannot be ignored.

Balance of Payments Implications

5.58 The trends outlined in the EGAT program point up clearly the troublesome balance of payments implications. Whether the future in the 1990s is based on oil or coal, there clearly will be a higher return to energy imports in the 1970s. Unless the gas or lignite programs can be further expedited to produce more, Thailand will face another serious energy problem in the mid- to late-1990s.

Table 5.19: EGAT ENERGY GENERATION BY TYPE OF FUEL
FY85-2000

	1985	1990	1995	2000
Total Generation in GWh	23,050	35,460	46,970	61,260
Percentage Share				
Lignite	12	25	24	19
Imported Coal	0	0	1	44
Natural Gas	35	56	56	16
Fuel Oil	33	1	1	8
Hydro	15	16	15	11

Source: Based on EGAT 1985 projections.

VI. PETROLEUM PRODUCT DEMAND, SUPPLY AND PRICING

Historical Petroleum Product Demand

6.1 In tandem with the high rates of economic growth Thailand experienced during the 1970s, petroleum product consumption increased at an average annual rate of 9.5% during that decade, rising to 218,400 bbls/day in 1980. However, the 1979-80 period represented a fundamental turning point in both the level and structure of demand for petroleum products triggered by the doubling of oil prices during the second oil crisis. Between 1980 and 1982 the demand for petroleum declined 13%, reaching the low point of 189,800 bbls/day in 1982. This was due partly to the recession and the increase in retail prices 29/, as well as the advent in 1981 of natural gas as a major new energy source in the power sector. However, the recovery of petroleum demand between 1982-84 was as dramatic as its decline over the 1980-82 period. By 1984, the consumption of petroleum products rose to 224,400 bbls/day, implying an annual rate of increase of 8.7% between 1982 and 1984.

6.2 Thus, by 1984 petroleum demand exceeded its previous 1980 high point by nearly 3%. However, the structure of demand had undergone significant modification during that short four-year period. In particular, the share of fuel oil declined from 37% of the petroleum market in 1980 to 24% in 1984 as natural gas entered the energy supply mix. In addition, as a result of the distorted structure of retail petroleum product prices, which differ substantilly from their border price structure. the following occurred:

(a) A rapid increase in the demand for LPG, especially in the transport sector as a substitute fuel for gasoline in taxis and cars. Between 1980-1984 the consumption of LPG increased by about 28%/year, rising to 16,500 bbls/day in 1984 or about 45% of gasoline consumption (see Table 6.1). Indeed, LPG's share of the petroleum market rose to 7% in 1984 from 3% in 1980;

(b) An unprecedented increase in the demand for kerosene, the market share of which increased from 2% to 4% between 1980 and 1983. Demand for this product grew an average of 23% a year over the period, a large share of it caused by the adulteration

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29/ Between January 1980 and December 1982, the retail prices of premium gasoline, diesel oil and LPG increased by 72%, 51%, and 36% respectively.

of diesel oil with kerosene, as diesel oil was priced about 14% above kerosene at the retail level; 30/

(c) In the case of diesel oil, although demand declined by about 10% between 1979 and 1982, between 1982-84 consumption increased by one-third and the share of its use in the transport sector rose from about 50% in 1979 to 68% by 1984. This coincides with the increasing use of diesel-fueled rather than gasoline-fueled pick-ups and light trucks (see para. 6.28). While in 1979 diesel oil accounted for about 35% of petroleum demand, by 1984 this had grown to 41%;

(d) A 12% reduction in gasoline demand between 1979 and 1984, as the share of this product in the petroleum product market declined from 19% in 1979 to 16% in 1984. This in large part occurred because of the interfuel substitution of LPG and diesel fueled vehicles caused by the large price differences between gasoline, LPG and diesel resulting from higher gasoline taxes. Indeed, within the gasoline market itself a dramatic shift in demand has occurred between premium and regular gasoline due to the erratic retail pricing policies (para. 6.3) pursued for premium gasoline. While in 1979 premium accounted for about two-thirds of the gasoline market (Table 6.1), this share had collapsed to merely one-third of the market by 1982, during which time the differential between premium and regular gasoline increased sharply (Table 6.2).

Table 6.1: DEMAND FOR LPG, PREMIUM, AND REGULAR GASOLINE, 1970-1984
(barrels/day)

Year/Product	LPG	Premium Gas	Regular Gas	Total Gasoline
1970	1,500			16,300
1979	6,400	25,200	15,500	40,700
1980	6,100	21,400	17,300	38,700
1981	7,800	19,100	16,900	36,000
1982	10,400	11,900	22,800	34,700
1983	14,300	12,700	22,900	35,600
1984	16,500	14,500	21,900	36,400

30/ As a result of measures instituted by the government in late 1983, kerosene demand had declined by almost 50% in 1984. These measures included a 50% reduction in the kero/diesel price differential and government regulation of bulk sales to peddlars.

6.3 During the 1979-1981 period, the retail prices of premium gasoline were 4-6% above those of regular, and the total demand for gasoline declined some 12% with premium dropping about 24% and regular rising some 9% (see Table 6.1). This occurred even while the differential in their retail prices was between 4-6%; consumers were moving to the lower priced fuel, a simple choice between two easily substitutable fuels. However, following the 1981 Baht devaluation, the price of premium was raised to 18% above regular and remained at that level until March 1983 when it was reduced to about 13.5% above the price of regular gasoline (Table 6.2). The response from consumers was immediate. What had been a gradual shift from premium to regular in a declining gasoline market over the 1979-81 period was transformed into a precipitous collapse of premium demand (by 38%) in 1982; the consumption of regular gasoline increased by 35% even though total demand for gasoline declined by 4% in that year.

Table 6.2: RETAIL PRICES OF PREMIUM AND REGULAR GASOLINE, 1979-PRESENT
(Baht/litre)

Dates	Premium Gas	Regular Gas	Ratio Prem/Reg
14 July 79-Feb. 80	7.84	7.45	1.052
10 Feb. 80-20 Jan. 81	9.80	9.26	1.058
21 Jan. 81-1 Dec. 81	11.90	11.40	1.044
2 Dec. 81-28 March 83	13.45	11.40	1.180
29 March 83-20 Oct. 83	12.60	11.10	1.135
1 Dec. 83 to Present	11.70	10.80	1.083

6.4 Annex 6 shows the consumption, imports and refinery production for each petroleum product between 1970-84. Of special note is:

(a) the dominance of diesel oil (41%) in the petroleum market in 1984, followed by fuel oil (24%), and gasoline (16%);

(b) the growth in gasoline demand of 10.7% a year between 1970-79, which turned into an annual average decline of 3.2% between 1979-1983;

(c) the associated explosion in LPG demand, especially after 1978, as retail pricing policies induced the substitution of gasoline. The annual average growth rate of LPG demand jumped from 17.5% between 1970-1979 to 23.9% during 1979-1983; and

(d) the consumption of fuel oil, which had grown 13% a year between 1970-1980, started to decline during 1980-1984, by an average 9.4% per year, initially as a result of the recession and then as natural gas began to flow in 1981.

6.5 The disaggregation of petroleum demand by fuel type and economic sector is shown in Annex 7 for the period 1971-1983. Unfortunately, there are significant problems regarding the reliability of end-use data due to the method used to establish sectoral use which is outlined below. The oil companies make direct sales of product to major consumers and also to intermediate agents who in turn sell to others. Present practices identify major end-users of each product as those who purchase directly from the oil companies. However, in the case of sales through intermediate agents the end-use sector is not identified explicitly. For example, in the case of gasoline, 91% of sales by volume are through agents, while for kerosene, diesel, LPG and fuel oil the proportions are 82%, 73%, 72%, and 14%, respectively.

6.6 The current NEA method of allocating agent sales by sector is based on the percentages of identified direct sales. This would be appropriate if no difference were expected between large and small consumers in fuel type and use patterns, but this is not the case. In the assessment team's view, NEA should undertake, on a continuing basis, end-use surveys among the smaller consumers in particular in order to estimate consumption shares for the various sectors. Such data are especially important to the issue of petroleum product demand forecasting which is discussed below (para. 6.38). Overall, the estimation and analysis of energy use by economic sector is an area of energy planning which, in the assessment team's view, NEA needs to strengthen and assign higher priority.

6.7 Despite these limitations, it is possible to draw broad conclusions about the trends in demand for petroleum products for the major economic sectors in Thailand. In volumetric terms, the transport sector has dominated petroleum demand over the last several years; its share has risen slowly from 45% in 1971 to 52% in 1983. The share of petroleum products used in the manufacturing sector declined from 20% in 1971 to about 13% in 1983, while that of agriculture has moved only slightly, from 12% in 1971 to 10% in 1983. The share of petroleum product used by the power sector increased from 12.6% in 1971 to about 20% in 1979 but subsequently declined to 15% in 1983 due to the emergence of natural gas.

6.8 In the case of diesel oil, demand has traditionally been driven by the transport and agricultural sectors which together accounted for 77% of diesel consumption in 1971 and 90% in 1983. What has been particularly significant over the last couple of years has been the rapidly rising share of diesel oil consumption being devoted to transport uses. While in 1971 the transport sector accounted for 46% of diesel use and agriculture about 31%, by 1983 the share of transport had jumped to

63% and that of agriculture had declined to 26%. 31/ Fuel pricing policies have played a major role in acclerating this trend (para. 6.28). Almost all larger trucks, tractor/trailers and most buses are diesel fueled (accounting for roughly 15% of total motor vehicles) with cars and taxis being largely spark ignition engines fueled with gasoline and, increasingly, LPG. In the range of small trucks, pick-ups and other light commercial vehicles there is a mixture of both diesel and spark ignition engines. It is in this mixture of engine types (diesel and spark ignition) among light trucks and pick-ups that dramatic changes have occurred in the last couple of years. Table 6.3 shows the estimated annual sales of passenger cars and light trucks/pick-ups in Thailand between 1977-84.

Table 6.3: ESTIMATED SALES OF PASSENGER CARS AND LIGHT TRUCKS IN THAILAND, 1977-84

Year	Total Passenger Cars	Light Trucks/Pick-ups		
		Diesel	Gasoline	Total
1977	21,400			36,400
1980	26,900	9,800	29,900	39,700
1982	27,300	36,600	7,800	44,400
1983	33,400	53,200	5,600	58,800
1984	33,400	63,200	3,900	67,100

Two important points are highlighted in this table:

(a) annual sales of passenger cars relative to light trucks/pick-ups declined from 59% to 50% between 1977 and 1984. This was reflected in light truck sales increasing at 14% a year between 1980-84 compared to 5.6% in the case of passenger cars; and

(b) since 1980, when vehicle assembly plants in Thailand began introducing light trucks/pick-ups with diesel-fueled engines, a dramatic shift has occurred in the ratio of gasoline to diesel fueled engines among this class of vehicle. While in 1980 diesel engined light truck sales only made up 25% of total sales, by 1984 diesels had captured 94% of new light truck sales. Based on an estimated annual use of about 50,000 kilometers this switch in engine type is estimated to have accounted for more than 80% of the increase in use of diesel oil over the past couple of years.

31/ By 1984, the share of diesel in transport rose to 68% and that of agriculture declined to about 22%.

6.9 The other important sector which uses diesel oil is agriculture, which includes fisheries. In this sector, fisheries activities account for roughly two-thirds of diesel use (approximately 15% of total diesel demand in 1984) as most fishing vessels have diesel engines.

6.10 Fuel oil consumption is dominated by the manufacturing and electricity generating sectors. In 1971, manufacturing claimed 57% of total fuel oil use; however, this declined to 37% by 1983. The two subsectors that have driven the manufacturing use of fuel oil to date are cement and textile production, using about 41% and 20%, respectively, of the fuel oil consumed in this sector in 1983. In contrast, the share of fuel oil used by the power sector had increased from 37% in 1971 to 55% (31,600 bbls/day) in 1983.

6.11 About 90% of the demand for gasoline arises from the transport sector, and kerosene consumption traditionally has been dominated by the residential sector (76% of demand in 1979) although it declined to 32% in 1983. The main use of kerosene in residences is for lighting in non-electrified households which in 1982 represented about 4.3 million households 32/ (or 52% of total households) and, to a much lesser extent, for cooking purposes. Based on an estimated kerosene use for lighting of about 1 litre/week/non-electrified household, total consumption for this purpose is estimated at about 3,800 bbls/day, which would account for 80-90% of that allocated to residential use. An increasingly large proportion of kerosene demand (61% by 1983) is unidentified in terms of end-use sector (Annex 7). The amount of unidentified use had been rising since about 1981 due to the growing adulteration of diesel oil with kerosene. However, new measures instituted by the government in late 1983 to reduce adulteration effectively reduced kerosene demand by nearly 50% in 1984.

6.12 In the case of LPG, the demand structure has changed over the past few years. In 1983 about 45% of its use was in transport, 40% in the residential sector (for cooking and hot water), and 13% in manufacturing. In 1979, residential use made up 56% of LPG demand, and transport only 20% because of the low retail price of LPG relative to gasoline.

Petroleum Product Pricing

Background

6.13 Similar to the principles of gas pricing outlined earlier, the proposals for petroleum product pricing in Thailand are based on the assumption that optimal fuel use and investment will result if local

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32/ Based on 1982 data, 79% of urban households (1.45 million) and 41% of rural households (6.8 million) were electrified.

retail prices reflect the true opportunity costs of fuels to the country. The best way to achieve this is by decontrolling petroleum product prices to ensure that domestic prices automatically reflect the opportunity costs of petroleum products. In the view of the assessment team, Thailand should be moving towards such a policy. Until it is adopted, the most severe distortions in the petroleum product pricing system need to be addressed and measures undertaken immediately to remedy them. Since all the petroleum products consumed in Thailand are traded internationally, their opportunity costs are the prices at which they are imported (if local demand exceeds supply) or exported (if domestic supply exceeds local demand). This has two implications:

(a) the overall retail price level of petroleum products should reflect at least the international price levels for the relevant market (Singapore); and

(b) the structure of domestic retail prices should reflect the structure of relative international petroleum product prices.

6.14 With regard to the first issue, the value of a reconstituted barrel of oil in Thailand at the retail level in February 1985 was only about 22% above import prices (see Table 6.4 below), excluding jet fuel 33/ Although from the viewpoint of petroleum price levels this would appear adequate, there is an important fiscal issue to consider. This is because the present average price is lower in relation to import prices than it was before the October 1984 devaluation when it was about 40% and roughly in line with general tax rates. Clearly, this has had substantial revenue implications for the government. As such it is of some urgency that the average retail price level be raised back to the level of about 40% that prevailed before the latest devaluation. It is very important also that domestic prices continue to reflect international prices following future changes in either exchange rates or world prices.

6.15 The key problem with petroleum product prices in Thailand relates to their structure at the retail level which promotes uneconomic fuel use and introduces distortions in demand to such a degree that major incremental investments in conversion capacity in the refining sector may appear warranted if the resulting demand patterns are to be met largely from local refining capacity. In particular:

(a) automotive diesel oil retail prices are too low relative to premium or regular gasoline prices;

33/ Due to the decrease in c.i.f. prices (even when expressed in Baht) since February 1985, by June 1985 the value of the reconstituted barrel at the retail level had risen to about 31% above that at the c.i.f. level.

(b) LPG retail prices are too low relative to the prices of gasolines;

(c) kerosene retail prices have been too low relative to automotive diesel oil; and

(d) the retail price differential between premium and regular gasoline should not exceed the benefit in improved fuel economy from the higher octane fuel 34/ (about 1% improvement in fuel economy increase in octane number). This differential has been reduced to around 8% since December 1983, compared to 14-18% in the period December 1981 to December 1983 (Table 6.2).

6.16 Table 6.4 shows the structure of petroleum product prices in February 1985 from import parity (c.i.f.) through to the retail level.

Table 6.4: STRUCTURE AND LEVEL OF PETROLEUM PRODUCT PRICES, FEBRUARY 1985 c/
(Baht/litre)

Product/Price	C.I.F. Level a/	Taxes & Duties	Marketing Margin	Oil Fund (Deficit)	Retail Price
LPG b/	4.674	0.502	0.931	(0.717)	5.39
Premium Gasoline	6.245	4.043	0.569	0.843	11.70
Regular Gasoline	5.706	3.956	0.525	0.613	10.80
Kerosene	6.073	0.432	0.3964	(0.781)	6.12
Auto. Diesel Oil	5.808	0.959	0.439	(0.506)	6.70
Resid. Fuel Oil (3.5% sulphur)	4.853	0.001	0.147	(0.911)	4.09

a/ Exchange rate Baht 27.7 = US$1.00.
b/ This refers to "controlled" LPG price (i.e. for non-automotive purposes). In addition this unit price is for a 50 kg cylinder but expressed in liters.
c/ The weighted average c.i.f. price in June 1985 had declined by about 8% compared to February 1985 due to decreases in kerosene, diesel oil and fuel oil prices ranging between 7-12%.

6.17 Product prices are set at the ex-refinery level through the Ministry of Industry, and at the retail level through the National Petroleum Policy Committee (NPPC). The ex-refinery prices are established on the basis of Singapore posted prices and notional freight, and are converted into Baht at the prevailing floating exchange rate. The ex-refinery price is based on an average of Singapore price postings using a different price base for imported and domestically refined products. Ex-refinery prices are calculated by the Ministry of Industry

34/ In the case of 97 (RON) octane premium and 85 octane regular gasolines this differential should be less than about 10%.

and changes are put in effect by the Petroleum Policy Committee when either Singapore prices or exchange rate variations require a petroleum price change. Up to the October 1984 devaluation the ex-refinery prices of products in Thailand were consistently below (about 1-2%) c.i.f. import parity prices. However, since October 1984 the ex-refinery prices of most products have been somewhat higher (about 1-3%) than the c.i.f. import prices of these products. In the view of the assessment team, it is critical that the local refining sector not be subsidized and in this context policy regarding ex-refinery pricing of petroleum products becomes very important.

6.18 The retail price includes import duties, business and municipal taxes which are levied on imported products or excise and municipal taxes which are levied on locally produced products. In addition, retail prices include a margin for marketing activities and a contribution to or a subsidy from the Oil Fund. There is no difference in retail price regardless of whether the product is imported or produced locally.

6.19 The Oil Fund was established by the government in 1974, initially for one year, as a price stabilization mechanism during a period when international prices were undergoing major upward changes. The position of each product vis-a-vis its contribution to or subsidy from the Oil Fund as of early February 1985 is shown in Table 6.4. The massive Oil Fund transfers for LPG, kerosene, diesel oil and fuel oil are of special concern because if they are sustained throughout 1985 they would amount to some 5 billion Baht, or nearly 1/2% of GDP. The Oil Fund stabilizes retail prices by absorbing increases or decreases in ex-refinery prices through a cross-subsidization mechanism between products which do not require any direct transfers to or from the government's budget as long as the Fund remains more or less in balance or in surplus. In the past, however, the Fund has often run major deficits which have required contributions from the government. As noted above, the Fund has recently been accumulating a monthly deficit because the impact of the November devaluation has not been passed through to retail prices. The original objective for establishing the Oil Fund, namely, the stabilization of short-run international oil price movements, appears now to play a secondary role. In practice the Fund has become a discretionary mechanism to delay adjustments in retail prices resulting from increases in the cost of petroleum products to the country (through Baht devaluation or increases in international product prices) and a mechanism to cross-subsidize petroleum products, and it can be fairly costly in terms of tax revenues for the government.

6.20 One desirable alternative to resolve this issue would be to abolish the Fund and establish a mechanism by which domestic prices are linked to those at the international level and reflect automatically changes in either exchange rates or border prices. In addition, retail prices would need to be increased so that the average level of the reconstituted barrel is at least 40% above the c.i.f. value, thereby re-establishing the level which prevailed before the October 1984 devaluation and which is roughly in line with the general tax level in Thailand.

In effecting this adjustment, a new structure of retail prices which reflects the structure of product prices at the border price level more closely could also be put in place. There may be some practical problems, however, in implementing such reform, for example because of existing tax ceilings which would not allow the higher taxes required for diesel oil, LPG and kerosene. Consequently, while these issues are being resolved, the Oil Fund could be restructured in such a way that the economic costs of petroleum products are reflected automatically in retail prices. The Fund would need to be subject to an automatic "trigger" which would signal the need for changes in retail prices. The magnitude of the price change could be related directly to changes in international prices valued in domestic currency. This procedure could be used in the short-term to correct the price structure.

6.21 As shown in Table 6.4, the higher taxation on gasolines compared to automotive diesel oil results in a major change in their relative prices at the retail level compared to the c.i.f. level. For example, retail premium gasoline currently is priced 75% above diesel oil, while at the border price level it is only 7.5% above. Much smaller distortions occur in the case of other products, as shown in Table 6.5. For example, kerosene is 5% above automotive diesel at the border level and 9% below at the retail level. The major consequences of these price distortions are outlined below with special reference to the fuels used in the transport sector (accounting for almost 52% of petroleum product consumption).

Table 6.5: PETROLEUM PRODUCT PRICE RATIOS AT RETAIL AND C.I.F. LEVELS, FEBRUARY 1985

Ratio	C.I.F. Level	Retail Price Level
Premium Gas/Diesel	1.08	1.75
Regular Gas/Diesel	0.98	1.61
Kerosene/Diesel	1.05	0.91
LPG/Diesel	0.81	0.81
Residual Fuel Oil/Diesel	0.84	0.70

Pricing Fuels Used in Transport: Gasolines, Diesel and LPG

6.22 The compression ignition diesel engine has a considerably better fuel economy compared to the gasoline fueled spark ignition engine. This is due to the lack of throttling losses, use of a higher compression ratio engine, as well as the use of a fuel with a higher specific energy content per volume unit. Many comparisons of the fuel economies of gasoline and diesel powered vehicles often are made in cases where both vehicles have equal engine displacements (c.c. ratings). However, in such comparisons the diesel vehicle would have a lower horsepower and hence less power output and poorer performance (e.g., in acceleration). Consequently, the most appropriate comparison is for vehicles of comparable performance and weight but different engine displacements. Pertinent data for such cars are shown in Table 6.6.

Table 6.6: VEHICLE PERFORMANCE AND FUEL ECONOMY FOR GASOLINE AND DIESEL CARS OF EQUAL HORSEPOWER AND WEIGHT a/

Performance Data	Gasoline Model	Diesel Model
Fuel Economy, kms/litre		
City driving	9.4	12.3
Highway driving (90 km/h)	13.2	15.3

a/ Data from manufacturers.

Two important characteristics of the data in this table generally are also valid for other diesel/gasoline car models. First, although the improvement in fuel economy of the gasoline car in highway versus city conditions is about 40%, for the diesel vehicle this improvement is only about 24%. Second, under city driving conditions the diesel obtains almost 30% higher fuel economy than the gasoline car, whereas on the highway this declines by about one-half. The key issue is the better fuel economy of the diesel especially under the stop/start, stressed conditions of city driving. Although the above data refer to developed country conditions, the traffic congested Bangkok environment would tend to favor diesel performance more than the above data will suggest.

6.23 The benefits in higher fuel economy of the diesel engine are offset both by its higher investment cost and its higher running costs (the latter due in part, to higher lube oil requirements). In the case cited above, the differential investment cost relative to the gasoline model c.i.f. Bangkok was about US$900 in 1984 with differential running costs being some US$150 a year.

6.24 Whereas the substitution of diesel oil for gasoline requires an engine change, LPG can directly substitute for gasoline in a spark ignition engine merely by changing the fuel supply system. Such simple modifications could be achieved at relatively low cost (about US$250 in Bangkok in 1984) and have already been undertaken extensively in Thailand over the recent past (para. 6.2). There is no significant incremental running cost when LPG is substituted for gasoline. The performance characteristics of LPG as a motor fuel in spark ignition engines depends on the composition of the LPG, i.e., the fractions of propane and butane going to make up the mixture. Since these components have different characteristics the mixture that may be optimum for meeting cooking uses may not be when used as a substitute for gasoline. For example, propane has a higher octane number (RON 111) than butane (RON 94) while butane's energy content per volume unit is 13% higher than that of propane. This means that if 100% propane is used as a gasoline substitute, or LPG containing a high propane fraction, the optimum fuel use would be from a high compression ratio spark ignition engine (11-12:1) rather than in a low compression ratio engine (7-8:1). Virtually all the gasoline fueled vehicles in Thailand belong to the latter category. When LPG rich in propane is used in low compression ratio engines, the benefit of the higher octane number cannot be taken advantage of and hence the fuel economy penalty on a volume basis is quite severe. Because LPG has a lower energy content per unit volume compared to gasoline, the fuel economy penalty in reduced kilometers per liter is about 30% relative to gasoline. However, if such LPG rich in propane gas were used in a high compression ratio engine the fuel economy penalty would only be about 15%.

6.25 In order to compare the benefits and costs of operating these vehicles with different fuels (gasoline, diesel and LPG) two types of driving modes are examined. The first simulates that of a Bangkok taxi (high annual kilometers) driving about 80,000 kms/year with around 90% city and 10% highway driving. The second simulates a private motorist (low annual use) in the greater Bangkok area driving about 24,000 kms/year, 70% under city and 30% highway conditions. The operating costs of each mode are expressed in Baht per kilometer and where differential investment or running costs are involved these are expressed relative to gasoline. Table 6.7 shows these comparisons based on product prices at the c.i.f. and retail levels in Bangkok 35/ without taking into account investment or running cost differentials. Table 6.8 reflects total costs including these differentials.

Table 6.7: COMPARISON OF UNIT FUEL COSTS FOR GASOLINE, LPG AND DIESEL FUELED CARS IN BANGKOK a/

Relative unit fuel costs (Baht/km)

Fuel Prices	Taxi			Private Motorist		
Feb. 1985	Diesel	LPG	Gasoline	Diesel	LPG	Gasoline
C. I. F. Prices a/	0.46	0.62	0.64	0.44	0.58	0.59
Retail Prices in Bangkok b/	0.53	0.86 b/ 0.72 c/	1.20	0.51	0.80 b/ 0.67 c/	1.11

a/ See Table 6.4 above.

b/ Retail prices given in Table 6.4 above except for LPG in which case a price of 6.5 Baht/liter was used which represented the February 1985 price level for automotive uses.

c/ Based on February 1985 controlled retail price for LPG domestic uses.

35/ Based on February 1985 prices.

6.26 With the c.i.f. price structure, the lowest fuel cost option is diesel, followed by LPG and gasoline, irrespective of the mode of use. The difference between LPG and gasoline is marginal. With the retail price structure, LPG fuel costs per unit are below those of gasoline for both modes and diesel remains the lowest cost fuel for both modes.

6.27 Turning to Table 6.8, which compares total unit costs after factoring in the incremental capital and running costs for diesel and LPG relative to gasoline, the following significant modifications occur:

(a) at the c.i.f. price level, in the taxi mode there is no clear advantage or disadvantage between LPG and gasoline. However, the diesel fueled taxi has a lower economic cost (about 10%) than either of the other fuels due to the high annual mileage of taxis which offsets the additional incremental costs;

(b) based on c.i.f. prices, in the private motorist mode the lowest cost fuel is gasoline, followed by LPG (about 7% higher cost), while diesel is the most costly fuel by a significant margin (about 31% above that of gasoline). This is due to the low annual mileage in this mode;

(c) based on the retail price structure, for the taxi mode diesel is the lowest cost fuel, followed by LPG, and gasoline is nearly 85% more costly than diesel use and between 36-60% more than LPG depending on whether "controlled" or "uncontrolled" LPG is compared. For this particular mode of use therefore the retail price structure still sends the correct economic signal between diesel and other fuels but not between LPG and gasoline; and

(d) in the private motorist mode, with the retail price structure LPG is the least cost fuel, followed by diesel, and gasoline again with excessively high cost -- being between 30-50% higher than LPG. In this case, prices at the retail level are sending a signal completely at variance with what they should be to promote economic choices.

6.28 The above analysis has focused on cars; however, as noted earlier (para. 6.8) major changes have occurred in Thailand since 1980 in the sales of diesel versus spark ignition-engine light trucks/pick-ups. Table 6.9 compares the estimated total unit costs for gasoline and diesel fueled light trucks in Bangkok. Once more the relative costs in Baht/kilometer based on c.i.f. and retail prices of gasoline and diesel oil form the basis of the analysis. The following points should be noted:

(a) based on the c.i.f. price structure the gasoline fueled light truck/pick-up has lower total unit costs (by about 15% at current prices) than the diesel version;

(b) however, at the level of retail prices, diesel unit costs are about two-thirds of those of gasoline. Clearly, such a price structure provides a sizable financial incentive to consumers to pursue the economically inefficient option (para. 6.8).

Table 6.8: COMPARISON OF TOTAL UNIT COSTS FOR GASOLINE, LPG AND DIESEL FUELED CARS IN BANGKOK a/
Relative Total a/ Unit Costs (Baht/km)

	Taxi b/			Private Motorist b/		
Fuel Prices	Diesel	LPG	Gasoline	Diesel	LPG	Gasoline
C. I. F. Prices c/	0.58	0.64	0.64	0.77	0.63	0.59
Retail Prices in Bangkok d/	0.65	0.88 d/ 0.74 e/	1.20	0.84	0.86 d/ 0.72 e/	1.11

a/ Including incremental capital and running costs for diesel and LPG fueled vehicles relative to gasoline powered vehicles.
b/ Taxi life assumed 5 years and that of private car 7 years, cost of capital taken as 12%.
c/ See Table 6.5 above.
d/ Retail prices from Table 6.4 above except LPG which was taken as 6.5 bhat/liter -- the uncontrolled Bangkok retail price for automotive uses.
e/ Based on the February 1985 controlled retail price for LPG for domestic uses.

Table 6.9: COMPARISON OF ESTIMATED TOTAL UNIT COSTS FOR GASOLINE AND DIESEL FUELED LIGHT TRUCKS IN BANGKOK a/
(Relative Total a/ Unit Costs (Baht/km)

	Light Truck b/	
Fuel Prices	Gasoline	Diesel
c.i.f. Prices c/	0.83	0.95
Retail prices in Bangkok c/	1.56	1.06

a/ Including incremental capital and running costs for diesel fueled light trucks relative to gasoline ones. Capital cost differential about Baht 30,000 in 1984 (US$1300) with an annual running cost differential of about Baht 6,000 (US$260 in 1984).
b/ Truck life taken as 6 years assuming an average 50,000 kms/year of use and the cost of capital as 12%. Fuel economies taken as 7.5 kms/liter for gasoline and 8.5 kms/liter for diesel vehicle.
c/ See Table 6.4 above.

6.29 What is shown by the above analysis is the degree to which relative price distortions at the retail level between transport fuels encourage drivers of both cars and light trucks/pick-ups to select fuel choices which are not the lowest cost fuel from the national standpoint. For example, from the economic perspective, gasoline should be the fuel used for all private motoring as well as for light trucks. However, it is so heavily taxed relative to its fuel substitutes that it is the most costly fuel for all of these classes of drivers. In this context, private cars, light trucks and pick-ups represented more than 80% of the registered motor vehicles (excluding motorcycles) in Thailand in 1984. Among the light weight vehicles (cars, taxis, light trucks and pick-ups) it is only in the case of taxis that diesel is the least economic cost option and this arises essentially because of the high annual mileage. Regarding the choice between LPG and gasoline (in low compression ratio spark ignition engines) it is only in the taxi mode that either fuel is an economic choice, while for the private motorist gasoline is the preferred fuel from the economic standpoint (costing about 7% less than LPG).

6.30 One issue that arises is the sensitivity of the preceeding analysis to c.i.f. price differentials between the key transport fuels: gasoline, LPG, and diesel oil. Table 6.10 shows the average posted prices of LPG, premium gasoline and automotive diesel oil in Singapore between 1977 and February 1985. Over this period the ratio of premium gasoline to LPG prices ranged from a high of 1.37 to a low of 1.22--the low level occurring during the height of price instability, 1979 and 1980. This ratio, based on c.i.f. Bangkok prices (Table 6.4) in February 1985, was 1.34, and these prices were used in the above analysis for these two fields. If the ratio of border prices of premium gasoline and LPG increases to about 1.40 (which is higher than any level in the past decade) gasoline still remains the lowest cost economic fuel for private motoring (though only marginally so), while for taxis LPG becomes the marginally lower cost fuel. In other words, the above conclusions (para 6.27) do not change substantially even when the LPG/premium gasoline border price differential is assumed to be wider than at any time in the past decade.

6.31 When one turns to premium gasoline and diesel oil the variation in Singapore posted prices over the past several years (Table 6.10) is greater than for LPG and premium gasoline. For example, the ratio between 97 octane premium gasoline and automotive diesel oil average posted prices has decreased from 1.17 in December 1977 to 1.01 in December 1982, increasing slightly to 1.11 in February 1985. The above analysis was based on the c.i.f. Bangkok price ratio of 1.075 for these two fuels in February 1985 (Table 6.4). This ratio would have to increase to about 1.30 for the choice between gasoline and diesel fueled light trucks/pick-ups to be indifferent at the border price level.

Table 6.10: HISTORICAL WORLD PRICE DIFFERENTIALS BETWEEN GASOLINES, DIESEL OIL AND LPG a/ (1977-1985)

Date	Singapore Average Posted Prices of: US$/US gallon			Ratios of Average Posted Price	
	LPG	Premium Gas (97 oct.)	Diesel Oil (0.5% S)	Premium Gas/ LPG	Premium Gas/ Diesel Oil
Dec. 1977	34.5	47.3	40.6	1.37	1.17
Dec. 1978	34.5	47.5	40.2	1.37	1.18
Dec. 1979	64.5	80.4	76.5	1.25	1.05
Dec. 1980	86.7	106.1	102.1	1.22	1.04
Dec. 1981	83.5	110.9	107.2	1.33	1.04
Dec. 1982	78.9	104.2	103.5	1.32	1.01
Dec. 1983	73.6	94.3	82.0	1.28	1.15
Dec. 1984	66.6	87.8	79.0	1.32	1.11
Feb. 1985	65.0	87.8	79.2	1.35	1.11

a/ Average Posted Prices of LPG, 97 octane premium gasoline and 0.5% S automotive diesel oil in Singapore on the dates indicated.

6.32 A further case of incorrect pricing signals at the retail level involves kerosene and diesel oil. There has been substantial adulteration (estimated at about 40% of non-aviation kerosene use) of automotive diesel oil with kerosene. This adulteration requires no engine modifications and is a very attractive option available to owners of diesel vehicles. Since the cost to the economy of kerosene is about Baht 0.27/litre higher than that of diesel oil (February 1985 c.i.f. prices) but the price of kerosene to the consumer is 0.58 Baht/liter less than the price of diesel oil, it is clear that about 0.27 Baht are lost to the economy for every litre of kerosene so diverted at present. 36/

6.33 In seeking to reflect the correct economic price structure (i.e. the structure of border prices) at the retail price level for petroleum products, a number of constraints have to be recognized:

(a) petroleum products represent a major source of government tax revenue and gasoline has traditionally borne most of the tax burden;

(b) whereas gasoline, LPG and kerosene have significant final user applications, fuel oil is used extensively as an intermediate input (e.g., in the production of electricity and manufactured goods). This means that it may be economically inefficient to levy an equal tax on all products;

36/ Measures instituted by the government in late 1983 to reduce this adulteration have been very effective in that in 1984 kerosene demand declined to about 50% of its 1983 level.

(c) the possibility of adverse impacts on low income groups from significant upward adjustments in the price of fuels like kerosene; and

(d) the near impossibility of developing a single set of breakeven prices among the transport fuels due to the differing fuel efficiencies and differential capital and running costs between different fuel consuming activities.

6.34 Given that some of these constraints are mutually exclusive, developing a satisfactory structure of retail prices becomes a matter of doing the least violence to each of the above factors while signaling to consumers that uneconomic fuel uses are to be discouraged and simultaneously protecting government's total revenue. In this context, the following types of measures need to be considered:

(a) an immediate upward adjustment in the retail prices of all products to account for the effect of the October 1984 devaluation;

(b) in undertaking this adjustment, the resulting structure of retail prices should reduce the differential between gasoline and its main competitors in the transport sector -- diesel oil and LPG. This implies increased taxes on these two fuels;

(c) if there are strong fiscal reasons for raising additional revenue, then fuel oil should begin to attract some tax. Since imported coal already attracts an import duty of some 10%, a similar levy should be imposed on fuel oil to ensure equivalent tax treatment; and

(d) the level of tax increase needed on diesel oil could be limited by the adoption of non-fuel price policies. First, in the case of diesel engine light trucks/pick-ups and passenger cars, an excise duty higher than that levied on the equivalent spark ignition engine vehicle should be introduced. Second, a higher annual registration fee on such diesel vehicles should also be levied. These combined measures would reduce, though by no means eliminate, the financial incentives for uneconomic switching of engine types provided by the current fuel pricing system. For example, a 40% increase in the excise duty on the diesel version of light trucks would virtually double (to about Baht 60,000) the existing selling price differential between the equivalent diesel and gasoline versions. When combined with a differential annual registration fee of about Baht 6,000 for the diesel versions this would merely equate the estimated financial cost per kilometer 37/ of operating a gasoline or diesel fueled light truck, if gasoline and diesel fuel retail prices are restructured along the lines recommended by the assessment team below.

6.35 Table 6.11 shows the past and present structure of retail petroleum product prices, as well as that proposed by the assessment team. These structures are expressed in terms of the ratio of the retail prices to the c.i.f. price for each product. The assessment team's recommendation should be considered as indicative of the type of structure which should achieve many of the desired objectives subject to the constraints outlined above. This structure is similar to that proposed in the PEIDA Energy Pricing Study. Certain points about this table are worth noting:

(a) the ratios in February 1985 are systematically lower than those of October 1984 because the devaluation adjustment has not been passed through to retail prices yet;

(b) the new level of retail prices proposed by the assessment team and the associated new structure would result in the following changes in retail prices above their current levels:

Premium gasoline	-0.70 Baht/liter
Regular gasoline	-0.70 Baht/liter
Kerosene	+1.78 Baht/liter
Automotive diesel oil	+1.40 Baht/liter
Residual fuel oil	+1.41 Baht/liter
LPG	+1.02 Baht/liter

6.36 The most important result of this proposed structure would be to narrow the current differential between premium gasoline and automotive diesel oil from 5 Baht/liter to 3 Baht/liter. In addition, fuel oil would begin to attract a modest import duty (about Baht 0.48 per liter). This is to ensure equal tax treatment for coal and fuel oil as well as to strengthen government revenues from petroleum products -- this would raise at least 0.7 billion Baht annually. Adoption of this structure and its associated levels of product prices would increase the value of the reconstituted barrel in Thailand to about Baht 7.68/liter, or 40% above that at the border price level. The impact of introducing such a structure of retail prices on product demand over the rest of the

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37/ These measures merely achieve equality of financial costs though, as shown in Table 6.9, the gasoline fueled engine is 15% lower in economic cost that the diesel engined light truck based on a premium gasoline/diesel oil border price difference of 7.5%. Hence the proposals above can be considered as the minimum required to achieve the correct economic signal.

decade and the implications for refinery sector configuration are discussed below (para. 6.76).

Table 6.11: PAST, PRESENT AND PROPOSED RETAIL PRICE STRUCTURE: FOR PETROLEUM PRODUCTS: RATIOS OF RETAIL TO C.I.F. PRICES

Product	Ratio of Retail December 1983	Ratio of Retail October 1984 Pre-Devaluation	Prices to C.I.F. Import Prices Feb. 1985 Current a/	Prices to C.I.F. Import Prices Proposed New Structure with Devaluation Adjustment
			(Prices in Baht/liter)	(Prices in Baht/liter)
Premium Gasoline	2.13	2.25	1.87 (11.70)	1.76 (11.0)
Regular Gasoline	2.17	2.28	1.89 (10.80)	1.76 (10.1)
Kerosene	1.17	1.21	1.01 (6.12)	1.3 (7.9)
Automotive Diesel	1.35	1.38	1.15 (6.70)	1.4 (8.1)
Residual Fuel Oil (1500 sec.)	1.04	1.01	0.84 (4.09)	1.13 (5.5)
LPG (large cylinder)	1.35	1.39	1.15 (5.39)	1.37 (6.41)

a/ These retail prices do not reflect the effect of the 1984 October devaluation.

6.37 The government has available to it two other options to deal with the gasoline/LPG/diesel oil problem of consumer choice in the transport sector. The first option would involve banning the use of new diesel fueled cars (other than taxis) and light trucks/pick-ups. If this is done the high differentials between gasoline and diesel oil retail prices could be maintained, since the uneconomic use of diesel in certain transport modes (cars and light trucks/pick-ups) would simply be prohibited. This option is attractive because of its simplicity in achieving the desired objective without having to raise the tax ceilings on diesel oil, as well as introducing differential non-fuel price disincentives for using diesel engines in cars and light trucks. The other option involves having an equal excise tax on all petroleum products. In this manner, the structure of retail prices would remain the same as that of border prices, thereby signalling to consumers that financial and economic differentials remain unchanged and limiting the incentive for uneconomic choices of fuels and engines in the transport sector. Under this option the structure of retail prices (based on February 1985 border prices, Table 6.4) would be as shown below assuming that the retail value of the reconstituted barrel were set at 40% above import parity:

Product	Retail Price (Baht/litre) a/
Premium gasoline	8.74
Regular gasoline	7.99
Kerosene	8.50
Auto Diesel Oil	8.13
Resid. Fuel Oil	6.79
LPG	6.54

a/ Based on 40% above February 1985 c.i.f. Prices--Table 6.4.

Petroleum Product Demand Projections

6.38 The future demand for petroleum products depends on the growth and structural transformation of the economy and demand management policies such as energy pricing and interfuel substitution. The most important interfuel substitution options in Thailand over the next decade pertain to natural gas, which is increasingly being used as a fuel in the power and manufacturing sectors in place of fuel oil. Within the manufacturing sector such substitution is already well under way in the cement industry though the shortfall in gas supply in 1983 and 1984 has somewhat reduced the rate of gas penetration.

6.39 Lignite offers another substitution option; already in 1983 it fueled about 10% of the electricity generated by EGAT. As discussed earlier the power expansion programme over the rest of this decade and during the early part of the 1990s calls for further major additions of lignite fueled capacity. These developments indicate that fuel oil demand will decline further over the next few years as substitution of existing fuel oil using capacity in the power and cement sectors works its way through.

6.40 In the transport sector (para. 6.24-6.37), the inter-fuel substitution trends between gasoline, LPG and diesel oil which are stimulated by the current retail price structure of these products have already been mentioned. Finally, in the household sector, the substitution of LPG for traditional fuels in cooking and electricity for kerosene in lighting can be expected over the next several years as rural incomes rise and the rural electrification programme continues to expand.

6.41 Currently, both the NEA and PTT project the demand for petroleum products by regression estimates of the relationship between the demand for a particular petroleum product and the determinants of that demand. These determinants include petroleum product retail prices and those of their substitutes, GDP or components thereof, motor vehicle population, etc. The appropriateness of applying such forecasting techniques to the Thai energy sector can be seriously questioned. First, the regression methodology makes no allowance for the rapid structural changes in the composition of output which are expected and planned for in Thailand over the next decade. Second, regression estimates are highly sensitive to the data variation at the beginning or the end of the estimation period selected for the analysis. This becomes especially serious when the end of the period includes data reflecting a one-time response to a sudden shock such as occurred to energy consumption in Thailand following the large increases in domestic prices in 1980 and 1981.

6.42 The assessment team has based its forecast of petroleum products on energy end-use demand projection methodology. The end-use projection is based on the ratio of energy used per unit of output produced, the change of this ratio over time and the expected growth rate of output in each sector. An application of this demand forecasting methodology was developed into a simple model by the PEIDA consultants during their energy pricing study to demonstrate the impact of price changes on petroleum demand.

6.43 The model includes eight broad economic sectors: agriculture, mining, construction, electricity, transport, services, manufacturing, and others. The manufacturing sector is further divided into 19 subsectors which allow the model to distinguish between a total of 26 subsectoral and sectoral activities. The demand for each petroleum product is calculated as the sum over all sectors of the fuel requirement per unit of output in each sector (input coefficients) multiplied by the sectoral output. The input coefficients are model parameters and the sectoral outputs are exogenous, making the model "output driven". The input coefficients are affected by changes in price levels and price relativities through individual and cross price elasticities for each fuel. These price effects are allowed to "feedback" through interfuel substitution and conservation. Table 6.12 shows the individual and cross price elasticities for gasoline, kerosene, diesel oil and LPG used in the model to project demand for these products and illustrate the impact of different pricing regimes on future product demand. These elasticities are partly based on estimates recently made in Thailand. 38/ The assessment team has been guided by these estimates with some modifications. For example, in the case of LPG the individual and cross elasticities were reduced due to possible overestimation because of the nature of the LPG transport market in which most substitution has taken place in the taxi fleet but very little in that of private motorists. Individual price elasticities range from 0.15 for diesel, 0.20 for kerosene and gasoline to 0.30 for LPG. As for cross-price elasticities, as expected, that between gasoline and LPG is highest at about 0.45, while that of diesel oil with respect to the price of gasoline is 0.25, indicating that increases in gasoline prices result in a higher response in LPG demand than for diesel oil demand. In part, this is because of the need for an engine change to occur in the case of diesel oil.

38/ "Estimation of Petroleum Product Demand Functions", by Terra Ashakul (NESDB), February 1985.

Table 6.12: ESTIMATES OF LONG-RUN PETROLEUM PRODUCT DEMAND ELASTICITIES WITH RESPECT TO PRICE

Petroleum Product	Prices of: Gasoline	Kerosene	Auto. Diesel	LPG
Gasoline	-0.20	0.00	+0.25	+0.45
Kerosene	0.00	-0.20	+0.05	0.00
Automotive Diesel	+0.25	0.00	-0.15	0.00
LPG	+0.45	0.00	0.00	-0.30

6.44 GDP sectoral outputs for the period 1983-1995 were used to generate the demand forecasts for gasoline, LPG, diesel oil and kerosene. To project GDP two scenarios were assumed -- the high one in which an overall annual rate of 6.0% is assumed and the low one of 4.5% over the same period 1985-1995. In both cases the agricultural sector is assumed to grow at 3% annually with non-agricultural sectors growing at 7% and 5% in the high and low scenarios, respectively.

6.45 The other critical parameter required to project future petroleum product demand is the international price of oil over the next ten years. The uncertainties involved here are well known. Given current perceptions of soft international demand for oil and sufficiency of supply which are likely to persist over the next few years, the assessment team adopted the latest World Bank projections of crude oil. These crude oil price projections were combined with projections of crude oil to product price ratios 39/ to yield estimates of product prices -- these projections are shown in Table 6.13. According to these projections prices are expected to decline by about 7% in real terms in 1986 over the 1985 level and then remain fairly constant in real terms until 1990 (an actual annual increase of 0.9%). After 1990 they are projected to rise in real terms at an annual rate of about 4.9% up to 1995. To assess the sensitivity of the fuel demand projections to world oil prices, three alternative perceptions of such prices over the 1985-95 period were also used. These other price scenarios were:

(a) constant 1985 prices throughout the period;

(b) all product prices escalating at 3% a year in real terms between 1985-95; and

(c) all product prices declining 3% a year in real terms between 1985-1995.

39/ World Bank Appraisal Report (April 1985), "Bangchak Oil Refinery Rehabilitation."

Table 6.13: PETROLEUM PRODUCT PRICE PROJECTIONS, 1985-95 a/
(Constant 1984 $/bbl)

Year/ Product	LPG	Premium Gas	Kerosene	Auto. Diesel	Residual Fuel Oil	Crude Oil
1985	26.8	36.1	35.9	35.8	26.1	27.8
1986	24.8	33.4	33.2	32.9	24.0	25.9
1987	24.9	33.7	33.4	33.1	23.6	26.1
1988	25.1	33.8	33.6	33.2	23.9	26.4
1989	25.2	34.1	33.8	33.5	24.3	26.6
1990	25.3	34.1	34.1	33.8	24.5	26.8
1991	26.5	35.8	35.7	35.4	25.	28.1
1992	27.6	37.3	37.5	36.9	27.7	29.5
1993	28.6	38.9	38.8	38.4	29.4	30.9
1994	30.0	40.8	40.7	40.3	30.8	32.5
1995	31.5	42.8	42.7	42.3	32.3	34.1

a/ Based on World Bank crude oil price projection of January 1985.

6.46 For each scenario of c.i.f. product prices over the projection period the two structures of retail prices were examined. The first structure was the traditional one and the alternative was that proposed by the assessment team (see Table 6.11).

6.47 Using the above assumptions regarding the evolution of world crude oil, retail petroleum product prices, and the high and low scenarios of GDP growth, projections of demand for gasoline, kerosene (excluding jet fuel) 40/, diesel oil and LPG were made based on the model developed by PEIDA. Variations in natural gas supply over the next several years will primarily affect fuel oil demand. For this reason future demand for fuel oil has been projected independently of the model and is discussed below (para. 6.50-6.60). The assessment team's estimates of demand for LPG, gasoline, kerosene and diesel oil are shown in Table 6.14 in the case of the high GDP growth and current World Bank Crude oil price projections. The effect of instituting a change in the structure of retail prices to reflect more closely the structure at the c.i.f. level is clearly illustrated over the period up to 1990 when little real increase in prices is assumed, and between 1990-95 when real prices are assumed to begin a stronger upward trend once more. For example, by 1990 gasoline demand under the assessment team's proposed retail price structure would be about 18% above that which would result from the traditional price structure. In contrast, the demand for LPG and diesel oil under the proposed price structure would be 13% and 10% lower, respectively, in 1990 than under the existing pricing regime. This stimulation of gasoline demand at the expense of diesel oil and LPG promotes a more efficient allocation of these fuels in the transport sector and therefore should be encouraged.

40/ The mission has projected jet fuel demand independently of the model.

Table 6.14: PETROLEUM PRODUCT DEMAND (1984-1995) AND EFFECTS OF CHANGED RETAIL PRICE STRUCTURE a/
(bbls/day)

		Traditional Retail Price Structure				Proposed Retail Price Structure			
Product	1984	1987	1990	1993	1995	1987	1990	1993	1995
LPG	16,500	23,400	33,100	45,400	54,900	21,500	29,300	39,400	46,900
Gasoline	36,400	39,400	40,500	40,200	39,000	45,800	47,700	46,300	44,300
Diesel Oil	90,900	105,400	122,300	139,800	150,500	99,300	111,300	124,300	131,900

a/ High GDP growth scenario and January 1985 World Bank crude oil price projections (Table 6.13).

Table 6.15: RATIO OF THE PROJECTED PRODUCT DEMAND USING THE TRADITIONAL RETAIL PRICE STRUCTURE/DEMAND USING MISSION'S RECOMMENDED STRUCTURE

Product	1990	1995
LPG	1.13	1.17
Gasoline	0.85	0.88
Diesel Oil	1.10	1.14

6.48 The effects of the proposed retail price structure on the foreign exchange costs of gasoline, diesel oil and LPG (as measured by their c.i.f. prices) are also important. Based on the World Bank crude oil price projection, the result of leaving the traditional retail price structures in place would be to increase the foreign exchange acquisition costs of these three products in 1990 and 1995 by 4% and 9%, respectively, over the assessment team's proposed structure. 41/

6.49 From the standpoint of changes in GDP, under the medium growth scenario (4.5%/year between 1984-95) the only important modification under all world oil price assumptions is a lowering of petroleum demand. The level of reduced demand varied from 10-12% for gasoline, diesel and LPG by 1990 and from 20-23% for these products by 1995. In fact, in the case of LPG and diesel oil, the reduction in demand by 1990 under the medium GDP growth case is about the same as the reduced demand for these products in the high GDP growth scenario as a result of

41/ The cumulative effect of adopting the mission's recommended price structure between 1986-95 would be to lower the foreign exchange cost of supplying these three products by about US$1.2 billion (1985$) relative to a cost of US$25.5 billion over this period in the absence of any adjustment.

adopting the assessment team's proposed retail price structure instead of the traditional one.

6.50 Under the high GDP growth case and the assumption that oil prices evolve along the path of the World Bank's projections, diesel oil demand increases at about 3.5% a year over the 1984-95 period based on the assessment team's proposed retail price structure (Table 6.14). Growth in LPG demand is estimated to remain strong (around 10% p.a.) with an increasing number of households switching over to this fuel for cooking purposes. Gasoline demand is projected to grow again under the proposed price structure, with an annual increase of some 4.6% expected up to 1990. This would represent a significant turnaround in the gasoline market. However, as real oil prices begin to increase more rapidly in the 1990s (under the World Bank price scenarios) continued growth in gasoline demand is likely to weaken again unless further measures are taken in the early 1990s to ensure that the retail price differentials between gasoline, LPG and diesel oil do not begin to widen relative to c.i.f. levels.

6.51 During the early part of the 1970s (1970-73) jet fuel demand increased very rapidly (about 32% a year). After the first oil shock, however, demand for this product remained constant throughout the rest of the 1970s with some growth resuming in the early 1980s (at about 6.9% a year between 1979-84). The demand for this product is very dependent on the operations of Thai Air and the degree of fuel up-lift by foreign air carriers at Bangkok airport. With more fuel efficient aircraft being introduced the demand growth is expected to slow despite an increasing level of air traffic forecast over the period. The assessment team projects jet fuel demand to increase at about 4% a year over the period 1984-95 in the high GDP growth scenario. In the case of kerosene, the successful measures of the government to reduce the adulteration of diesel oil with this product resulted in almost a 50% reduction in demand in 1984. If these measures remain effective, demand growth should be very modest, especially since the rural electrification program is resulting in a major substitution of electricity for kerosene. The assessment team projects demand for kerosene to increase at only 1.5% a year over the period 1984-1995.

6.52 The assessment team's estimates of demand for all major petroleum products other than fuel oil are set out in Table 6.16. These estimates refer to the most likely scenario -- high GDP growth and oil prices evolving in line with World Bank projections. Finally, the demand estimates assume that the assessment team's proposed retail price structure is put into place before the end of 1985.

Table 6.16: MISSION'S PETROLEUM PRODUCT DEMAND PROJECTION (1984-95) a/
(bbls/day)

Product	1984	1987	1990	1993	1995
LPG	16,500	21,500	29,300	39,400	46,800
Gasoline	36,400	45,800	47,700	46,300	44,300
Kerosene	4,900	5,200	5,500	5,900	6,100
Jet Fuel	20,900	23,500	26,400	29,700	32,100
Diesel Oil	90,900	99,300	111,300	124,300	131,900

a/ High GDP growth scenario accompanied by World Oil Prices evolving in line with the World Bank's Oil Price Projection. This demand forecast assumes that the mission's proposed retail price structure is in place by the end of 1985.

Projected Fuel Oil Demand

6.53 The power and cement production sectors have driven fuel oil demand in Thailand over the last decade, accounting for over 70% of consumption. Future demand for fuel oil over the next decade therefore will critically depend on the extent and rate of substitution of natural gas, lignite and imported coal in these two sectors. The use and substitution of fuel oil in the power sector has been addressed earlier; the cement sector is analyzed below.

6.54 Thailand has a large and well developed cement industry consisting of six main plants operated by three companies. Siam Cement Company operates three plants -- two located in the Saraburi area about 100 kms. north of Bangkok and another in the southern peninsula about 900 kms. south of Bangkok (at Thung Song). Siam City Cement operates one plant, also in the Saraburi area. Jalaprathan's two plants are located at Cha-am -- about 180 kms. southwest of Bangkok -- and at Takli -- about 200 kms. north-northwest of Bangkok. The capacities and fuels used in these plants are summarized in Table 6.17. In 1984, installed cement capacity was 9.5 million tons and clinker capacity 7.5 million tons. All plants use the modern dry process except the one at Takli, which has been converted from wet to semi-dry. Major conversions of fuel sources away from exclusive dependence on fuel oil has been under way in the sector for some time. The two Siam Cement plants in Saraburi, representing about 50% of the country's cement capacity, were converted to a dual-fired fuel oil/gas system. Indeed, the company built a US$60 million extension to the natural gas pipeline delivering gas to EGAT. Initially, gas was in short supply in 1983 and 1984, and this restricted the amount used by Siam Cement; however, with gas now becoming more available, the main constraint to increased gas use in this sector is the price of gas and its ability to compete with coal and lignite. Siam Cement's third plant, at Thung Song, has fared better in its conversion to imported coal, which was completed in mid-1984. In the case of the Jalaprathan plants both of these now use high grade lignite and fuel oil as fuels, the former generally being used in the pre-calciners and for meeting part of the heat requirements in the clinkering kilns. Fuel oil is then used also in these kilns to achieve high enough temperatures, since the availability of high grade lignite (about 8,000-10,000 BTU/lb) is limited. Finally, the Siam City plant near Saraburi was converted to use both lignite and imported coal in different parts of the plant, although fuel oil still is being used for some operations.

Table 6.17: CEMENT PLANTS AND THEIR CHARACTERISTICS, 1984

Ownership	Location	Cement Capacity ('000 tons/annum)	Fuels Used	Amounts at Full Capacity
Siam Cement	Ta Luang (Saraburi)	3,200	dual fuel oil/ gas system	4,200 bbls/day fuel oil or 26 MMCFD gas if available
Siam Cement	Kaeng Khoi (Saraburi)	1,700	dual fuel oil/ gas system	2,400 bbls/day fuel oil or 15 MMCFD gas if available
Siam City	Tab Kwang (Saraburi)	2,800	lignite, imported coal and fuel oil all currently used in different part · operation	100,000 tons/per year coal plus 200,000 tons/ year lignite or 205,000 tons/year fuel oil (3,600 bbls/day)
Jalaprathan	Takli (North of Bangkok)	420	lignite supplemented with fuel oil	64,000 tons/year lignite plus 17,000 tons/year fuel oil
Jalaprathan	Cha-am (180 kms. southwest of Bangkok	450	lignite supplemented with fuel oil	73,000 tons/year lignite plus 17,000 tons/year fuel oil
Siam Cement	Thung Song (900 kms. from Bangkok)	900	100% coal or 80% coal and 20% fuel oil	120,000 tons/year coal plus 400 bbls/day fuel oil (22,000 tons/year)
Total		9,470		

6.55 Cement demand in Thailand rose from some 2.5 million tons in 1970 to about 7.1 million tons in 1983, representing a growth rate of 8.4% a year over this period. At the same time GDP increased at about 6.6% a year, implying an elasticity of cement growth to GDP of about 1.3. The Thai cement industry has projected cement demand to increase at around 10% a year up to 1990. However, based on the assessment team's assumed rate of GDP growth of 6% a year up to 1995 and a more conservative estimate of future elasticity of cement growth to GDP of 1.2, the future demand, plant capacity, and total energy use in the sector is shown in Table 6.18. Cement demand is projected to rise from about 7.5 million tons in 1984 to 16.1 million tons by 1995, and an additional 8.0 million tons of new capacity to be added between 1987 and 1994 to meet this demand. Of particular importance in such new capacity is the fuels on which it should be based and the location where expansions should occur.

6.56 Before these issues are addressed, however, it is essential to grasp the scope and rate at which fuel oil substitution in the cement sector has occurred over the past four years. In 1980, about 5.3 million tons of cement were produced and fuel oil use in the sector amounted to some 12,000 bbls/day -- with virtually all facilities then using this fuel. 42/ By 1982, when cement production rose to 6.6 million tons, fuel oil use had already declined to about 9,900 bbls/day due to its partial substitution by gas, lignite and coal in the facilities mentioned earlier. Despite the limited availability of gas in 1983 and 1984 for use in the cement industry, the assessment team estimates that in 1985 fuel oil use in the industry amounted to some 4,600 bbls/day, which would account for about 44% of total sectoral energy requirements, the remainder coming from gas (34%), coal (12%), and lignite (10%).

6.57 Four key factors emerge in assessing the degree of competition among these fuels in the sector. The first is, of course, their relative prices c.i.f. the plant gate; second is their qualities; third-- the transport logistics involved in moving these fuels from their points of origin to the plants in question; and fourth, the costs of converting from fuel oil use to gas, lignite or coal use. Currently, lignite is transported in Thailand by truck to its non-mine-mouth uses while the small quantities of coal imported for the cement industry are lightered in the Ko Sichang area and barged to the plants in question. Trucking distances vary from 450 kms (to the Jalaprathan plant at Takli) to 850 kms (to their plant Cha-am). In the case of delivery to the Saraburi area a distance of about 550 kms is involved by truck and present delivered costs of lignite to this area are about US$30-33/ton (US$1.68-1.84/MMBTU). 43/ Around one-third of this cost represents transport costs (about USç2/km). In contrast, the current price of Australian coal c.i.f. Bangkok is about US$55-60/ton, resulting in a delivered price at Saraburi of about US$66-70/ton (US$2.50/MMBTU) after lightering, barging, handling and trucking costs are included. With the costs of converting to coal or lignite firing being roughly equal but with operating costs being higher in the case of lignite, the latter has a marginal cost advantage at the above delivered prices of coal and lignite in Saraburi.

42/ Major energy conservation measures had not yet been taken to reduce energy use in this sector from almost 1 bbl of fuel oil/ton of cement to half this level.

43/ For high quality lignite with 4,500 kcal/kg calorific value.

Table 6.18: PROJECTED DEMAND, CAPACITY ADDITIONS AND ENERGY USE IN THE CEMENT SECTOR, 1983-95

Year	Demand	Plant Capacity	Plant Utilization	Capacity Added Above 1984 Base	Total Energy Needed to Meet Demand	Energy Requirements Estimated to be Met by Fuel Oil
	('000 tons)	('000 tons)	(%)	('000 tons)	(bbls/day of fuel oil equivalent)	
1984	7,500	9,470	79		9,900	
1985	8,000	9,470	84	+ 300 in 1986	10,500	4,600
1987	9,200	9,770	94		12,100	1,000
				+ 1,600 in 1987		
				+ 1,500 in 1987		
1990	11,400	13,470	85	+ 600 in 1990	15,000	1,000
1992	13,100	15,070	87		17,200	1,000
				+ 1,600 in 1992		
				+ 1,600 in 1993		
				+ 1,600 in 1994		
1995	16,100	19,870	81		26,100	1,000

6.58 When the costs of converting from fuel oil to coal, lignite or gas firing in a cement plant are taken into account as well as the transport costs of these three fuels 44/, the most competitive fuel depends on the plant location. For example, in the case of all cement plants lignite is a more competitive fuel than fuel oil by a large margin. The competition between lignite and coal (at current coal prices) is marginally in favor of lignite for plants not more than about 500 kms from the mines. The competition between gas and lignite depends upon two issues -- whether or not a pipeline already exists, and the price/availability of gas. For gas to compete with lignite and/or coal in the cement industry in Saraburi, its delivered price would have to be less than about US$3.00/MMBtu. Even if the existing gas pipeline is treated as a sunk cost, it would be difficul for gas to compete with these fuels on the basis of current prices. Only if there is an abundantly sustainable supply of gas and an associated decline in price can a major role be envisaged for gas use in the expanding cement sector.

6.59 The 1.6 million ton expansion in capacity at the Siam Cement Co. plant at Kaeng Khoi in Saraburi province which is already under way and scheduled to be commissioned in 1987 is based on total flexibility in fuel use. Though the design is to use lignite for up to 60% of the total heat requirement, the remaining 40% of energy needs can be supplied by gas, coal or fuel oil depending on availabilities and relative prices. It is expected that coal and fuel oil would supply the remaining energy needs for this expansion. Increased gas availability by 1990 (Table 4.5) could allow increased gas off-take by the cement sector in Saraluiri, but this would depend purely on the price rather than availability in the 1983-84 period.

6.60 In summary, fuel oil use in the cement sector is likely to decline to around 4,600 bbls/day in 1985 and continue to decline to about 1,000 bbls/day by 1987 as substitution of coal is completed at the Siam city plant. Fuel oil use in the cement sector would be about 1,000 bbls/day (or 6% of the sector's 1992 energy needs) and remain at this level for the next several years. In this sector it would be used on a small scale in the two Jalaprathan plants as well as the Siam Cement plant at Tnung Song in the south where it is utilized along with coal and/or lignite. By 1990, the assessment team estimates the following pattern of energy inputs in the cement industry: fuel oil (7%), gas (45%), coal and lignite (48%); the split between these fuels will be determined by the price differentials prevailing then assuming the new plant additions (Table 6.18) between 1986 to 1990 will be able to use both fuels. This could imply that close to 1 million tons/year of lignite, about 500,000 tons/year of coal, and 40 MMCFD of gas would be consumed by the early 1990s.

44/ PEIDA "Energy Pricing Study", Section 6.

6.61 Table 6.19 highlights the past as well as the future demand for fuel oil projected by the assessment team up to 1995. Power sector demand for fuel oil is expected to continue declining over the next several years from the 1982 level of 26,300 bbls/day to about 6,000 bbls/day in 1990 with a further reduction to around 4,500 bbls/day in 1995. In the case of the cement sector, its use of fuel oil will be very low from about 1987 onwards, at about 1,000 bbls/day. Clearly, given the decreasing role of fuel oil in these two sectors, its demand will be driven increasingly by the degree to which gas substitution further penetrates other manufacturing sectors. In 1971, fuel oil demand outside of the power and cement sectors accounted for about one-third of total fuel oil demand -- by 1982 this proportion was about 30%. Of this use roughly 90% arose from the manufacturing sector other than cement, with textiles and food processing being especially important. In contrast to the power and cement sectors this remaining 30% of fuel oil use is made up of large numbers of small consumers who are not usually in the forefront of the transition to new fuels such as gas due to the absence of an extensive gas distribution system which is not expected to be in place by the mid-1990s. Nevertheless, some substitution of gas for fuel oil is expected to occur over the next several years among those manufacturing sector consumers located close to the gas distribution lines.

Table 6.19: PAST AND PROJECTED DEMAND FOR FUEL OIL
(bbls/day)

Year	Power Sector Demand	Cement Sector Demand	Total Demand	Total Demand Net of Power and Cement Sectors
Actuals				
1971	11,200	9,400	30,800	10,200
1975	20,200	9,000	45,600	16,400
1977	33,100	10,100	60,800	17,600
1980	51,700	12,000	81,400	17,700
1982	26,300	9,900	51,600	15,400
1983	31,600	8,700	58,000	17,700
Forecasts				
1985	10,400	4,600	32,600	17,600
1987	4,300	1,000	24,500	19,200
1990	6,000	1,000	28,900	21,900
1992	6,000	1,000	27,900	20,900
1995	4,500	1,000	27,500	22,000

6.62 The elasticity of growth in fuel oil use outside of the power and cement sectors relative to GDP between 1971-80 was about 0.9. Given the expected weakening of this elasticity during the next several years as energy is used more efficiently in the manufacturing sector, the assessment team estimates 45/ that fuel oil demand excluding the power and cement sectors should rise to about 21,900 bbls/day by 1990. The impact of substituting gas for fuel oils among these "residual" consumers should be felt in the early part of the 1990s as gas availability improves and the distribution system is extended into areas with a high density of manufacturing entities. As such, very little growth in fuel oil demand is expected for these users between 1990-95. However, by 1995 about 80% of fuel oil use will arise from outside of the power and cement sectors compared to 30% in 1982.

6.63 When these end-use projections of fuel oil demand are aggregated, total demand for this petroleum product is expected to drop from about 51,600 bbls/day in 1982 to 28,900 bbls/day in 1990 (see Table 6.19). A further decline should occur in the early 1990s as gas availability improves so that by 1995 fuel oil demand is likely to be around 27,500 bbls/day.

Petroleum Product Supply

6.64 Overall responsibility for planning and investment decisions in the petroleum refining sector is vested in the National Petroleum Policy Committee (NPPC) which was established by the Cabinet in 1981 This Committee sets policies and targets for development of the petroleum industry and the pricing of petroleum products. There are currently two sub-committees of the NPPC, one dealing with refining expansion, and the other with petroleum pricing and procurement (para. 6.17).

6.65 Thailand presently has a total crude distillation refining capacity of about 175,000 bbls/day distributed between three refineries -- T.O.R.C. (65,000 bbls/day), Bangchak (65,000 bbls/day), and Esso (45,000 bbls/day). Esso is a fully owned subsidiary of Exxon, while TORC is a joint venture between the government and private oil companies, Shell and Caltex. The government owns 49% of the equity through the PTT, the Crown Property Bureau 2%, and Shell and Caltex own the remaining 49%. This refinery is operated under a service contract with Shell. The Bangchak refinery (BPC) has had a checkered history as reflected in its poor performance over the past several years compared to the other two refineries. Initially established by the government in 1964 and operated by the Defense Ministry, the management and operation of BPC were transferred to Summit International Corporation, a private company, through a 15-year lease in 1965. On expiration of the lease, the affairs of Bangchak were eventually transferred to P.T.T. and, under a Bank-financed

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45/ Based on the high GDP growth scenario of an annual 6% rate between 1984-1995.

rehabilitation project, an autonomous commercial company, Bangchak Petroleum Co. (BPC) was recently established. 46/

6.66 In 1983, the refining sector processed some 163,000 bbls/day of crude oil and condensates, 47/ equivalent to 93% of design capacity. Esso operated in this year at 110% of design capacity, TORC at 98%, and BPC at 78%. TORC and Esso have consistently followed a satisfactory repair and maintenance program. In contrast, the BPC refinery has not repaired and maintained its processing facilities, which reduced crude throughput to about 50,000 bbls/day in 1983.

6.67 Due to an exceedingly rapid growth in diesel oil and LPG demand between 1982-84 (paras. 6.4 and 6.8), the share of the petroleum product market supplied by locally refined products has declined recently. In 1982, local products satisfied 79% of demand 48/; this fell to 73% in 1983 and 68% in 1984. The remaining requirements traditionally have been met by product imports, mainly from Singapore. This dependence on finished product imports is nothing new to Thailand in that in 1970 when petroleum demand was only 88,200 bbls/day, product imports accounted for 27% of total supply with diesel oil then representing some 76% of such imports. Indeed, this continued but limited level of dependence on product imports has been critical in many ways to providing a degree of competition to the local refining sector in that ex-refinery prices have been kept generally equal to or below c.i.f. product import prices over the past several years. In fact, up to the devaluation in October 1984, ex-refinery prices had been consistently below the c.i.f. import level. However, since October 1984, ex-refinery prices for most products have been above those of direct imports -- the degree depending on the product 49/ (para. 6.17).

6.68 The aggregated yield pattern of the refining sector in 1984 relative to product imports and demand is shown in Table 6.20. As shown, middle distillates (kerosene, jet fuel and diesel oil) made up 45% of the refineries product yield and fuel oil, 29%. This slate is somewhat out of line with the structure of demand (middle distillates 52% and fuel oil 24%), causing the pattern of imports to be weighted heavily (66%) towards middle distillates. This inability of the refining sector's yield pattern to more closely conform to that of demand is due to:

46/ BPC's equity is owned by PTT (30%), the Government, and Krung Thai Bank.

47/ Of which 7,000 bbls/day were condensates and natural gasoline separated from natural gas, some 6,000 bbls/day of indigenous Sirikit crude oil and the remaining 150,000 bbls/day of imported crude oil.

48/ Roughly the same level as in 1979.

49/ In May 1985, for example, the ex-refinery price of automotive diesel was about 5.6% above import parity.

(a) the uneconomic stimulus given to diesel demand in transport by past and current retail pricing policies;

(b) increasing amounts of natural gas which are substituting for fuel oil, thereby eroding the market share of an important petroleum product; and

(c) there is very limited processing flexibility in the refining sector to modify product yield patterns. Currently this flexibility is limited to a 8,800 bbls/day fluid catalytic cracker (FCC) and a 12,000 bbls/day visbreaker, both of which are in the TORC refinery.

Table 6.20: REFINERIES PRODUCTION, IMPORTS AND DEMAND FOR PETROLEUM PRODUCTS, 1984

Products	Refineries Production a/		Imports a/		Demand a/	
	(Bbls/day)	(%)	(Bbls/day)	(%)	(Bbls/day)	(%)
LPG b/	4,300	(2.8)	11,900	(16.0)	16,500	(7.4)
Gasolines	34,600	(22.6)	1,200	(1.6)	36,400	(16.2)
Kerosene	4,100	(2.7)	800	(1.1)	4,900	(2.2)
Jet Fuel	17,600	(11.5)	3,600	(4.8)	20,900	(9.3)
Diesel Oils	47,700	(31.1)	44,800	(60.3)	90,900	(40.5)
Fuel Oil	45,000	(29.4)	12,000	(16.2)	54,800	(24.4)
Total	153,300	(100)	74,300	(100)	224,400	(100)

a/ The sum of production and imports may not equal demand due to inventory changes.
b/ Excludes LPG production from the gas separation plant of 600 bbls/day averaged over 1984. The plant began operations late in 1984.

6.69 The performance and capabilities of the these three refineries vary widely, as shown in Annex 8 where their 1983 production patterns are compared. For example, in 1983 the middle distillate yield patterns at the TORC and Esso refineries were 54.5% and 54.2%, respectively, compared with that at Bangchak of 35.8%. In addition, the fuel oil yields at TORC and Esso were 12% and 21%, respectively, with Bangchak being about 37%. The TORC refinery runs very light crude feedstocks and this combined with its conversion facilities contributes to its low fuel oil, high middle and light distillate yields. In the case of Esso, although this is a simple hydroskimming refinery with no conversion capacity, by judicious choice of light spiked crude oils its yield pattern is close to the structure of Thai demand (Annex 9 and Table 6.20). The narrowing of the differential between heavy and light crudes in the past couple of years has facilitated Esso's task of running a small (45,000 bbls/day) hydroskimming refinery profitably in Thailand -- an achievement by any standards. Indeed, Esso is now in the process of debottlenecking its refinery to increase its throughput capacity to 65,000 bbls/day (44%

capacity increase), at minimal cost, again with no conversion facilities being added. The yield pattern of the expanded facility therefore would be similar to that shown in Annex 9 when running similar light crudes. At the Bangchak refinery the poor mechanical state of the plant and its associated low throughput have caused significant losses over the last several years. 50/ However, the World Bank is financing a project to rehabilitate the refinery by 1989/90 to make it a profitable operation.

6.70 Part of this rehabilitation project includes establishing a commercial company, Bangchak Petroleum Corporation (BPC), which now owns the refinery with PTT, the government, and Krung Thai Bank holding the equity. The other part of this project consists of physically rehabilitating the facility at a total cost of about US$144 million, of which the World Bank will provide about US$85 million of financing. There will be no increase in crude distillation capacity although a thermal cracking and a visbreaking unit will be restored to their original design basis to improve middle distillate yields.

6.71 The refinery sector in Thailand has been the subject of several studies over the past few years as government and the private sector have struggled with decisions about the level to expand refinery capacity, if at all, the type of conversion facilities, if any, and the complexity to allow the sector. The uncertainties in the world oil price and refining environment in which these studies 51/ have been done have highlighted the significant risks involved in making major investment decisions about the profitability and economics of different types of conversion options in Thailand during a period (up to about 1990) when a major surplus of refining capacity is a worldwide phenomenon. Indeed, within Southeast Asia, Indonesia and Malaysia are moving rapidly to almost complete self-sufficiency in product requirements over the medium-term. The joint venture Petromin/Shell refiniery at Jubail in the Persian Gulf of 250,000 bbls/day capacity is now on-stream with the Far East targeted as its prime market area. These developments have exacerbated the surplus refining capacity situation in Southeast Asia over the short to medium term as evidenced by the 50% average throughput for the Singapore refining center.

6.72 The Thai refining sector will need to be restructured over the medium term to achieve the following objectives:

(a) produce the full product slate required by the economy at costs that are fully competitive with directly imported products which are traded internationally. In this context, ex-refinery

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50/ "Bangchak Oil Refinery Restructuring Project", World Bank Appraisal Report, April 1985.

51/ Foster-Wheeler study of TORC expansion options in 1980. A Lummus study of the entire refining sector in Thailand in 1981/82.

prices must be set less than or equal to those of directly imported products 52/;

(b) ensure that local refining capacity remains somewhat below projected demand for products to guard against excess capacity developing in the 1990s. This allows Thailand to enjoy the benefit of direct product imports traded competitively due to excess refining capacity in the region. Keeping the Thai market open to a tributary flow of product imports to meet demand maintains the competitive pressure on local refinery operators; and

(c) encourage the private sector, both local and foreign, to play a larger role in undertaking the risks and investments associated with further developing the sector while reducing the role of the state.

6.73 Several uncertainties in the refining industry in Thailand should be considered before any decisions are taken concerning investment:

(a) the border price differentials between residual fuel oil and distillate products, which are a key factor in determining the profitability of investments in conversion facilities -- whether catalytic or hydrocracking;

(b) government retail pricing policies for diesel oil, gasoline and LPG over the next several years and the impact of changing pricing policies on the structure of demand for transport fuels;

(c) the degree of penetration of natural gas into the manufacturing sector over the next several years. This will increasingly determine the level, if any, of fuel oil surpluses in Thailand in the early 1990s given that about three-fourths of fuel oil demand after 1990 will come from outside of the power and cement sectors.

6.74 The uncertainties and wide variations in relative prices between residual fuel oil and middle distillates over the past decade are shown in Table 6.21. Although this is no guide for the future, it should highlight the potential pitfalls for projects which are very sensitive to

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52/ A covenant attached to the Bangchak rehabilitation project calls for the government to "continue to set ex-refinery prices of petroleum products which (i) allow refineries, operating efficiently, to meet their expenses, service their debts, and earn a reasonable rate of return on capital employed, and (ii) be reasonably competitive internationally."

these variations. The ratio of these prices in Rotterdam varied from 1.39 in 1974, 2.35 in 1979, 1.65 in 1981, and 1.38 in April 1985. For hydrocracking investment to become attractive, sustained ratios at least above 1.70 are required at present. Given these uncertainties and those raised above, the risks associated with major conversion investments in the refining sector become apparent, especially when undertaken by the state.

Table 6.21: RATIOS a/ OF SPOT PRICES FOR DIESEL OIL AND RESIDUAL FUEL OIL IN ROTTERDAM, 1974-85

Year	Ratio (Diesel Oil/Resid. Fuel Oil)
1974	1.39
1975	1.61
1978	1.68
1979	2.35
1981	1.65
1983	1.52
1984	1.38
April 1985	1.38

a/ Weight and not volume ratios.

6.75 Based on current firm plans in the refining sector, by 1990 the Bangchak refinery will be rehabilitated and the Esso refinery expanded (this by 1986). Assuming that decisions on expansion and conversion investments at TORC are not made until the end of the decade so that in 1990 the TORC refinery still has its current size and configuration, the production of petroleum products from the three refineries should be as set out in Annex 9. Table 6.22 summarizes the aggregate refinery production, product demand and required product imports in 1990. The demand shown in Table 6.22 is based on the assessment team's high GDP growth scenario assuming that the assessment team's recommended retail product price structure (Table 6.16) has been implemented from 1986 and the fuel oil demand levels estimated by the assessment team (Table 6.19).

Table 6.22: ESTIMATED 1990 PETROLEUM PRODUCT PRODUCTION, DEMAND AND IMPORTS

Product	Refineries (bbls/day)	Production a/ (% yield)	Imports (bbls/day)	Demand (bbls/day)	Demand (%)
LPG	4,500	(2.4)	+7,000 b/	29,300	(11.8)
Gasolines	42,600	(22.5)	+2,700 c/	47,700	(19.2)
Kerosene/Jet Fuel	33,800	(17.9)	-1,900 d/	31,900	(12.8)
Diesel Oil	62,600	(33.1)	+48,700 e/	111,300	(44.7)
Residual Fuel Oil	39,000	(20.6)	-10,100 f/	28,900	(11.6)
Total	182,500	(96.5)	46,400 g/	249,100	(100.0)

a/ Based on refinery yield patterns and production given in Annex 9.
b/ An estimated 17,800 bbls/day of LPG will be produced from the LPG separation plant.
c/ An estimated 2,400 bbls/day of natural gasoline from the LPG separation plant will be used directly in the gasoline blending pool.
d/ This small surplus of kerosene/jet fuel would be blended into the diesel oil fraction rather than exported.
e/ The import requirement of 46,800 bbls/day of middle distillate production arising from the 1,900 bbls/day of the karo/jet cut being blended into the diesel fraction.
f/ This surplus would be exported or cracked if such a unit were installed at TORC.
g/ This reflects the net import position.

6.76 Compared to the 1984 local refinery supply/demand balance (Table 6.20) that estimated by the assessment team for 1990 (Table 6.22) highlights the following factors:

(a) although total product demand is expected to rise by about 11% over the 1984-90 period, net product imports are projected to decline to around two-thirds of their 1984 level (46,400 bbls/doz);

(b) the level of refinery production would increase by 19% above the 1984 level due to ESSO's debottlenecking and the major investment in rehabilitating the Bangchak facility;

(c) although diesel oil demand is expected to rise by about 22% over the period (even with the assessment team's recommended retail prices in place), imports of diesel oil are only expected to rise by about 4-5% above their 1984 level of 44,800 bbls/day. Diesel oil would still, however, remain the dominant petroleum product imported by Thailand, representing by 1990 about 100% of net product imports;

(d) a surplus of fuel oil is projected by 1990 (about 10,100 bbls/day) and this will have to be exported;

(e) LPG demand should rise by about 78% above its 1984 level by 1990; however, although refinery production of this fuel would change little, imports will decline to about 60% (7,000 bbls/day) of their 1984 level due to major production (17,800 bbls/day) by the LPG separation plant; and

(f) finally, even as growth in gasoline demand resumes (31% by 1990) with new retail pricing policies, import levels remain modest (around 2,700 bbls/day) due to increased refinery production and the use of about 2,400 bbls/day of natural gasoline from the gas separation plant being directly used in the gasoline blending pool.

6.77 To achieve the refinery product yield patterns outlined in Table 6.22 it is assumed that the Esso and TORC refineries continue to run light feedstocks, including condensates, similar to 1983 and that the rehabilitated Bangchak refinery continues to run an increasingly light slate of feedstocks. In this context, having access to the highly competitively priced Sirikit crude and natural gas condensates is an essential element of this refinery's future profitability and yield pattern. Table 6.23 shows the low fuel oil (low in sulphur) and high middle distillate yields of Sirikit crude compared to Arab light. Indeed, it is quite an ideal crude for Thailand given the structure of market demand which is becoming less skewed to fuel oil. The only disadvantage of Sirikit crude is its waxy character, which gives it a residue with a high pour point. This problem can be dealt with through blending with other non-waxy feedstocks since the estimated volume of Sirikit crude (about 20,000 bbls/day) will only be about 10% of the refinery industry's feedstock in 1990.

Table 6.23: COMPARISON OF SIRIKIT AND ARAB LIGHT CRUDE YIELD PATTERNS FOLLOWING DISTILLATION

Product	Percentage Yield by Volume	
	Sirikit Crude	Arab Light
Gasolines & lighter	20	16
Middle Distillates	50	44
Fuel Oil Residue	30	40

6.78 To date, the refinery industry has used most of the natural gas condensate produced as feedstock along with crude oil in refinery runs. In 1983, TORC used some 6,300 bbls/day of condensate in this manner. However, with the gas separation plant now on-stream natural gasoline, propane, butane and ethane will be removed from the gas stream. Condensates still extracted from the gas at the well head would remain available for refinery feedstock use; however, that extracted from the gas separation plant (principally natural gasoline--about 2,500 bbls/day) can be added directly to the gasoline blending pool at a refinery since it has a good octane number.

6.79 As shown in Table 6.22, net product imports would meet about 21% of Thailand's product requirements in 1990. This is based on a refinery configuration in which Esso debottlenecks its hydroskimming facility to 65,000 bbls/day, the Bangchak refinery is rehabilitated to 65,000 bbls/day, and TORC remains at the same capacity and complexity. Given the scale of surplus refining capacity in Singapore and the emergence of the Jubail export refinery in the Persian Gulf, the assessment team considers it advantageous for Thailand to continue to import products over the next several years at about this level. Beyond 1990 the need could arise for an increase in refinery distillation and conversion capacity as petroleum demand continues to grow. However, such decisions should not be made until the late 1980s. Under the Bangchak rehabilitation project yet another study will be undertaken of the Thai refining industry with the objective of identifying the least-cost option for supplying petroleum products to the economy. Without preempting the conclusions of this study, the assessment team believes that in taking any major decisions in the late 1980s about the capacity and complexity levels of the Thai refining industry in the 1990s, the private sector should play the dominant role and accept the risks associated with any given strategy. This should include an action programme by government/PTT to reduce its financial involvement.

6.80 Table 6.24 shows the changes in imported crude oil and products projected by the assessment team in 1990 compared with the position in 1983, based on the refinery configuration outlined in para. 6.79 above.

Table 6.24: CRUDE OIL AND PRODUCT IMPORTS, 1983 AND 1990
('000 bbls/day)

	Imports		Local Supply		Total Supply	
	1983	1990	1983	1990	1983	1990
Crude Oil	159.0	169.0	6.6	16.0	165.6	185.0
Condensates as Refinery feedstock	--	--	6.7	4.4	6.7	6.8
Petroleum Products (Net)	56.9	46.4	155.0	202.7 a/	211.9	249.1

a/ Of which 17,800 bbls/day is LPG from the gas separation plant and 2,400 bbls/day of natural gasoline.

VII. NATURAL GAS DEMAND, SUPPLY AND PRICING

Background

7.1 With the discovery of commercially exploitable natural gas in the Gulf of Thailand in 1975-76 discussions began between Union Oil Company and the government regarding the development and marketing of the gas. The newly formed state company, Petroleum Authority of Thailand (PTT), and Union Oil signed the first gas supply contract in 1978 under which Union was obligated to supply, and PTT obligated to take, 200 MMCFD of gas from October 1981 to September 1982 and 250 MMCFD for subsequent years. In order to market the gas a 34-inch submarine pipeline 53/ 425 kms long was built offshore from Union's production platform to an onshore terminal. An onshore pipeline 170 kms long was then built to EGAT's power stations at Bang-Pakong and South Bangkok. Since Union Oil and other private sector interests expressed no interest in joint venture activities in establishing the offshore pipeline, the State, through PTT, had to undertake the full risk in owning this pipeline to ensure that the gas was marketed (para. 4.45).

Uses of Gas

Power

7.2 Initial plans for using gas focused on power generation. Therefore, to accelerate the rate of gas utilization, the three 300-MW steam units at the South Bangkok power station were converted from fuel oil-fired to dual gas/fuel oil-fired boilers. This was completed in 1981 in time for gas supplies from the Gulf. Concurrent with this a series of large gas turbine units 8 x 60 MW were commissioned at Bang-Pakong by mid-1981 with 2 x 120 MW waste heat boilers being added in 1982. By that time the Bang-Pakong station had 2 x 360 MW of combined cycle plant capable of burning natural gas or diesel oil. Additional dual-fired gas/fuel oil capacity was added at Bang-Pakong in the form of 2 x 550 MW steam units commissioned in 1983 and 1984. During this period, however, it became difficult for Union Oil to meet its gas commitment. For example, in 1982, 1983 and 1984 gas supplied under Union's first contract amounted to 128, 146, and 184 MMCFD. This represented an important setback for all parties concerned -- EGAT, Union, PTT, and the government. However, with additional gas now flowing under Union's second contract (para. 4.33), the availability of gas for power sector use has improved. Currently, the dual-fired gas/fuel oil capacity at Bang-Pakong and South Bangkok power stations are capable of utilizing some 400 MMCFD if all 2,720 MW of capacity is base loaded. By the end of

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53/ With a free flow capacity of some 500 MMCFD.

1986 the two 200-MW fuel oil-fired steam units at South Bangkok station also will be converted to dual-firing gas/fuel oil capability. At that time the potential maximum level of gas demand in the power sector will be about 460 MMCFD 54/, which would imply an average level of about 400 MMCFD given normal power dispatch criteria. Additional power plants (Table 5.20) capable of using gas are not expected to be commissioned before 1990 (300-MW combined cycle at Nam Phong), 1991 (600-MW No. 3 steam unit with gas/fuel oil and coal firing capability at Bang-Pakong), and 1993, when the second 300-MW Nam Phong combined cycle will be commissioned. Issues concerning the further use of gas in the power sector are discussed below (para. 7.18-7.24).

LPG Extraction

7.3 The non-associated gas from Union's producing areas is rich in propane, butane, ethane and natural gasoline. Extracting these products from the gas was a high priority PTT project. The first gas separation plant with a throughput capacity of 350 MMCFD of gas was commissioned in late 1984. The production from this plant is set out in Table 7.1. Since LPG is being used extensively for household cooking and for transport fuel, any LPG production from gas extraction plants would be absorbed by the domestic market displacing imported LPG. There appears little scope for LPG exports given the rate of growth of local demand.

7.4 A second gas extraction plant is being considered by PTT to also separate gas from the Gulf. This plant, originally proposed with a capacity of 350 MMCFD, now has been scaled down to 150 MMCFD and is expected to be commissioned in 1989. This and the first plant would enable some 500 MMCFD of Gulf gas to be processed, and there are reasonable expectations that gas supplies from the Gulf should not be less than this level up to the end of the century, assuming production begins under a Texas Pacific and/or Union III contract by 1990. The second plant would use about 30 MMCFD of gas and produce around 175,000 tons of LPG a year. A third gas separation plant has been proposed to process associated gas from the Sirikit oil producing field. This plant would have to be small (with a throughput of around 30 MMCFD) because of the very limited level of associated gas production expected from this field. LPG production from this third plant would be around 46,000 tons a year with about 7 MMCFD of gas used in the extraction process. The longevity of gas supplies from the Sirikit field is insuffiently known, and the DMR figures do not allow for the production of gas cap. Any venture to establish such a plant should probably be undertaken by the joint venture at its own risk unless gas availability conditions change significantly. Current prospects for gas extraction from the two plants are as set out in Table 7.1.

54/ If all this capacity, 3,120 MW were base loaded.

Table 7.1: GAS SEPARATION PLANTS

Plant No.	Throughput	Gas Use	LPG	Ethane	Natural Gasoline	Commissioning Date
	- - - - (MMCFD) - - -		- - - - ('000 tons) - - - - -			
1	350 (Gulf gas)	70	457	320	66	1984
2	150 (Gulf gas)	30	175			1989

By 1990 about 21,900 bbls/day (687,000 tons annually) of LPG will be extracted from gas at these two plants, thereby contributing about 75% of the LPG demand in that year.

Petrochemicals

7.5 The consumption of petrochemicals has been growing rapidly in Thailand; the demand for polyethylene more than doubled during 1980-83 and polypropylene and vinyl chloride also doubled during this period. Nevertheless, the consumption of plastic products in Thailand remains low by international standards, being only 3-4 kg per person compared with 20 kg in Taiwan and South Korea or 30 kg in the US and Japan. Nevertheless, the use of natural gas has been proposed as a feedstock for establishing a petrochemical industry to supply local demand. Ethane and propane from the gas separation plants would be used as a feedstock for an olefins plant which will include an ethane cracker producing 315,000 tons per year of ethylene and propane dehydrogenerator producing 105,000 tons of propylene, both of which will supply a downstream petrochemical complex. Such a complex would use 43 MMCFD of gas. Construction was delayed by uncertainties about gas availability as well as developments in the international petrochemical markets. However, plans to develop the US$350 million olefins complex are now under way and the project is expected to be completed in 1989.

Fertilizers

7.6 Although the use of fertilizers increased from 150,000 tons in 1966 to about 800,000 tons in the early 1980s, fertilizer use remains low in comparison with most East Asian countries. However, Thailand has to import all of its fertilizer requirements, and, with continued agricultural growth, future demand is likely to increase. The government established the National Fertilizer Corporation (NFC) in 1982 to undertake the construction of a fertilizer plant using natural gas and phosphate as feedstocks. The proposed plant would produce about 150,000 tons of urea and 700,000 tons of ammonia and urea, using 30 MMCFD of gas. The investment associated with this complex is about US$250 million and, according to current plans, this project should be completed in 1989.

Cement

7.7 As discussed in paras. 6.54-6.60, the cement industry has exhibited high levels of growth over the past 15 years. This sector was one of the first major industrial users of fuel oil to begin diversifying away to natural gas, lignite and imported coal as a means of lowering production costs. Indeed, Siam Cement Co. was one of the first major private gas consumers to finance an extension of the gas pipeline network to Saraburi (170 kms northeast of Bangkok) at a cost of US$60 million for a line with a capacity of some 90 MMCFD (para. 6.54). This coincided with the conversion of their two Saraburi plants to dual gas/fuel oil firing. However, the off-take of gas contemplated (45 MMCFD) for the two Siam Cement plants has been well below original targets with only some 25 MMCFD being used in 1984.

7.8 The experiences of both EGAT and the cement industry, which have proceeded with major investments in gas infrastructure and conversions of equipment to be able to use gas, have been far from satisfactory to date. The euphoria that accompanied plans to develop Union's offshore gas has given way to extreme caution bordering on skepticism on the part of major gas users. Several of them already have suffered by investing in gas utilization equipment years before supplies are available. Added to these negative factors there is the issue of gas pricing policy and what markets gas should seek to penetrate (para. 7.13).

7.9 The availability of gas for cement use has been improving since 1985, with 60 MMCFD potentially being available for the next couple of years (Table 7.3). However, as a result of gas prices and initial supply constraints, it is unlikely that gas would be able to compete with imported coal and/or lignite for most of the cement industry over the next several years. Therefore, the assessment team does not envisage a level of demand for gas in the cement sector above 40-50 MMCFD over the period to 1997.

Refineries

7.10 Fuel for the three refineries in Thailand is provided by refinery waste gases and residual fuel oil. To run about 170,000 bbls/day of feedstock in the refining industry about 5,000 bbls/day of residual is used as fuel; the rest are waste gases. Natural gas can easily substitute for this fuel oil as refinery fuel. At the levels of refinery throughput expected up to 1990 this substitution would require some 30 MMCFD. The key issue facing the refiners is whether the price incentive for using gas in this mode offsets their problems and costs of fuel oil disposal given that by 1990 the assessment team expects a surplus of fuel oil requiring export (Table 6.23). The economic value of fuel oil then would be its f.o.b. Bangkok price or the f.o.b. Singapore price. Based on current Singapore fuel oil prices of US$21.50/bbl (US$3.40/MMBTU), gas would have to be priced at a discount of 5-10% below fuel oil parity to encourage any conversion in the refinery sector.

Small Industrial Users

7.11 By the early 1990s about 75% of fuel oil demand will arise from manufacturing entities outside of the cement sector and the power sector (para. 6.63). The assessment team estimates modest levels of substitution of gas for fuel oil in small manufacturing operations close to major gas pipeline systems would continue to occur during the early 1990s. Such substitution, however, is unlikely to exceed about 20 MMCFD (3,200 bbls/day of fuel oil) of gas distributed over several small consumers.

LNG

7.12 One possible use of gas that has been raised is a major LNG export project. However, the assessment team has found no evidence to support such a project and strongly advises against the government assigning any priority to this project, for three reasons:

(a) Thai gas is expensive (about two-three times) relative to Malaysian or Indonesian gas, which puts the country at a severe disadvantage to these countries as a major gas exporter or as an exporter of gas-based products;

(b) the reserve base has not been established in Thailand to justify committing about 4.4 trillion cubic feet of gas reserves 55/ to any LNG project; and

(c) committment to an LNG project at present would result in a lower net benefit to Thailand than virtually all other gas uses (para. 7.14).

Gas Value and Optimal Use

7.13 Pricing policies will play the key role in ensuring not only that gas is used optimally but also in accelerating the exploration and development process (para. 4.27-4.29). Maximizing the net value to Thailand requires not only that the price of gas be at least equal to its economic production costs but also at a level which encourages those uses which yield the highest net economic benefits. This requires setting prices no lower than the opportunity cost of gas -- i.e. the net benefit to the last user of gas (the marginal consumer) when the various uses of gas are ranked by their economic benefit and gas supplies allocated to those with the highest benefits. When gas supplies are constrained, as they are presently and likely to be for the foreseeable future, the opportunity cost is the true cost of the resource to the nation. The

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55/ Relative to proven reserves of 3.7 TCF and probable and possible reserves of 9.2 TCF.

marginal economic production costs become the opportunity cost only when gas supplies have expanded sufficiently so that all potential users with a benefit higher than the marginal production cost have been supplied.

7.14 Estimates of the net-back values of using gas in power generation, cement, LPG extraction, petrochemical and fertilizer production and LNG indicate the most valuable uses of gas under different international fuel and commodity price scenarios. This is shown in Table 7.2.

Table 7.2: GAS NETBACK VALUES a/
(1984 US$/MMBTU)

Uses	World Price Scenario Low b/
Petrochemicals	3.9
Power Sector (Fuel oil substitution in existing plant)	3.5
Power Sector (in new base load plant)	4.3
LPG	3.4
Process Heat (Cement)	3.9
Fertilizers	3.3
LNG	1.1

a/ Peida Energy Pricing Study, 1984.
b/ The low price scenario corresponds to constant, real crude oil prices from 1985 to 1995 at about US$26.70/bbl (1983 $). Fertilizer and petrochemical product prices are assumed constant in real terms from 1984 to 1995. For new power generation the breakeven analysis compares gas-fired combined cycle plants with coal-fired steam plants. The coal price was taken in the low scenario as constant at $61.90/ton (US$2.70/MMBTU).

The gas netback values were assessed for low oil and commodity price scenarios. In the low crude oil case prices remained constant in real terms at a 1985 value of US$26.70/bbl (1983 $). Several key factors energe from the values in this Table.

(a) LNG use gives the lowest netback (even when high oil prices are considered) -- indeed, the gas value is less than its cost at any known fields in Thailand (Table 4.3). As noted above, this is not an option that should be pursued;

(b) fertilizers netbacks are sensitive to product values, oil prices (and hence feedstock costs) and capital costs. The reported low bid price for construction of the fertilizer plant in Thailand is a major factor in the gas netback value in the above Table being as high as US$3.3/MMBTU placing this option on a par with LPG extraction.

(c) petrochemical production is also highly sensitive to price assumptions although in the low oil price case the gas netback value compares favorably with other options;

(d) LPG extraction shows good netback values which do not vary significantly as the oil price scenario changes. This should assign high priority to LPG extraction;

(e) high priority is equally assigned to substituting fuel oil in steam based power plants -- a process that already is about to be completed in the EGAT system;

(f) substitution of fuel oil in the cement sector (provided gas pipeline infrastructure already exists (para. 6.58)) offers a reasonable netback -- this is again not highly sensitive to significant oil price changes;

(g) similar to LPG extraction, substituting gas for coal in steam power units provides a good netback though, as expected, lower than substituting for fuel oil in such units (para. 7.20-7.23).

7.15 It is clear that the power sector holds the key for developing the gas industry, as it can be expected to dominate gas demand until the end of the century. Since petrochemical netback values appear good relative to gas costs even in the low price scenario, the proposed petrochemicals project (para. 7.5), which will only demand some 43 MMCFD of gas, appears justified. The same cannot be said, a priori, for the fertilizer plant (para. 7.6). However, since very attractive terms apparently have been negotiated for this project, its ranking is considerably higher. In addition, only 30 MMCFD of gas use is involved, so if the project is financially viable but economically sub-optimum, the project should not be too costly to the country. Clearly, the second LPG separation plant to process Gulf gas should be undertaken as a high priority project, with total gas demand for the first and second plants being 70 and 30 MMCFD, respectively. Table 7.3 summarizes the supply and demand balance for gas in Thailand to 1997.

7.16 From the gas supply standpoint, in 1985 available gas should double from 231 MMCFD in 1984 to about 485 MMCFD (para. 4.32). This means that gas use in the power sector's gas-fired units can begin on a large scale with some 320 MMCFD of demand expected. As shown in Table 7.3, gas demand in the power sector accounts for two-thirds to three-fourths of total gas demand for the entire period 1985-97. Due to the high benefits associated with gas use in LPG, petrochemical and power sector uses, fluctuations in available gas have been reflected in this table by varying the gas demand in (i.e., the availability to) the cement sector and small users.

7.17 Even without including potential gas demand from end-uses such as refinery fuel, it is clear that the gas industry will be supply constrained over the entire period to 1997 except, possibly, in

1985/86. This, combined with expected variations in gas volumes and values to different end users, highlights the need for gas tariffs to certain consumers to include an interruptible component (clearly at a very competitive price). In the case of industries such as the gas separation plant, fertilizer, and petrochemicals, such fluctuations in feedstock volumes cannot be easily tolerated. In the power sector, a large fraction of gas demand in the power sector must be considered firm; but some variations are possible not so much because some gas-fired plants do intermediate load duty during the course of a day but because hydropower contributions cannot be perfectly regulated from one season to the next and from one year to the next.

Gas Use in the Power Sector

7.18 Another important issue which should be emphasized is the optimal use of gas in the power sector, since this will determine the gas industry's future over the next decade. There are three modes in which gas can be used in the power sector assuming hydro will continue to cover the system peak up to the late 1990s. These modes are:

(a) dual-fired gas/fuel oil boilers raising steam, operating as a base load unit;

(b) triple-fired gas/fuel oil/coal boilers raising steam, operating also as a base load unit; and

(c) gas-fired combined cycle unit consisting of gas turbines (GT) with retrofitted waste heat boilers using the hot gases from the GTs to generate additional electricity in a steam turbine.

Table 7.3: NATURAL GAS DEMAND AND SUPPLY, 1985-87
(MMCFD)

Year	LPG	Petro-chemical	Ferti-lizer	Cement	Small Users	Total Non-Power	Power	Total Demand	Supply a/	Differ-ential b/	Year
1985	70	-	-	35	-	105	380	485	485	0	1985
1986	70	-	-	40	-	110	420	530	548	+18	1986
1987	70	-	-	40	-	110	465	570	568	-2	1987
1988	70	-	-	44	-	114	480	594	594	0	1988
1989	100	43	30	30	-	203	420	623	622	-1	1989
1990	100	43	30	40	20	233	520	753	763	+10	1990
1991	100	43	30	40	17	230	520	750	750	0	1991
1992	100	43	30	40	20	233	560	793	812	+19	1992
1993	100	43	30	40	19	232	600	832	832	0	1993
1994	100	43	30	40	19	232	597	829	829	0	1994
1995	100	43	30	40	19	232	572	804	804	0	1995
1996	100	43	30	40	19	232	577	809	809	0	1996
1997	100	43	30	40	21	234	615	849	849	0	1997

a/ From Scenario II, Table 4.5.
b/ Difference between supply capability and demand. Positive number implies excess supply capability.

7.19 Two important factors should be noted. First, the combined cycle unit has an efficiency of fuel use of about 43% compared to 36% for well-run steam units. Second, while steam-fired boilers can use fuel oil or coal in addition to gas, the combined cycle gas turbine can use only distilled fuel oil or diesel oil as a replacement for gas, and diesel oil normally costs about 20-30% more than fuel oil.

7.20 Annex 10 compares the use of gas in a steam-fired unit and a unit fired by coal, fuel oil and lignite. Combined cycle units are the lowest cost generating thermal systems available in Thailand due to their low investment and fuel costs when using gas (Table 5.14). This is expressed in Annex 10 in terms of the gas netback value for the use of gas in steam units and combined cycle units when compared to coal, fuel oil and lignite-fired steam plants. At base load, the netback for gas use in steam units are US$3.49/MMBTU, US$3.23/MMBTU and US$3.14/MMBTU when compared to fuel oil, lignite and coal-fired steam units using these fuels at prices of US$22/bbl, US$20/ton, and US$55/ton, respectively. The spread is only 9% between the so-called "fuel oil parity" price and the "coal parity price" for gas use in steam plants.

7.21 Gas has the highest value when used in the base loaded combined cycle mode. Compared to a coal-fired steam unit, using US$55/ton coal, the breakeven price of gas in a combined cycle is US$4.37/MMBTU for that small part of the system where it is applicable. 56/ This has very important implications for the allocation of gas use by plant type in the power sector. As long as incremental gas becomes available for power sector use it should be committed to combined cycle use and not to additional dual or triple-fired (coal/fuel oil/gas) steam capacity.

7.22 The need for dual-fired (fuel oil/gas) steam capacity in the power system only occurs at the beginning of gas development. Indeed, the existence of Bang Pakong and South Bangkok steam plants as gas-using facilities was vital in accelerating the development of a gas market at its infancy. It also provided flexibility to burn fuel oil in the event gas were not available. An important jump occurs in investments and strategy as one moves from dual-fired (fuel oil/gas) steam units to triple-fired (fuel oil/gas/coal) ones. In the former case the investment differential relative to a single-fired gas or fuel oil unit is negligible. However, once coal firing capability is introduced in the triple firing mode investment differentials with single-fired coal units may increase mainly because of the difficulty of having sites that are convenient for both supply of gas and coal.

56/ The break-even price of US$4.37/MMBTU establishes a parameter for investment planning. A lower price based on operating cost and fuel efficiency would be necessary for plant scheduling. Price payable to producers would also have to reflect location, guarantees on long-term gas availability, rate of gas production, quantity and other factors.

Gas Pricing

7.23 The establishment of a gas pricing system for producers and consumers in Thailand is a matter of the highest priority (para. 4.27-4.29). Although the guidelines for establishing this system were discussed in Chapter IV, there are further details and issues which should be noted. First, the linkage between the Basing Point price and international prices of competing fuels is critical. This linkage also must be able to track the relatively short-term movement in prices, perhaps quarterly. With a large amount of equipment in the power and cement sectors possessing dual-fired gas/fuel oil capability, a major slump in fuel oil prices could cause consumers to switch from gas to fuel oil unless gas prices move downward in tandem. This is not the case as yet, even at today's low fuel oil prices of US$21-22/bbl (US$3.33-3.49/MMBTU), which remain 33-40% above the economic cost of producing gas. Only if fuel oil prices begin to drop below about US$15/bbl would the outlook change.

7.24 Second, since the power sector is the most important user of gas in Thailand and would remain so until the end of the century, gas pricing policies for this sector are very important. The current gas price to EGAT is US$3.20/MMBTU which is close to the estimated "coal parity price" (Annex 10). At current prices this is also 90% of the "fuel oil parity" in steam units. Clearly, the ceiling value of gas used in the power sector would be about US$4.3/MMBTU (Annex 10), which would be the breakeven price between use in a combined cycle unit and power generation in a coal-fired steam unit, but pricing gas near this ceiling value would seriously affect its use in the existing 2400 MW of dual-fired fuel oil/gas steam capacity. On the other hand, the present economic production cost of gas, which is about US$2.5/MMBTU and does not take into account the prospect of reserve depletion, is not a sustainable floor price, since it would imply a freeze in the development of a coal-based alternative. Pricing gas to EGAT close to or just above the "coal parity price" in a steam unit neither distorts planning decisions in the long run nor dispatch decisions in the short run (see para. 5.39). It strikes a good balance between the above considerations of economic efficiency and financial revenue requirements by both EGAT and the gas industry.

7.25 Third, for the gas pricing system to be transparent to producers and consumers, there is a need to know the price at which gas would be transmitted by pipeline systems that are not owned by producers or consumers. This price would depend on the volume, distance, and interruptibility of the gas transmitted. In this way both producers and consumers can determine their well head and plant gate gas prices respectively from the stated Basing Point price in Bangkok. Based on current perspectives of gas availability over the next several years as well as medium-term trends in international coal and fuel oil prices, in the assessment team's view the Basing Point price of gas in Bangkok should be set at about the Singapore fuel oil price, which currently is close to the equivalent coal parity. The differential between fuel oil and coal, however, would have to be continually monitored.

VIII. RURAL ENERGY SECTOR

Introduction

8.1 The process of modernization occurring in rural Thailand involves complex interactions between various social and economic factors including production technologies, institutions, and changes in the patterns of energy consumption. Trends toward increasing population density, mobility, migration, deforestation, intensive land use, mechanization, monetization, and material consumption are interrelated and directly reflected in energy use. For example, modern transportation, which relies upon petroleum fuels, increases the mobility of people and provides easier access to new products and markets. The outcome is that rural Thailand is moving away from a self-sufficient lifestyle based on renewable energy sources (wood and agricultural residues) to one which is dependent on non-renewable fossil fuels and electricity.

8.2 Energy consumption patterns differ significantly between rural and urban areas. Patterns also differ among rural communities depending on their regional location and distance from urban centers such as Bangkok. Rural areas in the more developed and irrigated parts of the Central region are well advanced in the transition to using modern fuels, while in the more remote regions of the north, northeast and south, the process is just beginning.

Modernization and Rural Energy Use

8.3 Although Thailand's economy has been growing since the mid-nineteenth century, until the 1950s there was little change in the overall patterns of energy demand, which relied on traditional fuels. The establishment of a reliable and growing overseas market for rice provided the main sources of economic expansion from 1850 onwards and led to a dramatic growth in paddy production. Farming techniques, however, remained traditional, relying on animal and human power. Even the railway system was dependent on wood for fuel up to the 1950s. Fuelwood also remained the principal household cooking fuel in rural areas, while it was supplemented by charcoal in urban areas. Fuel for lighting continued to come mostly from kerosene, oil lamps or homemade candles; only in Bangkok was electric light at all prevalent by 1950.

8.4 Thailand's economic growth since 1950 has been accompanied by a large increase in the use of modern fuels, which have more than doubled the growth of traditional fuels. 57/ This shift has progressed furthest in the urban areas of Thailand, particularly in Bangkok, where industry, commerce and transport are now almost entirely dependent upon modern fuels. Urban household energy consumption patterns also have been extensively transformed by the increased availability of numerous electric household appliances and LPG gas for cooking.

8.5 Rural areas have also undergone major changes in their energy environment. For example, the post 1950 agricultural expansion prompted by the mechanization of production methods, which has created a growing demand for petroleum fuels. The rapid expansion of the infrastructure of roads and electricity supply has provided greater access to modern consumer goods including energy-using appliances. The availability of credit facilities also has accelerated the purchase of such appliances. Nevertheless in most rural areas, households continue to rely on traditional fuels for cooking. The rapid increase in road transport in rural areas spurred much of the growth in demand for petroleum fuels during 1950-1980.

8.6 To understand what is happening within rural communities, it is useful to examine the changes that have typically been occurring in the agricultural, transport and household sectors. 58/ Agricultural expansion has been associated with an increasing degree of on- and off-farm mechanization. At the same time the opportunities for increased agricultural production were greatly enhanced by improved transport facilities. The development of roads linking villages to main highways which began in the 1960s opened new markets and encouraged specialized market-oriented production of sugarcane, poultry and animal rearing. Village products in the form of crops, vegetables and husbandry now are regularly trucked to nearby urban markets. Production thus has shifted from a form that was intensive in animal and human energy to one which increasingly makes use of mechanized energy both for on-farm activities and for trucking cash-oriented production to market.

8.7 The development of the rural road infrastructure has led to a great expansion in the number and types of vehicles used and owned in villages. The buffaloes and oxen which once served the dual purposes of draft and farm power and transportation, have been replaced by tractors, bicycles, motorcycles and trucks. Travel and transport have become major aspects of village life. Rural people are travelling more frequently,

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57/ Here the term "modern fuels" applies to petroleum products and electricity, and "traditional fuels" or "biomass" includes firewood, charcoal, agricultural and animal residues. "Fuelwood" refers to both firewood (burned directly) and the wood equivalent of charcoal.

58/ The discussions in para. 8.6-8.11 are based on the paper produced for the assessment by Jasper and Fern Ingersoll, "Changes in Energy Use in Village Thailand: A Review of the Experience," July 1984.

over greater distances, and for longer durations than they did a generation ago. Bicycles are now owned by ordinary families and motorcycles have become commonplace. Bus and truck transport have also grown rapidly. Many villages now have frequent bus services to nearby towns and truck traffic built up substantially during the 1970s. Pick-up trucks are becoming more popular both for passenger transport as well as for freight hauling, and regularly carry agricultural produce to and from markets. The proliferation of vehicles also has facilitated migration from rural to urban areas and permitted rural people to work in nearby towns.

8.8 The higher incomes generated from the increased agricultural output and remittances received from new urban dwellers have encouraged new expenditure patterns and a change in household energy demand. At upper income levels, purchased LPG and electric rice cookers are replacing charcoal and fuelwood. Its association with modern Bangkok living makes LPG and electric cookers the prestige fuel choices for many rural residents. Electricity and the cleaner gas flame of LPG cookers are more compatible with the more closed-in living quarters characteristic of urban dwellings and, increasingly, urban-style houses, which have become more popular in rural areas.

8.9 The demand for cooking fuels in rural areas also has been influenced by the reduced availability of wood caused by deforestation. Where LPG supplies are available and household incomes sufficient, the situation has encouraged the shift to modern fuels. However, where modern fuels are not accessible or incomes are not sufficient, the tendency has been for charcoal to replace fuelwood for household cooking. As forest boundaries have receded, those villagers who depend on collecting "free" wood have to travel increasingly further distances to obtain fuelwood, thus encouraging the conversion of fuelwood into charcoal in the forest to make it easier to transport the fuel back to the village. 59/ Exposure to urban habits including cooking with charcoal rather than wood may also account for the expansion of charcoal-making even in areas where wood supplies remain plentiful. Reduced availability of traditional fuels has had less effect on higher and moderate income families but poorer households who cannot afford modern fuels have to spend more time collecting fuelwood from woodlots and forests. In parts of the Central Plains and much of the northeast, where much of the natural forests have already disappeared, these households have suffered severe hardship.

59/ Village woodlots, which used to provide a continuous, reliable and regenerative source of fuelwood, have also been converted to what is perceived as more profitable uses for growing cash crops such as sugarcane and cassava. Indeed, growing cash crops instead of fuelwood is perceived as part of the modernization shift from self-sufficiency to market-oriented production.

8.10 Where electricity has become available, electric light is replacing kerosene lamps and homemade candles. Wealthier households are also acquiring fans, a rice cooker, television, iron, and refrigerator. 60/ Over 50% of households in some villages in the Central region had television sets in 1983. Poorer households which cannot afford the cost of being connected to the electrical system as well as a minimum level of interior wiring and lighting fixtures continue to remain dependent on kerosene lighting. It is important to note that an absolute minimum of 4 liters of kerosene are required each month to meet the basic lighting needs of a non-electrified household. At current retail prices this costs about 24 Baht/month. In contrast, at current PEA tariffs a household with 100 watts of incandescent light used four hours daily (i.e. 12 kWh/month) would pay only 12.5 Baht/month -- one-half the cost of using kerosene.

8.11 Rural life in Thailand thus is undergoing changes which involve a shift away from a self-sufficient, subsistence agrarian economy based on renewable energy to one which is technologically, economically, and culturally focussed on commercial production for larger markets. Continued rural development thus will lead to further increases in rural demand for modern fuels both for residential and transport uses. On the other hand, the demand for traditional fuels for cooking in rural households is likely to remain substantial well beyond the year 2000. Meeting these demands without damage to the environment will require careful planning.

Rural Energy Demand Patterns

8.12 Despite the widespread migration to urban areas in Thailand, rural areas still accounted for half of total energy consumption in Thailand in 1983: 96% of traditional fuels and 23% of modern fuels. 61/ Households in these areas consumed 60% of the traditional fuels and industry 40% (Table 8.1). Petroleum products supplied 70% of the modern fuels consumed in rural areas for transportation purposes.

60/ In those villages which obtain electricity from isolated micro-hydro or diesel units, supply or maximum wattage levels are likely to be severely restricted to certain times of the day. In these circumstances the acquisition rate of appliances is slower and families with electricity connections might use it only for electric lights and television.

61/ Rural areas are defined here as all non-urban areas. Urban areas are municipalities and urban sanitary districts. It follows that rural areas are rural sanitary districts and non-municipal areas outside sanitary districts.

8.13 The modernization trends are also extending into the more traditional forms of energy. Although charcoal and wood remain the major fuels used by rural households, their relative importance was reversed between 1962 and 1980. Whereas fuelwood was used by two-thirds of village households in 1962 and charcoal one-third, by 1980 the proportion using fuelwood had fallen to 40%, and that using charcoal had risen to 55%. The trend away from traditional energy was more pronounced in the villages in the Central Region, where higher incomes and a more developed infrastructure provide better access to distribution centers. By 1980, 11% of rural households in this region were making some use of LPG as a cooking fuel -- more than three times that of the national rural average. 62/ Rural households in Thailand thus are beginning to follow urban household trends.

8.14 Rural electrification grew substantially between 1970 and 1980, as the proportion of rural households with electricity increased from 5% to 28%. Again, the Central Rcgion led the way with 45% of rural households electrified compared to 19% in the northeast. The use of electricity is initially limited to lighting but a number of appliances are being acquired and are increasing at a relatively rapid rate. By 1980, for example, 16% of rural households had a fan, 10% a television set, and 7% a refrigerator.

8.15 The available industrial statistics do not permit a clear distinction between urban and rural industries, but a rough picture of energy use by the latter may be shown. Despite the changing technology resulting from electrification, rural cottage industries produce food products or household goods which generally require very little fuel and therefore remain largely labor intensive. Larger rural industries which are also affected by electrification, however, often use by-product biomass as well as other traditional fuels such as for food processing (in rice milling, rice husks; cassava processing, fuelwood; sugar milling, bagasse), sawmilling or brick-making. Bagasse provides one half of the traditional fuel used in rural industry, mostly by sugar mills themselves (excluding bagasse, industry accounted for 19% of total rural energy consumption, mostly in the form of fuelwood, as compared to 48% for household demand).

8.16 Thailand's agricultural growth averaged 5% per year during 1960-80. More intensive farming of irrigated land during this time involved some mechanization and substantial amounts of fertilizer, while an extension of the total cultivated area generated an increased demand for labor in excess of population growth which spurred the use of mechanical equipment. The rapid increase in the number of tractors (25% per year during 1967-80), water pumps and threshing machines has resulted in a concomitant growth in commercial energy use. In 1983, 440,000 toe of petroleum products (diesel fuel and gasoline) were estimated to have been used in agriculture.

62/ Eleven percent is a regional average; in some villages a much larger proportion of households are using LPG and electricity for cooking.

Table 8.1: ENERGY CONSUMPTION (1983 and 2001)
('000 toe)

	1983				2001	1983-2001
	Rural	Urban	Total	Rural as % of Total	Projected a/ Rural Energy Use	Projected Growth of Rural Energy
				(%)		(%)
A. By Sector						
Households (Fuels)						
Traditional	4,180.3	295.2	4,475.5	93.4	4,607	0.5
Modern	381.2	418.7	799.9	47.7	669	3.2
Cottage Industry	380.0	-	380.0	100.0	380	-
Industry (Fuels)						
Traditional b/	2,363.0	-	2,363.0	100.0	3,498	2.2
Modern	229.2	2,363.8	2,593.0	8.8	683	6.3
Agriculture	449.9	-	449.9	100.1	1,055	4.9
Transport	1,427.8	4,237.3	5,665.1	25.2	4,513	6.6
Commercial/ Government	-	615.9	615.9	-	-	-
Fisheries	-	(680.9)	680.9	-	-	-
Total	9,411.4	8,566.6	18,023.2	52.2	15,405	5.0
B. By fuel						
Traditional						
Fuelwood	2,971.7	15.0	2,986.7	99.5	2,844	-0.2
Charcoal	2,219.7	280.2	2,499.9	88.8	3,480	2.5
Agricultural Residues	526.9	-	526.9	100.0	635	1.8
Bagasse	1,205.0	-	1,205.0	100.0	1,526	1.3
Subtotal	6,923.3	295.2	7,218.5	95.9	8,485	1.3
Modern						
Petroleum Products	2,259.4	6,938.2	9,197.6	24.6	6,138	5.7
Electricity	190.5	1,236.8	1,427.3	13.3	695	7.8
Lignite/Coal	38.2	141.6	179.8	21.2	38	-
Subtotal	2,488.1	8,316.6	10,804.7	23.0	6,920	5.8

a/ Projections based on procedures outlined in paragraph 8.18.
b/ Bagasse accounts for 50% of traditional fuels used in rural industry.

Source: Assessment team estimates.

8.17 The expansion of the rural road network between 1960 and 1980 had a great impact on the use of commercial fuels for transport purposes. Household expenditures on transportation and on the ownership of vehicles grew quickly. Real per capita expenditures on transport services grew by 8% per year in rural areas between 1962 and 1976 -- more than three times faster than the growth in per capita rural incomes. The ownership of bicycles, which started the process, increased from 30% of rural households in 1962 to 50% in 1980; other forms of transport are following suit, as the ownership of motorcycles increased from 1% to 19%, and cars from zero to 4%. In the Central region 7% of rural households owned an automobile or truck in 1980. As a result, the use of commercial fuels for transport is estimated to have grown by 7% per year during 1960-83 to reach 1,427,000 toe in 1983.

Projections

8.18 The assessment team developed projections of the likely volume and composition of energy demand in rural areas during the next 15 years based on the assumption that relative prices for various fuels remain as at present and the economic growth experienced in the past will continue although at a somewhat slower rate. A two-step procedure was adopted for projecting household demand. The first was to project the number of households using a particular fuel as their main energy source; the second was to project the consumption levels for these households. The proportion of rural households using fuelwood as their main fuel was assumed on the basis of current trends to decline to only 15% by 2001 as households switch over to charcoal use. However, the switch to charcoal was assumed to be partially offset by other households, mostly higher income, switching to LPG or electricity as the availability of these fuels increases. The number of households relying on charcoal was thus assumed to remain at about 55%, while those using LPG were to increase from 5% in 1983 to 25% by 2001 (from 325,000 households in 1983 to 2,200,000 in 2001). On the basis of the assessment team's evaluation 63/ of the way in which the current rural electrification program is being

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63/ GDP is assumed to grow at an average rate of 6.0% p.a. (3.0% in agriculture and 7.0% p.a. in the non-agricultural sectors). The population projections are:

	1983	2001	Annual Growth Rate
	(millions)		(percent)
Urban	12.0	22.4	3.5
Rural	36.1	43.7	1.0
Total	48.1	66.1	1.8

By the year 2001, the rural population will have declined to about 66% of the total population compared with 75% at present. If the rural population had grown at the national rate, it would have reached 50 million in 2001, i.e., 6 million people are assumed to migrate from rural to urban areas and in the process shift from a rural energy consumption pattern to an urban one with greater use of modern fuels.

implemented, 75% of all rural households are projected to have electricity connections by 2001.

8.19 To project the growth in fuel consumption by households using a particular fuel, assumptions were made about income elasticities. The income elasticity of electricity was estimated at 1.2, which is consistent with PEA's experience over the past decade. In the absence of similar data for other fuels, a value of 0.5 was used, which appears consistent with experience in other countries. Combining the two steps, aggregate household consumption is projected to increase, but the demand for firewood would decline. Aggregate traditional fuel demand increases by 0.5% per year to reach 4,607,000 toe in 2001, compared with 4,181,000 toe in 1983. The demand for modern fuels increases by 3% per year, with LPG demand growing by 13% and electricity by 9%. Kerosene demand declines, reflecting the increased number of households that are projected to use electricity for lighting.

8.20 Energy demand by cottage industries appears to be growing quite slowly while the use of wood and charcoal by larger industries has increased somewhat. Nevertheless the latter is expected to grow more slowly than industrial output because of increasing technological innovations and labor-saving techniques which will undoubtedly emphasize the use of more modern fuels. The use of bagasse and agricultural residues in industry are supply-determined reflecting agricultural output; the growth of the sugar industry is slowing, and hence the use of bagasse is assumed to flatten out in the 1990s. To sum up the various changes that can be envisaged at this stage, on the basis of current trends, the growth of industrial use of modern fuels is projected to increase by 6.3% per year and traditional fuels by 2.2%.

8.21 The mechanization of agriculture is expected to continue at a fairly rapid pace up to 1990 when opportunities for additional mechanization fall off. As such, the use of diesel and gasoline is projected to grow by 6% per year through 1991, and 4% thereafter and slightly faster than the growth in agricultural output. However, despite this rapid growth in the use of commercial energy, its use for agriculture should not rise much above 1 million toe by 2001.

8.22 Transportation to and from rural areas is the most dynamic element in the entire picture as commercial fuel use in this area is projected to keep pace with the entire modernization process. The demand for transport fuel would grow by 7% per year and reach 4,500,000 toe in 2001, which is more than currently is consumed by transport in the whole country. The volume and growth rate of diesel/gasoline demand are likely to be the largest components of this growth, depending on pricing and the types of vehicles that are used. The modernization and urbanization process has gone so far and the links with the rural areas are becoming so close that it is hard to envisage a slowdown in this process.

8.23 Projections indicate, therefore, that the demand for modern fuel in rural areas is likely to grow by 5.8% per year and the demand for traditional fuels by only 1%. Such growth in the demand for modern fuels in rural areas by 2001 implies that about 7,000,000 toe will be consumed. Nearly 6,000,000 toe will be in the form of petroleum products, 75% of which is for fuels to be used in transport. Electricity use would increase to about the equivalent of 695,000 toe. Commercial energy will be necessary to fill what could become a growing energy shortage in rural areas. The effect of vast road construction, the rural electrification programs and such agricultural improvements as are related to irrigation, mechanization, the availability of fertilizer and improved seeds, all fostered by the public sector, have stimulated a strong modernization trend accompanied by a rapidly growing use of energy both at the construction stage and even more so as the private village sector has taken fuller advantage of the public facilities created. Villagers and farmers who in the past looked to the central government to bring the facilities are now themselves introducing their own momentum to the process. Rural inhabitants are buying all kinds of appliances, mostly on credit. Villagers who in the past have participated in cost-sharing or have contributed local labor to obtaining public facilities are now obtaining television sets and motor bicycles. Dynamic village leaders such as head priests, teachers and village headmen who in the past have been primarily responsible for the actual success in bringing public works to the village are now becoming entrepreneurial as farmers, truckers or middlemen. Outside merchants are making a major contribution, particularly in providing credit for hire purchases. Greatly expanded use of modern energy has been the end result of all of the activities.

8.24 Policy guidelines are needed to improve the incentives faced by these entrepreneurs. In general it means letting the market function as freely as possible: allowing prices to reflect proper economic values; avoiding the monopolistic power of large dominant enterprises, whether public or private; planning the development of energy resources so that they can be made more available in direct response to the demands of the rural population. Rural residents who have tasted modernization are unlikely to be willing to revert to an energy economy primarily based on traditional fuels. A reasonably accurate view of commercial energy requirements must be related to what can be accomplished in the next two decades in the production of traditional fuels and how far the existing population using fuelwood and charcoal will continue to use it.

Traditional Fuel Supplies

8.25 Fuelwood shortages and serious environmental problems are beginning to occur in certain areas, although the overall national fuelwood supply situation is not yet critical, and substantial areas of natural forests are still accessible in many parts of the country. Forest depletion rates have exceeded sustainable levels by 400% in certain areas and give cause for concern for the future. Continued demand for fuelwood at current rates has already put a strain on the accessible forests and resulted in the deforestation of large areas, e.g. in Central Thailand. The combination of fuelwood collection, agricultural expansion, commercial fellings, shifting cultivation and the effects of urbanization have reduced the country's forested land area from 27 to 16 million hectares in the last 25 years (Annex 11). By 2001 the area is likely to be less than 11 million hectares if current trends continue. The total sustainable supply of fuelwood from all sources 64/ in 1983 is estimated to be about 15.5 million m^3, which compares with the 1983 consumption level of about 38.6 million m^3, including urban demand (Table 8.2). The 23.1 million m^3 deficit is met by overcutting the forests. By 2001 potential demand could increase to a level of 50 million cubic meters while the sustainable supply without a fuelwood program would decline to about 13.9 million m^3, leaving a gross deficit of about 36.1 million m^3. Although these numbers have a margin of uncertainty, there can be no disagreement on the direction of the trend and the nature of its potential impact. If unchecked, the excessive exploitation of natural forests could quickly lead to environmental damage, fuelwood shortages and a decline of agricultural productivity in many areas.

Table 8.2: FUELWOOD DEMAND AND SUPPLY
(Million m^3 Wood)

	1983	2001
Demand	38.6	50.0
Supply from Public Sources	11.5	9.9
Sustainable Yield	7.5 a/	6.9 b/
Other	4.0 c/	3.0
Supply from Private Sources d/	4.0	4.0
Gross Deficit	23.1	36.1

a/ 15.5 million hectares, 20% economic accessibility, MAI 2.5 m^3/ha/y.
b/ 11 million hectares, 25% economic accessibility.
c Includes state plantations, mangrove forests and logging wastes.
d/ Total private sources can amount to 4-14 million cu.m. depending on assumptions. The mission considers 4 million cu.m. a more realistic estimate.

Source: Mission estimates based on discussions with RFD and NEA.

8.26 Furthermore, although the geographical distribution of forest resources in Thailand is uneven and there are remote forest areas with abundant cover, the process of deforestation is likely to spread as more

64/ Existing sustainable wood supplies from all private sources assumed to be about 4 million m^3.

of these areas become accessible. Charcoal, which requires between 5 to 9 m^3 of wood per tonne, will continue to be produced, not only because it is a preferred fuel in many households but also because it has double the energy density of wood and therefore is cheaper to transport over increasingly greater distances as the forests recede. Thus, the devastation may continue long before its damage is fully recognized. Indeed, the 1980 NEA rural energy survey showed that many households in the northeast (15%) and the southern regions (46%) already obtain a substantial portion of their fuelwood from relatively distant forests (Table 8.3). For the country as a whole, 16% of the fuelwood was already coming from "distant" forests, over 5 km away from villages.

Table 8.3: SOURCES OF FUELWOOD FOR RURAL HOUSEHOLDS

Sources	North	North-east	Central 1	Central 2	South	National
	Percentage of Fuel Supply					
Free Sources						
Within own compound	64.9	35.7	85.1	31.1	5.2	35.4
Other's compound	3.9	21.4	2.3	0.9	2.4	14.4
Nearby forest (less than 5 km)	21.2	26.9	6.9	61.0	44.1	31.7
Distant forest	5.9	14.6	3.9	0.6	45.8	16.3
Subtotal	95.7	98.6	98.3	93.6	97.5	97.8
Commercial Sources	4.3	1.4	1.7	6.4	2.5	2.2

Source: Chirarattananon (op. cit.), based on NEA Rural Energy Survey.

Household Energy Prices

8.27 The impact of continued overcutting in due course will be not only to increase the distance that households must go to collect wood, but will raise both the cost and price of fuelwood and charcoal. This is already happening in numerous areas of the country. The effect on costs can be imputed as is illustrated in Table 8.4. In village 1, fuelwood from forests within 2 kms carries an implicit cost of Baht 0.38 per kg; in village 2, where the forests are 15 kms away, fuelwood costs Baht 1.03 per kg. Similarly, the cost of charcoal would increase from Baht 2.0 per kg in Village 1 to Baht 3.5 per kg in Village 2. In provincial municipalities the actual price of charcoal has already been running about Baht 3.5 per kg, while in Bangkok the price is Baht 5 per kg because charcoal supplies come from as far as 100-150 kms away. These cost and price levels compare to those of competing commercial fuels as follows. The retail price of LPG is about Baht 10 per kg in Bangkok, and Baht 13.3 per kg in provincial municipalities. Because LPG has only recently begun to be distributed in rural areas, no published price data are available, but the assessment team did hear of reports of LPG as high as Baht 20.5 per kg in village stores.

Table 8.4: REPRESENTATIVE COMPARATIVE FUEL PRICES IN RURAL AND URBAN AREAS, 1983
(Baht per Unit) a/

	Rural	Provincial Urban	Bangkok
Fuelwood (kg)			
Imputed cost			
Village 1 b/	0.38 (1.4)		
Village 2 b/	1.03 (3.7)		
Urban	-	-	-
Charcoal (kg)			
Imputed cost			
Village 1 b/	2.0 (1.4)	-	-
Village 2 b/	3.5 (2.5)	-	-
Market price	-	3.5 (2.5)	5.0 (3.6)
Kerosene (liter)			
Retail price	8.0-12.5	6.5	6.1
LPG (kg)			
Retail price	13.3-20.5	13.3	10.0
	(2.2-3.3)	(2.2)	(1.6)
Electricity (kWh)			
Tariff	1.17-1.75 c/	1.75	1.83
	(1.4-2.1)	(2.1)	(2.2)

a/ Figures in brackets are Baht per Useful 1,000 Kcal where calorific content and end use efficiencies of various fuels are:

	Fuel Unit	Heat Value	End Use Efficiencies	Net Useful Energy Kcal per Unit
Fuelwood	kg	3500	8%	280
Charcoal	kg	7000	20%	1400
LPG	kg	11,154	55%	6135
Electricity	kWh	860	95% (rice cooker)	817

b/ Village 1 is assumed to be within 2 km of fuelwood supplies, Village 2, 15 kms.

c/ Tariff depends on amount of power consumed per month.

Source: Assessment team estimates based from information received from NEA and other Thai sources.

8.28 When the differing heat content and end-use efficiencies of the various fuels are taken into consideration, fuelwood and charcoal are the most economic fuels for cooking, particularly when fuelwood supplies are still located in nearby villages. However, as wood has to be transported over greater distances, it becomes more costly and LPG becomes more competitive. Present subsidized electricity tariffs in areas where wood is becoming more costly make electric rice cookers also competitive. Location, as well as the level of subsidy now prevailing are, of course, critical. In those areas where overcutting continues and the forest is receding or even disappearing as in Central Thailand, the higher cost of traditional fuels and the low subsidized prices for commercial fuels have already made LPG and electricity sufficiently attractive to be the fuel of choice for many medium-to high-income households.

8.29 As shown in Table 8.4, LPG currently is competitive with fuelwood in Village 2 situations; in the case of charcoal it is competitive in Bangkok and in provincial urban and rural Village 2 settings. This also applies to the use of electric rice cookers at present tariffs.

8.30 As forest cutting continues and cheap fuelwood becomes less accessible the rising cost of traditional fuels will make LPG competitive even in Village 1 locations. To these supply side effects have to be added the increasing demand side preference for LPG as a cooking fuel in provincial urban and rural settings -- a process which is reinforced by the impact of rising disposable incomes of rural households.

Rural Use of Modern Fuels and Policies

8.31 The effects of these cost and price changes already are adding pressure to traditional fuels and causing additional switching to modern fuels beyond those that have been assumed in the projections in Table 8.1. The cost of such switching to the country and the extent of the switch is open to conjecture. Various possible scenarios have been considered in this report. The scenario considered most realistic by the assessment team assumed that the number of households using LPG rises from the projected 35% to 50% and the use per household increases from 45 kg to 60 kg per year. 65/ In addition, electricity use could easily increase from the 2.0 kWh per household using electricity per day assumed in the projection in Table 8.1 to 2.5 kWh per day. The aggregate impact of such an increase when combined with the additional use of LPG would result in only a 585,000 toe increase in the total demand for commercial

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65/ This would be equivalent to about 270,000 tons of LPG a year (about 6,800 bbls/day, which is roughly 50% of total 1984 LPG demand, or around 90% of the LPG currently used in transport).

fuel. 66/ Such an increase in commercial energy use is less than 4% of total commercial energy used in 1984. Substitution by commercial fuels is feasible providing the policy framework applied is sound. Great care should be taken to improve the distribution mechanisms and the pricing system to ensure that significant segments of the population are able to obtain adequate energy supplies. The avoidance of subsidies for modern fuels is particularly important to prevent growing distortions which result in uneconomic demand for the wrong fuels, e.g. diesel and LPG use in transport. The continued underpricing of some of these fuels and the maintenance of subsidies will soon result in an increasingly onerous burden on Thailand's public finances.

8.32 The tariff for rural electricity, which presently receives a subsidy, also needs to be revised to reflect the LRMC and to avoid an excessive financial burden on the electric system. A principal contributor to the EGAT system peak at the present appears to be the small residential consumers, particularly those served by PEA. The substantial quantities of electricity used by higher income households who cook with electricity should be supplied at full economic cost. At current PEA tariffs low income households with consumption levels less than about 15 kWh/month are estimated to spend much less on electricity than on kerosene for lighting purposes (para. 8.10). Since LPG use is likely to be limited to the upper income half of the population, its price should reflect full economic costs. A proxy for this could be a wholesale price based on border prices. The elimination of controlled retail LPG prices for residential use, which has resulted in a two-tier pricing system, would help to remove existing incentives to divert cheap household LPG to transport uses. Deregulating prices should also be used to encourage the entry of additional suppliers into the LPG market, to create a competitive environment which is essential to the development of an efficient distribution and sales network in rural areas.

8.33 Higher energy prices no doubt will begin to seriously affect many rural households. The higher costs of firewood and charcoal will amount to a burden of as much as US$650 million per year by 2001 for rural households. Moreover, switching to modern fuels will require substantial initial expenditures because the use of LPG requires a deposit of Baht 300 on a gas cylinder of 15 kg. Thus, if LPG were used by 50% of rural households in 2001, this would require a financial outlay of $90 million in cylinder deposits by these consumers. The purchasing of gas and electrical cooking equipment would also require a substantial investment. The government cannot be expected to share in the burden of this investment for these households, most of whom would be among the relatively high income groups. The increasing role of LPG as a cooking fuel in provincial urban and rural locations highlights the issue of the

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66/ Of which 310,000 toe is LPG and 275,000 toe (1100 GWh) of electricity.

role of the private sector both in providing the bottles and stoves and in efficiently distributing the fuel in these areas. Here it is important that government not permit the emergence of any LPG marketing and distribution monopolies if these efficiency objectives are to be achieved. One issue for the suppliers of LPG concerns the financing of deposits on cylinders by consumers. There is no apparent reason why the private sector could not only sell the gas but also lease or provide credit for the equipment.

Forestry, Conservation and Biomass Substitution Program

8.34 Over the next twenty years, the various economic factors affecting rural energy demand and the decline in natural forest resources will result in a growing deficit of fuelwood. Whether the situation will lead to a faster shift to modern fuels than assumed is a question which will affect the supply strategy that needs to be adopted. The present structure of prices (Table 8.4) shows clearly that fuelwood-derived energy is in some cases a less expensive option to consumers and that the process of large-scale switching to modern fuels in rural areas would involve high costs to rural households. Since as much as 25% of rural incomes may be spent for energy, maintaining fuelwood supplies may be the least cost approach to meeting many of the rural household cooking needs whenever fuelwood supplies can be planted close to consumers. Charcoal produced from wood from a nearby plantation can provide cooking energy, allowing for differing end-use efficiencies, at Baht 1.0 per useful Kcal compared with Baht 2.2-3.3 for LPG and a LRMC of Baht 5.0 for electric rice cookers. The essence of the rural energy strategy needs to combine two objectives -- that of improving the supply and efficiency of using traditional cooking fuels while at the same time efficiently providing rural consumers with access to commercial fuels other than just electricity at competitive and economic prices.

8.35 Consequently, traditional fuels have an important role to play in an overall rural energy strategy. A critical element in such a strategy is the size of the appropriate fuelwood program, the determinants of which include not only the estimated deficit but also considerations related to the feasibility of implementation. It will be possible, therefore, to set a definite program magnitude only after further study of certain specific information such as the viability of private fuelwood plantations and the amount of sustainable wood resources already in place in non-public lands. Nevertheless, to provide planning perspective, the assessment team has identified possible components of a fuelwood program which would supply some 20 million cubic meters of wood equivalent by the year 2000 through afforestation, conservation and biomass substitution (Table 8.5). The program is ambitious but feasible in the view of the assessment team, if the implementation issues discussed below are effectively addressed. However, even at full implementation, a net deficit of up to 16 million cubic meters of wood equivalent could still remain, to be be met by overcutting and/or increased use of modern fuels.

Table 8.5: FUELWOOD PROGRAM

	Annual Production 2001 (Million Cu.M Wood Equivalent)	Investment Costs 1986-2001 (Million US$)
I. Supply Strategy		
1. 0.45 million ha private sector plantations	9.0	240.0
- 0.3 M ha small farmers		
- 0.15 M ha industrial-scale		
2. 75,000 ha intensively managed RFD plantations	1.7	40.0
3. Homesteads, 100 million trees	2.5	20.0
Total	13.0	300.0a/
II. Conservation Strategy		
1. Improved Kilns (5000 producers, 370 t/y ave)	2.7	5.0b/
2. Improved Charcoal Stoves (800,000 units)	1.8	
3. Improved Firewood Stoves		7.5c/
(600,000 units)	0.5	
Total	5.0	12.5
II. Substitution with Biomass Residues		
1. Rice Husks	1.0	3.0c/
2. Sawmill Wastes, etc.	1.0	
Total	2.0	3.0
Overall Total	20.0	315.5

a/ Initial investment only. Excludes administrative costs.
b/ Includes cost of kilns, accessories and administration.
c/ All program costs included.
Source: Mission estimates based on discussions with NEA, RFD and other Thai officials.

8.36 The afforestation effort outlined in Table 8.5 would involve:

(a) establishing 450,000 ha of private fuelwood plantations; 300,000 ha in small farm holdings (about 5 ha each) that have been converted to growing fuelwood as a cash crop, and 150,000 ha of industrial-scale plantations near wood markets. An average yield of 20 m^3/ha/yr could be obtained in such plantations generating 9 million m^3 wood annually.

(b) tree-planting around homesteads by 2 million rural households, each with about 50 trees. With a rotation period of 6-10 years, this would provide 2-3 million m^3 of fuelwood annually.

(c) converting 75,000 ha of state-owned forest land into intensively-managed government plantations. At an assumed yield of 20 m^3/ha/yr, this would contribute about 1-2 million m^3 per year to the supply.

(d) increasing the proportion of total forest area that will be economically accessible for fuelwood collection by 2001, through, for example, building roads into more remote forested areas to permit managed commercial exploitation of fuelwood to supply charcoal.

8.37 Complementary demand-side actions are also needed. An achievable objective would be to have about one-fourth of charcoal production in 2001 carried out in improved kilns with 25% higher efficiencies than those of present kilns. 67/ The program could result in savings of about 2.7 million m^3 of fuelwood and would engage about 5,000 charcoal producers a year in producing a total of 370 tonnes. 68/ Additional savings could be achieved by promoting wider use of improved household stoves. A feasible 15-year program would be to have about 10% of households using improved stoves, i.e., requiring the deployment of about 800,000 units of improved charcoal stoves and about 600,000 units of improved firewood stoves. The efficiency increases of 20%-30% for charcoal stoves and 8%-15% for firewood stoves produce a combined fuelwood savings of about 2.3 million m^3.

8.38 Substitution with biomass residues, particularly rice husks and sawmill wastes, could be pursued in certain areas of the country. The maximum potential in 2001 for rice husks is 3.2 million m^3 wood equivalent. In the rice producing regions, the natural shift to paddy husks for cooking as wood becomes more costly to obtain may increase their use from about 100,000 m^3 at present to 500,000 m^3 by 2001. It may be possible to push use up to as much as 1.0 million m^3 through the appropriate programs. Sawmill wastes, now used for fuel at probably less than 0.5 million m^3, may be promoted to increase usage to about 1.0 million m^3. Other potential sources include wood obtained from clearing for agricultural expansion. These are slashed and burned in the field at present and very little end up as household fuel.

67/ Projected total charcoal demand by 2001 is 7.7 million tonnes.

68/ Part of this shift to more efficient methods will probably occur even without government intervention.

Implementation Issues in Traditional Fuel Programs

8.39 A critical element in the analyses presented in this report relates to how large a fuelwood program is feasible. The targets outlined above are certainly ambitious and should be considered at this time as a tentative ceiling. Whether in fact they can be achieved will depend on a host of institutional, economic and sociological factors which are discussed in the sections that follow. In the context of this discussion, it is important to emphasize that:

(e) the targets were estimated to permit quantification of the necessary efforts. They do not represent fixed numbers from which some upward or downward deviation would be unexpected.

(f) at full implementation, the program can at best meet only about half of the projected fuelwood gap, clearly indicating the initiatives that need to be taken on the modern fuels side.

(g) a more modest program achievement would still represent a significant contribution to the fuelwood supply plus important but unquantifiable impacts on the environmental degradation caused by continued overexploitation of the natural forest resource base.

8.40 This report emphasizes the importance of getting the private sectorinvolved in all rural energy programs and particularly the rural afforestation fuelwood program. In this area the government already is leasing land to farmers at a lump-sum fee of Baht 20/rai to grow wood on a 30-year lease. Some farmers are already taking up these leases.

8.41 A further issue concerns the need to integrate the fuelwood supply program and all charcoal kiln efficiency improvement projects, and not treat them as separate activities involving the fuelwood supplier on the one hand and the charcoalier on the other.

Private Sector Role

8.42 The program relies heavily on private sector participation to minimize government investment and actual planting work to be done by RFD. About 85% of the total target area is planned to be planted by the private sector; two-thirds of this area would be small farmer's lots and one-third industrial-scale plantations. The basic incentive to private tree growers would be the attractive financial rate of return on investment, shown to be about 23% for plantations supplying the fuelwood needs of charcoal makers within 5 km from the plantation gate (Annex 12). The economic rate of return is about 23% at a land rental cost of 500

Bahts/ha/year. 69/ However, such estimates of financial viability are not likely to be the only basis for private farmer or company decisions. In practice other key factors will have equal or greater importance. First is the existence of established market outlets for the wood produced. Where charcoal makers have easy access to "free" wood from natural forests, the market will not be there. Hence the project should give priority to areas such as in the south and northeast where supplies are distant from consumers. A second consideration would be the perceived advantages of using the same land for agricultural crops instead of trees. Fuelwood plantations even for fast growing species require at least four-five years before the first harvest. Most agricultural cash crops require much less time. A third factor is the actual availability of suitable land for afforestation within an economic hauling radius of main townships. These issues need to be addressed in detail in the context of each project.

Previous Experience

8.43 Experience with past and ongoing Bank agriculture projects in Thailand provides valuable insights on potential implementation difficulties and possible means to surmount these. The Highland Forestry Component of the Northern Agricultural Development Projects (NADP), for example, has exceeded its original physical targets of 7,700 hectares of planted area. However, community participation, which is a crucial requirement for the successful implementation of larger planting efforts, has remained a problem. Serious incidents of community resistance were encountered by the implementing agency, RFD, when it planted in areas traditionally cultivated by local hill tribe people. RFD is only gradually learning to include such social factors in its planning. In addition, legislative restrictions on forest reserve lands and RFD's present lack of extension expertise have limited the role of local farmers. Virtually none of the component's woodlot plantations are managed and harvested by the farmers.

8.44 The other forestry activity of the NADP, the smaller Upland Forestry component, is being implemented by the Land Development Department. It is likely to achieve only one third of the original target of 4,050 ha of planted area. Aside from technical difficulties (inadequate culling of seedlings, unsuitable tree species for certain sites, selection of sites with extremely poor soil, etc..) the more significant problems were sociological in nature. Since a fair amount of wood is still available from nearby forests, the farmers do not perceive any urgency in planting their own trees. Also, common woodlots do not seem to gain acceptance because of their collective and voluntary nature.

69/ Sensitivity analysis indicates that if the rental cost of land were to double, the economic rate of return would still be 20%.

8.45 These particular problems point to the critical role for continuous, expert extension work; the need to select woodlot sites and tree species more judiciously; the importance of securing the rights of farmer participants; the need to review the collective as opposed to the individual woodlot approach; the need to carefully delineate responsibilities and working relations of all relevant RTG agencies, the location of planting -- areas where free wood is remote -- and the price that can be expected for charcoal.

Organization

8.46 For the proposed program, the organization and institutional roles should be subject to careful study before projects are undertaken (Annex 8.3). RFD will need to be the lead government agency, as it has the forestry expertise and the custodial responsibility over much of the land that will be converted to fuelwood plantations. To ensure consistency with national land use policies and plans, RFD must have the support of and coordination with the Land Development Department, the Office of Agricultural Land Reform, and the Department of Lands. On the conservation and biomass substitution side, NEA should continue to provide research assistance, especially on the development, field testing and standardization of improved kilns and household stoves. The manufacture and marketing of these fuel-conserving devices should, however, be turned over to commercial producers as soon as possible. The dissemination of improved charcoal making techniques to rural households and small charcoal producers is probably best done by RFD field staff who are more familiar with village conditions and personalities.

8.47 The program will obviously require a substantial increase in RFD manpower, including new staff with specialized training in social forestry and wood-based energy. The institutional expansion and staff-training can be done gradually, in consonance with the long term plantation development plan. Again, this aspect of the program, including the budgetary implications not only for RFD but for all other involved agencies, needs careful study at the pre-investment stage.

Policy Measures

8.48 Program implementation must be supported by policy measures and activities designed to protect the remaining natural forests and encourage private sector participation in plantation establishment. Two important broad policy objectives are: (a) to limit as far as possible the removal of fuelwood from national forests to low income groups of the population who cannot afford modern fuels; and (b) to encourage, within the group that must rely on traditional fuels, maximum self-production of needed supplies, e.g., dedicated plantations for wood-burning industries, homestead planting and agro forestry, etc.

8.49 Recommended policy measures include:

(a) gradual imposition of fuelwood extraction fees from the royal forests which more closely reflect economic rent for the resource. A fair stumpage fee, for example, may be the "willingness to pay" by final users minus all cutting, collection, and transport costs. Aside from the economic objective, the policy can encourage private sector plantations by making the latter's product more competitive;

(b) ensure security of land tenure, and hence the ability to obtain credit, to energy plantation farmers through the continuation of current land titling programs;

(c) provision of flexible pricing for tree seedlings. In poorer and remote rural areas, free distribution of seedlings may be needed as an incentive for small farmers to take up tree planting. For larger scale tree farmers situated close to potential cash markets, a policy of full cost recovery may be applied; and

(d) provision of strong support to conservation-oriented research and demonstration activities for improved charcoal kilns and cooking stoves.

Action Plan

8.50 Specific program activities for financial support for plantation development, research and institutional strengthening are listed in Annex 13 and in the action plan outlined below and highlighted in Table 8.5.

8.51 As an immediate step, the above recommedations should be translated into a two-phased action plan. Phase I would consist of two studies which focus on fuelwood issues which are not being addressed in current preparatory work for projects financed by the Bank and other agencies. 70/ The studies, which should be carried out in an integrated manner, would:

(a) Identify the specific conditions for viable operation of fuelwood plantations by the private sector (small farmers and

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70/ It is imperative to first determine potential areas of overlap with other ongoing/planned studies of broader scope, such as the preparation work for the proposed Rural Land Use Project. The Phase I study should be coordinated with that work, to ensure complimentarity of objectives and specific areas of investigation.

industrial companies). The study would make a more detailed financial and economic analysis of the fuelwood growing business, considering typical farm sizes, locations, suitable species and likely yields; examine existing and projected fuelwood and charcoal markets; assess the feasibility of charcoal making as an adjunct to wood production in the proposed plantations and the impact of this option on small, landless charcoal producers; examine, under various conditions and locations, the competitiveness of fuelwood growing versus other agricultural crops; examine the feasibility of inter-cropping and co-production of non-fuelwood forest products (poles, timber, fruit, etc.) which could improve profitability; examine the actual availability of suitable land, as well as potential constraints that may be imposed by existing and forthcoming land-use policies and plans 71/ and determine the required government mechanisms and resources for leasing forest reserves and providing seedlings and technical extension support. It will also be useful to examine more recently acquired RFD fuelwood supply data, especially the magnitude of fuelwood available from existing private sources, in preparation for the Phase II study which, among others, will reassess the physical targets of the planting program proposed in this report.

(b) Review the sociological aspects of a fuelwood supply, conservation and biomass substitution program. This would essentially be an assessment of people's awareness of the fuelwood supply problem and their attitude to participation in a government program to plant trees in and around homesteads and in village woodlots, and to use improved cooking stoves in lieu of the "normal" less efficient kinds. These sociological analyses at the household and community levels are necessary before making any major investments because experience has shown that centralized planning perspectives of what constitutes optimal solutions to the fuelwood "crisis" may not always be in accord with the perceptions of target groups. As noted earlier, a substantial amount of information is already available from experience with Bank projects and many socio-economic studies that have been done by CUSRI, NEA, PEA and other agencies. A fresh and more expert analysis of the data is probably of greater value than additional extensive field interviews.

71/ The Land Titling Project (Loan 2440-TH), Land Reform Areas Project (Loan 2198-TH), The Northern Agricultural Development Project (Credit-929-TH) the Land Use Policy Component to the SAL I and SAL II loans, a World Bank research project on the impact of tenure security on land productivity, and the proposed Rural Land Use Project are important sources of information on this particular subject.

Implementing Phase I might require the input of an Energy Planning Economist, a Forester and Sociologist for a total of about nine man-months. The detailed terms of reference for the two Phase I studies need to be worked out with RTG at the time of reviewing the overall energy assessment report.

8.52 Phase II would depend on a positive outcome to Phase I. The results of Phase I would be used to reassess the physical targets for each program component to ensure that they are achievable, and to determine the most feasible institutional mechanisms for carrying out each component as well as the overall program. The exact roles of each government agency and the budgetary implications of such roles would be examined in this phase. The Phase II work would also examine the relationship of each program component with similar activities under the proposed Rural Land Use Project, to ensure complimentarity and to explore whether certain components could be carried out under that Project.

8.53 A tentative estimate of the cost of these two studies would be US$150,000 for Phase I and US$250,000 for Phase II, assuming a combination of overseas and local expertise.

IX. POTENTIAL FOR AN ENERGY EFFICIENCY IMPROVEMENT PROGRAM

9.1 Although the sharp increase in oil prices since 1973 has reduced Thailand's elasticity of commercial energy to GDP from 2.1 during 1960-73 to 0.7 during 1973-83, the elasticity has shown signs of rising again in the face of declining energy prices. This would imply that energy demand will pick up and grow more rapidly than it has in recent years even though GDP is growing more slowly. If these trends continue, the future import of commercial fuels may indeed rise. As discussed in Chapter 2, it is expected that increasing energy imports could cause a renewed balance of payments crisis in the mid- to late-1990s. Further, the burden of large public sector energy investment is causing severe financial constraints.

9.2 It will be important to ensure that fuels are used more efficiently to minimize the financial pressures over the next decade -- a process which should prove feasible, as Thailand is faced with the same potential for improving energy efficiency as most developing countries. Some energy intensive industrial plants are consuming 20% to 30% more energy per unit of output than the best international practice, and some consume over twice as much. Some oil-using plants can be converted to use other fuels costing substantially less than the petroleum fuel equivalent. Most transport entities in Thailand could reduce consumption per ton-km by 10-20% through low-cost improvements and by much more if the many problems with roads and vehicles were properly addressed. Some savings might be obtained by improving electric power transmission and distribution facilities. In rural areas improved fuelwood and charcoal stoves requiring only half as much wood as traditional stoves might be used.

9.3 Three energy consuming sectors stand out as offering the best potential for immediate reductions in consumption by increasing the efficiency of fuel use. The first is households, where the use of traditional fuels such as fuelwood and charcoal can be reduced by improving the efficiency of stoves and charcoal-making kilns. The two major users of commercial fuels -- the manufacturing and transport sectors -- have already demonstrated that substantial fuel can be saved, although most reductions have taken place by the private sector responding to higher energy prices. There can be little doubt that substantial potential for further energy savings remains and could be achieved through stronger government actions in that sector. This chapter briefly reviews the scope for increased energy efficiency and the major options for accelerating its implementation.

Efficiency in Using Traditional Fuels

9.4 Despite the expected rapid growth of commercial fuels for use in household cooking in rural areas, the sheer magnitude of current demand for fuelwood (in the form of both firewood and charcoal) makes it certain that fuelwood will continue to be the predominant household fuel in rural areas for at least the next 20 years. If present consumption trends continue, the total fuelwood-equivalent demand will increase to about 53 million m^3 by 2001, severely straining natural forest resources. Forestry programs outlined are not at a maximum expected to produce more than an additional 21 millions m^3 of fuelwood. Commercial energy may be the only practical alternative, and it may be feasible only for supplying part of the rural population. The most promising measures for reducing the level of demand relate to the improved charcoal kilns and cooking stoves.

Charcoal Making

9.5 Of the total fuelwood consumption in 1983, about two-thirds or 26 million m^3 of it was used in the production of 3.7 million tons of charcoal. This implies an energy loss equivalent to about 16 million m^3 of wood (41% of the total fuelwood demand) as a consequence of the charcoal-making process. Charcoal production is practiced in nearly every area with forest resources. Producers include households who make small quantities of charcoal for their own use, as well as larger scale operators who produce charcoal for commercial purposes. The southern region, with its mangrove resources, appears to have the best established commercial production systems, using large permanent kilns. Reflecting relatively scarcer forest resources, charcoal in the North and Northeast is produced by smaller, more inefficient kilns which are moved periodically.

9.6 The average kiln efficiency is difficult to estimate, as it depends on the physical properties of the wood input, the kiln design and construction materials, and the specific operating method. A 1982 survey by NEA made some limited field measurements and reported average charcoal-to-wood weight conversion ratios ranging from about 18% for the earthmound type kilns to about 30% for the permanent (mud/clay) oven-type kilns. 72/ The implication is that with current charcoal production methods, about 20-30 kg of charcoal can be produced from 100 kg of wood. In fact, 70-80 kg of wood are consumed in the process. 73/ There

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72/ About 40% of commercial charcoal production is carried out in small (7-9 m^3) oven-type mud/brick structures and the remainder in pit or earth mound types usually with even smaller capacity, at the village level. The earthmound type kilns predominate. The large (50-100 m^3) oven type is used especially in the South region for carbonizing mangrove, and the sawdust mound type is used mainly for sawmill wastes and para rubber wood residues. A few portable metal kilns--the so-called "Mark V" kilns of about 3-7 m^3 capacity--are also used in some parts of Thailand, introduced in the 1970s by the FAO for salvaging the residues of clearfelling operations.

73/ Considering that charcoal has nearly twice the energy content of wood, the amount of wood wasted as a result of carbonization would only be about 30-40 kg per 100 kg wood carbonized.

is clearly potential for introducing more efficient charcoal-making techniques and kiln designs.

9.7 Through a USAID-financed renewable energy project, NEA and RFD have been engaged in evaluating and adapting to their conditions higher efficiency kilns including permanently situated systems (e.g., Brazilian beehive, earth and rice-husk mounds) as well as portable metal kilns (drum type, Mark V kilns, etc.). Improvements in efficiency of up to 30-50% have already been demonstrated in the RFD work. An aggressive program for disseminating the improved designs by extension work would be justified. One goal would be to educate the private sector, while at the same time stimulating credit mechanisms and other incentives which might be combined with tighter government measures to prevent significant deforrestation. In view of the predominance of small and highly inefficient producers, priority should be given first to them. The potential fuelwood savings are substantial; for example, if only 10% of 1983 charcoal production achieves an efficiency improvement of 25% over the current average (which appears possible), the implied wood savings would be about 500,000 m^3, or roughly the sustainable yield of 200,000 ha of natural forests.

9.8 The Rural Energy Report proposed that a program be established to have 25% of charcoal production by the end of the century carried out in improved kilns. 74/ The kilns would have 25% higher efficiencies on average than present kilns, which could result in about 2.7 million m^3 of fuelwood savings. About 5,000 charcoal producers would be involved producing 370 tons a year. 75/

Household Cooking Stoves

9.9 Although the Thai bucket stove is a significant improvement over the three-stone stove of the past, further scope for improvement is possible, for example, by narrowing the hot air exhaust gap, deepening the stove "seat", better lining and grate design, etc., NEA and RFD have developed bucket stoves with 10% higher efficiency compared to currently available commercial stoves. As with kilns, the potential fuelwood savings from such improved stoves would be great. Replacing, for example, 500,000 firewood stoves of 8% efficiency with improved versions of 15% efficiency could save up to 500,000 m^3 of fuelwood annually.

9.10 The Rural Energy Report has proposed a 15-year program to have about 10% of households using improved stoves. The program would provide incentives for the private sector to provide about 800,000 units of improved charcoal stoves and about 600,000 units of improved firewood

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74/ The projected total charcoal demand by 2001 is 7.7 million tons.

75/ Because of the savings involved part of this shift to more efficient methods will probably occur even without government intervention.

stoves, with assumed efficiency increases averaging 20%-30% for charcoal stoves and 8%-15% for firewood stoves. The combined fuelwood savings would be about 2.1 million m^3. Such a strategy involving both charcoal kilns and cooking stoves potentially could cut fuelwood demand in 2001 by as much as 4.8 million m^3. A seven-year demonstration and dissemination program for improved cooking stoves, jointly carried out by the government and the private sector, would target 1 million households and is estimated by NEA to require a total capital investment of US$5.3 million over a 15-year period. The assessment team's analyses show that such a program would reduce energy demand by a half million tons of oil equivalent per year.

Industrial Energy Efficiency

9.11 With industrial growth averaging 11% per annum during 1960-1980, industry already accounts for 25% of the total energy consumed. Its share has continued to grow rapidly, and, in fact, its intensity is also increasing. At the present time, industry is consuming over 4,000,000 toe per year. The major industrial subsectors are food (30% of sectoral GDP in 1982), textiles (26%), chemicals (15%), fabricated metals (11%), and non-metallic minerals (6%). The consumption of energy differs somewhat because of substantial differences in energy intensities. For example, non-metallic minerals (cement, brick making and ceramics), textiles and food processing all have relatively high intensities and account for 83% of the total energy used in industry. The most widely used form of energy is fuel oil -- accounting for about 48%, followed by electricity (19%), gasoline (9%), and diesel (7%). In fact, half of the fuel oil and 70% of the electricity used by all sectors in the economy was recently consumed by industry. The cement industry by itself in 1982 consumed about 25% of the country's total fuel oil. This industry's energy consumption is projected to grow to more than 2.6 million toe per year by the end of the century, of which approximately 60% could still be in the form of fuel oil. The potential both for changing the energy mix and for both using that energy more efficiently and substituting cheaper fuels in the cement industry is great. For example, if gas is cheap relative to coal, its use could grow to 66 MMCFD by the end of the century supplemented by about 174,000 tons of coal annually. However, if gas remains expensive and coal becomes cheap, the fuel mix could be 15 MMCFD plus 965,000 tons of coal. In terms of economic efficiency, if the comparative relative prices used are their economic prices, then the cement industry would receive the correct signals and could adjust accordingly (paras. 6.53-6.63).

9.12 Correct energy pricing to date has been the single most effective factor in both interfuel substitution and related energy efficiency improvement. The effectiveness, however, has been delayed because the real domestic price of the two most important industrial energy inputs -- fuel oil and electricity -- did not increase significantly until after 1979. At that point, the increases had a substantital effect on energy consumption patterns. In 1979, oil-based products provided the most energy used by the manufacturing sector. By 1982, after the price adjustments, non-oil energy inputs exceeded oil-based inputs. A noticeable trend was the decline in the use of oil in all industrial subsectors, offset by a growth in the use of coal, lignite and fuelwood. Total energy intensity remained relatively constant despite the fact that the energy intensity of oil fell by about one-third between 1979 and 1982 (Table 9.1). This emphasizes the dynamic effects that already have taken place in Thailand as the result of higher oil prices. With increasing gas availability and cheaper imported coal the use of fuel oil in cement, for example, has not only declined but is expected to continue that decline over the near future.

9.13 One question concerns the effect on the overall intensity of energy use of the government's policy of supporting a slow shift towards heavy industry while continuing priority for labor-intensive light industry and food processing. Heavy industries to be promoted during the next five or six years include a fertilizer project and a petrochemical industry, both expected to use natural gas as a feedstock. The demand for natural gas by these two industries by 1988 is projected to be 30 MMCFD and 43 MMCFD, respectively. This, togther with the substitution of natural gas for fuel oil in the cement industry (of up to 60 MMCFD), would raise the demand for natural gas by the industrial sector to 133 MMCFD by 1990. The total demand for natural gas by the industrial sector would raise its consumption level from 400,000 toe in 1986 to 1,350,000 toe by 1991. This would represent 21% of the total end-use demand for energy by the industrial sector.

9.14 In 1982, industry's use of electricity amounted to 665,000 toe. Approximately 30% of this was used in heavy industry (mostly cement, iron and steel), 25% was used in light industry, and 15% in food processing. Growth in the demand for electricity is very much influenced by what happens in these three industrial subsectors. The latest projections used by the assessment team show that the demand for electricity in all of industry would rise to 1,240,000 toe in 1991 and 2,170,000 toe in 2001, representing annual growth rates of 7.2% during 1982-91 and 5.7% during 1990-2001.

9.15 The largest consumer of gasoline in the industrial sector is the construction industry (28.3%), followed by heavy industry - intermediate (24.2%), while the largest user of diesel is in mining (49.2%). The demand for gasoline is expected to increase from 307,000 toe in 1982 to 836,000 toe in 2001, representing an annual growth rate of 5.4% per year. During the same period the demand for diesel would rise from 230,000 toe to 608,000 toe, or at an annual growth rate of 5.2%.

9.16 The demand for fuel oil, on the other hand, could remain fairly stable during 1982-86 as a result of an increased use of natural gas by the cement industry. However, there has been significant switching in this industry to coal and lignite and to relatively small amounts of gas so far. Future consumption levels are very much linked to the relative prices that can be expected for fuel oil, natural gas, lignite and coal.

The government's pricing policy for these products will be crucial in determining demand by practically all industries.

9.17 Isolating the effects of substitution to cheaper fuels separately from other forms of efficiency improvements will require detailed analyses at the subsector level. Improvements in energy efficiency that have already occurred will have to be pinpointed to determine where progress can still be achieved. In some cases where there is low substitution potential with electricity, electricity intensity might be used as a de facto indicator of potential improvements in general energy efficiency. 76/

9.18 Analysis at a subsector level makes it clear that textiles, paper, chemicals, non-metallic minerals and fabricated metals have already made progress in energy conservation, while food processing and wood products have relied on substitute fuels, and the basic metals subsector increased its energy intensity. The non-metallic minerals subsector has also made a major switch to substitute fuels.

9.19 The textile industry reduced both its total energy intensity and its electricity intensity by about 30% during 1979-82. Most of it was attributable to process improvements. Further progress therefore probably would require substantial investment in new technology. The paper industry has already reduced total energy intensity by 36% during the same period and electricity intensity by 13%. Chemicals has reduced its energy intensity by 52%, and further improvement also probably will require substantial investment in new technology. Fabricated metals already reduced its overall energy intensity by 21%, and there may still be room for improvement.

9.20 Non-metalic minerals in this period moved quickly to substitute cheaper lignite and coal for fuel oil. The move to substitute cheaper fuels was mandated by the fact that in this industry, energy accounts for 30% of production costs. Total energy intensity also decreased by 14% during this period, indicating that some significant operational improvements had been achieved. It is the view of the assessment team, however, that further reductions will be possible, but only if substantial investments are made in new technology.

76/ At the macro level, only small improvements in electricity intensity and hence in process efficiency have taken place. The energy to output ratio for electricity peaked in 1980 at 391 TJ BAHT and fell to 370 TJ BAHT in 1982, or at an average of 3% p.a. This improvement in efficiency (3% p.a.) appears to have been achieved through better operational procedures rather than investing in retrofitting or installing new energy efficient equipment.

Table 9.1: ENERGY INTENSITY a/

Manufacturing Sector	1976	1979	1982	Distribution of Consumption of Oil and Electricity
				(%)
TOTAL MANUFACTURING				100
Electricity	0.38	0.38	0.37	
Oil and Electricity	1.88	1.74	1.32	
Total (Including other fuels)	...	2.48	2.45	
FOOD				18
Electricity	0.21	0.25	0.25	
Oil and Electricity	1.02	0.83	0.80	
Total (Including other fuels)	...	2.92	3.95	
TEXTILES				17
Electricity	0.49	0.47	0.32	
Total (Oil and Electricity)	1.44	1.18	0.85	
WOOD				1
Electricity	0.17	0.23	0.27	
Total (Oil & Electricity)	1.03	1.13	0.72	
PAPER				5
Electricity	0.50	0.46	0.40	
Total (Oil & Electricity)	2.53	2.23	1.52	
CHEMICALS				8
Electricity	0.30	0.26	0.18	
Total (Oil & Electricity)	1.26	1.38	0.65	
NON-METALS				31
Electricity	0.87	0.88	0.77	
Oil and Electricity	10.33	9.60	6.87	
Total (Including other fuels)	...	11.81	10.23	
BASIC METALS				5
Electricity	3.13	1.38	2.06	
Total (Oil & Electricity)	5.73	3.89	4.16	
FABRICATED METALS				2
Electricity	0.15	0.17	0.11	
Total (Oil & Electricity)	0.52	0.27	0.21	
OTHER				13
Electricity	0.75	1.17	0.93	
Total (Oil and Electricity)	6.23	14.82	4.80	

a/ Terrajoules per billion Baht of output (1972 prices).

Source: Mission estimates.

9.21 In food processing, cheaper indigenous fuels have substituted for imported oil products, while it has not yet been possible to improve overall energy intensity. It appears, therefore, that there may be substantial scope for increasing efficiency. As a large energy user, this subsector is a priority target for retrofitting. For another area -- wood processing -- commercial energy intensity has fallen 36%, electricity intensity has actually risen, and the inference appears to be a move to cheaper fuels along with a deterioration in process efficiency. There may be some scope, therefore, for additional operational improvements.

9.22 Electricity intensity has increased in basic metals, while total energy intensity remained relatively stable. This appears to indicate a move to a more expensive but more efficient form of energy (electricity) in the face of rising prices. Falling production during 1982 combined with the continued use of old electric furnaces explains some of the subsector's performance problems. Both its energy intensiveness and the growing use of energy per unit of output in this subsector should give it priority in studying the effects of introducing more modern technology.

Overall Investment Requirements

9.23 Energy efficiency achieved to date has probably been due to the effects of substantial fuel switching by one industry -- cement -- and the widespread use of low cost operational 'housekeeping' savings. Investment in retrofitting existing plants and installing new energy efficiency equipment has been limited. 77/ As Thailand's 45,000 factories had an average age of 13.4 years in 1982, pre-oil crisis designs predominate. The potential for retrofitting, therefore, still appears significant. Studies sponsored by JICA and ADB found that further energy savings from more efficient use of petroleum products could be as much as 15-20%, while those for electricity could average between 3-6% (Table 9.2). 78/

9.24 The ADB study extrapolated its results to estimate the potential savings and required investments for the whole economy but not all the savings could be realized because of different penetration rates in each sector (Table 9.3). The financial requirements for such a program were estimated to be about $690 million, plus another US$50

77/ Only 59 applications have been made for import duty exemption on energy saving equipment, of which 41 were approved.

78/ The JICA study focused on technical efficiency while the ADB study focused on economic investment opportunities.

million for natural gas substitution. 79/ The funds would be used mainly to retrofit existing equipment (US$185 million) and purchase new energy efficient equipment (US$505 million).

Government Activities to Date

9.25 The NEA has been the lead government agency in promoting efficiency and has carried out the work necessary to bring an industrial energy efficiency program close to the implementation stage. NEA is also undertaking a study on industrial efficiency incentives and disincentives to assess the policy reforms required before starting an investment phase. NEA is preparing to involve the private sector in implementation through the establishment of a joint government/private energy management center to be known as the Energy Conservation Center for Thailand (ECCT). 80/ Lending by development banks for energy efficiency has been very limited; in 1983, the Industrial Finance Corporation of Thailand (IFCT) approved loans for energy efficiency projects amounting to only US$2.8 million (out of total approved loans by that agency of US$70 million).

Table 9.2: POTENTIAL FOR ENERGY SAVINGS:
Average Savings as Percent of Total Energy Used, 1983

	Petroleum Products		Electricity	
Sector	JICA	ADB	JICA	ADB
Ceramic/Glass	12.2	9.44	1.5	3.4
Paper	21.5	18.5	0.3	2.8
Textile	10.2	14.9	5.3	10.9
Metal	22.5	8.9	1.7	4.2
Chemical/Plastic	11.1	19.1	4.4	3.1
Food	15.0	16.8	3.1	2.9
Average	15.8	...	2.5	5.5

Source: JICA Report on the study on Energy Conservation Project in the Kingdom of Thailand; Summary of Phase I January 1984, Japan International Cooperation Agency; ADB study "Industrial Energy Audits and Conservation Program in Thailand", October 1984.

79/ The ADB investment potential was based on a sample of 49 audits and 19 feasibility studies.

80/ This would differ substantially from the Energy Conservation Centre set up within NEA.

Table 9.3: ENERGY SAVINGS POTENTIAL AND INVESTMENT REQUIREMENTS BY SUBSECTOR AND TYPE OF MEASURE (1984 Dollars)

Subsector	Total Energy Savings (million BOE)	Total Monetary Savings (million US dollars)	Total Investment (million US dollars)
I. Subsector a/			
Food and Beverage	0.7	21.0	50.8
Textiles	0.888	26.64	24.8
Wood	0.86	2.58	5.0
Paper	0.151	4.53	6.9
Chemicals	0.158	4.74	3.7
Non-Metallic b/	1.224	36.72	540.3
Basic Metals	0.167	5.01	19.8
Fabricated Metals	0.176	5.28	18.5
Other Industry	0.539	16.17	16.3
Totals	4.089	122.67	686.1
II. Type of Measure a/			
Conservation			
Housekeeping, Better Management	0.922	27.66	17.7
Process Improvement - Some New Equipment	2.415	72.45	164.69
New Equipment	0.752	22.56	503.8
Total	4.089	122.67	686.1
III. Fuel Substitution (Oil Displaced) c/	2.803	84.09	54.6

a/ This excludes the fuel substitution measures.
b/ Includes cement.
c/ This figure represents oil displaced and the value of the oil and are thus gross savings which do not allow for the value of the gas substituted.

Note: World oil price is assumed to be US$30 per barrel.

Source: Asian Development Bank, op. cit.

Strategy for an Industrial Efficiency Program

9.26 Although NEA has been undertaking the necessary preliminary work, the government has yet to formulate a strategy for accelerating energy efficiency in the industrial sector. What could have been done since 1979 to promote conservation in the absence of such a program has been largely realized through adjustments in energy prices, although there has been some slippage since the November 1984 devaluation.

9.27 Increases in oil and electricity prices since 1979 have resulted in the private sector undertaking substantial initiatives to use energy more efficiently. But in addition to appropriate pricing policies, two other areas require government action to institute an effective strategy. The first is to identify and eliminate fiscal and financial constraints to private sector adoption of higher efficiency measures. The second is to assist in making the private sector aware of opportunities for cost saving measures (housekeeping, retrofitting and new equipment). Publicly sponsored demonstration projects in selected subsectors would go a long way in removing private sector apprehensions about the commercial viability of investments to increase energy efficiency.

9.28 The need for additional government action was highlighted by the ADB study which surveyed 349 factories and found that individual enterprises did not feel that energy efficiency was a high priority issue. There would appear to be several key factors determining whether companies invest in energy conservation: (a) return on investment; (b) government support; and (c) availability of capital. The required payback period for investments in energy efficiency improvement projects is 3.7 years in Thailand and 4.5 years for capacity expansion projects. The lack of knowledge about investment opportunities and the lack of technical skills are very serious constraints to investment in energy conservation.

9.29 Creating a policy environment conducive to increasing energy efficiency investments requires providing selective fiscal incentives for investing in retrofitting and replacing inefficient plant. Fiscal incentives would signal to industry the government's commitment to the program. The experience in developed countries has shown accelerated depreciation allowance to be very effective, but care should be taken that these incentives are not made permanent.

9.30 The availability of financing is also required for energy saving projects which are in the national interest. With the generally small loan size and the large number of potential applicants, the involvement of the private banking sector in the financing of any investment program will be essential. 81/ However, commercial banks lack the expertise to evaluate the technical aspects of loans for efficiency projects. The expertise of IFCT should be built up to provide some support in this area.

9.31 The government also needs to facilitate importation of the latest energy saving technology by streamlining import restrictions and minimizing bureaucratic procedures. More explicitly, the government should ensure that:

(a) technically competent people are obtained to advise industry on required retrofitting;

81/ Excluding the cement industry (average loan US$29 million), the average conservation loan would be in range of US$16,000 to US$298,000.

(b) a system is created to help certify companies in the private sector which have sufficient potential savings so that their loan applications can be seriously considered; and

(c) finance from commercial banks is available in the suitable form to meet the needs of the industry.

Recommendations for Government Action

Short Term

9.32 The government's industrial energy efficiency program should be articulated in sufficient detail to formulate an action program. The role of the ECCT, IFCT, private banks, industry associations, and government departments should be identified and coordinating mechanisms established. More specifically, NEA should concentrate on policy development, while the ECCT, IFCT, and others should concentrate on implementing policy. Specific measures to be undertaken in the short term are to:

(a) Start the process, in conjunction with the private sector, of formulating a retrofitting program and identifying promising plant investments;

(b) Establish ECCT. Present proposals undercapitalize the center. More multilateral and bilateral aid should be sought. The appointment of an experienced and well respected Thai CEO will be critical to the Center's success. Expatriate technical support may also be needed;

(c) Review the relationship between this new center and the existing ECC in NEA. Also, review the demonstration program being carried out by ECC.

(d) The existing Energy Conservation Center within NEA should start to train private sector entrepreneurs in energy-auditing and energy-saving techniques. These trained individuals would be the catalysts for the investment program. Successful trainees should be approved and be able to prepare industry's investment applications to commercial banks;

(e) NEA, in conjunction with NESDB and the Ministry of Finance, should develop fiscal and financial policies to encourage private sector investment in energy saving equipment. The details of the policies would be defined after the ongoing study on industrial energy conservation incentives has been completed;

(f) NEA, in conjunction with IFCT, Ministry of Finance and commercial banks, should prepare a timetable for implementing investments. IFCT should assist in developing the institutional and financial framework for implementing investments through the commercial banking system. Further, depending upon the government's progress in putting in place the above policy and institutional set-up, a suitable conservation action plan should be designed and implemented;

(g) PEA, MEA, EGAT and PTT also need to be involved in energy conservation. They should be on the Board of the ECCT and provide a substantial annual contribution to the ECCT.

Long Term

9.33 Measures to be undertaken in the longer term:

(a) NEA should monitor the operations of the ECCT to ensure training and technology transfer are achieved.

(b) NEA should install an industrial energy data base which should be the basis for setting program targets and developing industrial energy policy;

(c) after completing the retrofitting phase of the program, the ECCT activities should be redirected into other sectors such as transport, hotels, etc. where high returns and oil savings could be achieved; and

(d) all market reinforcement incentives should be reviewed periodically.

Energy Efficiency in Transport

Introduction

9.34 With the transport sector consuming about 60% of petroleum products in 1983, it is important to evaluate how the sector has been responding to the increase in fuel prices in recent years and whether fuel is beginning to be used more efficiently. The transport system is dominated by the road sector, which accounts for about 80% of total freight ton-km and 90% of passenger kilometers. 82/ Road transport made up about 95% of the total fuel used in the transport sector.

9.35 During the past 25 years, the road transport sector has grown rapidly. The highway network has been expanded from 17,000 km in 1963 to 43,000 km in 1982, and rural roads have increased from 35,000 km in 1970 to 106,000 km in 1982, giving Thailand a very high density of roads compared with other LDCs. The country's motor vehicle fleet increased from about 400,000 units in 1978 to over 1,000,000 units in 1982 -- an annual growth of 9% (including motorcycles, the growth was from 740,000 units to 2,200,000 units). Commercial vehicles--buses, trucks and other utility vehicles--account for at least 60% of four-wheel vehicles, with automobiles making up the remainder. The average growth of vehicle traffic (excluding motorcycles) outside of urban areas was around 7% p.a. in the 1970s. Light trucks lead the growth with a rate of 15% p.a., followed by light buses at 9%, heavy trucks 6%, car traffic 4%, and heavy buses at less than 3%. Traffic is forecast to grow in the range of 6-8% p.a. during the remainder of the 1980s, slightly ahead of GDP growth.

9.36 The Bangkok area accounts for about 80% of total cars and taxis, 70% of buses, and almost 30% of trucks. About 50% of motorized traffic (excluding motorcycles) on all non-urban roads is also concentrated within a radius of 150 km from Bangkok, highlighting Bangkok's leading role as the center for government, commerce, industry and transport.

9.37 The transportation sector dominates the consumption of gasoline, diesel and jet fuel. Approximately 60.5% of end-use gasoline consumption is used in the transport sector, with roughly 50% of this in commercial vehicles while the other 50% is used by private motorists. Jet fuel is by definition completely consumed in the transportation sector, while 74% of end-user diesel consumption is used in the transportation sector.

9.38 In 1982, the transportation sector consumed 5,171,000 toe of commercial energy, or roughly 29% of total end-use gasoline consumption. It is therefore a critical sector in terms of an energy conservation program. During the 1970s the consumption of gasoline, diesel and jet fuel in the transport sector grew at relatively high annual rates of 6.4%, 6.6% and 8.0%, respectively. The use of LPG was low and remained fairly low throughout the 1970s. However, with the second oil shock in 1979/80 and the distorted price structure of retail petroleum products, the consumption of gasoline, which is mostly used in passenger cars, passenger trucks, samlors, light trucks and motorcycles, declined consistently. Between 1979 and 1984 the consumption of gasoline in the transport sector fell by 2.7% per year, partly due to increasing

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82/ 1981 figures, excluding urban traffic, which is predominantly by road.

efficiency as a result of the higher oil price and partly as a result of substitution of LPG and diesel in certain types of vehicles.

9.39 There has been a substantial amount of substitution away from gasoline over the last four or five years. Nearly all taxis in Bangkok and a very substantial proportion of samlors have converted to LPG. Light trucks, passenger trucks and passenger cars have also changed to diesel or LPG. Data on new diesel fueled passenger and light trucks clearly reveal this trend. In 1980 roughly 75% of the light or passenger trucks produced had gasoline engines, but the proportion declined to only 6% in 1984. Approximately 94% of light and passenger trucks produced are now diesel fueled.

9.40 The substitution resulted in a 90% per year increase in LPG consumption in the transport sector during the period 1980-84. The consumption of diesel also rose relatively fast during the same period -- at roughly 15.5% per annum.

Efficiency Through a Better Choice of Fuels

9.41 The most important factor in conservation concerns the changes that have taken place in retail fuel prices. For the future, if the distortions in consumption patterns that appear to be developing are to be eliminated then prices must reflect current economic costs. While overall price movements have been reasonably appropriate, the relative price of different transport fuels has been seriously distorted. Thus, while gasoline has been heavily taxed, diesel has been taxed lightly and LPG and kerosene essentially not taxed. 83/ These distortions have had a substantial impact on fuel use, as evidenced by the rapid conversion of automobiles and other light vehicles from gasoline to LPG in Bangkok and other major urban areas since 1980. For new vehicles there has also been a shift from gasoline to diesel engines. In addition, diesel is being adulterated by kerosene. These trends and their economic costs have been discussed in detail in Chapter VI.

9.42 The low retail price of LPG (propane and butane) relative to gasoline has motivated the transport sector to use about 50% of LPG consumption, requiring continued imports of LPG. The low retail price of diesel has resulted in a shortage of the fuel from domestic refineries and a very rapid increase in imports. One answer which has been widely proposed is a large expansion in secondary refinery facilities, which would be very costly. Another is to increase the use of gasoline through better pricing relationships. A third is to use compressed natural gas (CNG: methane) as a partial solution and as a possible way of using more of Thailand's natural gas in transport. As a replacement for gasoline or diesel fuel, CNG may offer a higher value use of gas than when gas is used as a substitute for fuel oil, coal or lignite in power generation.

83/ Taxes net of oil fund contributions or receipts.

Efficiency

9.43 Transport operators and users can modify their behavior so as to reduce the energy used per passenger or ton kilometer. One approach is to shift traffic to more efficient types of vehicles, i.e., passengers from cars to buses and freight from smaller to larger trucks. Perhaps the most striking example is that fuel use per passenger kilometer for cars is two or three times higher than fuel use for buses. Thus, whereas cars account for only 30% of the passenger-kilometer in buses, the total fuel consumption of cars is about 80% of that of buses. 84/ While this might suggest substantial potential for fuel conservation, it is, however, notoriously difficult to shift existing passenger traffic out of cars. More realistically, the emphasis should be on inhibiting future passengers from switching away from bus travel to private cars. For freight traffic some measures to encourage the use of large trucks have been proposed including the promotion of tractor-trailers over existing ten-wheel trucks (although Bangkok port roads are not currently suitable for such large vehicles) and developing freight centers to handle the larger loads needed by larger trucks. However, in Thailand the trucking industry is largely free from regulations that would inhibit the use of larger freight vehicles and the amount of fuel that could realistically be saved may be small.

9.44 The other approach is to reduce fuel use in each class of vehicle. A number of measures can have substantial fuel savings. 85/ Promoting energy awareness in driving habits such as vehicle tuning and enforcement of speed limits has been found to have energy savings of up to 20%. Introducing newer vehicles has significant fuel savings potential. New automobiles are about 30% more fuel efficient and trucks 10-20% more efficient than those of the early 1970s. Thus, measures to encourage the purchase of more efficient models, introduce technical inspection of old vehicles to check fuel efficiency and encourage scrapping of older vehicles, where feasible, could lead to greater fuel efficiency. The Ministry of Industry can play a useful role in encouraging manufacturers to introduce fuel efficient models.

Government Transport Conservation Policies

9.45 The Cabinet has approved the Ministry of Communication's Action Plan on Policy Measures for Energy Conservation in Road Transport, but no serious attempt has yet been made to implement it. The plan contains a large variety of proposals, and a first step would be to identify those

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84/ 1978 data.

85/ Intensifying fleet use by eliminating restrictions on common carriers in order to increase truck loads has increased fuel efficiencies 5% or more in some countries. However, the trucking industry in Thailand is already largely unrestricted.

measures which have the greatest, most cost-effective energy savings potential and to set priorities. The next step would be to define the critical components of priority measures, establish which agency will implement them and set implementation schedules, targets and procedures for monitoring implementation.

Traffic Congestion in Bangkok

9.46 The first, most important target for increasing fuel efficiency is to reduce traffic congestion in Bangkok. Bangkok's traffic conditions are among the worst in Asia and in recent years have been deteriorating steadily. Severe congestion is the principal symptom, with high fuel consumption resulting from very low traffic speeds. The economic benefits, including energy savings from reducing congestion, are considerable. For example, a 1982 study of the effect of the automatic traffic control system in a small part of Bangkok indicated substantial savings in car and bus journey time resulting in fuel savings of up to 20%. Also, the introduction of bus lanes increased speeds 10-20%, achieving comparable fuel savings without slowing car speeds. These measures were introduced at very low cost.

9.47 While low cost traffic engineering methods can be very effective when dealing with a given level of traffic demand, they would not be sufficient to deal with potential growth in Bangkok traffic by the year 2000. The population of the Bangkok metropolitan area is expected to increase from 4.7 million in 1980 to about 10 million by 2000. Urban developments are likely to increase employment and reduce residential accommodation in the central part of Bangkok, thus increasing the demand for commuting even more than population growth. In addition, the ownership of private vehicles in Bangkok, which had been growing by 9% per year during 1978-83, is likely to continue to grow rapidly and could triple the number of vehicles by 2000. Thus, long-term (and even medium-term) solutions require serious consideration of priorities for investment in transport facilities and their energy implications.

9.48 Urban transport problems worldwide have partially stemmed from the failure to consider energy implications in the course of attempting to balance demand and supply for transport facilities as cities have grown. The growth of city population and economic activity in many cities resulted in an even faster growth of transport demand in the inner part of cities. The cost of supplying transport services to these areas of high land values with construction difficulties rises disproportionately, eventually outstripping the government's ability to meet the costs. In particular, the feasibility of continuing to build roads in the central areas of Bangkok is questionable. Bangkok has grown much more rapidly than most other cities. Since its growth is occurring after the automobile and bus period, the case for rail mass transit is no longer a financially attractive solution.

9.49 Although Bangkok's traffic situation is by no means unique, it is in serious difficulty. The system is unable to cope with existing transport demands, let alone projected or latent growth. Travel speeds will continue to decline until certain trips are deferred or altogether cancelled as the cost of travel becomes too high. Indeed, this may already be occurring, since average car speeds are only 12 km/h and bus speeds 9 km/h during the heaviest travel hours in the central area of the city. Furthermore, congestion has reached such high levels that no "peak hours" are discernible as heavy traffic spreads throughout most of the working day. Further evidence of the deteriorating situation is the progressive spreading of acute congestion outward from the city as motor vehicle ownership increases.

9.50 Within Bangkok about 60% of person-trips on arterial streets are carried by buses and minibuses, which constitute only 6% of the stream of passenger vehicles. In contrast, private cars, which comprise over half of the traffic stream, carry only one-fourth of all person-trips. Public bus services are provided by BMTA, which carries about 3.8 million passengers daily. 86/ About 20% of public transit trips are provided by minibuses, both legally and illegally registered.

9.51 Transport problems in Bangkok are exacerbated by a highly fragmented institutional structure, duplication and conflict over functions, insufficient coordination among the agencies concerned, and, in some cases, lack of suitably trained staff. There are approximately 15 agencies concerned with providing urban transport infrastructure and services in Bangkok. Lack of clarity and cooperation in interagency roles is particularly acute in (a) traffic management and (b) multi-modal transportation policy/planning/programming.

Past Traffic Policies and Programs

9.52 To date, the approach to dealing with the urban traffic problem has been a combination of measures including:

(a) Construction. Road building, including the first stage expressway (toll road), flyovers and river bridges;

(b) Traffic Engineering. Automotive traffic control in a small part of Bangkok, introduction of bus lanes and one way system and reductions on parking on main roads; and

(c) Nationalization of private bus companies to form BMTA in 1976.

However, demand management measures such as the introduction of street parking charges and cordon pricing schemes have not been undertaken.

86/ BMTA is severely under-capitalized, does not have a suitable fare structure for profitable operation, and has lacked suitable management control over its operations.

9.53 In view of the severe urban transportation problems facing Bangkok, and with it the tremendous cost in terms of energy consumption, a number of investment proposals have been considered by public authorities. Among these are to:

(a) expand the toll road system;

(b) establish a 50-km elevated mass transit system;

(c) elevate approximately 13 km of the rail system to minimize disruption to the arterial road system;

(d) expand and modernize the BMTA bus fleet and maintenance facilities;

(e) complete the middle and outer ring road system; and

(f) make extensions to the primary and secondary arterial road system.

(g) develop a joint public/private vehicle maintenance program.

These investments would total about US$2.0 billion, or about US$400 per resident to Bangkok, a very high level relative to the government's fiscal resources. An investment study is addressing this problem of conflicting urban transportation investment priorities. 87/

9.54 In the meantime, however, the government gave approval for construction of the Second Stage Expressway in March 1985. A budget of Baht 12 billion was approved for Part I construction during 1985-91. Construction of the whole scheme will take many years and will relieve traffic in only part of the city. Moreover, experience elsewhere has shown that such a road will generate new volumes of traffic both on itself and on other roads and will create new congestion problems at access/exit points (as evidenced by the First Stage Expressway). Thus, although the expressway will provide partial relief for a few years, it will not provide a lasting solution by itself; therefore a comprehensive strategy is needed.

An Urban Transport Strategy to Save Energy

9.55 A comprehensive energy savings strategy is needed to include both the supply of transport facilities and traffic demand management measures. While there may be serious doubt about the priority of building more expressways, the projected growth of 250,000 people and 100,000 motor vehicles each year in the metropolitan area will certainly require some substantial investment.

87/ Metropolitan Bangkok Short-term Urban Transport Review Project, Halcrow Fox and Associates.

9.56 Traffic engineering measures such as traffic signalization, one way systems, median barriers, right turn and bus bays, intersection channelization, on-street parking removal, street signing and marking, and street lighting are increasing vehicle capacity and improving safety conditions. However, given the continued growth in Bangkok, these measures will only marginally delay or reduce congestion levels.

9.57 In addition to improving the effectiveness of the urban road network, there is a need to greatly improve public transport facilities. A critical element is to ensure a more convenient and comfortable bus service. Public transit must be made sufficiently efficient to attract a higher percentage of riders than now; every effort should be made to avoid shifts from bus to less fuel efficient and congestion-inducing private transport (mainly automobiles and motorcycles). BMTA, as a publicly owned entity, has major problems and represents a significant financial drain on the government. At a minimum, high priority should be given to stabilizing BMTA's financial condition by allowing for fare increases and to assist BMTA in improving its bus fleet. Given the failure to address the numerous problems facing BMTA up to now, there is a serious need to readdress the potential role of private transit operators in providing public transit services.

9.58 However, as long as buses have to travel on the same congested roads as other vehicles, they will offer little advantage over private cars. Indeed, allowing for the time waiting for a bus and to walk from the house to bus stop, even private transport in Bangkok is faster. The solution is to segregate buses from other traffic, and a low-cost way of doing this is to provide bus lanes. Contra-flow buses have proved very successful but are limited to streets with one way traffic. With-flow bus lanes require effective policing, and this has proved difficult over a long period. An alternative would be to have separate bus-ways in the middle of main roads with access at bus stops by overbridges, but this is costly. In addition, proposals have been made for light and heavy mass transit rail systems, but these are also very capital intensive, and to extend them throughout the city could take as long as 20 years. Very careful analysis would be needed before undertaking such large investments. Corridors (e.g., Taksin and Phanon Yothin) which carry passenger flows of up to 15,000 passengers per hour in one direction could well be candidates for using light rail instead of busways.

9.59 Investment in roads and public transport will have to be complemented with <u>management of traffic demand</u> to restrict the use of low occupancy vehicles. There can be no solution to the problem of congestion in Bangkok unless a majority of people traveling in the densely built-up area use public transport, especially during peak hours. In Tokyo, only about 8% of peak-hour travellers to the city center can be accommodated by private transport, in New York 6%, London 12%, and Paris 20%. The majority use public transport, even though they possess their own cars. The modal split is achieved by a combination of incentives through the provision of public transport and disincentives to the use of private (or low occupancy) vehicles.

9.60 In Bangkok, about 25% of travellers are currently carried by private vehicles; therefore, it will be critical for at least 75% of the growth in passenger journeys between now and 2000 to take place in public transport. This will require substantial disincentives to private cars, particularly in view of the projected tripling of vehicle ownership during this period. Thus, although it has proved difficult in the past to introduce adequate demand measures, there really is little option but to do so if Bangkok is to continue to meet its transport demand and continue its dynamic economic growth. The alternative is a growing traffic paralysis with serious consequences for the economy.

9.61 In the final analysis, the only answer may be to enforce traffic management measures which discourage the use of low-occupancy automobiles such as removing on-street parking, more aggressive enforcement of parking regulations, increased charges for parking spaces, closing central area streets to private traffic and, in the longer term, more land-use controls. It is at best a partial solution. The most effective, quick action might be a cordon scheme to charge low occupancy vehicles for entering or using road space in the center of Bangkok. Given the political difficulties of introducing this, a public education program to build support for such rigorous measures needs to be undertaken as soon as possible.

X. SIXTH PLAN INVESTMENTS PRIORITIES

10.1 The demand forecasts outlined in this report and the supply programs suggested in the various chapters imply a substantial level of investment will be needed to develop, produce and distribute energy in Thailand over the coming years. With the exception of oil company activities in oil and gas, the Thai public energy enterprises have been responsible for the bulk of investments in the sector. A primary concern of the government is to determine how the level and composition of public energy investments for the Sixth Plan Period can be controlled and supplemented by private sector support. Responsibility for energy investments recently has been shared among several agencies, namely, PTT, EGAT, MEA PEA, BCP and DED, as well as a number of joint companies such as TORC. The Sixth Plan represents a major transition in that private sector investment is being strongly encouraged. More effective incentives will be needed to expand resource exploration and development while improving the regulatory climate. The current energy strategy emphasizes minimizing public sector investment and operating cost levels particularly by maximizing the use of gas together with less capital-intensive technologies. In practice this has proven especially difficult because of uncertainties about the timing and amount of gas which might be available on the one hand, and the amount of alternative resources that might be developed on the other. Uncertainties regarding the price and availability of imported fuels also have complicated decision making.

10.2 The severe constraints on financing, both domestically and worldwide, have forced the government to reevaluate the role of investment in the public sector. A number of options have been discussed for redefining and focusing the role of PTT in both upstream and downstream activities in oil and gas. The role of the public sector in future refinery investments should be reassessed. Another suggestion has been to promote lignite activities beyond electric power and to obtain contributions of private equity for EGAT. Joint ventures are believed to be a promising means of expanding private sector participation in oil and gas, and in lignite. It is difficult at this stage to determine how far the privatization of investment in energy will go quantitatively, but this process is likely to be a determining factor in the success of the government's future energy strategy.

10.3 This chapter presents the current public sector investment proposals of the individual energy agencies which will go into the formulation of the Sixth Plan. For convenience these proposals have been assembled in the format of a program. Many of them are under review within the government, and a number of them have not yet even been considered by NESDB as part of its budgetary review process. They represent a list of projects from which responsible public sector agencies might eventually formulate their programs based on national priorities and resource availabilities. The energy program which needs to be assembled from this collection of public sector projects is at all stages of identification and preparation and still needs to be combined with a detailed review of what is possible in the private sector. The public sector projects and programs being discussed amount to US$5-6 billion for the period 1987-91.

10.4 These large levels of public sector investment in energy are a continuation of the experience of the last five years. The increased cost of imported energy supplies and the discovery of new domestic gas resources has led to a rapid expansion in capital spending for the whole energy sector. This expansion in investment has been particularly rapid since 1980, with the result that energy is now the single most important sector for public spending, having increased its share of total public expenditure from 12.5% in 1977 to 22.1% by 1981 and a somewhat higher share since then. For the Fifth Plan Period, NESDB projected that the energy sector will have contributed about 26% of total governmental spending, up from an average 18% during the Fourth Plan Period. Energy sector capital spending weighs even more heavily in total public investment; having reached a peak share of 31.9% in 1981, up from 13.5% in 1970 and 13.7% in 1977, it is anticipated to average 24% during the Fifth Plan Period. Energy sector enterprises in recent years have accounted for more than 50% of state enterprise investment and are expected to remain at about the same level during the Fifth Plan Period. The power sector agencies have contributed the bulk of these investments: during the Fourth and Fifth Plan periods EGAT accounted for about 60% of total public investment in the energy sector, MEA for 7-8%, and PEA for 15%.

10.5 In the past, much of this public sector capital investment, particularly in the power sector, has been heavily financed by foreign borrowing. In fact, foreign borrowing has been a key factor in the government strategy in recent years to meet the growing energy demands of the Thai economy. As much as 65% of the financing required for the sector's investments has been obtained from external grants and loans. EGAT's average level of borrowing, both foreign and domestic, has run about 70% over the period 1979-84. The government's current view appears to be that such a high level of foreign borrowing should no longer be permitted and that a higher share of capital should be obtained through a combination of private equity and a higher internal generation of funds from each individual enterprise.

10.6 A large part of PTT's investment was equally financed by foreign borrowing. PTT and its predecessor's share in public investment was insignificant until 1979 but it increased substantially when natural gas reached about 18% of the capital expenditure of energy sector enterprises during 1977-81. Since then, its investments have declined and its share in public investment in energy is expected to be close to 15% during the Fifth Plan Period. PTT's investment level is expected to decline further during the latter half of the 1980s to about 11% and even further in the 1990s. This base case forecast, however, assumes a limited role for PTT in oil and gas development and processing (with a much greater role by the private sector). Otherwise, its investments could be substantially higher and its share in the total could be 20% or even higher during the 1990s.

Table 10.1: CAPITAL EXPENDITURES IN THE ENERGY SECTOR AS A PERCENTAGE OF TOTAL INVESTMENT

	FY 1982	FY 1983	FY 1984	5th Plan 1982-86	6th Plan 1987-91
Share in total gross investment	10.1	8.5	7.9	8.2	n.a
Share in total public investment	27.2	26.1	24.0	20.0	n.a.
Share in total state enterprise investment	57.8	57.6	49.8	50.0	n.a.
Share in capital expenditure of energy sector agencies	100.0	100.0	100.0	100.0	100.0
EGAT	76.2	74.7	54.8	65.8	74.6
MEA	4.0	4.2	4.8	4.2	8.7
PEA	16.4	12.1	15.6	15.5	5.4
PTT	3.4	9.0	24.8	14.5	11.3

After the expansion in power and gas development of the late 1970s and early 1980s when public sector investment in energy reached its peak, the share of energy enterprises in public investment has been declining from about 27% in 1982 to about 23% in 1984, and it is anticipated to average 24% during the Fifth Plan Period. The share of public energy investment in total gross investment also has declined from about 10% in 1982 to about 8% in 1984, with an average of about 8% over the Fifth Plan Period. Both shares are anticipated to remain roughly constant or decline slightly through the 1980s if the government's private sector strategy proves successful.

Electricity Supply Program

10.7 Excluding the oil and gas program, energy investments have been largely synonymous with the program for public electricity supply. The preliminary program of electricity investments for the period 1987-91 amounts to B112,000 million (US$4,012 million). This compares to the latest estimate of expenditures of B81,670 (US$3,267 million) for the Fifth Plan period. After adjusting for inflation, the Sixth Plan period expenditures would be somewhat lower than those of the Fifth Plan period.

Table 10.2: PROJECTED ELECTRICITY SECTOR INVESTMENT, 1987-1991

	US$ million
Power Generation	
Hydro	369
Oil	62
Lignite	870
Gas CC	407
Dual-fired	65
Triple-fired	1,004
	2,777
Transmission and Distribution	
Transmission	495
MEA	465
PEA	275
	1,235
TOTAL	4,012

Source: Based on July 15, 1985 Summary of ESAT Investment Plan, FORM ES-1.

10.8 The two largest projects in the electricity sector proposed for the Sixth Plan are Mae Moh lignite-fired generating units totalling 900 MW, and the Bang Pakong triple-fired generating units totalling 1,200 MW, with combined expenditures of about $965 million during this period. Furthermore, a start is being made on the Ao Phai triple-fired units (600 MW each) which will require expenditures of about $485 million in this period. The issues raised in Chapter 5 suggest a shift to less capital intensive options may have to be considered in the second half of the Sixth Plan period for implementation after the completion of the Mae Moh lignite plants 9 and 10 (para. 5.68). The analysis in this report suggests that this may be the appropriate time to start with a plant designed solely on the basis of imported coal, e.g., at Ao Phai, on the assumption that additional gas might not be forthcoming. Both the Bang Pakong and Ao Phai Thermal expansions proposed by EGAT would have to burn either oil or gas and, in any case, later on would be fueled with imported coal. Designing for multi-fired capacity appears to be an expensive approach to diversifying the supply of fuel. These points should be reviewed again carefully before a final decision is reached.

10.9 The rural electrification program which had been so greatly expanded between 1977 and 1983, 88/ is approaching relative saturation now that 50% of Thai villages have electricity. Only a modest expansion therefore is projected to take place during the Sixth Plan period. In

88/ Over this period the number of villages electrified increased from 1,570 to 4,674.

fact, PEA's program, which was about B15,800 million for the 1982-86 period, is now projected at only B7,500 million for 1987-91.

Lignite Mining, Exploration and Development

10.10 The EGAT lignite mining program under way includes an expansion of production to 5 million tons by the end of 1987 and an increase to 10.5 million tons during 1988-1991 to fuel Mae Moh units 8-10 which are to be installed during the 6th Five Year Plan period. EGAT estimates that their expenditures for this program would amount to nearly B16,200 million (US$578 million). This would incorporate only $2 million for lignite exploration and development, an amount which the assessment team considers too small.

Rural Energy

10.11 The essence of the rural energy program will be to improve the supply and efficiency of using traditional cooking fuels while at the same time more effectively providing rural consumers with access to commercial fuels other than just electricity at competitive and economic prices. Programs have been outlined to supply some 20 million cu.m. of wood equivalent by the year 2000 through afforestation, conservation and biomass substitution. This would still leave a net gap of about 16 million cu.m. to be met by either overcutting or increasing the use of modern fuels. Afforestation efforts envisaged in this program would involve: (a) establishing 450,000 ha of private fuelwood plantations; (b) treeplanting around homesteads by 2 million rural households; (c) converting 75,000 ha of state-owned forest land into intensively-managed government plantations; and (d) increasing the proportion of total forest area that will be economically accessible for fuelwood collection by 2001, through, for example, building roads into more remote forested areas to permit managed commercial exploitation of fuelwood to supply charcoal.

10.12 Complementary actions on the demand side would involve improving the efficiency of charcoal production through the use of improved kilns with 25% higher efficiencies than those presently in use. Additional savings would be achieved by promoting wider use of improved household stoves. It is proposed that in 15 years about 10% of households would use improved stoves. To achieve this a program deploying about 800,000 units of improved charcoal stoves and about 600,000 units of improved firewood stoves would be required.

10.13 The cost of this program for 1986-2001 has been estimated by the World Bank's Rural Energy Assessment Report at $315.5 million, $240 million of which would ultimately be for private sector plantations. Roughly $100 million would be scheduled for the 6th Five Year Plan period, a significant share of which would probably be in the public sector.

10.14 The program would be guided by RFD and, although it would require significant funds in the early years, it would rely heavily on private sector participation to minimize government investment and actual planting work. About 85% of the total target area is planned to be planted by the private sector; two-thirds of this area would be small farmer's lots and one-third industrial-scale plantations.

Energy Efficiency Improvement

10.15 Energy efficiency improvement is currently being assessed by various government agencies in Thailand and a program to promote conservation needs to be formulated. Three energy consuming sectors stand out as having immediate potential for increased efficiency of fuel use. Besides households, where the efficiency of stoves and charcoal making kilns has already been discussed, the two major users of commercial fuels -- manufacturing and transport -- demonstrate substantial opportunity for savings. Energy efficiency investments in industry have taken the form of fuel switching by the cement industry and low cost operational 'housekeeping' improvements in some 50 industries. Investment in retrofitting existing plants and installing new energy efficiency equipment has been limited, although the potential is obviously significant. Studies sponsored by JICA and ADB revealed potential energy savings from more efficient use of petroleum products to be about 15-20%, while those for electricity are estimated to average between 3-6%. These studies have roughly estimated that an effective program would involve financial requirements of about $690 million, plus another US$55 million for natural gas substitution for fuel oil. The funds would mainly be required for retrofitting existing equipment (US$185 million) and purchasing new energy efficient equipment (US$505 million); the largest part of these expenditures would have to be undertaken by the private sector. An Energy Conservation Center is being formed by NEA to review and possibly help implement these programs and to make policy recommendations with regard to governmental incentives. This report has incorporated a nominal figure of $25 million as the public sector's expenditures for this program.

PTT's Oil and Gas Program

10.16 PTT's investment program is devoted mostly to the development of natural gas and, to a lesser extent, oil. Projects under construction or recently completed include a gas separation plant, LPG marketing installations, and a tie-in pipeline to supply gas from the Second Union Contract. The timing and magnitude of future projects are subject to substantial change resulting from the uncertainty in gas supplies.

Nevertheless, feasibility studies and other preparatory work need not wait until supply estimates and contracts are entirely confirmed.

10.17 The investment program (1982-86) that PTT presented to NESDB in late 1982 has been revised downward, and investment outlays for most projects have been postponed for one or two years with respect to previous plans (and could be delayed even more). Based in part on input from PTT, a recent Bank mission made preliminary estimates of PTT's investment program for the period 1987-1991 totalling some $500 million (excluding a contribution to TORC). Additional public sector investments in joint ventures, Banchak and TORC refineries, bring the total to about $900 million. This still represents a substantially scaled-down program from the one submitted to NESDB at the end of 1982, which totalled $2.8 billion for the ten-year period 1982-1991. Based on the downward revision of gas production/consumption prospects, some projects are expected to be shifted from the Fifth to the Sixth Plan period, and certain projects are no longer included in the current investment estimate. 89/ The PTT program includes the construction of a pipeline (with offshore compressor) from Texas Pacific to the Union Oil Erawan field, and a second LPG plant with 150 MMCFD of capacity.

Table 10.3: PUBLIC SECTOR OIL AND GAS PROJECTED INVESTMENTS, 1987-91 (in million US$)

PTT Projects	
LPG market and distribution	5
Pipeline from ESSO to Konkaen	20
Pipeline from Texas Pacific to Erawan (with offshore compressor)	303
Gas distribution pipeline (industrial markets)	42
Petroleum exploration/development (Block 5/27)	15
Petroleum products marketing	58
Second Gas Separation Plant (150 MMCFD)	60
	503
Joint Venture Projects (proposed)	
Block S-1 field exploration development (25%)	89
Ethylene Cracking plant (49%)	21
Fertilizer Plant (22%)	9
Khorat Field exploration development (20%)	50
Bangchak Petroleum Company	45
TORC refinery expansion	189
TOTAL	403
	906

Source: PTT and World Bank Oil and Gas Mission estimates. See Table 10.6 for details.

89/ Details of the earlier investment program have been presented in World Bank Report No. 4366-TH, August 31, 1983.

10.18 The Texas Pacific (TP) pipeline is expected to be postponed until the end of this decade to coincide with the delayed commencement of TP's production. In relation to the Erawan/Southern Thailand pipeline, investment for an additional gas-fired power plant located at the Eastern Seaboard is likely to be the least cost solution to meeting the needs of the South, and a gas-fired plant in Khanom is no longer in EGAT's investment program. Consequently, a pipeline from Texas Pacific or Union-Erawan to Khanom in Southern Thailand may not be justified during the 1980s and is not included in Table 10.3.

10.19 Except for the offshore compressor and investment related to Esso-Khorat field development, PTT's core investment program for gas development is expected to be essentially the same under the various scenarios of gas supply presently considered. In projecting the gas production profile, the investment implications have been taken into account. Under the low gas supply scenario, to avoid the investment for an offshore compressor which would only be required for a few years, gas production from the Gulf is projected to be limited to 500 MMCFD, which is the free-flow capacity of the submarine trunk line. Similarly, under the medium and high gas supply scenario, gas production from the Gulf is projected to be limited to 700 MMCFD, which is the design capacity of the existing submarine trunk line; this would minimize incremental gas transmission investment, which would be idle for most of the time.

10.20 In addition to the aforementioned pipeline from TP, other future gas development investments are expected to include a second gas separation plant, infrastructure relating to the Esso gas discovery, joint venture projects in an ethylene cracking plant and a fertilizer plant. As the margin between domestic demand for LPG and the local supply from the first LPG plant and refineries is projected to grow, a second LPG plant is being planned to replace the growing imports of LPG. However, the optimal timing and sizing of the second LPG plant are dependent on the availability of Gulf gas since the gas from the Esso-Khorat field is high in methane and unsuitable for LPG recovery. Based on the present estimate of Gulf gas production, it would reach a peak plateau of some 500 to 700 MMCFD during the next decade, thereafter declining rapidly to well below 350 MMCFD, which is the design capacity of the first gas separation plant. In effect, the maximum Gulf gas available for the second gas separation plant could vary between 150 to 350 MMCFD, for a period of about 10 years. Because of the uncertainty of gas supply at this stage, PTT would need to weigh the incremental benefits of a second gas plant sized at more than 150 MMCFD capacity against the incremental cost and risk of oversizing in the event of a low gas supply scenario. Preliminary analysis indicates that a second gas separation plant at 150 MMCFD would be economic given the present expectations regarding gas supplies from the Gulf. Because of the need to ensure gas availability for the economic life of the LPG plant, PTT will need to await the firm conclusion of the next offshore gas supply contract before awarding a contract for this LPG plant. To minimize the risk of oversizing, the Bank's oil and gas mission believes that PTT's program should include a second gas separation plant at 150 MMCFD instead of the 350 MMCFD initially considered by PTT.

10.21 Regarding investment relating to the Esso gas discovery, EGAT has planned to build a power plant (600MW) at the Esso field (Nam Phong) which could utilize an average of about 100 MMCFD of gas. However, the location of the proposed plant at the field should be carefully evaluated against the alternative of locating it at the nearby city of Kon Kaen, which is the regional center for electricity distribution in northeastern Thailand. Major power transmission lines run near Nam Phong and Kon Kaen such that 600 MW of power could be transmitted at fairly low cost. Gas transmission through a short pipeline (40 km) to Kon Kaen would allow for the possibility of diversified gas utilization which, in addition to power generation, could also cover other potential industrial uses. The reserves at Nam Phong are uncertain and may be substantially more than projected by DMR; there may be discoveries elsewhere in Western Khorat which could justify a sustained gas supply of perhaps 350-400 MMCFD in the early 1990s. These higher levels of gas supply may eventually require the construction of a $160 million pipeline from Khorat to the major power and gas consumption centers in Greater Bangkok and the Eastern Seaboard. On the basis of these higher production levels, PTT would also need to invest an additional $100 million as its share of the field investment cost. This field investment would in large part be self-financed out of production. As this higher level of gas supply has been excluded from the base case, the investment has been omitted from the core PTT Investment Program.

10.22 In contrast to non-associated gas production, the prospects for domestic oil and associated gas production have improved since the preparation of the Fifth Plan. PTT has almost finalized plans for its joint venture with Shell in Sirikit, and most of its $89 million investment requirements will be generated directly from earnings of the project. If discoveries in the Sirikit area are high enough to grant the development of a second Sirikit, PTT investment could increase, perhaps by a further $300 million during 1992-2000 but this too would be largely self-financed. In light of the high liquids content of the gas in the Shell Block S-1, PTT is investigating the feasibility of an LPG plant at the Sirikit oil field. The assessment team's estimate of PTT's program currently excludes an LPG plant of 30 MMCFD capacity ($20 million) to recover LPG before supplying the dry gas to EGAT for power generation as this plant will most probably be covered by the joint venture. The availability of gas has yet to be agreed with DMR.

10.23 PTT's investment program has been and is expected to continue to be dominated by infrastructure for gas transmission. However, as noted above, PTT's role has been expanding to include direct participation in oil/gas exploration and production. The current estimate for this activity includes investment for minority shares in joint venture operations at Shell Block S-1 (25%) and Esso-Khorat field (20%). In addition, while it is too uncertain at this stage to be included in PTT's investment estimate, it is possible that it would participate in the development of the TP field, perhaps up to 25%. Further, PTT is currently undertaking a seismic survey in Block 5/27 with the assistance of PetroCanada. Again, the timing and magnitude of PTT's future investments in E&P activities is uncertain and would vary considerably under different oil/gas reserve scenarios. Realistically, the public sector's core investment level in oil and gas has been indicated at a maximum of around $900 million. However, if the kind of success implied in the high gas supply scenario materializes and/or there is a significantly higher discovery rate at Sirikit, larger public sector investments would be required -- perhaps up to an additional $500 million.

Private Sector Investment in Oil and Gas

10.24 For petroleum exploration and development activities, the government strategy has been to rely mainly on international oil companies (IOC's). To date, private sector investment has amounted to more than $1 billion. The World Bank has prepared estimates of additional IOC investment based on varying oil/gas supply scenarios for the next two decades, as follows:

Table 10.4: REQUIRED PRIVATE SECTOR INVESTMENT IN OIL AND GAS
(In $ billion, 1986-2000)

Oil/Gas Supply Scenarios	Exploration	Development	Total
Low supply	0.1	2.0	2.1
Medium supply	0.4	3.0	3.4
High supply	0.9	5.0	5.9

These scenarios are based on estimates of geological prospects using plausible assumptions about the timing of exploration, development and contracting of supplies.

10.25 As indicated in Table 10.4, additional private sector investment amounting to some $2 billion is expected to be required under a low oil/gas supply scenario. Substantially more investment over a longer period of time is expected to be required for achieving higher levels of oil/gas supply, amounting to some $3.5 billion and $6 billion under the respective scenarios of medium and high oil/gas supply. Clearly, the timing and magnitude of the investment are closely related to oil/gas reserves and government policy towards IOC's participation which, as discussed above, are the major issues in the petroleum sector. While the estimates of future investments are subject to considerable uncertainty at this stage, it is nevertheless quite clear that adequate incentives would be needed to encourage IOC's to invest the substantial sums required for the efficient development of indigenous oil/gas reserves.

10.26 If proper incentives were established, the Bank group estimates that the private sector could provide about $1.3 billion during the years 1987-91 (medium case scenario), of which about 20% would be for exploration. A more optimistic outlook for output might involve similar expenditures totalling $1.4 billion during the same period but would rise to a much higher investment expenditure over the decade of the 1990s and even after 2000 (i.e., $5.9 billion in the high scenario compared with $3.4 billion in the medium scenario). Of course, there would be a close interrelationship between the level of expenditures by the private sector and what investment might be called upon for infrastructure. As early as the 6th Five Year Plan, investment requirements could rise quite substantially if both a high growth scenario and a successful private sector oil and gas program are assumed to materialize. Preliminary estimates indicate a program of at least $2-3 billion more than currently envisaged would be required under these circumstances.

Table 10.5: PROJECTED PUBLIC SECTOR ENERGY INVESTMENT, 1987-1991
(US$ million)

	Currently Reviewed Projects	Projects Based on High Growth Scenario a/
Electric Power		
Hydro electric projects	369	370
Thermal power plants	2,406	3,900
EGAT transmissions	495	840
MEA	465	790
PEA	275	400
	4,010	6,300
Oil and Gas Projects		
Pipelines	365	525
Exploration and development	154	500
Marketing	63	59
Gas separation	60	60
Refineries	234	261
Miscellaneous	30	75
	906	1,480
Lignite Mining	578	700
Rural Energy Programs	100	100
Energy Efficiency Program	25	25
Total	$5,620	$8,605

a/ Some of these projects could be in the private sector.

10.27 A significant part of the increase would be the result of a need for an additional 1,500 MW due to higher demand for electricity. However, more gas transmission pipeline capacity and significantly greater activity in the exploration and development of oil, gas and lignite would also be needed. If increased programs in infrastructure related to high growth are justified in the context of a more successful private sector effort and higher growth prospects there should be a potential for increasing private equity participation.

Table 10.6: PUBLIC SECTOR ENERGY INVESTMENTS, 1987-1991
(US$ million) a/

	Total Project Cost	Approximate Program 1987-91
Power Projects		
Hydro generation		
Chiew Larn 1-3	182	44
Srinagarind 5	33	36
Nam Chon 1, 2	350	246
Kraeng Krung 1, 2	87	43
Hydro Sub-total	652	369
Thermal generation		
Second Power Plant Barge	82	62
Mae Moh 8	380	293
Mae Moh 9	380	286
Nam Phong CC	221	221
Mae Moh 10	290	290
Bang Pakong 3	654	553
Nam Phong 2	186	186
Bang Pakong 4	512	262
Krabi 2	236	65
Ao Phai 1	922	189
Ao Phai 2	584	--
Thermal Sub-total	4,448	2,407
Power Generation	5,099	2,736
Transmission	495	495
MEA Distribution	465	465
PEA	275	275
Total Power	6,334	4,011
Lignite Mining - Exploration & Development	600	578
PTT Oil and Gas		
Ongoing Projects		
Gas separation plant No. 1	--	--
LPG market and distribution	100	5
Pipeline from Union (Block 10)	53	--
Proposed Projects		
Pipeline from ESSO to Kon Kaen	20	20
Pipeline from Texas Pacific to Erawan (with offshore compressor)	303	303
Gas distribution pipeline (Poochaosming Pral & Bang Plee industrial markets)	42	42
Petroleum exploration/development (Block 5/27)	20	15
Petroleum Products Marketing	116	58
LPG Plant (30 MMCFD) at Sirikit		
Second Gas Separation Plant (150 MMCFD)	60	60
Joint Venture Projects (proposed) d/		
Block S-1 field exploration development (25%)	202	89
Ethylene Cracking plant (49%)	44	21
Fertilizer Plant (22%)	19	9
Khorat field exploration development (20%)	97	50
Bangchak Petroleum Company	45	45
TORC refinery expansion	189	189
Total PTT Oil and Gas	1,121	906
Rural Energy Program	316	100
Energy Efficiency Program b/	690	225
TOTAL PUBLIC SECTOR	9,061	5,620

a/ All prices are expressed in current dollars. All EGAT figures include interest during construction.

b/ Mostly in the private sector. For purposes of allocation $25 million assumed nominally in public sector.

Source: Based on preliminary estimates available in March-April 1985. EGAT project estimates as of July 15, 1985.

Table 10.7: PTT INVESTMENT PROGRAM (1985-1991) a/
(In Million US$ Current Prices)

	1985	1986	1987	1988	1989	1990	1991
Ongoing Projects							
Gas separation plant	64	--	--	--	--	--	--
LPG market and distribution	40	35	5	--	--	--	--
Pipeline from Union (Block 10)	6	7	--	--	--	--	--
Subtotal	110	42	5	0	0	0	0
Proposed Projects							
Pipeline from ESSO to Khon Kaen	--	--	4	10	6	--	--
Pipeline from Texas Pacific to Erawan (with offshore compressor)	--	--	--	--	56	150	97
Gas distribution pipeline (Poochaosming Prai & Bang plee - industrial markets)	--	--	12	25	5	--	--
Petroleum exploration/development (Block 5/27)	--	--	5	--	10	--	--
Petroleum products marketing	8	10	13	15	10	10	10
Second gas separation plant (150 MMCFD)	--	--	12	30	18	--	--
Joint Venture Projects (proposed)							
Block S-1 field exploration & development (25%)	69	44	34	34	21	--	--
Ethylene cracking plant (49%)	2	21	21	--	--	--	--
Fertilizer plant (22%)	4	6	3	6	--	--	--
Khorat field exploration development (20%)	--	--	--	13	13	12	12
Bangchak Petroleum Company	36	9	--	--	--	--	--
TORC refinery expansion a/	--	--	--	--	--	--	--
TOTAL	229	132	109	133	139	172	119

a/ Excludes interest during construction.

b/ Assumed to be project financed and PTT's contribution to equity expected to be negligible. According to current plans, the TORC expansion would be built during four years (1986-1989) at a cost of about $700 million. PTT might assume 20% of commercial credits. Accordingly, its financial responsibility would amount to about $140 million as follows: (A recent estimate of TORC was $189 million.)

1986	1987	1988	1989	Total
28	42	42	28	140

Source: Based on World Bank Oil and Gas Mission estimates prepared in April 1985.

Table 10.6: SUMMARY OF EGAT INVESTMENT PLAN a/, 1987-1991

Description	1987 US$	1987 M. Baht Total	1988 US$	1988 M. Baht Total	1989 US$	1989 M. Baht Total	1990 US$	1990 M. Baht Total	1991 US$	1991 M. Baht Total	1987-91 US$	1987-91 M. Baht Total
Hydroelectric Projects												
Chiew Larn Project Unit 1, 2, 3 (240 MW)	44.2	1,238.5	—	—	—	—	—	—	—	—	44.2	1,238.5
Khlong Yan Multipurpose Project (Kaeng Krung Dam 80 MW)		—	—	—	6.1	171.6	16.1	451.7	20.6	577.4	42.9	1,200.7
Mae Ngat Unit 1, 2 (9 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Nam Chon Unit 1-4 (580 MW)	7.7	214.4	31.[illegible]	877.0	94.1	1,513.4	73.7	2,063.5	79.1	2,716.1	245.9	6,884.2
Sai Buri Project (46 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Srinagarind Second Stage Unit 5 (180 MW)	4.6	121.9	20.8	[illegible]	10.6	797.4	—	—	—	—	36.0	1,009.1
Protection of Ubol Ratana Dam	—	—	—	—	—	—	—	—	—	—	—	—
SUB TOTAL Hydroelectric Projects	56.5	1,382.6	52.1	1,458.8	70.8	1,982.4	80.8	2,515.0	99.7	2,793.5	360.0	10,332.3
Thermal Power Plant Projects												
Ao Phai Thermal Unit 1 (600 MW)	—	—	—	—	—	—	28.9	808.1	160.1	4,481.9	188.9	5,290.0
Ao Phai Thermal Unit 2 (600 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Ao Phai Thermal Unit 3 (600 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Ao Phai Thermal Unit 4 (600 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Bang Pakong Thermal Unit 3 (600 MW)	15.3	427.0	108.8	3,046.0	146.5	4,101.8	127.6	3,574.2	154.6	4,328.7	552.8	15,477.7
Bang Pakong Thermal Unit 4 (600 MW)	—	—	—	—	22.5	629.0	76.0	2,127.0	163.5	4,579.2	262.0	7,335.2
Coal-Fired Unit 1 (600 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Coal-Fired Unit 2 (600 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Coal-Fired Unit 3 (600 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Krabi Thermal (2) Unit 1 (150 MW)	—	—	—	—	—	—	7.5	211.4	57.0	1,596.6	64.6	1,808.0
Krabi Thermal (2) Unit 2 (150 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Krabi Thermal (2) Unit 3 (150 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Mae Moh Thermal Unit 7 (150 MW)	—	—	—	—	—	—	—	—	—	—	—	—
Mae Moh Thermal Unit 8 (300 MW)	89.8	2,515.8	108.8	3,047.7	94.6	2,649.2	—	—	—	—	293.3	8,212.7
Mae Moh Thermal Unit 9 (300 MW)	19.3	540.0	71.7	2,006.4	101.1	2,831.9	94.2	2,638.6	—	—	286.3	8,016.9
Mae Moh Thermal Unit 10 (300 MW)	19.3	540.0	71.5	2,001.7	93.3	2,612.7	86.3	2,415.0	19.3	541.5	289.7	8,110.9
Nam Phong Combined Cycle #1 (300 MW)	4.5	126.1	37.9	1,061.4	125.0	3,500.5	40.8	1,143.5	12.4	346.3	220.6	6,177.6
Nam Phong Combined Cycle #2 (300 MW)	—	—	1.9	53.6	3.9	109.1	41.1	1,151.9	138.9	3,890.4	185.9	5,205.0
Power Plant Barge	50.3	1,408.9	11.9	334.3	—	—	—	—	—	—	62.3	1,743.2
SUB TOTAL Thermal Power Projects	198.5	5,557.8	412.5	11,551.1	586.9	16,434.2	502.5	14,069.5	705.0	19,764.6	2,405.3	67,377.2
SUB TOTAL Transmission Projects	56.3	1,575.7	88.9	2,488.8	131.0	3,669.4	99.5	2,787.1	119.4	3,343.2	495.2	13,864.2
Mining Projects												
Mae Moh Mine Stage 4 (For Mae Moh #5, 6 & 7)	64.3	1,799.6	36.8	1,029.4	—	—	—	—	—	—	101.0	2,829.0
Mae Moh Mine Stage 5 (For Mae Moh #8, 9)	12.6	352.7	70.0	1,959.2	115.0	3,221.0	90.9	2,544.4	46.5	1,300.8	334.9	9,378.1
Mae Moh Mine Stage 6 (For Mae Moh #10)	—	—	—	—	5.8	163.3	36.0	1,007.2	100.4	2,811.0	142.2	3,981.5
SUB TOTAL Lignite Mining Projects	76.9	2,152.3	106.7	2,988.6	120.8	3,384.3	126.9	3,551.6	146.9	4,111.8	578.1	16,188.6
Miscellaneous Projects												
Miscellaneous Plant Addition	21.4	600.0	21.4	600.0	21.4	600.0	21.4	600.0	21.4	600.0	107.1	3,000.0
System Expansion	7.1	200.0	7.1	200.0	7.1	200.0	7.1	200.0	7.1	200.0	35.7	1,000.0
SUB TOTAL Misc. Projects	28.5	800.0	28.5	800.0	28.5	800.0	28.5	800.0	28.5	800.0	142.8	4,000.0
GRAND TOTAL	416.7	11,668.4	688.8	19,287.3	938.2	26,270.3	847.3	23,723.2	1,100.3	30,813.1	3,991.3	111,762.3

a/ Proposed plan — EGAT System Planning Department — July 15, 1985. Project estimates include physical contingencies, price escalation, taxes and duties, and interest during construction.

ENERGY BALANCE IN ORIGINAL UNITS, 1983

	Primary Energy								Secondary Energy									
	Traditional Fuel			Non-Traditional Fuel							Petroleum Products							
	Fuelwood	Bagasse	Residue	Hydro	Crude Oil	Gas	Lignite	Coal	Charcoal	Electricity	LPG	Gasoline	Jet Fuel	Kerosene	Diesel	Fuel oil	Bitumen
Gross Supply	30723,4	5524,8	1610,3	3659,8	9503,4	56731,8	1997,0	129,2	-	675,6	602,5	-	88,8	117,8	1251,3	1068,6	-
Production	30723,4	5524,8	1610,3	3659,8	847,5	56731,8	1997,0	-	-	-	-	-	-	-	-	-	-
Imports	-	-	-	-	8655,9	-	-	129,2	-	675,6	602,5	-	88,8	117,8	1251,3	1068,6	-
Conversion:																	
Petroleum Refining	-	-	-	-	(9125,3)	-	-	-	-	-	228,0	2062,8	1069,8	423,3	3062,3	2160,8	128,3
Charcoal Production	(24284,0)	-	-	-	-	-	-	-	3642,6	-	-	-	-	-	-	-	-
Elec. Power Generation	-	-	-	(3659,8)	-	(54452,4)	(1573,4)	-	-	18856,6	-	-	-	-	(40,8)	(1832,1)	-
Conversion Losses	-	-	-	-	(378,1)	-	-	-	-	-	-	-	-	-	-	-	-
Power T & D Losses	-	-	-	-	-	-	-	-	-	(2625,9)	-	-	-	-	-	-	-
Non-energy use	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(128,3)
Statistical Difference	-	-	-	-	-	955,2	-	-	-	25,1	-	3,9	6,1	3,1	98,7	135,1	-
Final Consumption	6439,4	5524,8	1610,3	-	-	1324,2	423,6	129,2	3642,6	16931,4	830,7	2066,7	1142,5	538,0	4361,3	1532,4	-
Agriculture	-	-	-	-	-	-	-	-	-	115,7	-	57,6	-	-	419,4	-	-
Fishery	-	-	-	-	-	-	-	-	-	-	12,2	-	-	-	732,9	-	-
Industry	485,6	5524,8	468,9	-	-	1324,3	423,6	129,2	88,5	8013,5	113,1	15,2	-	31,8	401,4	1270,8	-
Transport	-	-	-	-	-	-	-	-	-	101,6	372,5	1891,6	1142,5	184,9	2784,1	182,2	-
Residential	5953,8	-	1141,4	-	-	-	-	-	3554,1	4187,8	247,9	-	-	321,3	-	-	-
Commercial/Govt.	-	-	-	-	-	-	-	-	-	4512,8	85,0	102,3	-	-	23,7	79,4	-

Units: Fuelwood, Bagasse, Agr. Residues, Lignite, Coal, Charcoal — Thousand tons

Hydro and Electricity — GWh

Crude Oil and Petroleum Products — Million liters

Natural Gas — Million cubic meters (mmscf)

Note: See the attached documentation for sources and explanation.
Parentheses indicate outflows.

ENERGY BALANCE, 1983
('000 TOE)

	Primary Energy								Secondary Energy										
	Traditional Fuel			Non-Traditional Fuel							Petroleum Products								
	Fuelwood	Bagasse	Residue	Hydro	Crude Oil	Gas	Lignite	Coal	Charcoal	Electricity	LPG	Gasoline	Jet Fuel	Kerosene	Diesel	Fuel Oil	Bitumen	Total	Line Total
Gross Supply	10541.2	1205.0	526.9	935.1	8565.4	1401.8	489.5	76.0	—	57.0	375.7	—	75.1	107.2	1149.6	1029.4	—	2737.0	26534.9
Production	10541.2	1205.0	526.9	935.1	763.9	1401.8	489.5	—	—	—	—	—	—	—	—	—	—	—	15863.4
Imports	—	—	—	—	7801.5	—	—	76.0	—	57.0	375.7	—	75.1	107.2	1149.6	1029.4	—	2737.0	10671.5
Conversions:																			
Petroleum Refining	—	—	—	—	(8130.4)	—	—	—	—	—	142.1	1698.3	895.7	385.1	2804.1	2081.5	123.6	8130.4	0.0
Charcoal Production	(2499.6)	—	—	—	—	—	—	—	2499.6	—	—	—	—	—	—	—	—	—	0.0
Elec. Power Generation	—	—	—	(935.1)	—	(1345.5)	(385.7)	—	—	4468.7	—	—	—	—	(37.5)	(1764.9)	—	(1802.4)	0.0
Conversion Losses	(5832.2)	—	—	—	(435.0)	—	—	—	—	(2874.9)	—	—	—	—	—	—	—	—	(9142.1)
Power T & D Losses	—	—	—	—	—	—	—	—	—	221.4)	—	—	—	—	—	—	—	—	(221.4)
Non-Energy Use	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	(123.6)	(123.6)	(123.6)
Statistical Difference	—	—	—	—	—	23.6	—	—	—	2.1	—	3.2	5.2	2.8	90.7	130.1	—	(216.1)	190.4
Final Consumption	2209.4	1205.0	526.9	—	—	32.7	103.8	76.0	2499.6	1427.3	517.8	1701.5	965.6	469.5	4006.9	1476.2	—	9157.5	17238.2
Agriculture	—	—	—	—	—	—	—	—	—	9.8	—	47.4	—	—	385.3	—	—	432.7	442.5
Fishery	—	—	—	—	—	—	—	—	—	—	7.6	—	—	—	673.3	—	—	680.9	680.9
Industry	166.6	1205.0	153.4	—	—	32.7	103.8	76.0	60.4	675.5	70.6	12.5	—	28.9	368.8	1224.2	—	1705.0	4178.4
Transport	—	—	—	—	—	—	—	—	—	8.6	232.1	1557.4	965.6	168.2	2557.7	175.5	—	5656.6	5665.1
Residential	2042.8	—	373.5	—	—	—	—	—	2439.2	353.0	154.5	—	—	292.4	—	—	—	446.9	5655.4
Commercial/Govt.	—	—	—	—	—	—	—	—	—	380.4	53.0	84.2	—	—	21.8	76.5	—	235.5	615.9

Note: Parentheses indicate outflows.

EXTENSION OF THE SIAM2 MODEL

The model is a multisector general equilibrium model which distinguishes 17 types of energy. There are also 27 types of production activities; 11 energy activities and 16 non-energy activities.

The 17 types of energy are:

1. Premium gasoline
2. Regular gasoline
3. Diesel
4. LPG
5. Fuel oil
6. Kerosene
7. Jet fuel
8. Other petroleum products
9. Natural gas
10. Crude oil
11. Condensation
12. Electricity
13. Charcoal
14. Fuelwood
15. Coal and lignite
16. Bagasse
17. Other energy

The model defines 27 types of activities in energy, agriculture, industry, transportation and services, as follows:

1. <u>Energy</u>

1.1 Petroleum refining which produces gasolines, diesel, LPG, fuel oil, kerosene, and other petroleum products.

1.2 Natural gas which produces natural gas and condensate.

1.3 Crude Oil

1.4 Electricity. Five types of electricity generation are distinguished:

- Hydro
- Coal & lignite fired
- Natural gas fired
- Fuel oil fired
- Other methods (e.g. diesel)

1.5 Coal & lignite
1.6 Hydro
1.7 Charcoal
1.8 Fuel Wood
1.9 Paddy husk
1.10 Bagasse
1.11 Other energy

2. Agriculture

   2.1 Rice and paddy
   2.2 Sugar and sugarcane
   2.3 Fishery
   2.4 Other agriculture (other crops, forestry, livestock)

3. Industry

   3.1 Mining and quarrying
   3.2 Food processing
   3.3 Light industry
   3.4 Chemical and rubber products
   3.5 Fertilizer
   3.6 Heavy industry - intermediate products
   3.7 Heavy industry - machineries
   3.8 Construction

4. Transportation

   4.1 Transportation and communication

5. Services

   5.1 Trade
   5.2 Market services
   5.3 Non-market services

The data base used includes the 1982 Input-Output Table, the socio-economic survey (1980/81), labor force surveys, and national income accounts data. The 1982 I-O Table was specially built for this purpose and has disaggregated the energy sector as described above. Although certain parts of the table are simply updated from the 1980 I-O Table, the energy sector sub-component relies on recent surveys on energy use in the various sectors.

Substitution between different types of energy

Four types of substitutions among different types of energy are allowed in the model:

(a) Charcoal, fuelwood, electricity, LPG-already discussed.

(b) Electricity, kerosene - as already discussed.

(c) Natural gas, fuel oil, coal. This is undertaken by adjusting coefficients of the Input-Output table.

(d) Gasoline, diesel, LPG, for transportation. Elasticities of substitution used are:

	Elasticity of Substitution	
	Short Run	Long Run
Gasolines, LPG vs. diesel	0.29	0.48
Gasolines vs. LPG	1.05	3.50
Premium vs. Regular	2.70	2.70

Scenarios

Given 3 scenarios for global energy situation and 3 scenarios for potential hydrocarbon production, the energy demand projections have been prepared for 5 main scenarios. These are:

1. Base Case This is the base case for both global energy situation and potential hydrocarbon production:

   . Potential hydrocarbon production - base case; and

   . All world prices remain constant in real terms at the 1985 level for the entire period 1985-2001. World inflation is assumed to be 6% per year and the exchange rates are assumed to remain at the 1985 levels.

2. Medium Gas, Base Price

   . Potential hydrocarbon production - medium case; and

   . All world prices remain constant in real terms.

3. High Gas, Base Price

   . Potential hydrocarbon production - high case; and

   . All world prices remain constant in real terms.

4. Base Gas, High Price

   . Potential gas production - base case;

   . Price of crude oil, petroleum products and natural gas to rise by 3% per year in real terms from 1986 onwards up to the year 2001.

   . Price of coal to rise by 2% per year in real terms for the period 1986-2001:

. All other world prices remain constant in real terms at the 1985 level; and

. World inflation 6% per year.

5. Base Gas. Low Price

. Potential gas production - base case;

. Price of crude oil, petroleum products and natural gas to fall by 3% per year in real terms from 1986 to the year 2001;

. Price of coal to fall by 2% per year in real terms for the period 1986-2001;

. All other world prices remain constant in real terms at the 1985 level; and

. World inflation 6% per year.

The Base Gas High Price scenario could also be considered as the Low Growth scenario as the higher oil prices have the effect of slowing down the country's economic growth. Similarly, the Base Gas Low Price scenario could be considered as the High Growth scenario.

In all these cases it is assumed that

. Relative prices of different types of petroleum products in the world market remain at the current level;

. The present retail structure of petroleum products is maintained and that domestic oil price level is always adjusted in line with any changes in the world price; and

. The level of imported coal remains at the present level.

Annex 4

THAILAND: ASSUMPTIONS ON GAS AND CONDENSATE PRODUCTIVITY

	Gas	Condensates
	(BCF/well)	(bbl/MMCF)
Union (single completions)		
Erawan	5.0	32.5
Second Contract:		
Baanpot	5.5	50.2
Satun	5.5	18.5
Platong	5.0	40.0
Third Contract		30.0
Texas Pacific (Dual Completions)	13.6	12.0
Esso	38.7	1.0

NATURAL GAS, CONDENSATE AND CRUDE OIL POTENTIAL PRODUCTION CAPABILITIES a/ STILL TO BE CONTRACTED AS OF APRIL 1985

	Off-shore						On-shore (I) b/					On-shore (II) c/			
	Union II		Texas Pacific		Sub-Total (Off-shore)		Esso (Nam Phong)	Shell (Additional "Half-Sirikit)		Sub-Total (On-shore I)		Additional Equivalent Sirikit	Additional Equivalent Esso field	Sub-Total (On-shore II)	
Year	Gas MMCFD	Condensate Bbls/day	Gas MMCFD	Condensate Bbls/day	Gas MMCFD	Condensate Bbls/day	Gas MMCFD	Gas MMCFD	Oil Bbls/day	Gas MMCFD	Oil Bbls/day	Oil Bbls/day	Gas Bbls/day	Oil Bbls/day	Gas MMCFD
1986	-	-	-	-	-	-	20	-	-	20	-	-	-	-	-
1987	-	-	-	-	-	-	40	3	3,050	43	3,050	-	-	-	-
1988	-	-	-	-	-	-	70	9	7,000	79	7,000	-	-	-	-
1989	-	-	-	-	-	-	100	12	9,050	112	9,050	6,000	-	6,000	-
1990	30	900	150	n.a.	180	900	120	14	9,650	134	9,650	14,000	-	14,000	-
1991	70	2,100	150	n.a.	220	2100	150	13	6,700	163	6,700	18,000	-	18,000	-
1992	130	3,900	200	n.a.	330	3,900	200	8	4,000	208	4,000	20,000	-	20,000	-
1993	195	5,800	250	n.a.	445	5,800	200	5	3,550	205	3,550	14,000	-	14,000	-
1994	255	7,600	250	n.a.	505	7,600	200	4	3,150	204	3,150	8,000	-	8,000	-
1995	345	10,300	250	n.a.	595	10,300	200	4	1,950	204	1,950	7,200	-	7,200	-
1996	380	11,400	250	n.a.	630	11,400	200	4	1,050	204	1,050	6,300	50	6,300	50
1997	350	10,500	250	n.a.	600	10,500	200	4	600	204	600	4,000	80	4,000	80

a/ These estimates are production capabilities. Union III includes Funan, Jakrawan, Pakarang & Trat fields. Texas Pacific is the "B" structure.

b/ This includes Esso's Nam Phong field and the "additional half-Sirikit" to oil fields discovered in northcentral Thailand, i.e., West Sirikit, Wat Tan, Pradu Tao, etc. The Bank's Project Report on Sirikit uses "additional full Sirikit" as a base case and projects larger amounts of Sirikit associated gas.

c/ This is based on production capability onshore assuming an additional crude oil field the size of Sirikit is proven and developed, and, in addition, a natural gas field equivalent to /ESSO's (Nam Phong) proven and developed.

Source: "Thailand Natural Gas Reserves and Petroleum Production Forecast," NESDB Supply and Investment Working Group (March, 1985).

PETROLEUM PRODUCT DEMAND, REFINERY PRODUCTION AND IMPORTS, 1970-84
(Barrels/day)

Item	Year	L.P.G.	Gasolines	Diesels (Auto + Indust.)	Kerosene	Jet Fuel	Fuel Oil	Total
Demand	1970	1,500	16,300	37,600	2,200	6,600	24,000	88,200
	1979	6,400	40,700	74,100	5,400	15,000	68,800	210,400
	1980	6,100	38,700	70,800	5,000	16,300	81,400	218,400
	1981	7,800	36,000	69,400	6,700	16,000	71,400	207,300
	1982	10,400	34,700	67,700	6,700	18,600	51,600	189,800
	1983	14,300	35,700	75,800	9,300	19,700	58,000	212,800
	1984	16,500	36,400	90,900	4,900	20,900	54,800	224,400
Refinery Production	1970	1,500	14,100	19,800	2,200	5,400	21,800	64,800
	1979	4,300	36,400	47,800	5,500	13,500	60,100	167,600
	1980	4,000	31,500	48,100	5,000	13,400	43,300	145,300
	1981	4,200	31,400	47,400	6,100	15,900	45,300	150,300
	1982	3,300	34,100	49,100	6,200	16,300	40,800	149,800
	1983	3,900	35,500	52,600	7,400	17,900	37,200	154,500
	1984	4,900 a/	34,600	47,700	4,100	17,600	45,000	153,900 a/
Net Imports	1970	---	2,200	17,800	---	1,200	2,200	23,400
	1979	1,300	3,600	28,200	100	1,800	24,000	59,000
	1980	2,300	8,000	27,200	100	3,100	37,900	78,600
	1981	4,000	4,800	20,300	700	1,400	22,600	53,800
	1982	7,300	300	20,100	1,200	1,800	10,900	41,600
	1983	10,400	---	19,700	2,000	1,900	20,500	54,700
	1984	11,900	1,200	44,800	800	3,600	12,000	74,400
Average Annual Growth Rates of Demand	1970-79	17.5%	10.7%	7.8%	10.5%	9.6%	12.4%	10.1%
	1979-84	20.9%	-2.2%	4.2%	-1.9%	6.9%	-4.5%	1.3%

a/ Includes some 600 bbls/day of production from the LPG separation plant.
Source: "Oil and Thailand, 1983," published by the N.E.A., and 1984 data provided by the NESDB.

Annex 7

SECTORAL CONSUMPTION OF PETROLEUM PRODUCTS, 1971-1983 a/
(Barrels/day)

Product	Year	Agriculture	Manufacturing	Construction	Electricity & Water	Transport	Residental	Commercial Other 2/	Total
LPG	1971	-	-	-	-	-	-	1,600 b/	1,600
	1979	200	1,200	-	-	1,300	3,600	100	6,400
	1982	200	1,300	-	-	3,500	5,100	300	10,400
	1983	200	1,900	-	-	6,400	5,700	100	14,300
Gasoline	1971	-	600	100	100	19,700	-	1,400 b/	21,900
	1979	900	1,00	-	-	36,400	-	2,700	40,700
	1982	1,000	900	-	100	30,800	-	1,900	34,700
	1983	1,000	200	-	-	32,600	-	1,900	35,700
Diesel Oil	1971	13,700	3,800	2,500	2,600	20,400	-	1,500	44,500
	1979	20,000	6,700	1,800	3,300	36,400	-	5,900	74,100
	1982	21,600	4,000	2,000	500	35,700	-	3,900	67,700
	1983	19,900	4,400	1,400	700	47,900	-	1,900	75,800
Fuel Oil	1971	-	17,500	100	11,200	1,100	-	800	30,700
	1979	-	28,300	100	38,400	1,300	-	700	68,800
	1982	-	23,100	200	26,300	1,000	-	1,000	51,600
	1983	600	21,300	200	31,600	3,100	-	1,200	58,000
Kerosene	1971	-	400	-	-	600	-	2,400 b/	3,400
	1979	-	1,100	-	-	-	4,100	200	5,400
	1982	-	800	-	-	100	3,200	2,600 c/	6,700
	1983	-	500	-	-	100	2,900	5,800 c/	9,300

a/ Excludes jet fuel sales which are all allocated to air transport.
b/ Before 1979 sectoral consumption between "residential" and "commercial and others" was not broken down.
c/ This large increase is due in large part to kerosene "leakage" into the transport sector through diesel oil adulteration that is not being picked up in the official data.
Source: "Oil and Thailand, 1983", published by the N.E.A.

Annex 8

OPERATING PERFORMANCE OF THAILAND'S REFINERIES, 1983

Product	TORC		ESSO		Bangchak	
	(bbls/day)	(% yield)	(bbls/day)	(% yield)	(bbls/day)	(% yield)
LPG	1,200	1.7	1,200	2.3	1,500	2.9
Gasolines	18,600	27.2	10,600	20.0	11,100	21.1
Jet Fuel	12,200	17.8	6,200	11.7	2,200	4.2
Kerosene	2,500	3.6	3,300	6.2	2,800	5.3
Auto Diesel	22,700	33.1	19,100	36.3	13,900	26.3
Fuel Oil	8,400	12.3	11,200	21.2	19,500	36.9
Total	65,600	95.7	51,600	97.7	51,000	96.6
Feedstock Run	68,500	100%	52,800	100%	52,900	100%

Source: "Bangchak Oil Refinery Restructuring Project", World Bank Appraisal Report, April 1985.

Annex 9

PRODUCT YIELD AND PRODUCTION IN 1990 FROM THE THREE LOCAL REFINERIES

Product	TORC a/		ESSO b/		Bangchak c/	
	(bbls/day)	(% yield)	(bbls/day)	(% yield)	(bbls/day)	(% yield)
LPG	1,100	1.7	1,500	2.3	1,900	3.0
Gasolines	17,300	27.2	12,700	20.0	12,600	20.4
Kerosene/Jet Fuel	13,600	21.4	11,400	17.9	8,800	14.2
Diesel Oil	21,100	33.1	23,100	36.3	18,400	29.8
Residual Fuel Oil	7,800	12.3	13,500	21.2	17,700	28.6
Total	60,900	95.6	62,200	97.7	59,400	96.0
Feedstock Run	63,700	100%	63,700	100%	61,750	100%

a/ Running similar light crude/feedstocks as in 1983. Throughput taken as 98% of design capacity.

b/ After de-bottlenecking of refinery completed in 1986. Same yield pattern and crude feedstock as in 1983 assumed with the throughput at 98% of design capacity.

c/ BPC rehabilitation assumed completed in 1989. Crude throughputs assumed to be 95% of design capacity with feedstock increasingly light--29% Sirikit crude, 7% condensate, 38% Arab Light, 13% Arab Heavy and 13% Arab Medium crudes.

Source: Mission estimates and World Bank Appraisal Report, April 1985 on "Bangchak Oil Refinery Restructuring Project."

Annex 10

DETERMINATION OF GAS EQUIVALENT VALUES OF ALTERNATIVE FUELS USED AS BASE LOAD IN THE POWER SYSTEM

1. The basic comparison is between base loaded generated power from steam fired units using gas, coal, lignite and fuel oil as fuels as well as combined cycle units fired by gas. The utilization factor is assumed to be 70%, interest rate of 10% with capital costs, construction periods, heat rates, economic lifetimes and estimated annual operations and maintenance costs as indicated in Table 5.16. In the case of lignite fueled generation account is also taken of transmission costs back to Bangkok from Mae Moh (650 kms away) in order to determine the gas equivalent value of lignite in power generation.

2. When the above factors are taken into account the following gas equivalent values are obtained for the competing fuels based on current prices of alternative fuels. These gas equivalent values are the break-even prices for gas use in steam or combined cycle units at which total power generation costs from the alternative fuels (coal, lignite and fuel oil) are equal.

Fuel	Mode of Use in Power System	Fuel Price	Gas Equivalent Value 1985 US$/MMBTU
Coal	Steam Unit	US$55/ton c.i.f. Bangkok (US$2.08/MMBTU)	3.14 a/
Fuel oil	Steam Unit	US$22/bbl (US$3.49/MMBTU)	3.49 a/
Lignite	Steam Unit at Mae Moh Power Transmitted to Bangkok	US$20/ton (US$1.86/MMBTU)	3.23 a/
Coal	Steam Unit	US$55/ton c.i.f. Bangkok (US$2.08/MMBTU)	4.37 b/

a/ This is the gas equivalent value for gas used in an equivalent size steam power generating unit.

b/ This is the gas equivalent value for gas used in an equivalent sized combined cycle unit.

SUPPORT ACTIVITIES FOR FUELWOOD PROGRAM

Program Activities

(a) Creation of a network of small-scale (village-level) tree nurseries in the rural areas, initially covering those parts of Thailand where deforestation is becoming severe. The activity must explore maximum involvement of private farmers, schools and NGO's in operating the nurseries, with RFD providing technical advice. A possible approach, for example, is for government to offer a guaranteed price to the participant for repurchasing and distributing seedlings for local planting schemes in the poorer rural areas.

(b) Establishment by RFD of an effective system of tree seed collection spread throughout the rural areas, with strong emphasis on faster growing indigenous trees that farmers perceive as having multiple benefits and on the introduction of selected fast growing fuelwood species, particularly those that have the potential for sustaining high branch-wood volume via pollarding or coppicing techniques (e.g., specieis of Leuceana, Azadirachta, Melia, Cassia, Eucalyptus, Melaleucae, and Acacia.

(c) Introduction of low cost tree seedling and tree seed distribution techniques (e.g., in areas of reasonably reliable rainfall or where trees are being planted on irrigated lands, a shift away from polythene pots to either the "basket" technique 1/ or, where appropriate, distribution of tree seeds for direct sowing on a farmer's holding).

(d) Continuation and expansion of the program of village woodlot planting already started by RFD with emphasis on their demonstration effect, particularly in relation to maximum biomass productivity techniques such as closer space and fertilizer application.

(e) A mass-media promotional campaign aimed at encouraging small farmers throughout the rural areas to augment the existing supply of trees maintained around homesteads by the planting of additional fast growing species on patches of wasteland unsuitable for agriculture or along farm boundaries.

1/ Growing of seedlings in shallow earth baskets from which they can be directly transplanted into a farmer's land or into a village woodlot (see Gujarat, India experience).

(f) Promotion of private sector investment in energy plantation tree farming aimed at, on the one hand, small scale 5 ha 30 RAI tree farms and, on the other, larger scale private sector energy tree plantations sited close to main fuelwood/charcoal markets, particularly urban centers.

(g) Encouragement of larger wood-based industries (pulp and paper, particle board, sawmilling, etc.) which also consume wood-based energy, to enter into long term marketing contracts with farmers and other agencies situated within an economic radius of such plants for supplying part of their future wood raw material needs.

(h) Preparation and publication by RFD/MOA/NEA of economic studies relating to wood-based energy products, e.g., alternative marketing arrangements for fuelwood and charcoal that would ensure a fair price to both tree growers and consumers; costs and benefits of various approaches to plantation establishment; harvesting and transport costing, etc.

Research Activities

(a) Strengthening of agro-forestry/fuelwood research, particularly in the area of improving the genetic and biological productivity of gas growing multi-purpose species.

(b) Extension of the household energy consumption surveys such as those already carried out by NEA with assistance from RFD. The surveys should be periodically updated and extended to other parts of the country. They should provide the starting point for assessing the appropriate size of reforestation programs and other basic project design considerations such as choice of appropriate species.

(c) Intensification of current NEA-RFD efforts for the development, field-testing and large-scale dissemination of improved charcoal kilns and cooking stoves. A study of the most appropriate mass production and marketing approaches must be conducted.

(d) Study of the fuelwood substitution potential of agricultural residues, especially rice hulls and bagasse. The study must assess, inter alia, the possibility for wider usage of rice hull fired stoves; the technical and financial requirements for producing excess bagasse from the sugar industry; approaches to resolving technical and social acceptance problems associated with the use of densified crop residues in rural industries and households.

Institutional Strengthening Activities

(a) A vigorous training program for RFD and the Department of Agriculture Extension (DOAE) staff. RFD should provide technical Subject Matter Specialist support to DOAE, who would be the main direct contact point with small farmers. RFD's own extension staff should provide the main technical support to larger tree farmers and private companies.

(b) Implementation of already existing proposals for making significant changes in the curricula of forestry training establishments such as Kasetsart University to place stronger emphasis on Social Forestry.

(c) Strengthening of technical support by RFD to credit institutions, such as BAAC, which could play a role in providing credit for energy plantation tree farming.

Table 1: RATE OF DEFORESTATION, 1961-1982 a/
Area of Forest by Region

Region	Total Land Area	1961	%	Forest Area 1973	%	1976	%	1978	%	1982	%
North	169,644	120,388	20.96	113,595	66.96	102,327	60.32	94,937	55.96	87,756	51.73
Northeast	168,854	71,199	42.17	50,671	10.01	41,494	24.57	31,221	18.49	25,886	15.33
Central	103,901	56,006	53.90	39,006	37.54	34,457	33.16	31,463	30.28	26,516	25.52
South	70,715	26,035	16.82	18,435	26.07	20,139	28.48	17,603	24.89	16,442	23.25
Total	513,115	273,628	53.33	221,707	43.21	198,417	38.67	175,224	34.15	156,600	30.52

a/ Based on recent Remote Sensing (LANDSAT) and Serial Survey Comparisons.

Source: RPD Statistics, 1982.

Table 2: INDIVIDUAL WOODLOT
I ha Model (Eucalyptus Camaldrensia)
Physical Analysis

Fuelwood Production	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
I. Investment																	
1. Tools																	
2. Seedling (pcs)	3,250																
3. Labor for preparation (MD)		53															
4. Fertilizer (MD)		2															
5. Fertilizer (kg) 15-15-15	325 kg																
6. Planting	17																
7. Supplementary plant (MD)	5																
II. Maintenance																	
1. Fire control and etc. (MD)		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
2. Weeding (MD)		26	26				26					26					26
III. Production																	
1. Logging (MD)							100					100					100
2. Production m^3							150					150					150

Other Assumptions

Rotation: 5 yrs (harvest at 6th yr)
Average Yield: 30 m^3/ha/yr
Discount Rate: 12%

Table 3: FINANCIAL ANALYSIS
Individual Woodlot
1 ha Model (Eucalyptus Camaldrenais)

Fuelwood Production	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
I. Initial expenses																	
1. Seedlings	4875	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
2. Labor for Land Prep		2385	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
3. Fertilizer		1950	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
4. Labor for Fertilizer App		90	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
5. Labor for Planting		765	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
6. Labor for Suppl. Planting		225	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
II. Maintenance																	
7. Labor for Fire Control		360	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360
8. Labor for Weeding		1170	1170	--	--	--	1170	--	--	--	--	1170	--	--	--	--	1170
III. Production																	
9. Labor for Logging		--	--	--	--	--	4500	--	--	--	--	4500	--	--	--	--	4500
Total Expenses		6945	1530	360	360	360	6030	360	360	360	360	6030	360	360	360	360	6030
Revenues		--	--	--	--	--	34500	--	--	--	--	34500	--	--	--	--	34500
Net Cash Flow		-6945	-1530	-360	-360	-360	28470	-360	-360	-360	-360	28470	-360	-360	-360	-360	28470

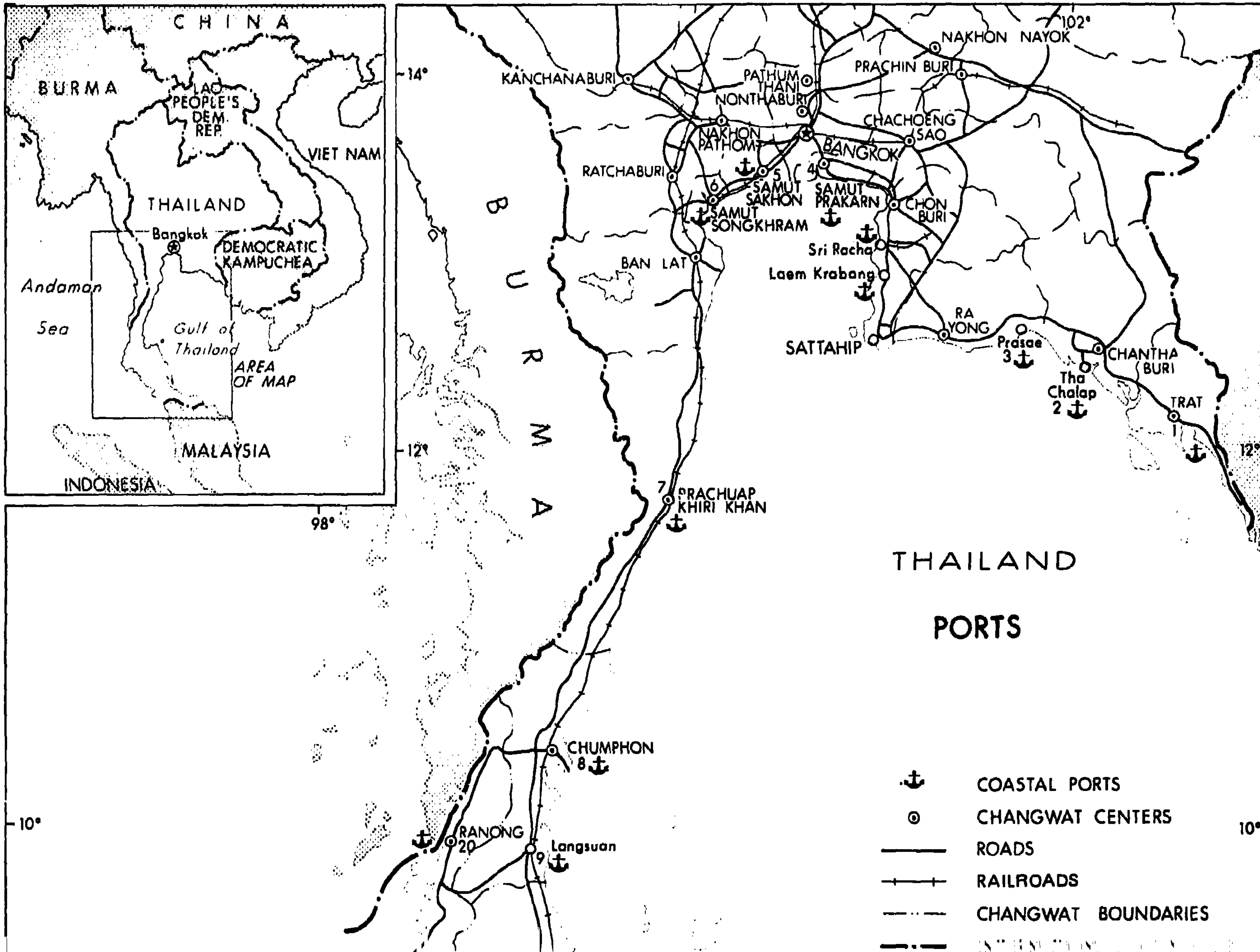
FINANCIAL RATE OF RETURN 23%

Table 4: ECONOMIC ANALYSIS

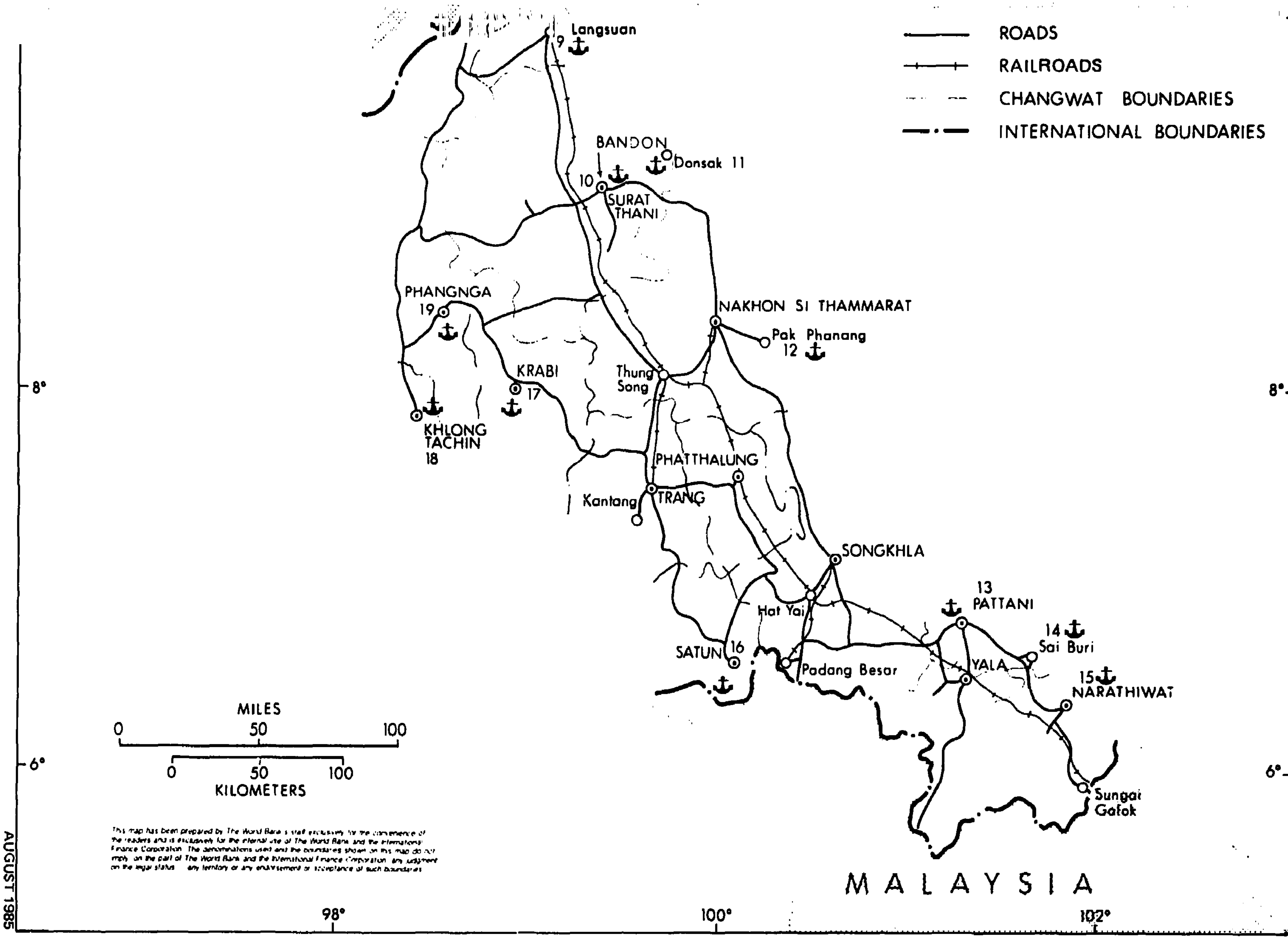
Fuelwood Production	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
I. INITIAL EXPENSES																	
1. Seedlings	3413	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
2. Labor for Land Prep.		1479	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
3. Fertilizer		1365	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
4. Labor for Fertilizer App		56	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
5. Labor for Planting		474	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
6. Labor for Suppl. Planting		140	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
II. MAINTENANCE																	
7. Labor for Fire Control		223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223
8. Labor for Weeding		725	725	--	--	--	725	--	--	--	--	725	--	--	--	--	725
III. PRODUCTION																	
9. Labor for Logging		--	--	--	--	--	2790	--	--	--	--	2790	--	--	--	--	2790
IV. OTHERS																	
10. Land Rental		130	130	130	130	130	130	130	130	130	130	130	130	130	130	353	130
TOTAL EXPENSES		4592	1079	353	353	353	3869	353	353	353	353	3869	353	353	353	353	3869
REVENUES		--	--	--	--	--	27600	--	--	--	--	27600	--	--	--	--	27600
NET CASH FLOW		-4595	-1079	-353	--	-353	23731	-353	-353	-353	-353	23731	-353	-353	-353	--	23731

ECONOMIC RATE OF RETURN 26% a/

a/ At land rental = 500B, IRR = 23%; at 1000B, IRR = 20%.



THAILAND
PORTS
CHINA
BURMA
LAO PEOPLE'S DEM. REP.
VIET NAM
THAILAND
Bangkok
DEMOCRATIC KAMPUCHEA
Andaman Sea
Gulf of Thailand
AREA OF MAP
MALAYSIA
INDONESIA
98°
102°
14°
12°
10°
BURMA
NAKHON NAYOK
PRACHIN BURI
KANCHANABURI
PATHUM THANI
NONTHABURI
CHACHOENG SAO
NAKHON PATHOM
BANGKOK
RATCHABURI
SAMUT SAKHON
SAMUT PRAKARN
CHON BURI
SAMUT SONGKHRAM
Sri Racha
Laem Krabang
BAN LAT
RA YONG
SATTAHIP
Prasae
Tha Chalap
CHANTHA BURI
TRAT
PRACHUAP KHIRI KHAN
CHUMPHON
RANONG
Langsuan
COASTAL PORTS
CHANGWAT CENTERS
ROADS
RAILROADS
CHANGWAT BOUNDARIES



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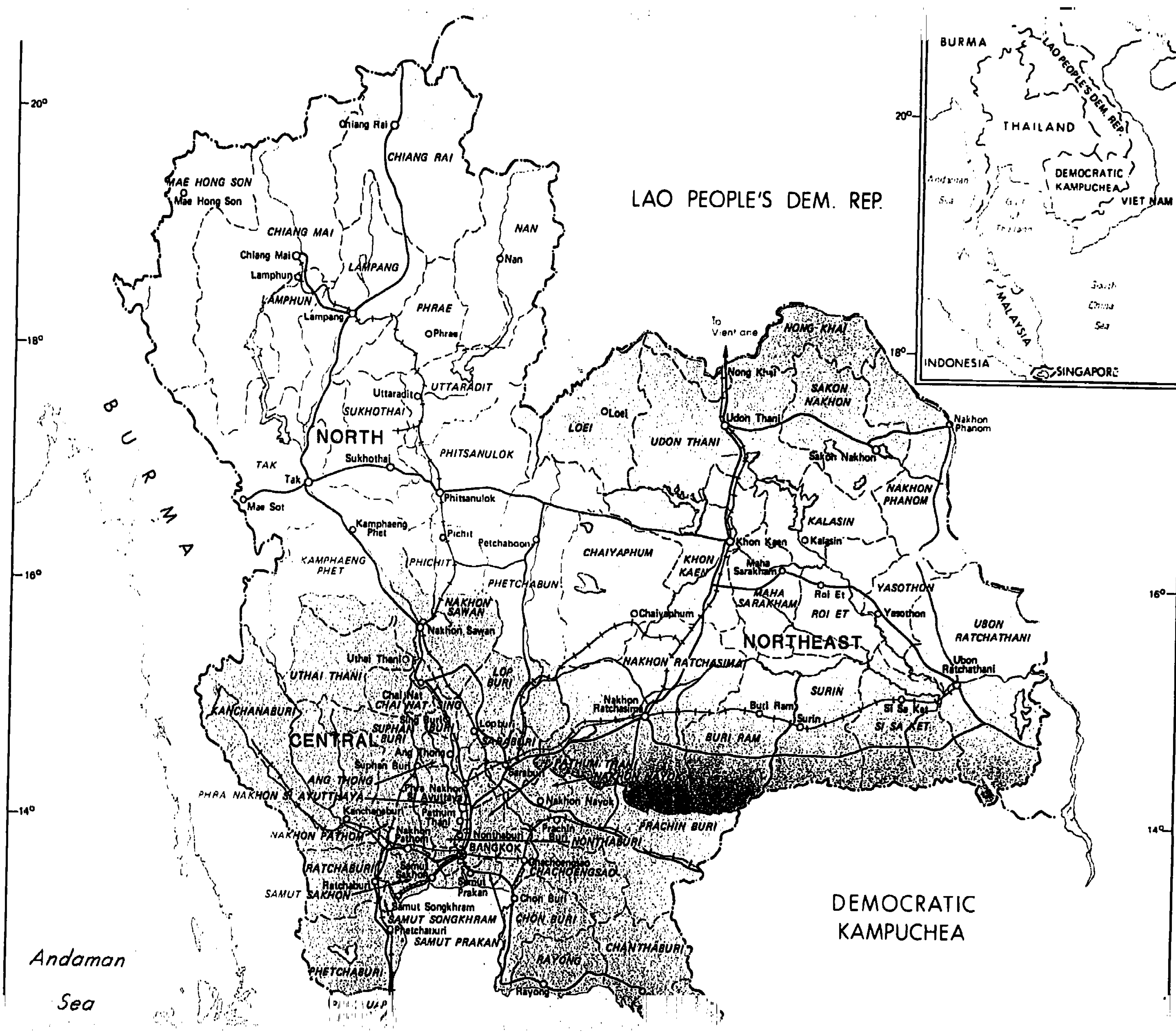
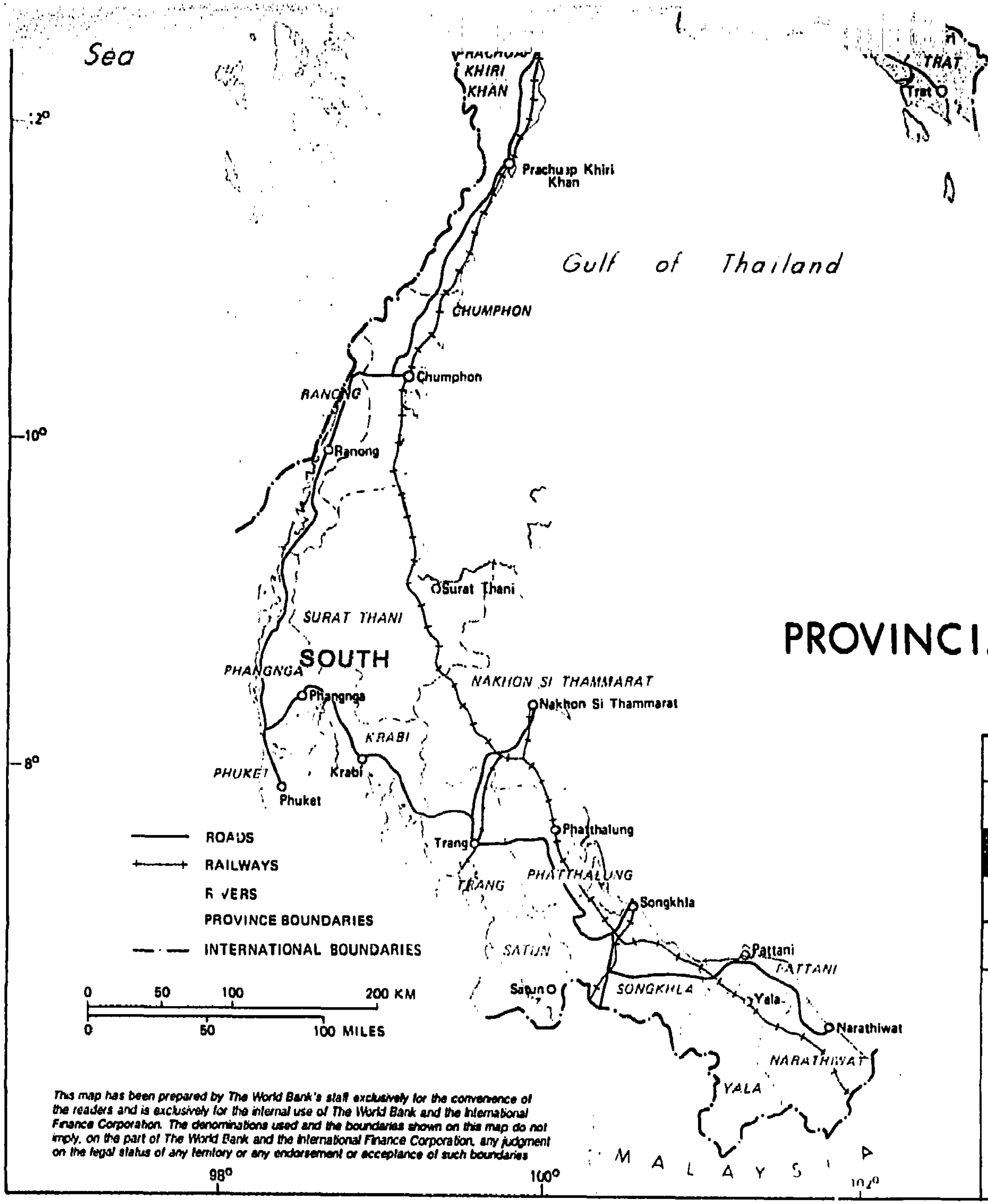


LAO PEOPLE'S DEM. REP.
BURMA
DEMOCRATIC KAMPUCHEA
Andaman Sea
NORTH
NORTHEAST
CENTRAL
MAE HONG SON
Mae Hong Son
CHIANG RAI
Chiang Rai
CHIANG MAI
Chiang Mai
Lamphun
LAMPHUN
LAMPANG
Lampang
NAN
Nan
PHRAE
Phrae
UTTARADIT
Uttaradit
SUKHOTHAI
Sukhothai
PHITSANULOK
Phitsanulok
TAK
Tak
Mae Sot
Kamphaeng Phet
KAMPHAENG PHET
Pichit
PHICHIT
Petchaboon
PHETCHABUN
NAKHON SAWAN
Nakhon Sawan
Uthai Thani
UTHAI THANI
LOP BURI
Lopburi
Chai Nat
KANCHANABURI
Kanchanaburi
SARABURI
Saraburi
ANG THONG
Ang Thong
Suphan Buri
PHRA NAKHON SI AYUTTHAYA
Phra Nakhon Si Ayutthaya
Pathum Thani
PATHUM THANI
NAKHON NAYOK
Nakhon Nayok
NAKHON PATHOM
Nakhon Pathom
Nonthaburi
NONTHABURI
BANGKOK
Prachin Buri
PRACHIN BURI
RATCHABURI
Ratchaburi
Samut Sakhon
SAMUT SAKHON
Samut Prakan
SAMUT PRAKAN
Samut Songkhram
SAMUT SONGKHRAM
Chachoengsao
CHACHOENGSAO
Chon Buri
CHON BURI
Phetchaburi
PHETCHABURI
RAYONG
Rayong
CHANTHABURI
To Vientiane
NONG KHAI
Nong Khai
LOEI
Loei
UDON THANI
Udon Thani
SAKON NAKHON
Sakon Nakhon
Nakhon Phanom
NAKHON PHANOM
KALASIN
Kalasin
Khon Kaen
KHON KAEN
CHAIYAPHUM
Chaiyaphum
Maha Sarakham
MAHA SARAKHAM
Roi Et
ROI ET
YASOTHON
Yasothon
UBON RATCHATHANI
Ubon Ratchathani
NAKHON RATCHASIMA
Nakhon Ratchasima
SURIN
Surin
BURI RAM
Buri Ram
Si Sa Ket
SI SA KET
20°
18°
16°
14°
BURMA
LAO PEOPLE'S DEM. REP.
THAILAND
DEMOCRATIC KAMPUCHEA
VIET NAM
MALAYSIA
INDONESIA
SINGAPORE
South China Sea



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THAILAND
PROVINCIAL ELECTRICITY AUTHORITY

REGION	VILLAGES WITH ELECTRICITY (END 1981)	VILLAGES TO BE ELECTRIFIED (1982–1986)
NORTH	6,245	3,825
[illegible]	6,072	6,296
CENTRAL	6,406	2,609
SOUTH	3,898	4,918
VILLAGES TO BE ELECTRIFIED UNDER THE NREP		5,500
TOTALS	22,621	23,148

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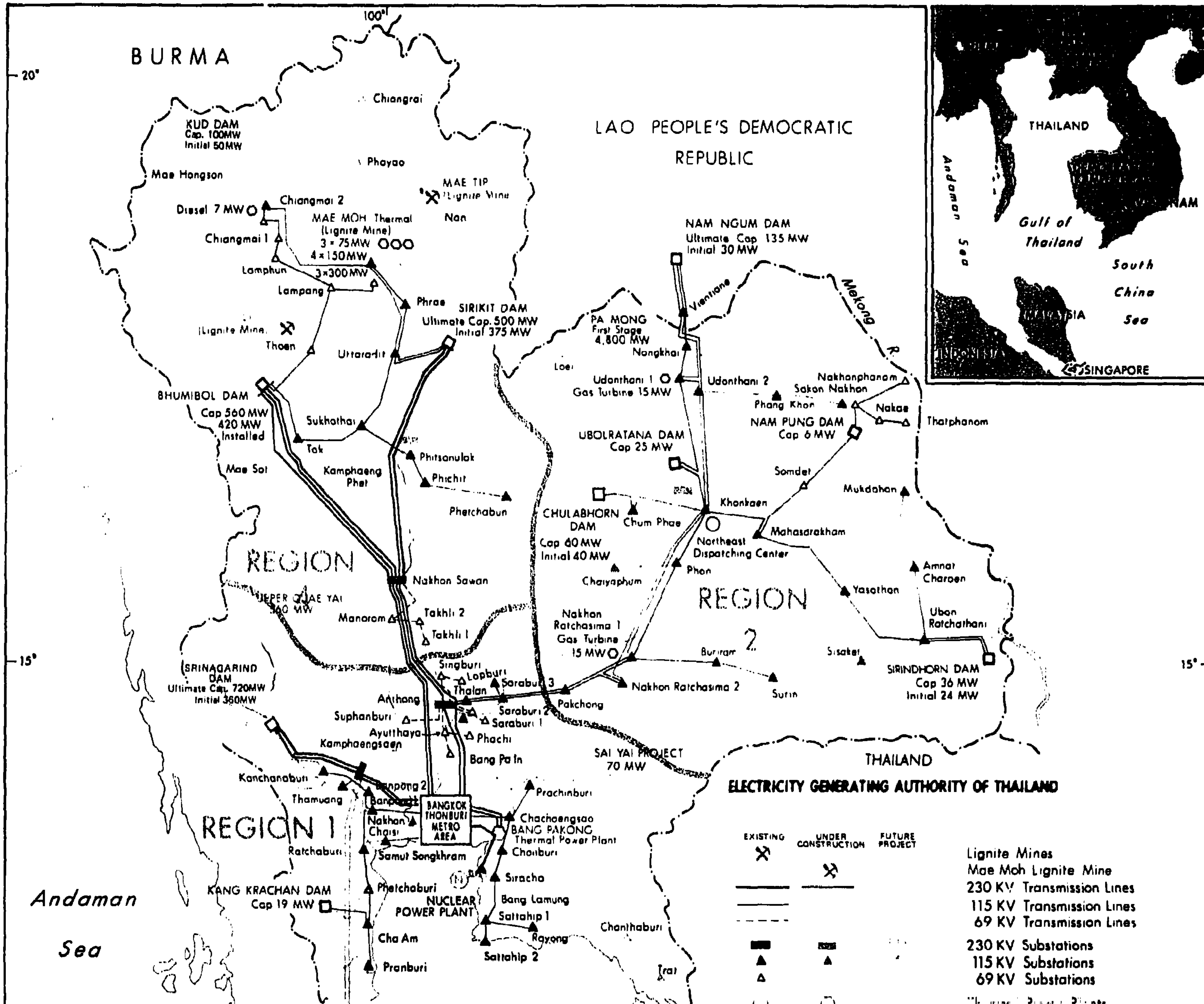
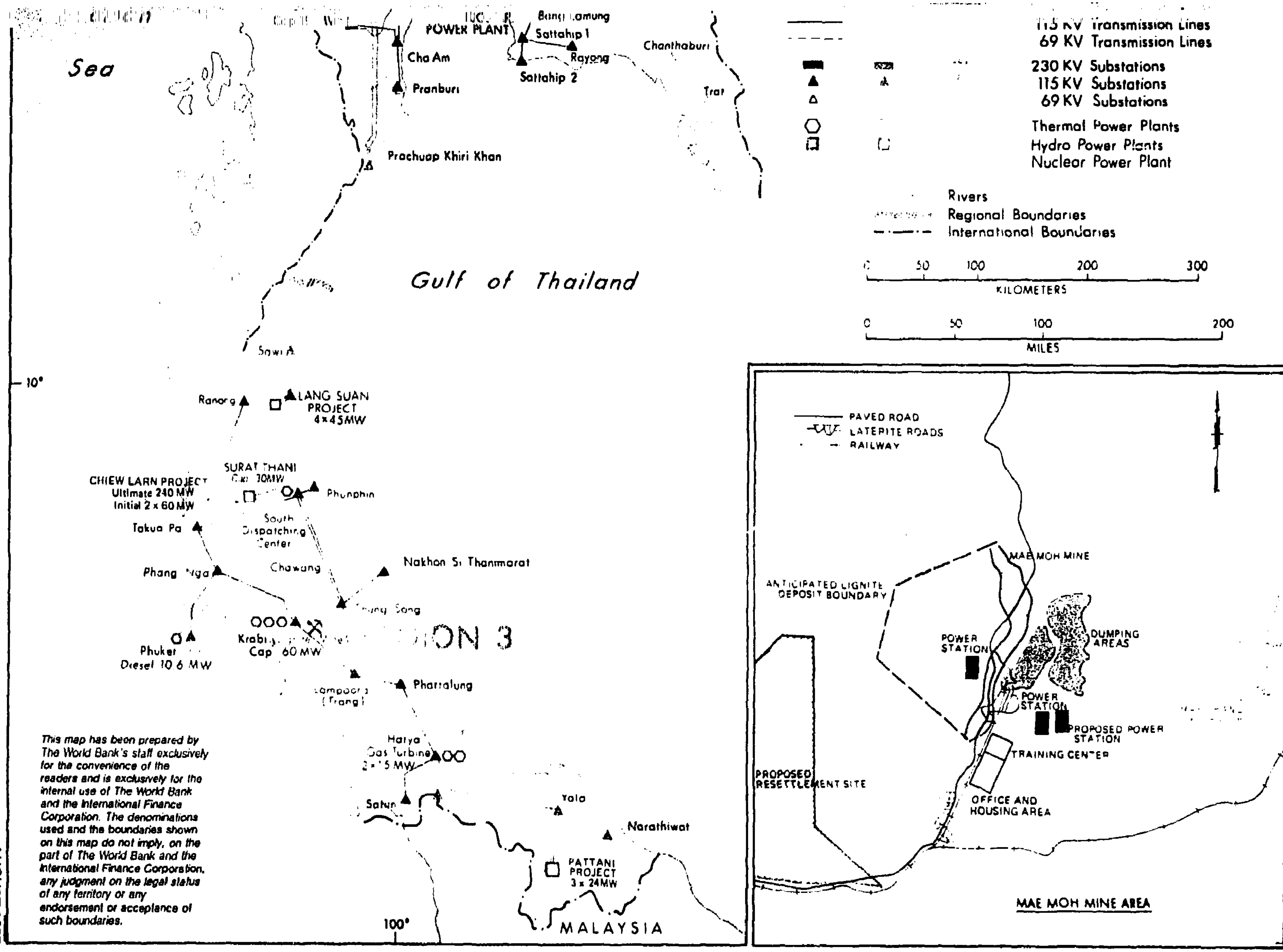

BURMA
LAO PEOPLE'S DEMOCRATIC REPUBLIC
THAILAND
Andaman Sea
Gulf of Thailand
South China Sea
MALAYSIA
INDONESIA
SINGAPORE
Andaman Sea
100°
20°
15°
Chiangrai
KUD DAM
Cap. 100MW
Initial 50MW
Mae Hongson
Phayao
MAE TIP
Nan
Chiangmai 2
Diesel 7 MW
Chiangmai 1
MAE MOH Thermal
(Lignite Mine)
3 × 75MW
4 × 150MW
3×300MW
Lamphun
Lampang
Phrae
SIRIKIT DAM
Ultimate Cap. 500 MW
Initial 375 MW
(Lignite Mine)
Thoen
Uttaradit
BHUMIBOL DAM
Cap 560 MW
420 MW
Installed
Sukhothai
Tak
Phitsanulok
Mae Sot
Kamphaeng Phet
Phichit
Phetchabun
REGION 4
Nakhon Sawan
UPPER QUAE YAI
Manorom
Takhli 2
Takhli 1
SRINAGARIND DAM
Ultimate Cap. 720MW
Initial 360MW
Singburi
Lopburi
Saraburi 3
Angthong
Thalan
Suphanburi
Saraburi 2
Saraburi 1
Ayutthaya
Phachi
Kamphaengsaen
Bang Pa In
Kanchanaburi
Banpong 2
Thamuang
Banpong 1
BANGKOK THONBURI METRO AREA
REGION 1
Nakhon Chaisi
Ratchaburi
Samut Songkhram
KANG KRACHAN DAM
Cap 19 MW
Phetchaburi
NUCLEAR POWER PLANT
Cha Am
Pranburi
Prachinburi
Chachoengsao
BANG PAKONG
Thermal Power Plant
Chonburi
Siracha
Bang Lamung
Sattahip 1
Rayong
Sattahip 2
Chanthaburi
Trat
Pakchong
SAI YAI PROJECT
70 MW
NAM NGUM DAM
Ultimate Cap 135 MW
Initial 30 MW
Vientiane
Mekong R.
PA MONG
First Stage
4,800 MW
Nongkhai
Loei
Udonthani 1
Gas Turbine 15 MW
Udonthani 2
Nakhonphanom
Sakon Nakhon
Phang Khon
Nakae
Thatphanom
NAM PUNG DAM
Cap 6 MW
UBOLRATANA DAM
Cap 25 MW
Somdet
Mukdahan
Khonkaen
CHULABHORN DAM
Cap 60 MW
Initial 40 MW
Chum Phae
Northeast Dispatching Center
Mahasarakham
Phon
Chaiyaphum
Amnat Charoen
REGION 2
Yasothan
Nakhon Ratchasima 1
Gas Turbine
15 MW
Buriram
Ubon Ratchathani
Sisaket
SIRINDHORN DAM
Cap 36 MW
Initial 24 MW
Nakhon Ratchasima 2
Surin
ELECTRICITY GENERATING AUTHORITY OF THAILAND
EXISTING
UNDER CONSTRUCTION
FUTURE PROJECT
Lignite Mines
Mae Moh Lignite Mine
230 KV Transmission Lines
115 KV Transmission Lines
69 KV Transmission Lines
230 KV Substations
115 KV Substations
69 KV Substations



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